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-2021-0312
Date Testimony Prepared:	November 17, 2021

BEFORE THE PUBLIC SERVICE
COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	**)**	**File No. ER-2021-0312**

Direct Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

November 17, 2021

Protecting Your Bottom Line

KM ENERGY CONSULTING, LLC

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	))))	Case No. ER-2021-0312

STATE OF WISCONSIN	)	
	)	SS
COUNTY OF WAUKESHA	)	

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 their 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-2021-0312

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 The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	))))))))	**File No. ER-2021-0312**

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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, 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 a corporation representing the interests of large commercial and industrial customers including those taking service from Empire District Electric Company, A Liberty Utilities Company ("Empire" or "Company") on its Large Power / SC-P / GP rate schedules.[1]

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 General Power (GP), Large Power (LP) and TS 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: GP/LP and TS Rate Design

[1] In its direct testimony and tariffs Empire proposed to change the name of the SC-P rate class to Transmission Service (TS) rate class. In this testimony I will use the Company's new designation (TS) for this rate class. I simply mention the previous identifier (SC-P) so that the reader can properly compare results from this case to previous cases.

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 Empire 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 the 2014 Empire case.

c) Empire's average industrial rates are over 22% higher than the state, regional and national averages respectively.

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) Empire's load profile characteristics indicate that it is a summer and winter peaking utility. For Empire, the peak months during the summer and winter that are within 10% of the system peak should be used to derive the allocators for fixed production plant-related costs. Looking at the Company's load profile there are 5 months that are within 10% of the system peak;

c) Either the coincident peak method or the A&E method are reasonable allocation methods for fixed production plant-related costs;

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, Empire and the other Missouri electric utilities utilize this approach. The reasonableness of the A&E approach is also demonstrated by comparing to other objective methodologies recognized in the NARUC cost allocation manual. Therefore, I recommend the A&E 5NCP allocator for allocating fixed production plant-related costs to customer classes;

e) While the magnitude varies, the results of my COSS are directionally consistent with that of the Company and confirm that at present rates, the residential and some lighting classes are paying rates that are substantially below cost responsibility. All other classes are paying rates 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 and certain classes continue to be chronically subsidized by other classes.

b) The Company's proposed revenue allocation approach is problematic and completely ignores its COSS results. Specifically, the Company's revenue allocation would provide (a) below average rate increases to classes that are paying rates that are below cost and (b) above average rate increases to classes that are already paying rates that are above cost.

c) Empire has indicated its intent to remove the Winter Storm Uri costs from this case through securitization. This has the effect of mitigating rate impacts compared to the current proposal. Furthermore, Staff's revised revenue requirement increase is just over half of the Company's proposed increase of 7.6%. Therefore, it is reasonable to take meaningful steps towards cost based rates in this case. The Commission ordered 25% positive revenue neutral adjustments to the residential class in the 2014 case and similar amounts again in the 2016 case in order to eliminate subsidies and get class revenues closer to cost. I recommend a similar approach in this case.

Section VI: Large Power / TS Rate Design

The Company proposed to increase the summer and winter tail block energy charges for LP rates by 56% and 38% respectively. Such a proposal is highly unreasonable considering that the base FAC factor is proposed to reduce by nearly 57%.

In order to eliminate intra-class subsidies, it is important that any rate design recover variable costs through energy charges and fixed costs through non-variable components of the rates such as demand charges. Given the sharp decline in variable costs (i.e., the base FAC factor), I recommend that any revenue requirement increase to the GP, LP and TS classes be recovered through increases in the demand charges.

III. IMPORTANCE OF COMPETITIVE INDUSTRIAL RATES

Q. HOW ARE THE COMPANIES REPRESENTED BY MECG IMPACTED BY THIS PROCEEDING?

A. This proceeding is of particular importance to MECG companies served under the TS and LP rate schedules because Empire is asking customers in these classes to pay much more than the Company's own COSS indicates they should – the proposed increase for the LP class is 7.2% and TS class is 7.6%. Recognizing that Empire recommends a system average increase of 7.6%, Empire is essentially proposing that all classes receive the same increase. However, the Company's own class cost of service shows that the LP and TS classes should get decreases of 3.5% and 10.3% respectively. Therefore, MECG's members served by Empire, whose rates are already substantially higher than state, regional and national averages, will be significantly impacted by the outcome of this proceeding.

Q. WHY ARE COMPETITIVE INDUSTRIAL RATES IMPORTANT?

A. I am advised that many of the companies served by Empire under the LP and TS rates operate energy intensive facilities and are therefore sensitive to energy cost increases, which affect their overall cost of doing business. Thus, energy affordability affects the competitiveness, output and potential employment levels for these companies. 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 particularly those businesses with facilities in many locations throughout North America, competitive rates are often central to a manufacturer's 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 EMPIRE CLASSES?

A. Yes. Not only do large companies provide jobs in the Empire 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 the 2014 Empire 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.[2]

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.

[2] Report and Order, Case No. ER-2014-0351, issued June 24, 2015, page 18.

Q. WHAT DOES MORE RECENT EEI DATA SHOW ABOUT THE COMPETITIVENESS OF EMPIRE'S INDUSTRIAL RATES?

A. The recent data shows that the Company's average industrial rates are not competitive. Based upon data from EEI's most recent publication that includes Empire's rates, the Company's average industrial rate is over 22% higher than the state, regional and national averages respectively.[3] [4] Figure 1 (a) shows this comparison.

Figure 1 (a): Average Industrial Rate Comparisons for 2020

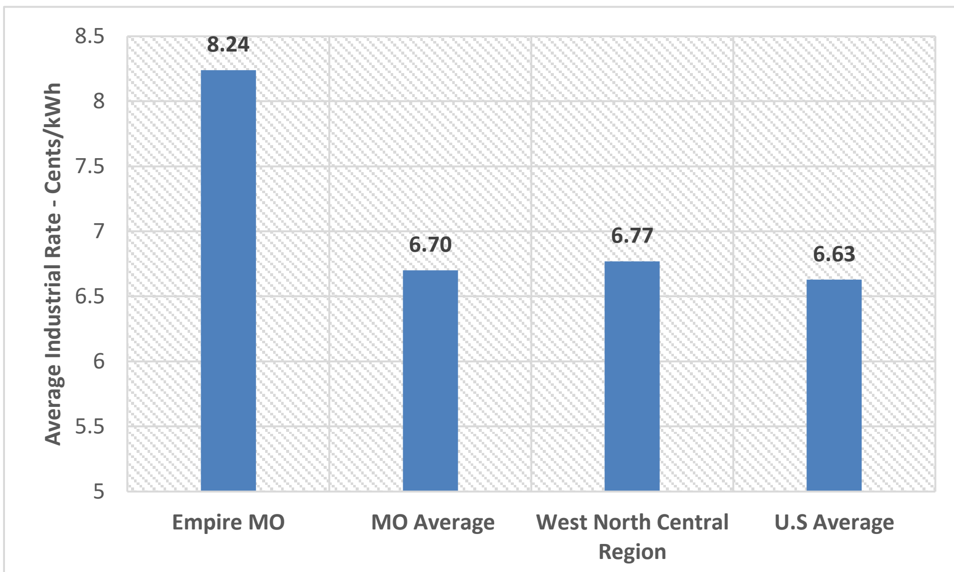


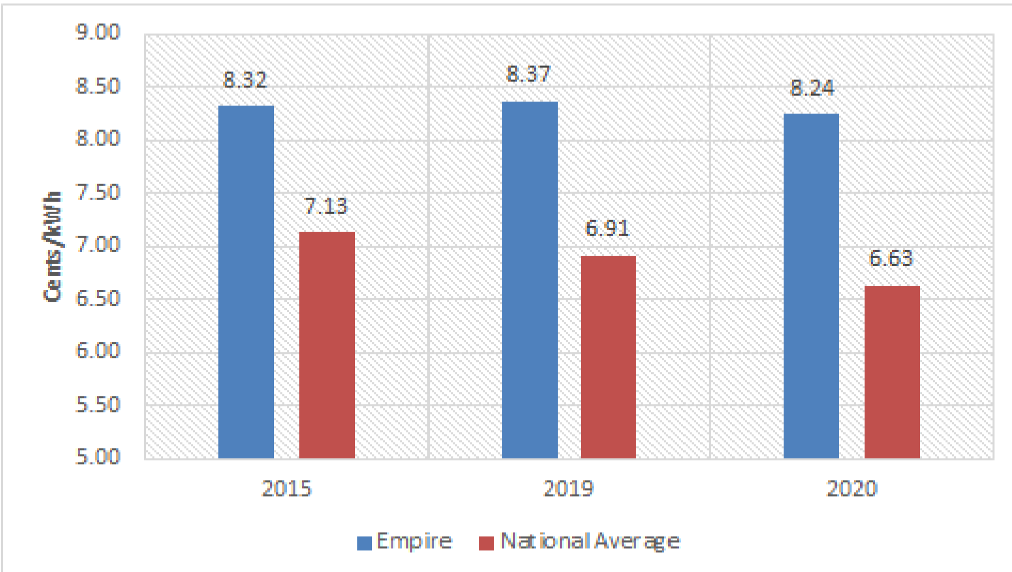
Figure 1 (b) shows the comparison of Empire's average industrial rates compared to the national average for 2015, 2019 and 2020 respectively. These years were chosen for roughly the same time period as the rate cases. This data shows that from a relative standpoint, the Company's average industrial rate in Missouri is continuing to

[3] EEI Typical Bills and Average Rate Report, Summer 2020.

[4] The EEI average rate comparison is also used by customers to evaluate and benchmark utility costs within the state, regionally and nationally. For example, see Mr. Steve Chriss' surrebuttal testimony in the Company's last rate case, docket ER-2019-0374.

decline in competitiveness. In 2015, the average industrial rate was approximately 17% above the national average, in 2019 Empire's industrial rate was 21% above the national average and in 2020 it is 24% above the national average.

Figure 1 (b): Average Industrial Rates: Empire Missouri vs. National Average



IV. 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 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 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.

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, as is the case in this proceeding, 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 lesser billing determinants. On the other hand, for classes where rates are set at artificially low levels, such as Empire's residential class, then the rates are not sending the price signal that those customers should engage in energy efficiency measures.

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 implying that building generation 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 Analysis

Q. DID YOU USE THE COMPANY SPONSORED COSS MODEL AS A STARTING POINT FOR YOUR ANALYSIS?

A. Yes, however, as discussed below, I used a revised allocator for allocating fixed production plant-related costs in the Company's COSS. Similarly, I correct the Company's methodology for allocating interruptible credit-related costs to each class. I discuss each of these issues in detail below.

1. Fixed Production Plant Allocation

Q. WHAT ARE FIXED PRODUCTION PLANT-RELATED COSTS?

A. Fixed production plant-related costs are costs that are functionalized as generation related and incurred in acquiring or procuring generation resources. In order to fulfill mandatory resource adequacy requirements, 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 investment in power plants, but do not include the variable cost (i.e., 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.

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

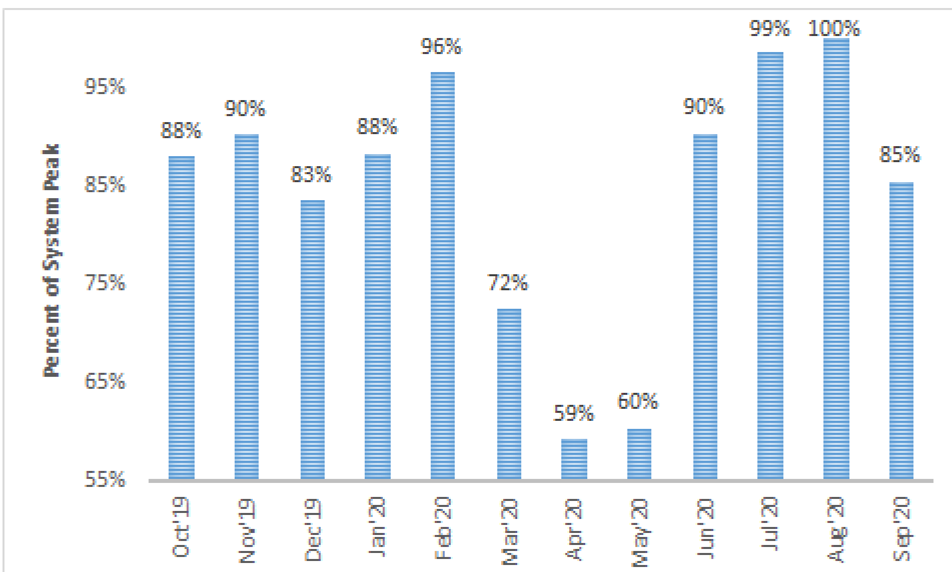
A. Since a utility needs to ensure that it has sufficient generation capacity to reliably meet its peak load requirements, the most important factor is the annual load pattern of the utility and the annual system peak. As Evergy witness Ives recently recognized, "Our system, as you are aware, is built to peak demand and load. So that means other than that design peak every other hour on the system is underutilized to some degree."[5] 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 then each class' contribution to the summer peaks is an appropriate cost causative allocator. If a utility is summer and winter peaking, like Empire, then the allocation method must consider the class demands imposed during those seasonal peaks. For a utility with non-seasonal load patterns or a high load factor, demands in all months and related class contributions may be relevant.

[5] Case No. ET-2021-0151, Transcript page 268.

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

A. Yes, I did. Similar to findings in the last case, the Company's Missouri retail system load shows that both a summer and winter peak exists for Empire.[6] Figure 2 shows the system monthly peaks as a percent of overall system peak for the test year. This chart shows that the system peaked in the summer in August (followed closely by July) with the winter peak in February at 96% of the annual system peak. 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.

Figure 2: Empire Missouri's Monthly Peak Demands As a Percent of Annual Peak [7]



As can be observed in Figure 2:

- The monthly peaks in February and July are within 5% of the system peak in August; and

[6] See Kavita Maini Direct Testimony in docket ER-2019-0374

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

- In addition to February and July, June and November peaks are within 10% of the system peak.

The class contributions to the aforementioned predominant 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.

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. In the case of Empire, class contributions coincident with the summer and winter peaks are appropriate because of the dual peaking nature of its load. In this regard, the average of the class contributions for February, July and August (i.e., 3 coincident peaks or CP) or February, June, July, August and November (i.e, 5 CP) are reasonable as the system demands in these months are within 5% to 10% of the system peak.

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.[8] 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 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:

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

> 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 COINCIDENT PEAK 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. As I indicated earlier, in terms of developing the allocator, either using the class coincident peaks during the highest peak months within 5% (3 months) to 10% (5 months) for either the coincident peak or for the A&E method would be reasonable approaches.

Q. WHICH ALLOCATION METHOD DO YOU RECOMMEND IN THIS CASE?

A. Like Empire and all of the Missouri utilities, I recommend the A&E demand method. While Empire considered 12 non-coincident peaks in this case, I rely on the non-coincident peaks experienced during three summer months (June through August) and two winter months (November and February) ("A&E 5NCP").[9]

[9] In the last rate case, I used the same "within 10% of the system peak" criteria. At that time the Company load profile showed that there were 6 months which fell within 10% of the annual system peak. Consequently, I used the 6NCP variation of the A&E approach. As reflected in Figure 2 *supra*, Empire's load profile has changed and now only 5 peaks meet the same 10% of the system peak criteria. For this reason, while I used consistent criteria in both cases, the variation in this case has gone from a 6NCP to a 5NCP approach.

Q. PLEASE EXPLAIN HOW YOU DERIVED THE A&E 5NCP ALLOCATOR.

A. Figure 3 shows the derivation of the A&E 5NCP allocator.

Figure 3: Derivation of the A&E 5NCP Allocator

Column	1	2	3	4	5	6	7
	Peak Demand	Energy Sales	Average	Excess	Average	Excess	Total
	5 NCP	with Losses	Demand	Demand	Demand	Demand	Allocator
Rate Class	(KW)	(kWh)	(KW)	(KW)	(%)	(%)	(%)
RG-Residential	529,044	1,796,885,034	205,124	323,920	39.85%	59.93%	49.82%
CB-Commercial	87,547	338,286,147	38,617	48,930	7.50%	9.05%	8.27%
SH-Small Heating	20,656	85,678,137	9,781	10,875	1.90%	2.01%	1.96%
GP-General Power	180,825	897,297,672	102,431	78,393	19.90%	14.50%	17.22%
TS - Transmission Service	8,368	71,646,849	8,179	189	1.59%	0.04%	0.82%
TEB-Total Electric Bldg	72,087	365,608,650	41,736	30,350	8.11%	5.62%	6.87%
PFM-Feed Mill/Grain Elev	168	486,329	56	112	0.01%	0.02%	0.02%
LP-Large Power	145,264	919,881,107	105,009	40,255	20.40%	7.45%	13.97%
MS-Miscellaneous	17	146,213	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,489	19,180,197	2,190	3,300	0.43%	0.61%	0.52%
PL-Private Lighting	4,679	13,499,939	1,541	3,138	0.30%	0.58%	0.44%
LS-Special Lighting	1,089	436,119	50	1,040	0.01%	0.19%	0.10%
Total	1,055,233	4,509,032,394	514,730	540,503	100.00%	100.00%	100.00%

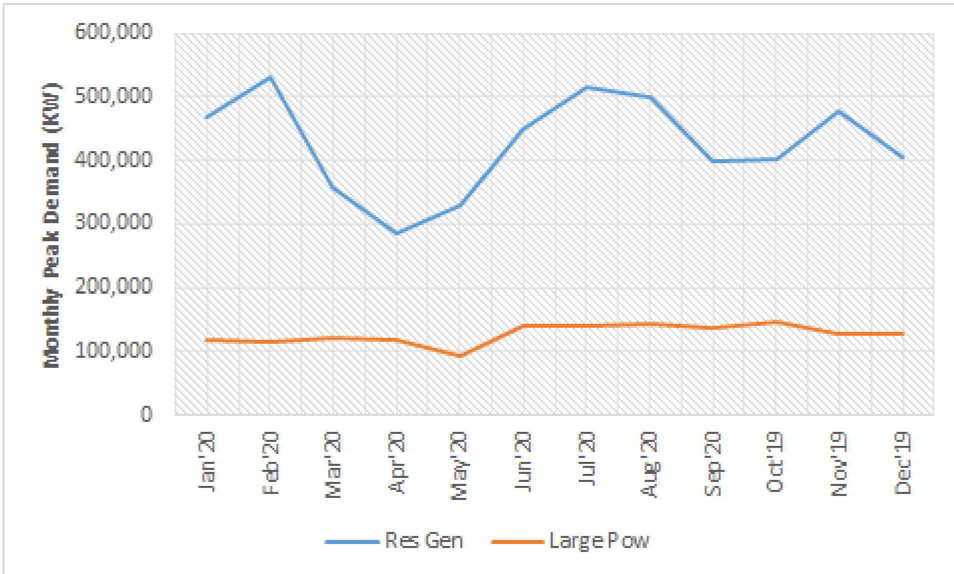
Column 1 shows the average of the five non-coincident peaks ("NCP") for the five peaking months by class. Column 2 shows the annual energy (kWh) by class and Column 3 converts this annual energy to average demand by dividing the annual energy usage by 8,760 (number of hours in the test year). The excess demand shown in Column 4 is calculated by subtracting the average demand in Column 3 from the average of the 5 NCP in Column 1. Column 5 shows each class' average demand as a percentage of the system average demand. So, for instance the residential average demand percentage is 205,124 kW divided by 514,730 kW. 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 323,920 kW divided by 540,503 kW. 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 (50.33%) and (b) weighting the class excess as a proportion to the total excess demand (Column 6) by 1 minus the system load factor (49.67%). 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 49.82% of the total fixed production plant-related costs, while the GP and LP classes should be allocated 17.22% and 13.97% of these costs respectively.

Q. WHAT INSIGHTS CAN BE GAINED FROM FIGURE 3?

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. These are the residential, commercial and lighting classes. Conversely, classes with average demand percentage shares higher than their excess demand shares have lesser variability and utilize the system more efficiently. Figure 4 demonstrates the difference in variability in peak demand for two classes, namely, residential and LP classes respectively. The graph shows the higher variability in residential peak demands compared to the LP class, which looks relatively flatter.

Figure 4: Residential and LP Class Monthly CP Demands



Q. ASIDE FROM YOUR RECOMMENDED A&E 5NCP PRODUCTION COST ALLOCATOR FOR ALLOCATING FIXED PRODUCTION PLANT RELATED COSTS, DID YOU ALSO EXAMINE OTHER ALLOCATION METHODS THAT COULD BE CONSIDERED APPROPRIATE?

A. Yes. I also considered other methodologies contained in the NARUC manual. **Schedule KM-2** shows the allocation factors using 3CP, 5CP and A&E 3NCP as well as my recommended A&E 5NCP allocator. The use of any of these allocators would be reasonable. As can be observed, the class allocators are similar. Specifically, all of them are consistent with and show the reasonableness of my recommended A&E 5NCP allocator.

2. Company's Production Cost Allocator

Q. DID THE COMPANY USE THE SAME PRODUCTION COST ALLOCATOR METHODOLOGY AS THE LAST CASE?

A. Yes. The Company used the A&E 12 NCP method and applied the same approach for calculating the load factor used for weighting the average and excess components.

Q. WHAT IS YOUR CONCERN WITH THE COMPANY'S APPROACH FOR CALCULATING THE LOAD FACTOR?

A. With regards to the calculation of the A&E allocation, the Company used an incorrect divisor to calculate the load factor, which is used to weight the average and excess components. As shown in the NARUC manual, the load factor calculation is average demand (which is MWh/8,760 hours) divided by the 1CP or the system peak.[10] Instead of using the system peak as the denominator, the Company used the average of the 12 coincident peaks. The Company's method leads to a system load factor of 57.3% compared to the corrected load factor of 50.33%. The end result is that the average component for each class is weighed more heavily under the Company's approach than appropriate and results in over-estimating the allocators for those classes that have high load factors and use the system in a more efficient manner and under-estimating the allocators for those classes that have higher variability (i.e., low load factors). Figure 5 shows the difference in class allocators.

[10] See NARUC Manual, page 82.

Figure 5: MECG Corrected vs. Company Calculated A&E 12NCP Allocator

Rate Class	MECG Corrected Company Allocator (%)	Company Allocator (%)
RG-Residential	48.67%	47.42%
CB-Commercial	8.32%	8.21%
SH-Small Heating	1.93%	1.93%
GP-General Power	17.68%	18.00%
TS - Transmission Service	0.81%	0.92%
TEB-Total Electric Bldg	6.89%	7.06%
PFM-Feed Mill/Grain Elev	0.02%	0.02%
LP-Large Power	14.51%	15.34%
MS-Miscellaneous	0.00%	0.00%
SPL-Municipal St Lighting	0.60%	0.58%
PL-Private Lighting	0.47%	0.45%
LS-Special Lighting	0.08%	0.07%
Total	100.00%	100.00%

Q. HOW DID THE COMPANY RESPOND TO YOUR CORRECTION IN THE LAST RATE CASE?

A. Mr. Lyons stated the following in his surrebuttal testimony:

> The NARUC Manual shows a load factor calculation based on 1CP because the example reflects a single system peak. The NARUC Manual does not show a load factor calculation based on 12CP (i.e., twelve system peaks). Consequently, we assumed for consistency purposes to use a load factor calculation based on 12CP. This approach is consistent with the Company's CCOS study in its last rate case filing in Docket No. ER-2014-0351.

Q. DO YOU AGREE WITH MR. LYONS' RESPONSE?

A. No. the divisor of the system annual load factor calculation is not dependent on the number of peaks used in the A&E allocator. Rather, the load factor is a standalone calculation that divides the average demand (i.e, total kWh/8760) by the system peak demand (i.e, highest peak for the Company). By way of support for my approach and the fallacy of Empire's approach, Ameren Missouri uses the same method of calculating the annual system load factor by using the system peak demand (1CP) as the denominator even though it relies on 4NCP within its A&E approach. Also, the NARUC manual does not state that it is using the system peak demand as the divisor for the load factor calculation because the example shows the A&E example is for a 1 CP case.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Company make the correction to the load factor calculation in its COSS.

3. Allocating Costs Associated with Interruptible Credits

Q. HOW DOES INTERRUPTIBLE LOAD BENEFIT THE SYSTEM?

A. Interruptible customers forgo firm service and help Empire to avoid building or acquiring generation capacity thereby providing benefits to the system. For the single customer in the TS class, the vast majority of the customer's load is interruptible. Since load on interruptible service can and is available to be interrupted, the Company does not have a capacity obligation for this load. According to SPP rules, utilities must have enough capacity to serve <u>firm</u> load plus a 12% planning reserve margin requirement. Figure 6 is a table provided by the Company in response to MECG Data Request 12.6, which shows that interruptible load for Empire (on a total company basis) is deducted from the forecasted demand before calculating the planning reserve margin requirement. Thus, because of the existence of this interruptible load, the Company avoids procuring an additional 9.41 MW of capacity it would have otherwise needed to procure (9 MW + planning reserve margin of 12%). The value of interruptible load is recognized by SPP in that it allows utilities to meet resource adequacy requirements through both supply side (generating units) as well as demand side (interruptible customers) resources.

Figure 6: 2021 Empire Resource Adequacy Requirement

	Summer 2021
Forecasted:	(MW)
Gross Peak	1,069
Interruptible	(8.4)
Net Peak with Interruptible	**1,061**
Iatan	84
Iatan 2	108
Plum Point (own)	50
Riverton 10	13
Riverton 11	16
Riverton 12	254
Energy Center 1	81
Energy Center 2	81
Energy Center 3	40
Energy Center 4	43
State Line 1	93
State Line C.C.	300
Ozark Beach	16
Plum Point PPA (50 MW)	50
Elk River Wind Farm PPA (150 MW)	33
Meridian Way Windfarm PPA (105 MW)	17
Neosho Ridge Wind (301 MW)	15.1
North Fork Ridge Wind (149 MW)	7.5
King's Point Wind (149 MW)	7.5
System Sale	(78)
Total Capacity	1,231
Reserve Margin Required	12.0%
Capacity Margin Required	10.7%
Capacity Responsibility	1,188
Capacity Balance	43
Reserve Margin	**16.0%**

In return for providing interruptible service, customers with such load receive an interruptible credit. 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. DID THE COMPANY ADOPT YOUR RECOMMENDATION TO FIRM UP PRESENT REVENUE TO ACCOUNT FOR INTERRUPTIBLE LOAD IN CERTAIN CLASSES?

A. Yes. Since all the fixed production plant related costs were allocated to interruptible load as though it is receiving firm service, the base revenues need to be firmed up to match up the revenues with the costs. Failure to do so would result in a mismatch between revenues and costs for such load because, for costing purposes, the treatment assumes that interruptible load is receiving firm service. However, the revenues are net of the interruptible credit. This mismatch would result in under estimating the rate of return earned from classes with interruptible load such as the TS class and essentially implies that interruptible load is paying for the interruptible credit it receives, for taking non-firm service. Therefore, the Company implemented this step appropriately. However, in the second step of allocating the costs of the interruptible credits to the classes, the Company incorrectly allocated the costs to interruptible load as well.

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE COSTS ASSOCIATED WITH INTERRUPTIBLE CREDITS?

A. While Empire correctly firms up class revenues to account for interruptible credits, the Company erroneously allocates the cost of the interruptible credits. Specifically, Empire proposes to allocate costs associated with interruptible credits using the A&E

12NCP allocator which results in erroneously allocating part of the interruptible credits to interruptible load because it includes billing determinants from firm and non-firm customers. In order to properly allocate these costs and be consistent with cost causation, the Company must develop a revised A&E allocator that excludes interruptible load, when allocating the interruptible credit related costs. Since interruptible load is getting credited for taking non-firm service and firm load benefits from the availability to be interrupted by such load, only firm load should be allocated these costs. Therefore, consistent with cost causation, the cost of the interruptible credits should be allocated to firm load only.

Q. HAVE YOU DEVELOPED A REVISED A&E ALLOCATOR TO REFLECT THE ALLOCATION OF THE INTERRUPTIBLE CREDIT RELATED COSTS TO FIRM LOAD ONLY?

A. **Schedule KM-3** page 1 shows the calculation of the A&E 5NCP allocation excluding interruptible load from the GP and TS class respectively. This Schedule is calculated in the same manner as the A&E 5NCP allocator shown in Figure 5 except that the interruptible load has been removed from the relevant classes. Schedule KM-3 also shows the difference in cost allocation to classes using the Company's allocator versus the MECG allocator.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Company develop a production cost allocator excluding interruptible load to properly allocate the costs to firm load only.

Q. IN SUMMARY, WHAT ARE YOUR CHANGES COMPARED TO THE COMPANY'S COSS?

A. I recommend the following changes in order to more closely align the cost allocation to classes with the underlying cost causative drivers:

- A&E 5NCP allocator for allocating fixed production plant related costs to classes; and
- Allocation of interruptible credit related costs from firm and interruptible load to firm load only.

Q. WHAT DO THE RESULTS OF YOUR COSS INDICATE?

A. **Schedule KM-4** shows a summary of the COSS results, based on my recommended allocators, at present rates. For comparison purposes, Figure 7 compares, at present rates, the earned rate of return ("ROR") and the indexed rate of return derived from my study as well as the Company's COSS. Similar to the last case, the results from both studies demonstrate that, from a directional standpoint, the residential and some lighting classes produce a ROR below the system ROR. This means that these classes are currently paying rates that are below the cost to serve those classes. All other classes are paying rates that produce greater than the system ROR of 5.28% although the magnitude varies. For example, under the MECG COSS, the LP class produces an ROR of 8.91% compared to the Company's result of 7.96%.

Figure 7: MECG v. Empire's CCOSS Earned Rate of Return ("ROR") and Indexed ROR by Class at Present Rates

	MECG COSS RESULTS		LIBERTY-EMPIRE COSS RESULTS	
	Earned ROR	Indexed ROR	Earned ROR	Indexed ROR
RG-Residential	2.48%	47	2.73%	52
CB-Commercial	6.20%	117	6.26%	119
SH-Small Heating	5.62%	106	5.73%	108
GP-General Power	9.02%	171	8.57%	162
TS - Transmission Service	12.61%	239	10.85%	205
TEB-Total Electric Bldg	9.86%	187	9.57%	181
PFM-Feed Mill/Grain Elev	8.94%	169	7.24%	137
LP-Large Power	8.91%	169	7.96%	151
MS-Miscellaneous	-3.71%	-70	-3.85%	-73
SPL-Municipal St Lighting	2.76%	52	2.45%	46
PL-Private Lighting	16.11%	305	15.76%	299
LS-Special Lighting	-7.68%	-145	-8.06%	-153
Company	**5.28%**	**100**	**5.28%**	**100**

V. REVENUE REQUIREMENT ALLOCATION

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

A. As I mentioned earlier, the 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 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 limited to no movement towards class cost responsibility and certain classes continue to be chronically subsidized by other classes.

Q. DID THE COMMISSION ADDRESS THE ISSUE OF THE MOVEMENT TOWARDS COST IN PAST CASES?

A. Yes. In Docket No. ER-2014-0351, the Commission ordered revenue neutral adjustments to present base revenues prior to an equal percent of the overall revenue requirement increase for all classes. A revenue neutral adjustment consists of revenue shifts between classes at present rates, without changing a utility's total system revenues. These adjustments are made to more closely align each class with its cost of service. A positive revenue neutral adjustment is made when the rates for a class result in revenues below costs to serve. Similarly, a negative revenue neutral adjustment is made when the rates for a class result in revenues above costs to serve.

In the 2014 case, the Commission ordered a 25% positive revenue neutral adjustment to the residential class in an effort to more fairly balance rate impacts and equity concerns. That is to say, the Commission ordered an adjustment to eliminate one fourth of the quantified residential subsidy. The Small Heating (SH), Commercial Building (CB), Large Power (LP), Total Electric Building (TEB), and General Power (GP) rate classes received the off-setting revenue neutral decrease to these classes' revenue. In the following case, ER-2016-0023, the Commission approved a settlement which also included a similar positive revenue neutral adjustment to the residential class and negative neutral adjustments to the GP, LP and TS classes.

Q. WHAT HAS THE COMMISSION DONE WITH THIS ISSUE SINCE THE 2016 RATE CASE?

A. There has been one rate case since the 2016 rate case. In the 2019 rate case (ER-2019-0374) the Commission did not make any revenue neutral shifts. Specifically, the Commission found that "[n]one of these CCOS studies are reliable due to the unavailability of reliable data needed to establish class and system peaks and billing determinants, and due to a large number of estimated bills."[11] Thus, the Commission's efforts to address the residential subsidy in previous cases stalled and the residential subsidy has gone unaddressed for over 5 years.

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 8 shows the derivation of the revenue neutral adjustments needed to align revenue responsibility with cost responsibility at present rates. Column 5 shows the net income required to achieve equal ROR. Column 6 shows the difference in income between the net income required to achieve equal ROR (Column 5) and income that produces the current ROR (Column 3). Column 7 shows the revenue neutral changes needed to base rates 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, the residential class would need a revenue neutral increase of

[11] Case No. ER-2019-0374, *Amended Report and Order*, issued July 23, 2020, page 41.

approximately 20% to base rate revenues in order to achieve cost based responsibility, while the GP, LP and TS classes would require revenue neutral decreases of approximately 20%, 19% and 30% respectively.

Figure 8: Revenue Neutral Adjustments Needed for Equal ROR at Present Rates ($ in Thousands)

Column	1	2	3	4	5	5	6	7	8
Rate Class	Current Base Revenues	Current Rate Base	Net Operating Income	Earned ROR	Indexed ROR	Income @ Equal ROR	Difference in Incomce	Revenue Change to attain Equal ROR	% Base Rate Revenue Neutral Increase @ equal ROR
RG-Residential	$216,633,250	$1,140,797,001	$28,265,457	2.48%	47	$60,196,788	$31,931,331	$41,926,713	19.35%
CB-Commercial	$43,153,741	$187,167,883	$11,601,063	6.20%	117	$9,876,345	($1,724,717)	($2,264,601)	-5.25%
SH-Small Heating	$9,356,502	$43,089,404	$2,421,950	5.62%	107	$2,273,712	($148,238)	($194,641)	-2.08%
GP-General Power	$82,426,006	$341,565,646	$30,801,876	9.02%	171	$18,023,500	($12,778,376)	($16,778,358)	-20.36%
TS - Transmission Service	$4,397,771	$13,794,168	$1,739,378	12.61%	239	$727,881	($1,011,497)	($1,328,124)	-30.20%
TEB-Total Electric Bldg	$35,162,635	$138,462,825	$13,652,861	9.86%	187	$7,306,311	($6,346,551)	($8,333,195)	-23.70%
PFM-Feed Mill/Grain Elev	$78,273	$333,067	$29,774	8.94%	169	$17,575	($12,199)	($16,018)	-20.46%
LP-Large Power	$67,285,606	$270,287,039	$24,090,260	8.91%	169	$14,262,320	($9,827,940)	($12,904,355)	-19.18%
MS-Miscellaneous	$14,032	$44,512	($1,649)	-3.71%	-70	$2,349	$3,998	$5,250	37.41%
SPL-Municipal St Lighting	$2,177,563	$22,823,194	$629,712	2.76%	52	$1,204,319	$574,606	$754,474	34.65%
PL-Private Lighting	$3,983,179	$8,745,316	$1,408,804	16.11%	305	$461,467	($947,337)	($1,243,880)	-31.23%
LS-Special Lighting	$80,357	$2,214,397	($170,073)	-7.68%	-146	$116,848	$286,921	$376,735	468.83%
Company Total	$ 464,748,916	$ 2,169,324,451	$ 114,469,413	5.28%	100	$114,469,413	$0	$0	

These results are of concern especially because the Company's average industrial rates are not competitive. Closer alignment of the industrial classes' revenue responsibility with cost responsibility would go a long way towards restoring competitiveness and help to push the Company's industrial rates towards the state, regional and national averages.

Q. DOES THE COMPANY'S PROPOSED REVENUE ALLOCATION RESULT IN MOVING CUSTOMER CLASSES CLOSER TO COST IN A MEANINGFUL MANNER?

A. No. The Company's revenue allocation proposal is unsupported by and inconsistent with its COSS results. Specifically, the Company's revenue allocation would provide below average rate increases to classes that already have rates that are below cost. For instance, the Company shows that, in order to get to cost of service, the residential class should receive an increase of 21.39% (Schedule TSL-9). Nevertheless, while seeking an overall increase of 7.6%, Empire proposes to increase residential rates by only 7.2% (Lyons page 34, Figure 10). In this way, the residential subsidy is exacerbated under the Company's proposal. Similarly, the Company's revenue allocation would provide above average rate increases to classes that are already paying rates that are above cost. For instance, the Company's study shows that the Feed Mill (PFM) class should receive a reduction of 0.99% (Schedule TSL-9). Nevertheless, while seeking an overall increase of 7.6%, the Company proposes to increase PFM rates by 9.6% (Lyons page 34, Figure 10). The Company's revenue allocation essentially disregards the results of that study.

Q. HAS THE COMPANY SUBMITTED RECENT TESTIMONY IN ANOTHER CASE WHERE ITS REVENUE ALLOCATION IS MORE CONSISTENT WITH COSS RESULTS?

A. Yes. Shortly after it filed this case, Empire filed for a rate increase for its gas operations. In that case Mr. Lyons submitted the class cost of service study and revenue allocation testimony. In that case (GR-2021-0320), Mr. Lyons' analysis showed the existence of a residential subsidy. Specifically, he asserted that "[t]he Company would need to increase Residential rates by $2.7 million, or 22.4 percent, to achieve the system ROR."[12] Contrary to his recommendation in this case, Mr. Lyons did not suggest that the residential class receive a below average rate increase. Instead, Mr. Lyons recommended that the Commission increase revenues for the Residential rate class by "$1.2 million, or 9.9 percent. The increase reflects a 44.0 percent movement to achieving the system ROR."

[12] Case No. GR-2021-0320, Lyons Direct, page 24.

Q. WHAT IS YOUR PREFERRED REVENUE ALLOCATION METHODOLOGY?

A. Consistent with the Commission's order from the 2014 and 2016 Empire rate cases, I recommend that the Commission make revenue neutral shifts sufficient to eliminate 25% of the interclass subsidies. After making these recommended revenue neutral adjustments at present rates, any overall change in revenue requirements can be applied across the board to the classes on an equal percentage basis. For example, Figure 9 shows the revenue changes needed to present base rates, in amounts and percent, to make a 25% revenue neutral adjustment to each class. Any rate increase would then be applied across the board on an equal percentage basis <u>after</u> the revenue neutral adjustments. Overall, I believe that this approach makes an explicit attempt to get classes closer to cost and is not arbitrarily choosing winners and losers as Empire's proposal accomplishes.

Figure 9: Revenue Neutral Adjustments at Present Rates [13]

Rate Class	Current Base Revenues	Revenue Change to attain Equal ROR	% Base Rate Revenue Neutral Increase @ equal ROR	25% Movement Towards COSS	Revenue Neutral Percent Change in Current Base Revenues
RG-Residential	$216,633,250	$41,926,713	19.35%	$10,481,678	4.8%
CB-Commercial	$43,153,741	($2,264,601)	-5.25%	($566,150)	-1.3%
SH-Small Heating	$9,356,502	($194,641)	-2.08%	($48,660)	-0.5%
GP-General Power	$82,426,006	($16,778,358)	-20.36%	($4,194,589)	-5.1%
TS - Transmission Service	$4,397,771	($1,328,124)	-30.20%	($332,031)	-7.5%
TEB-Total Electric Bldg	$35,162,635	($8,333,195)	-23.70%	($2,083,299)	-5.9%
PFM-Feed Mill/Grain Elev	$78,273	($16,018)	-20.46%	($4,005)	-5.1%
LP-Large Power	$67,285,606	($12,904,355)	-19.18%	($3,226,089)	-4.8%
MS-Miscellaneous	$14,032	$5,250	37.41%	$1,312	9.4%
SPL-Municipal St Lighting	$2,177,563	$754,474	34.65%	$188,618	8.7%
PL-Private Lighting	$3,983,179	($1,243,880)	-31.23%	($310,970)	-7.8%
LS-Special Lighting	$80,357	$376,735	468.83%	$94,184	117.2%
Company Total	$ 464,748,916	$0		$0	

[13] The revenue neutral change for LS-Special Lighting would need to be managed within the overall lighting class.

Q. WHAT DO YOU RECOMMEND?

A. Given that Staff has recommended significant revenue requirement adjustments to Empire's recommended overall rate increase and since Empire will likely be seeking to updates its rate case filing by removing storm Uri costs from the case and securitizing them (thereby resulting in lesser cost impacts compared to the original proposal), the 25% revenue neutral adjustment should be made in this case to continue the progress that stopped after the 2016 rate case. The interruptible credit related allocation (as shown in Schedule KM-3) should be assigned to firm load only as shown in Schedule KM-3 and should be a separate adjustment from the overall increase.[14]

VI RATE DESIGN

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

A. The Company's proposed increases for the LP class are provided in Figure 10 below. As can be observed, the tail block energy charges are proposed to increase 56% and 38% compared to existing summer and winter charges respectively.

[14] For example, see the Company's adjustment in the Target Revenues tab in its CCOSS Model.

Figure 10: Company's Rate Design Proposal for LP Class

	Current Rates	Proposed Rates	Percent Change from Current
Customer Charge	$283.55	$325.00	15%
First 350 Hours - Winter	$0.05778	$0.05778	0%
All Additional - Winter	$0.03270	$0.04528	38%
First 350 Hours - Summer	$0.06543	$0.06543	0%
All Additional - Summer	$0.03400	$0.05293	56%
Facility Demand kW - Winter	$1.88	$1.88	0%
Billed Demand kW - Winter	$8.66	$10.24	18%
Facility Demand kW - Summer	$1.88	$1.88	0%
Billed Demand kW - Summer	$15.69	$18.56	18%

Q. DO YOU SUPPORT THE COMPANY'S PROPOSAL?

A. No. It is highly unreasonable to suggest such drastic increases to the tail block charges especially when there are substantive decreases to the base energy cost of fuel. Specifically, Company witness Mr. Todd Tarter testifies that the base FAC factor should be reduced substantially from the existing rate of $0.02338 / kWh to $0.01011 / kWh – that is, a nearly 57% decrease.

Q. HOW HAS THE TAIL BLOCK ENERGY CHARGE BEEN ADDRESSED RELATIVE TO THE FAC BASE FACTOR?

A. As Figure 11 indicates the FAC base factor has decreased significantly (22% in the summer / 15% in the winter) since the FAC was implemented in 2008. Nevertheless, the tailblock energy charge for the LP class has inexplicably <u>increased</u> over that time

(18% in both the summer and winter). Since energy costs should be used for the recovery of variable costs (primarily fuel), this leads to the undeniable conclusion that the tailblock energy charge is capturing variable costs, but also an ever increasing amount of fixed costs.

Figure 11: Percent Change in FAC Factor v. LP Tail Block Charge

Missouri Rate Case	TYPE	Summer	Winter
ER-2008-0093	FAC Factor	$0.03001	$0.02744
ER-2019-0374	FAC Factor	$0.02338	$0.02338
	Percent Change	-22%	-15%
ER-2008-0093	Tail Block	$0.02870	$0.02770
ER-2019-0374	Tail Block	$0.0340	$0.0327
	Percent Change	18%	18%

Instead of recovering fixed costs through the energy charge, these costs should instead be recovered through the demand charge. The recovery of fixed costs through the energy charges serves to suppress the demand charge. Thus LP customers are sent the price signal that generation is cheaper than is actually the case.

Furthermore, the recovery of fixed costs through the energy charge results in an intraclass subsidy. Specifically, high load factor customers in the LP class are subsidizing the lower load factor customers in the class. Empire's proposal to increase the tailblock energy charges by 38% (winter) and 56% (summer) is inexplicable given that it proposes to reduce the FAC in this case by 57%. For all these reasons the Commission should reject Empire's proposed rate design proposal and take affirmative steps to eliminate fixed costs from the energy charges.

Q. WHAT IS YOUR RATE DESIGN RECOMMENDATION FOR THE GP, LP AND TS CLASSES?

A. As mentioned previously, in order to avoid intra-class subsidies, the Commission should be careful to collect variable costs (primarily fuel costs) through energy charges. Similarly, fixed costs should be collected through demand charges. Recognizing that the FAC base, the best measure of variable cost of generation, is recommended to be reduced by 57%, it would be appropriate to reduce the energy charges. Nevertheless, in the interest of gradualism, I recommend that the energy charges remain at current levels. Therefore, any rate increase for the GP, LP and TS classes should be recovered by increasing the billing demand charges.

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
34	E-999/CI-11-852	Renewable Energy Cost Impacts	Cost Effectiveness of Implementing Renewable Energy Standard	Lead Expert - MN Chamber

	Docket Number	Type by State/FERC	Major Issues	Role
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
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

Kavita Maini, KM Energy Consulting, LLC - Project Experience

	Docket Number	Type by State/FERC	Major Issues	Role
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 allo	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 ER14-24:	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

Schedule KM-2

Production Cost Allocators

Column	MECG RECOMMENDED ALLOCATOR			
	A&E 5NCP	A&E 3 NCP	5CP	3CP
Rate Class	(%)	(%)	(%)	(%)
RG-Residential	49.82%	49.56%	50.84%	51.27%
CB-Commercial	8.27%	8.48%	8.21%	8.40%
SH-Small Heating	1.96%	1.91%	2.04%	2.02%
GP-General Power	17.22%	17.59%	17.06%	17.17%
TS - Transmission Service	0.82%	0.82%	0.86%	0.83%
TEB-Total Electric Bldg	6.87%	6.71%	7.24%	6.98%
PFM-Feed Mill/Grain Elev	0.02%	0.02%	0.01%	0.01%
LP-Large Power	13.97%	13.88%	13.75%	13.31%
MS-Miscellaneous	0.00%	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	0.52%	0.49%	0.00%	0.00%
PL-Private Lighting	0.44%	0.43%	0.00%	0.00%
LS-Special Lighting	0.10%	0.11%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%

Schedule KM-3

(1) A&E 5 NCP Production Cost Allocator

Excluding Interruptible Load

Column	1	2	3	4	5	6	7
	Peak Demand	Energy Sales	Average	Excess	Average	Excess	Total
	5 NCP	with Losses	Demand	Demand	Demand	Demand	Allocator
Rate Class	(KW)	(kWh)	(KW)	(KW)	(%)	(%)	(%)
RG-Residential	529,044	1,796,885,034	205,124	323,920	40.51%	59.93%	50.32%
CB-Commercial	87,547	338,286,147	38,617	48,930	7.63%	9.05%	8.35%
SH-Small Heating	20,656	85,678,137	9,781	10,875	1.93%	2.01%	1.97%
GP-General Power	180,025	890,289,672	101,631	78,393	20.07%	14.50%	17.26%
TS - Transmission Service	768	5,070,849	579	189	0.11%	0.04%	0.07%
TEB-Total Electric Bldg	72,087	365,608,650	41,736	30,350	8.24%	5.62%	6.92%
PFM-Feed Mill/Grain Elev	168	486,329	56	112	0.01%	0.02%	0.02%
LP-Large Power	145,264	919,881,107	105,009	40,255	20.74%	7.45%	14.03%
MS-Miscellaneous	17	146,213	17	0	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,489	19,180,197	2,190	3,300	0.43%	0.61%	0.52%
PL-Private Lighting	4,679	13,499,939	1,541	3,138	0.30%	0.58%	0.44%
LS-Special Lighting	1,089	436,119	50	1,040	0.01%	0.19%	0.10%
Total	1,046,833	4,435,448,394	506,330	540,503	100.00%	100.00%	100.00%
Load Factor	49.51%						
1 - Load Factor	50.49%						
Average Demand	506,330						
	1,022,641						

(2) Difference in Allocation: MECG v. Company Approaches

	Company	RG	CB	SH	GP	TS	TEB	PFM	LP	MS	SPL	PL	LS
Company:Firm and Interruptible A&E 12 NCP	$377,856	$183,885	$31,441	$7,297	$66,821	$3,077	$26,041	$76	$54,845	$6	$2,286	$1,791	$291
MECG: Firm Only A&E 5NCP	$377,856	$190,120	$31,539	$7,452	$65,221	$281	$26,133	$60	$53,008	$6	$1,974	$1,677	$385

SCHEDULE KM-4

MECG COSS Results Summary at Present Rates

	Total	Res Gen	Comm	Small Heating	Gen Pow	Transmission	Total Elect Bldg	Feed Mill	Large Power	Misc. Service	Street Lts	Private Lts	Spec Lts
	Company	RG	CB	SH	GP	TS	TEB	PFM	LP	MS	SPL	PL	LS
Rate Base	2,169,324,451	1,140,797,001	187,167,883	43,089,404	341,565,646	13,794,168	138,462,825	333,067	270,287,039	44,512	22,823,194	8,745,316	2,214,397
Operating Revenues	658,163,117	293,087,513	57,708,396	12,998,398	120,420,914	7,413,192	50,618,069	99,637	107,045,756	20,103	4,029,092	4,622,426	99,620
Current Delivery Revenues	$ 464,748,916	$ 216,633,250	$ 43,153,741	$ 9,356,502	$ 82,426,006	$ 4,397,771	$ 35,162,635	$ 78,273	$ 67,285,606	$ 14,032	$ 2,177,563	$ 3,983,179	$ 80,357
Operating Expenses													
O&M Expenses	403,598,612	196,956,273	32,973,472	7,729,056	65,930,029	4,638,571	26,915,253	45,560	64,701,957	19,392	1,981,752	1,546,326	160,971
Depreciation & Amortization	93,598,105	52,268,974	8,446,493	1,871,584	12,954,656	463,916	5,312,707	13,625	9,933,522	2,315	1,130,485	1,057,070	142,759
Taxes Other than Income	33,838,116	18,755,461	3,032,713	676,890	4,825,078	177,962	1,975,924	4,956	3,739,985	1,042	340,045	265,032	43,028
Interest on Customer Deposits	590,827	490,429	73,549	12,807	9,149	-	4,404	50	-	8	-	-	431
Total Operating Income	126,537,457	24,616,376	13,182,170	2,708,061	36,702,002	2,132,742	16,409,780	35,446	28,670,293	(2,653)	576,811	1,753,997	(247,569)
Less:													
Interest Expense	38,840,052	20,425,075	3,351,094	771,482	6,115,465	246,974	2,479,068	5,963	4,839,277	797	408,631	156,578	39,647
Net Income Before Taxes	87,697,405	4,191,301	9,831,076	1,936,579	30,586,537	1,885,769	13,930,712	29,483	23,831,016	(3,450)	168,180	1,597,419	(287,216)
Total Income Tax	20,907,174	999,212	2,343,741	461,683	7,291,870	449,570	3,321,100	7,029	5,681,345	(823)	40,094	380,827	(68,473)
Excess ADIT Amortization & ITC	(8,839,130)	(4,648,292)	(762,634)	(175,572)	(1,391,744)	(56,206)	(564,181)	(1,357)	(1,101,312)	(181)	(92,995)	(35,634)	(9,023)
Net Income after Taxes	114,469,413	28,265,457	11,601,063	2,421,950	30,801,876	1,739,378	13,652,861	29,774	24,090,260	(1,649)	629,712	1,408,804	(170,073)
Earned ROR	5.28%	2.48%	6.20%	5.62%	9.02%	12.61%	9.86%	8.94%	8.91%	-3.71%	2.76%	16.11%	-7.68%