Exhibit No.:	
Issue:	Class Cost of Service Study, Revenue Allocation, Rate Design
Witness:	Kavita Maini
Type of Exhibit:	Rebuttal Testimony
Sponsoring Parties:	MECG
Case No.:	ER-2019-0374
Date Testimony Prepared:	March 9, 2020

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-2019-0374** Tariff No. YE-2020-0029

Rebuttal Testimony and Schedules of

Kavita Maini

On behalf of

MIDWEST ENERGY CONSUMERS GROUP

March 9, 2020

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-2019-0374

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 its behalf.

2. Attached hereto and made a part hereof for all purposes are my rebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2019-0374

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

Subscribed and sworn to before me this 9th day of March, 2020

Notary Public

**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-2019-0374** Tariff No. YE-2020-0029

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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-2019-0374** Tariff No. YE-2015-0074

Rebuttal 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. ARE YOU THE SAME KAVITA MAINI WHO HAS PREVIOUSLY FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I filed direct testimony on behalf of the Midwest Energy Consumers Group ("MECG"). My direct testimony provided recommendations regarding Empire District Electric Company, A Liberty Utilities Company's ("Liberty-Empire" or "Company") class cost of service study ("COSS"), revenue allocation to classes and rate design for the Large Power and Schedule SC-P rate schedules

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to (a) address issues related to the Company's and Staff's COSS methodologies, (b) provide COSS results using Staff's revenue requirements and (c) address Staff's rate design recommendations applicable to the LP and SC-P classes. The fact that I do not address any particular issue should not be interpreted as my implicit approval of any position taken by the Company or Staff on that issue.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND RECOMMENDATIONS.

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

Section III: Class Cost of Service Study Methods Summary

A. Company's COSS

a) I support the Company's use of the average and excess ("A&E") methodology to allocate fixed production plant related costs with two exceptions:

- First, the Company uses the average of class non-coincident peaks from all 12 months ("12NCP") thereby placing equal weight on each of the months. Such an approach dampens cost causation by not recognizing that the primary cost driver for acquiring generation capacity are the highest demands, and also results in under allocating costs to the cost causing weather sensitive loads (pages 7-8).

- Second, the load factor is calculated incorrectly in the context of the Company's A&E methodology and results in over-estimating the allocators for classes that are energy intensive and under-estimating the allocators for classes that have higher variability. I recommend that the Company make this correction to its COSS in its surrebuttal testimony (pages 8-9).

b) While I support the Company's classification method for certain distribution plant related costs (for FERC accounts 364-368) as customer and demand related, allocating the demand related costs on the basis of 6 class NCPs dampens the primary cost causative factor, i.e., class' maximum demands, that the Company recognized in the past. I believe that the Company's prior method, which is also my recommended approach and that used by other Missouri utilities such as Ameren, more appropriately recognizes the cost causative drivers and should be implemented (pages 9-10).

B. Staff's COSS

a) **Allocation of Fixed Production Plant Related Costs.** Staff utilizes class contribution to the highest 100 hours, which includes a non-representative load profile for the SC-P class. While I continue to believe that the established and mainstream A&E method such as the one I recommended in direct testimony is the more appropriate approach and should be adopted, if Staff prefers the highest hours approach, I recommend that (a) the SC-P load profile be corrected and (b) the class contribution to the highest 51 hours, representing peak demands within 10% of the system peak, be used (pages 11-13).

b) **Classification of Certain Distribution Plants Related Costs (FERC 364-368).** Staff utilized the Zero Intercept method for classifying certain distribution plant related costs assigned to FERC accounts 364, 366 and 368. There are wide differentials between Staff's results using this statistical method versus the Company's minimum size approach, which uses actual data. This wide disparity is contrary to the NARUC manual which indicates that the differences should be typically small, and symptomatic that Staff may not be considering all the costs. Further, some results are statistically unreliable. I conclude that Staff needs to vet its analysis further and should not utilize it in this case. Staff is relying on the Company's minimum size classification methods for costs assigned to FERC accounts 365 and 367. I recommend that the Company's minimize size classification approach be applied to all applicable distribution plant related costs (pages 13-15).

c) **Miscellaneous and Unassignable Cost Category.** Staff has included several costs items in this category including, but not limited to, general and intangible plant, administrative and general expenses and materials and suppliers. These costs are allocated on the basis of the energy allocator. Allocation on this basis is unwarranted. In the past case, Staff did not consider such costs miscellaneous and allocated them based on factors that were more reflective of cost causation than using the energy allocator. I recommend that Staff use these previous allocators for such categories in this case (pages 15-16).

Section IV: Class Cost of Service Study Results Summary

After incorporating the recommended adjustments to Staff's COSS models with and without the tax credits, the results[1] indicate the following:

[1] In this testimony I attempt to compare Staff's COSS allocation methodologies with my methodologies using Staff's recommended revenue requirement reduction. The COSS results contained in my direct testimony are based upon Company's recommended revenue requirement increase.

- From a directional standpoint, both Staff and my COSS show class rates of return ("ROR") higher than the system average for the CB/SH, GP/TEB and LP classes respectively. However, the magnitude varies. For example, my LP class ROR's are higher than Staff's results and the revenue reductions needed at equalized ROR are roughly double that of Staff's results (pages 17-21).

- Similarly, both Staff and my COSS show a residential class ROR that is lower than the system average. Once again, the magnitude varies, as my COSS shows a lower ROR for this class as compared to Staff and the revenue increases needed are substantially higher compared to Staff's results. In other words, the residential class revenue is significantly below costs to serve under my COSS results (pages 17-21).

- The biggest difference from a directional standpoint is that Staff's COSS produces a SC-P class ROR that is lower than the system average and my results show a ROR for this class that is above the system average. Consequently, while my COSS shows that this class should get a substantial revenue reduction (similar to the LP class), Staff's results indicate otherwise (pages 17-21).

The COSS results using my recommended A&E 6NCP allocator in conjunction with Staff's recommended revenue requirement, in place of Staff's highest 51 hours allocator, lead to comparable results.

Section V: Revenue Allocation Summary

Staff's recommended revenue allocation relies in large part of Staff's COSS results. However, as discussed in this testimony, Staff COSS model had a number of issues that needed to be addressed. I recommend therefore, that the revenue allocation approach should either rely on Staff's COSS, as adjusted, consistent with this testimony, or my A&E 6NCP approach. Further, consistent with what I stated in direct testimony, I continue to recommend greater movement towards cost. If there is a rate reduction comparable to that recommended by Staff, then more aggressive steps should be taken to align class responsibility with cost responsibility. If the decrease is smaller, then the Commission should consider, in an effort to bring classes closer to cost of service, not maintaining each class' portion of the tax rider credits (page 22).

Section VI: Rate Design for the LP and SC-P Classes Summary

Staff's limits on decreasing the energy charges are too stringent because while the load weighted and loss adjusted LMPs are about $0.03/kWh, the recommended energy charges are still much higher. Specifically, Staff's recommended energy charges in the tail block remain 14-18% above its suggested energy charge limit. Further, Staff recommends a 21% reduction in the customer, demand and facilities charges, which does not result in efficient pricing signals due to (a) existing under recovery of costs through these charges and (b) known forthcoming investments that will raise these charges. As a result of these factors, it makes more sense to maintain these fixed charges at current levels and instead, allocate the entirety of any revenue decrease to lowering the energy charges. I recommend this same approach for the LP and SC-P classes (pages 23-25).

III. CLASS COST OF SERVICE STUDY METHODS

A. Liberty- Empire's COSS Methodology

Q. ON PAGE 14 OF YOUR DIRECT TESTIMONY, YOU INDICATED THAT YOU WOULD ADDRESS ISSUES RELATED TO THE COMPANY'S COSS METHDOLOGY. WHAT ARE THESE ISSUES?

A. The two specific issues are the Company's allocators used to allocate: (1) fixed production plant-related costs and (2) certain distribution plant-related costs to customer classes.[2]

Q. PLEASE EXPLAIN THE ISSUES ASSOCIATED WITH THE COMPANY'S ALLOCATION OF FIXED PRODUCTION PLANT.

A. The Company uses the Average and Excess demand ("A&E") method, which is used by all Missouri investor owned utilities and is the method that I used to allocate fixed production plant-related costs to classes. The A&E approach considers the load profile of customer classes by incorporating the class maximum demands, load factor and average energy use. To summarize and as indicated on pages 18 and 19 of my direct testimony:

> The A&E Demand method consists of an average demand component and an excess demand component. The average demand component 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 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

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[2] Since I already addressed the Company's treatment of interruptible load and allocation of SB564 costs in my direct testimony, I do not repeat these issues here.

weighted by the system load factor and the excess component for each class is weighted by 1-load factor.

While I support the Company's use of the A&E approach, there are two exceptions.

Q. WHAT IS YOUR FIRST CONCERN WITH THE COMPANY'S A&E APPROACH?

A. First, as explained at pages 15-20 of my direct testimony, I calculated my A&E allocator based upon the average class non-coincident peaks for the highest 6 months. This was done because Empire constructs generation to meet system peak and I believe that the 6 monthly peaks within 10% of the highest peak would factor into this construction decision. The peaks in the remaining 6 months would be secondary to the highest six months and should not be used to calculate the A&E methodology. In contrast, the Company uses the average of class non-coincident peaks from all 12 months ("12NCP") thereby placing equal weight on each of the months. Such an approach dampens cost causation by not recognizing that the primary cost driver for acquiring generation capacity are the highest demands, thereby resulting in an under allocation of costs to the cost causing weather sensitive loads. As demonstrated in my direct testimony (page 17), Liberty-Empire is a winter and summer peaking and the class demands imposed in both these seasons are the primary cost causing demands to build or acquire more generation and should be given more weight. Further, in contrast to its reliance on 12 monthly peaks for purposes of allocating fixed production costs here, the Company places more importance on just the highest winter peak and the highest summer peak in making generation acquisition decisions in its Integrated Resource Plan. (See Executive Summary, Figure 1.4 in the Company's Resource Plan in docket EO-2019-0049 shown as KM Exhibit – R1). Finally, I also note that with respect to managing generation outages and from an operating reserves standpoint, since the Company is a market participant of the Southwest Power Pool ("SPP"), there should be more efficiency due to reserve sharing within the SPP footprint as well as generation outage coordination. Thus, I believe that instead of 12NCP, my recommended A&E method with the class average of 6NCP in the summer and winter peaking months (with peaks within 10% of the highest peak) appropriately places higher importance on the peaking months and therefore better represents cost causation.

Q. WHAT IS YOUR SECOND CONCERN WITH THE COMPANY'S A&E APPROACH?

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.[3] Instead of using the system peak as the denominator, the Company used the average of the 12 coincident peaks.[4] The Company's method leads to a load factor of 55% compared to the corrected load factor of 47.35%. 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 are energy intensive and under-estimating the allocators for those classes that have higher variability.

[3] See NARUC Manual, page 82.
[4] See Company COSS model spreadsheet, Tabs: Demand Data and Demand Allocators.

Table 1 shows the difference in class allocators. I recommend that the Company make this correction to its COSS in its surrebuttal testimony.

Table 1: Company's A&E12 NCP Corrected for Load Factor

	LIBERTY- EMPIRE DATA AND A&E12NCP ALLOCATOR						
	Peak Demand	Average	Excess	Average	Excess	Total	MECG
	12 NCP	Demand	Demand	Demand	Demand	Allocator	Corrected for Load Factor
Rate Class	(MW)	(MW)	(MW)	(%)	(%)	(%)	
RG-Residential	502,707	204,996	297,710	39.90%	56.79%	47.51%	48.79%
CB-Commercial	83,218	38,826	44,391	7.56%	8.47%	7.97%	8.04%
SH-Small Heating	21,343	10,422	10,921	2.03%	2.08%	2.05%	2.06%
GP-General Power	184,960	106,226	78,734	20.67%	15.02%	18.13%	17.70%
SC-P PRAXAIR Transmission	8,421	8,210	211	1.60%	0.04%	0.90%	0.78%
TEB-Total Electric Bldg	78,027	43,933	34,094	8.55%	6.50%	7.63%	7.47%
PFM-Feed Mill/Grain Elev	195	52	143	0.01%	0.03%	0.02%	0.02%
LP-Large Power	147,847	96,700	51,147	18.82%	9.76%	14.74%	14.05%
MS-Miscellaneous	17	17	0	0.00%	0.00%	0.00%	0.00%
SPL-Municipal St Lighting	5,748	2,749	3,000	0.53%	0.57%	0.55%	0.55%
PL-Private Lighting	4,488	1,585	2,904	0.31%	0.55%	0.42%	0.44%
LS-Special Lighting	1,077	94	983	0.02%	0.19%	0.09%	0.11%
Total	1,038,048	513,810	524,238	100.00%	100.00%	100.00%	100.00%

Q. PLEASE EXPLAIN THE ISSUES ASSOCIATED WITH THE COMPANY'S ALLOCATION OF CERTAIN DISTRIBUTION PLANT-RELATED COSTS TO CUSTOMER CLASSES.

A. The distribution system associated with equipment designated under FERC accounts 364-368, such as poles and towers, overhead conductors and devices, underground conduit, underground conductors and devices and line transformers, are classified as both customer and demand-related. The Company's classification approach is reasonable and based on a minimum size system approach to recognize the dual function of the these facilities: being capable of delivering service to customers (customer-related costs) and ensuring that the distribution system is large enough to provide reliable service (demand-related costs). The single exception is that in allocating the demand-related costs to customers, the Company modified its previous method of using the class non-coincident peak ("1NCP") and instead used the average of six class non-coincident peaks or 6NCP occurring in the months of December through February and June through August. Using the average of 6 class NCPs dampens the primary cost causative factor that drives the sizing of the distribution facilities – customers' maximum demands. This is because when designing primary and secondary distribution feeders, sufficient conductor and transformer capacity must be available to meet the maximum customer loads at the primary and secondary distribution service levels, whenever the maximum demands occur. By sizing it in this manner, the distribution infrastructure necessarily accommodates all demands lower than the maximum demands. For example, the primary reason that the facility demand is ratcheted in LP rates (i.e., based on the maximum customer demand over a twelve month period) is to recognize that the distribution facilities being used, are sized to accommodate the maximum demands, whenever they occur. Each class' single non-coincident peak demand is therefore a more reasonable indicator to reflect the cost causing characteristic of building the distribution-related infrastructure discussed above. Therefore, I believe that the Company's prior method, which is also my recommended approach and that used by other Missouri utilities such as Ameren, more appropriately recognizes the cost causative drivers and should be implemented.

B. Staff's COSS Methodology

Q. WHAT ISSUES DO YOU ADDRESS WITH RESPECT TO STAFF'S COSS METHODOLOGY?

A. I address the following:

- Allocation of fixed production plant-related costs to classes;
- Classification of distribution plant related to FERC accounts 364-368; and

- Allocation of costs in category entitled " Miscellaneous and Unassignable Costs"

1. Allocation of Fixed Production Plant-Related Costs

Q. WHAT METHOD DID STAFF USE TO ALLOCATE FIXED PRODUCTION PLANT-RELATED COSTS TO CLASSES?

A. Staff used the "highest hours" method, which consists of sorting the system hourly peaks in a year from the highest to the lowest and using class contributions to each hour of a total of 100 hours to derive the fixed production cost allocator. Staff indicated in part, that this method "helps mitigate concerns with the reliability of the hourly load data, as less emphasis is placed on the reliability of a relatively small number of hours than would occur using more simplistic traditional capacity allocation methods." While Staff considered allocators based on the top 12 hours (representing 95% of system peak) to 310 hours (representing 80% of system peak), Staff's subjective judgement was that using the 100 highest hours was reasonable.

Q. PLEASE COMMENT ON STAFF'S RECOMMENDED METHOD FOR TO ALLOCATING FIXED PRODUCTION PLANT COSTS TO CLASSES.

A. At the outset, it is important to stress that the traditional capacity allocation methods, such as the A&E method, though less complex in application than Staff's approach, is a mainstream and well established method that has been widely used and tested over time and has been adopted by utilities in Missouri and elsewhere. The method does not rely on just a few hours. Rather, it incorporates class maximum demands, load factor and average demand or energy usage in calculating a composite allocator by class. Importantly, load factor and average demand are based upon the usage for all hours. Thus, I continue to believe that the A&E approach such as the one I recommended in direct testimony is the more appropriate approach and should be adopted. However, if Staff prefers using the highest hours approach as a result of data reliability issues, I recommend the following:

- Modify SC-P class load profile to reflect its profile based on billing data; and
- Use the contribution to the highest 51 hours, which represents system demands within 10% of the system peak demand.

Q. PLEASE EXPLAIN YOUR MODIFICATION TO THE SC-P CLASS LOAD PROFILE

A. Staff imputed SC-P class hourly load profile based on the hourly load shape of the LP class. However, the load profile of the SC-P is unique and draws no correlation to the load profile of the LP class. While the LP class shows some variability in demand, the SC-P class demonstrates a very flat load profile with load factor over 95%. Consequently, the SC-P hourly load profile cannot be correctly imputed from the LP class load profile. In order to correct for this issue and be conservative, I replaced Staff's data for the SC-P class with the highest demand for each applicable month after adjusting for losses (reflected as the facility demand charge).[5] Any difference between Staff's imputed profile and my modified profile for this class was then assigned to the LP class in order to limit the impact of this change.

[5] As a practical matter, since SC-P class has a very flat load profile, the difference between the monthly billed demand and facility demand is not significant (See Workpapers of Staff Witness B.Murray for Praxair monthly data).

Q. REGARDING YOUR SECOND CONCERN, PLEASE EXPLAIN WHY THE ALLOCATOR SHOULD BE BASED ON THE HIGHEST 51 HOURS.

A. The highest 51 hours represent all hours within 10% of the system peak and is therefore consistent with my criteria of using the peaks in the A&E 6NCP method as well as with the NARUC manual.[6]

Q. PLEASE EXPLAIN HOW STAFF'S HIGHEST HOURS APPROACH WOULD CHANGE IF IT WAS BASED UPON 51 HOURS INSTEAD OF STAFF'S RECOMMENDED 100 HOURS.

A. Table 2 shows the comparison of Staff's recommended allocator (based on the highest 100 hours) as well as Staff's and my allocator using the top 51 hours.

Table 2: Staff v. MECG Allocator Based on Highest Hours

	Hours	Residential	CB/SH	GP/TEB	Large Power	Feed & Grain	SC-P	Lighting
Staff - 87% of Peak	**100**	48.7664%	10.3855%	26.1872%	13.4408%	0.0098%	1.1171%	0.0931%
Staff - 90% of Peak	**51**	49.1203%	10.3220%	26.0510%	13.3171%	0.0097%	1.1069%	0.0730%
MECG- 90% of Peak	51	49.1203%	10.3220%	26.0510%	13.4618%	0.0097%	0.9621%	0.0730%

A comparison of Staff's allocators using the highest 51 hours (or hours within 10% of the peak) with my modified allocator reinforces that the SC-P profile modification only impacts the allocators for the SC-P and LP classes as described earlier.

2. Classification of distribution plant related to FERC accounts 364-368

Q. WHAT IS STAFF'S METHOD FOR CLASSIFYING DISTRIBUTION PLANT-RELATED TO FERC ACCOUNTS 364-368?

[6] The NARUC manual indicates "all hours of the year within 5% or 10% of the system peak demand as a criteria for choosing the number of hours." See page 46.

A. Similar to the Company, Staff also correctly recognizes that the distribution system associated with equipment designated under FERC accounts 364-368 (such as poles and towers, overhead conductors and devices, underground conduit, underground conductors and devices and line transformers) serve a dual purpose of connecting customer to the distribution network (referred to as customer-related) and fulfilling the demand needs of customers (referred to as demand-related). However, unlike the Company's minimum system ("MS") approach of using actual data to classify the costs in each of these FERC accounts as customer and demand-related, Staff utilized a different method called the Zero-ntercept (ZI") method, which uses statistical techniques to extrapolate this classification. Staff classified costs in FERC accounts 364, 366 and 368 using this methodology. The costs in the two remaining FERC accounts, 365 and 367 appear to have been classified in accordance with the Company's approach.

Q. WHAT IS THE ZERO-INTERCEPT METHOD?

A. Aside from the minimum system approach, the ZI method is another method recognized by the NARUC manual for classifying certain distribution plant. On page 92, the NARUC manual provides the following description regarding this method:

> The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum size method. In most instances, it is more accurate, although the differences maybe relatively small. The technique is to relate installed costs to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression technique, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component (page 92)

Q. PLEASE COMMENT ON STAFF'S RECOMMENDED APPROACH.

A. As quoted above, the NARUC manual indicates that the differences in results between the MS and ZI methods should be relatively small. However, in the categories where Staff used the ZI method, the differences are very significant. For example, for Account 364, Staff's method would classify only 22.6% or $44 million as customer-related, whereas the Company's MS method shows that 53.1% or approximately $104 million should be classified as customer-related – the difference is more than two fold. Similarly, in the case of transformer costs in Account 368, Staff estimates that only 9.8% of the costs or approximately $11 million are customer-related versus the Company's results at 43% or about $48 million – the different here is more than four fold. Staff analysis is either not incorporating all the costs or is using inconsistent comparisons. For example, regarding Account 368, Staff's regression analysis shows that the "no-load" number is negative, which suggests that a negative percentage of costs are customer-related.[7] Such a result is not reliable. Given these observations, I believe that overall, Staff needs to vet its analysis further and should not utilize those results in this case.

3. Allocation of costs in category entitled " Miscellaneous and Unassignable Costs"

Q. WHAT ARE SOME ITEMS THAT STAFF ASSIGNS AS MISCELLANEOUS AND UNASSIGNABLE COSTS?

A. While there are several cost categories, some of the largest items are: Intangible and General Plant ($112.6 Million), Administrative & General **(**$43.8 Million), and Materials and Supplies ($31.6 million).

[7] See Kliethermes Working Papers, Minimum Study.xlsx (tab 368)

Q. HOW DOES STAFF ALLOCATE THESE COSTS TO CLASSES?

A. Staff uses the energy allocator to allocate these costs to classes.

Q. SHOULD THESE COSTS BE ALLOCATED ON THE BASIS OF THE ENERGY ALLOCATOR?

A. No. Staff's overreliance on the energy allocator is unwarranted.[8] In the past case, Staff did not consider such costs miscellaneous and allocated them based on factors that were more reflective of cost causation than using the energy allocator. Schedule KM-R2 shows a listing of the allocators used for these categories. I recommend that Staff use the previous allocators for such categories in this case.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING STAFF'S COSS?

A. To summarize, I recommend the following modifications to Staff's COSS:

- Utilize the A&E production allocator or, in the alternative, revise Staff's highest hours production cost allocator such that it reflects the adjustment to SC-P class load and uses class contribution to the highest 51 hours;
- Modify the classification of distribution costs in FERC Accounts 364, 366 and 368 to reflect the classification split utilized by the Company;
- At a minimum, allocate cost categories such General Plant, Administrative & General, and Materials and Supplies using allocator types from Staff's COSS in the previous case in Docket No: ER-2016-0023.

[8] The reliance on the energy allocator is punitive to high load factor classes such as the LP class that use energy in a more efficient manner (i.e., use a greater number of kilowatt hours for each kilowatt of demand). For example, the residential class has variability in its load profile and the LP class has a much more consistent load profile pattern as shown on Figure 3 of Mr. Timothy Lyons direct testimony on page 7.

IV. CLASS COST OF SERVICE STUDY RESULTS

Q. WHAT IS STAFF'S ADJUSTED REVENUE REQUIREMENT?

A. Staff's results indicate that the Company's total cost of service is approximately $492 million, and after netting for the jurisdictional portion of other revenues, the rate schedules should be revised to produce revenues of approximately $448.9 million, a reduction of $36.4 million. The Company's current tariffed rates on an annualized and normalized basis produce revenues of $467.5 million after adjusting for the temporary tax rider related credits of $17.8 million.

Q. DID YOU PREPARE COSS RESULTS USING STAFF'S REVENUE REQUIREMENT AND AFTER ADJUSTING STAFF'S COSS WITH YOUR RECOMMENDATIONS?

A. Yes, I did. Staff's workpapers included two COSS models in order to show the impacts on each class' rates of return at current tariffed rate revenues, with and without the impact of the temporary tax rider. In order to show an apples-to-apples comparison with Staff's results, I used both models and made adjustments as discussed in Section III. The detailed summary of results from both these models are provided in KM Schedule-R3.

Q. PLEASE PROVIDE A COMPARISON BETWEEN STAFF AND YOUR RESULTS FOR THE RATES OF RETURN WITH AND WITHOUT THE TEMPORARY TAX RIDER IMPACTS.

A. Table 3 shows the comparison. Important findings are as follows:

- From a directional standpoint, both Staff and my COSS show class rates of return ("ROR") higher than the system average for the CB/SH, GP/TEB and LP classes respectively. However, the magnitude varies. For example, my LP class ROR's are higher than Staff's results.
- Similarly, both Staff and my COSS show a residential ROR that is lower than the system average. Once again, the magnitude varies, as my COSS shows a lower ROR for this class as compared to Staff.
- The biggest difference from a directional standpoint is that Staff's COSS produces a ROR for the SC-P class that is lower than the system average and my results show an ROR for this class that is above the system average.

Table 3: Rates of Return Comparison at Tariffed Rates With and Without Tax Credit

	Rate of Return at Tariffed Rates		Rate of Return at Tariffed Rates Reduced by Tax Credit	
	Staff	MECG	Staff	MECG
Residential	6.78%	4.80%	5.53%	3.63%
CB/SH	12.83%	11.79%	11.37%	10.35%
GP/TEB	12.50%	16.19%	11.12%	14.67%
LPS	12.10%	16.80%	10.90%	15.47%
Feed & Grain	-36.17%	-133.54%	-37.28%	-134.99%
SC- P	7.48%	14.22%	6.30%	12.82%
Lighting	30.35%	22.47%	28.70%	20.87%
Total	8.49%	8.49%	8.49%	8.49%

Q. PLEASE PROVIDE A COMPARISON BETWEEN STAFF AND YOUR RESULTS FOR THE CHANGE NEEDED TO BRING EACH CLASS TO COST OF SERVICE, WITH AND WITHOUT THE TEMPORARY TAX RIDER IMPACTS.

A. Tables 4(a) and 4(b) show the changes needed for each class, both with and without the tax credit, in order to bring each class to cost of service.

Table 4(a): Comparison of Changes Needed to Tariffed Rates at Equal ROR

	$ Change to Tariffed Rates at equal ROR		% Change to Tariffed Rates at Equal ROR	
	Staff	MECG	Staff	MECG
Residential	$2,388,332	$16,983,848	1.07%	7.63%
CB/SH	-$7,988,723	-$6,676,789	-14.60%	-12.20%
GP/TEB	-$18,427,352	-$28,154,718	-14.32%	-21.88%
LPS	-$8,947,607	-$15,685,855	-13.39%	-23.47%
Feed & Grain	$90,323	$290,648	109.92%	353.71%
SC- P	-$45,766	-$792,220	-1.00%	-17.26%
Lighting	-$3,453,929	-$2,349,636	-44.18%	-30.06%
Total	-$36,384,722	-$36,384,721	-3.82%	-3.82%

Table 4(b): Comparison of Changes Needed to Tariffed Rates Reduced by Tax Credit at Equal ROR

	$ Change to Tariffed Rates Reduced by Tax Credit at equal ROR		% Change to Tariffed Rates Reduced by Tax Credit at equal ROR	
	Staff	MECG	Staff	MECG
Residential	$10,893,974	$25,493,726	4.89%	11.45%
CB/SH	-$5,929,498	-$4,621,938	-10.83%	-8.44%
GP/TEB	-$13,698,257	-$23,425,510	-10.65%	-18.21%
LPS	-$6,790,801	-$13,529,047	-10.16%	-20.25%
Feed & Grain	$92,642	$292,986	112.74%	356.56%
SC- P	$110,334	-$636,126	2.40%	-13.86%
Lighting	-$3,208,829	-$2,104,526	-41.05%	-26.92%
Total	-$18,530,435	-$18,530,434	-3.82%	-3.82%

Important highlights are as follows:

- My results show that with or without tax credits, the dollar and percent changes needed at equalized ROR for the residential class are significantly higher than Staff results. For the changes needed to tariffed rates, Staff's results show a positive adjustment of $2.38 million or 1.07% as compared to my results of $16.98 million or 7.63%. For the changed needed to tariffed rates reduced by the tax credit, Staff's results show a positive adjustment of $10.89 million or 4.89% as compared to my results of $25.49 million or 11.45%.

- My suggested change needed for the LP class is roughly double that of Staff's results. While Staff shows a negative adjustment of $8.9 million, my results show the negative adjustment should be $15.68 million at tariffed rates. For the change needed to tariffed rates reduced by the tax credit, Staff's results show a negative adjustment of $6.8 million as compared to my results of $13.5 million.
- Regarding the SC-P class, as has been noted, my COSS shows substantial negative adjustments compared to Staff's results at tariffed rates with and without the tax credit.

Q. PLEASE PROVIDE A COMPARISON BETWEEN STAFF AND YOUR RESULTS REGARDING THE PERCENT OF OVER OR UNDER CONTRIBUTION AT CURRENT RATES, WITH AND WITHOUT THE TAX CREDIT.

A. Table 5 provides this comparison. The level of over or under recovery is consistent with the results and comparisons discussed above.

Table 5: Comparison of % Under/ Over Contributions at Current Rates with and without Tax Credit

	% (Under) Over Contribution at Current Rates		**% (Under) Over Contribution at Current Rates Reduced by Tax Credits**	
	Staff	MECG - Staff Revised	Staff	MECG - Staff Revised
Residential	-1.06%	-7.09%	-4.67%	-10.28%
CB/SH	17.09%	13.89%	12.15%	9.22%
GP/TEB	16.72%	28.01%	11.92%	22.26%
LPS	15.46%	30.67%	11.31%	25.38%
Feed & Grain	-52.36%	-77.96%	-52.99%	-78.10%
SC- P	1.01%	20.87%	-2.35%	16.09%
Lighting	79.16%	42.97%	69.63%	36.84%
Total	3.97%	3.97%	3.97%	3.97%

Q. DID YOU ALSO RUN STAFF'S COSS MODEL, AT STAFF'S RECOMMENDED REVENUE REQUIREMENT USING YOUR A&E 6NCP PRODUCTION COST ALLOCATOR?

A. Yes, I did. While I would have preferred to also show COSS results based on Staff's updated demand and energy data using my A&E 6NCP approach, Staff's monthly CP and NCP data showed some inconsistencies.[9] As a result, I used the allocator I had developed for the COSS in direct testimony. Using Staff's CCOSS models (with and without the tax credit), I made the same adjustments to Staff's models as discussed in Section III, except that I replaced the revised production allocator (based on the top 51 hours) with my A&E6NCP allocator. A detailed summary is provided in KM Schedule-R4. Table 6 shows the ROR and dollar and percent changes needed to tariffed rates with and without the tax credit. The results of using the A&E 6NCP are similar in comparison to the modified COSS results shown earlier. This is not surprising considering that both production allocators choose peaks that are within 10% of the system peaks.

Table 6: MECG A&E 6NCP Results

	ROR at Tariffed Rates	ROR at Tariffed Rates Reduced by Tax Credits	$ Change to Tariffed Rates at Equal ROR	$ Change to Tariffed Rates Reduced by Tax Credits at Equal ROR
Residential	4.50%	3.34%	$19,312,911	$27,822,789
CB/SH	12.51%	11.05%	-$7,594,891	-$5,540,041
GP/TEB	17.98%	16.41%	-$32,587,817	-$27,858,609
LPS	16.44%	15.12%	-$15,204,470	-$13,047,663
Feed & Grain	-110.83%	-111.91%	$316,498	$318,838
SC- P	21.24%	19.65%	-$1,380,218	-$1,224,123
Lighting	3.82%	2.74%	$753,260	$998,371
Total	8.49%	8.49%	-$36,384,727	-$18,530,438

[9] For example, for the SC-P class, the monthly non-coincident peak KW was lower than the monthly coincident peak data for 9 out of 12 months. Since class non-coincident peak is meant to reflect the highest demand, it should necessarily be higher than the class coincident peak demand. Further, according to the hourly data, the highest peak occurs on March 5, 2019 (942,780 KW). However, the monthly coincident peak data shows the highest peak occurs in January 2019 (946,227 KW).

V. REVENUE ALLOCATION

Q. WHAT IS STAFF'S REVENUE ALLOCATION APPROACH?

A. Staff bases its revenue allocation on its recommended $36.4 million reduction and includes a two-step approach:

- In the first step, Staff recommends that all classes should retain its portion of the temporary tax rider credits, which is approximately $17.8 million; and
- In the second step, Staff recommends that the remaining $18.6 million reduction should be assigned as follows: 25% to CB/SH, 25% to LP and 50% to GP/TEB.

Q. PLEASE COMMENT ON STAFF'S REVENUE ALLOCATION APPROACH.

A. Staff's revenue allocation approach is driven, in large part, by its COSS results and I appreciate that Staff is making efforts to move classes towards cost. However, as discussed above, Staff COSS model had some issues that needed to be addressed. Consequently, I recommend that the revenue allocation approach should either rely on Staff's COSS, as adjusted consistent with this testimony, or my A&E 6NCP approach. As indicated in direct testimony, I continue to recommend greater movement towards cost. If there is a large overall rate decrease as recommended by Staff, more aggressive steps should be taken to align rates with costs. If the decrease is smaller, then the Commission should consider, in an effort to bring classes closer to cost of service, not maintaining each class' portion of the tax rider credits.

VI. LP AND SC-P RATE DESIGN

Q. WHAT IS STAFF'S RATE DESIGN RECOMMENDATION FOR THE LP AND SC-P CLASSES?

A. It is my understanding that for both the classes, Staff's recommendation consists of two steps. In the first step, Staff determines a limit on decreasing the energy charges and, after adjusting for the energy charge decreases, an equal percent decrease is applied to all remaining components of the bill. Staff considered the following average load weighted and loss adjusted LMPs in developing its limit for the energy charge decreases:

- LGS transmission: $0.02918 / kWh
- LGS Primary: $0.029847 / kWh
- LGS Secondary: $0.030472 / kWh

Q. WHAT ARE STAFF'S RESULTING RECOMMENDATIONS FOR THE LP CLASS?

A. Table 6 shows Staff's recommendation based on Staff's revenue decrease for the LP class. As can be observed, Staff's limits on any energy charge decreases results in lower percent decreases for the energy charges as compared to the other charges.

Table 6: Staff Recommended Rate Design for LP Class

	Current Charges	Current Net of Taxes	Staff Recommendation	% Change Compared to Current	% Change Compared to Current Net of Taxes
Customer Charge	$283.55	$283.55	$223.74	-21%	-21%
Summer Demand	$15.69	$15.69	$12.38	-21%	-21%
Winter Demand	$8.66	$8.66	$6.83	-21%	-21%
Facilities Demand	$1.88	$1.88	$1.48	-21%	-21%
Summer 1st 350 HU	$0.06809	$0.06511	$0.06002	-12%	-8%
Summer Add. HU	$0.03683	$0.03385	$0.03536	-4%	4%
Winter 1st 350 HU	$0.06048	$0.05750	$0.05402	-11%	-6%
Winter Add. HU	$0.03552	$0.03254	$0.03432	-3%	5%

Staff has a similar approach for the SC-P class with more specificity in the time of use rate related relationships between on peak, off peak and shoulder peak rates.

Q. PLEASE COMMENT ON STAFF'S RECOMMENDED RATE DESIGN APPROACH.

A. I believe that Staff's limits on decreasing the energy charges are too stringent because while the load weighted and loss adjusted LMPs are about $0.03/kWh, the recommended energy charges are still much higher. Specifically, Staff's recommended energy charges in the tail block remain 14-18% above its suggested energy charge limit. Further, Staff recommends a 21% reduction in the customer, demand and facilities charge, which does not result in efficient pricing signals for several reasons:

First, the Company's evidence indicates that a significant amount of fixed costs are currently collected through variable charges (the energy charge) instead of through a fixed charge (the demand or facilities charge). Thus, the Company's proposal is to decrease the energy charges even with a proposed overall rate increase because of significant under-recovery of fixed costs from both the billing demand and facility demand charges.

Second, it is my understanding that the Company is expected to file a rate case soon after the current case is completed in order to recover significant investment in wind generation. The addition of this wind generation will have the effect of increasing fixed costs and reducing variable costs. As a result, the demand charges should increase in that case. I question whether the Commission should reduce demand charges, as recommended by Staff, simply to increase those charges in the next case to reflect increased investment.

As a result of these factors, it makes more sense to retain the current fixed charges and instead, allocate the entirety of any revenue decrease to lowering the energy charges. I recommend this same approach for the LP and SC-P classes.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.