BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District	)	
Electric Company's Request for Authority	)	
to File Tariffs Increasing Rates for Electric	)	Case No. ER-2019-0374
Service Provided to Customers in its	)	
Missouri Service Area	)	

INITIAL POSTHEARING BRIEF

OF

MIDWEST ENERGY CONSUMERS GROUP

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In the Matter of The Empire District Electric Company's Request for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2019-0374

COMES NOW the Midwest Energy Consumers' Group ("MECG"), pursuant to the Commission's April 28, 2020 *Order Further Modifying the Procedural Schedule*, and provides its Initial Brief in this matter. In this Brief, MECG provides its discussion on certain issues of utmost importance to large commercial / industrial customers especially issues related to: class cost of service / revenue allocation / rate design and return on equity / capital structure / cost of debt. In addition, MECG provides briefing on WNG / SRLE mechanism; the Tax Cut and Jobs Act of 2017 impact; as well as the treatment of the Asset Retirement Obligation. MECG may provide, in subsequent briefing, its response to positions advanced by other parties in their initial briefs.

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I. INTRODUCTION

It is well accepted that energy rates play a fundamental role in an industrial company's ability to compete in a global market. In fact, less than five years ago, the Commission expressly recognized the importance of competitive industrial rates.

> Competitive industrial rates are an important factor in helping to retain and expand industry within the utility's service area. Business retention and expansion result in positive impacts on local economy and employment. Further, if businesses relocate or expand in Empire's service area, it has the potential of lowering costs for customers as the fixed costs are spread over larger amount of billing determinants. The converse is also true – if businesses shift operations from Empire's area, the remaining customers bear the burden of the same fixed costs but over a smaller amount of billing determinants thereby increasing rates for all customers. Thus, the Commission should be cognizant of how its decisions affect industrial rates.[1]

Given the undisputed importance of competitive industrial electric rates, MECG analyzed Empire's industrial rates. Discouragingly, the evidence shows that Empire's industrial rates are becoming more uncompetitive. Specifically, while Empire's industrial rates were 16.7% above the national average just five years ago, Empire's industrial rates are now 21.1% above the national average industrial rate.[2] The evidence is even more disconcerting when viewed on a regional basis. Specifically, MECG showed that, of the 95 investor-owned electric utilities operating in 28 Midwest and Central states, Empire's industrial electric rate is 12th highest.[3]

[1] *Report and Order*, Case No. ER-2014-0351, issued June 24, 2015, page 18.
[2] Exhibit 350, Maini Direct, page 9 (citing to EEI Typical Bills and Average Rate Report, Summer 2019).
[3] *Id.* at page 9 and Schedule KM-2.

INDUSTRIAL RATES

Utility	State	Rate	Utility	State	Rate
KCPL	Kansas	10.05	PacifiCorp	Idaho	6.87
Indiana Michigan Power	Michigan	9.79	El Paso Electric	Texas	6.86
Northwestern Wisc. Electric	Wisconsin	9.40	El Paso Electric	N.Mexico	6.84
Duke Energy - Ohio	Ohio	9.04	Mississippi Power	Mississippi	6.82
Tucson Electric Power	Arizona	9.01	Louisville Gas & Electric	Kentucky	6.69
Montana Dakota Utilities	N. Dakota	8.99	Westar - KGE	Kansas	6.68
Montana Dakota Utilities	S. Dakota	8.89	Toledo Edison	Ohio	6.67
Indianapolis Power & Light	Indiana	8.88	GMO	Missouri	6.64
Black Hills Power	Wyoming	8.61	Minnesota Power Company	Minnesota	6.59
Black Hills Power	Colorado	8.51	Otter Tail Power	Minnesota	6.59
Empire	Kansas	8.45	Entergy Mississippi	Mississippi	6.55
Empire	Missouri	8.37	DTE Electric	Michigan	6.55
Arizona Public Service	Arizona	8.33	American Electric Power	Kentucky	6.50
Madison Gas & Electric	Wisconsin	8.28	Cheyenne Light, Fuel & Power	Wyoming	6.38
Black Hills Power	S. Dakota	8.24	Dayton Power & Light	Ohio	6.37
Westar - KPL	Kansas	8.16	Ameren	Missouri	6.36
Northern States Power	Minnesota	8.15	Southwestern Electric Power	Texas	6.31
We Energies	Wisconsin	8.07	Public Service Company - Col.	Colorado	6.30
Consumers Energy	Michigan	7.91	Superior Water, Light & Power	Wisconsin	6.30
South Indiana Gas & Electric	Indiana	7.91	Northern States Power	Michigan	6.29
KCPL	Missouri	7.85	Alabama Power	Alabama	6.17
Nevada Power	Nevada	7.85	PacifiCorp	Wyoming	6.15
AEP - Columbus	Ohio	7.72	American Electric Power	Tennessee	6.12
Wisconsin Power & Light	Wisconsin	7.68	Kentucky Utilities	Kentucky	5.96
AEP - Ohio Power	Ohio	7.67	Southwestern Electric Power	Arkansas	5.92
Northern States Power	Wisconsin	7.62	PacifiCorp	Utah	5.91
Empire	Oklahoma	7.61	Wisconsin Public Service	Wisconsin	5.83
Montana Dakota Utilities	Wyoming	7.59	Entergy Arkansas	Arkansas	5.80
Duke Energy - Kentucky	Kentucky	7.53	Upper Mich. - Wisc. Pub. Serv.	Michigan	5.72
Interstate Power & Light	Iowa	7.52	MidAmerican	Iowa	5.67
CLECO Power	Louisiana	7.49	Upper Michigan - We Energies	Michigan	5.51
Duke Energy - Indiana	Indiana	7.49	Public Service Company - N.Mex.	N.Mexico	5.49
Empire	Arkansas	7.45	Idaho Power	Idaho	5.45
Northern States Power	S. Dakota	7.38	MidAmerican	Illinois	5.35
Northwestern Energy	Montana	7.29	Sierra Pacific	Nevada	5.24
Entergy New Orleans	Louisiana	7.21	Avista	Idaho	5.17
Otter Tail Power	N. Dakota	7.17	Upper Peninsula	Michigan	5.11
Northern Indiana Pub. Serv.	Indiana	7.16	Entergy Gulf States	Louisiana	5.08
Southwestern Electric Power	Louisiana	7.12	Southwestern Public Service	N.Mexico	5.01
Northern States Power	N. Dakota	7.11	OG&E Electric	Arkansas	5.00
AEP - Indiana Michigan	Indiana	7.04	Public Service Company - Ok.	Oklahoma	4.95
Otter Tail Power	S. Dakota	7.00	Entergy Louisiana	Louisiana	4.89
Montana Dakota Utilities	Montana	7.00	MidAmerican	S. Dakota	4.85
Unisource Electric	Arizona	6.93	Entergy Texas	Texas	4.76
Northwestern Energy	S. Dakota	6.92	OG&E Electric	Oklahoma	4.73
Black Hills Power	Montana	6.90	Cleveland Electric Illuminating	Ohio	4.30
Ohio Edison	Ohio	6.88	Southwestern Public Service	Texas	4.16
Commonwealth Edison	Illinois	6.88			

The general statistics provided in the EEI Typical Bills and Average Rates Report are supported by the real life experience of Empire customers. Specifically, in his surrebuttal testimony, Steve Chriss from Walmart indicates that the EEI data showing the uncompetitive nature of Empire's industrial rates is consistent with Walmart's experience. Given its operations in all 50 states and the District of Columbia, Walmart is "able to easily benchmark our utility cost in one market against other utilities in that market as well as against regional and national benchmarks."[4] Based upon its operational experience through the United States, Mr. Chriss concludes:

> **[redacted]**[5]

There are three ways that the Commission can address the competitiveness of Empire's industrial rates. ***First***, the Commission should thoroughly analyze the various revenue requirement issues and make certain that Empire's rates are set at the lowest possible cost while still ensuring safe and adequate service. Of utmost importance, in this regard, is the authorized return on equity and the capital structure to which that return on equity is applied.[6]

Second, the Commission should carefully review the class cost of service studies filed in this case and seek to eliminate any interclass subsidies. In this case, class cost of service studies presented by Empire, Staff and MECG all show that there is a significant

[4] Exhibit 353, Chriss Surrebuttal, page 5.
[5] *Id.* at page 7.
[6] MECG is a signatory to the Non-Unanimous Stipulation and Agreement. Pursuant to that agreement, the signatories all agree that no change to Empire's revenue requirement provides for safe and adequate service at just and reasonable rates.

residential subsidy in in that the residential class is not paying rates that cover its cost of service. In contrast, in order to compensation for this residential subsidy, all of the commercial and industrial rate classes are paying rates that are above cost of service.

Third, as pertains to rate design, the Commission should consider each class' allocated share of fixed and variable costs and make sure that energy charges only collect variable costs and that all fixed costs are collected through the relevant facilities or demand charges. The inappropriate collection of fixed costs through energy charges results in an intraclass subsidy that hinders the high load factor customers that utilize the electric system in the most efficient manner.

Through this brief, MECG addresses several key issues that will help guide the Commission in its efforts to make Empire's industrial rates more competitive.

II. OVERVIEW OF POSITIONS

1. **Rate of Return—Return on Equity, Capital Structure, and Cost of Debt**:

a. Return on Common Equity – what return on common equity should be used for determining rate of return?

Position: As reflected in both the testimony of the Commission's Staff as well as Public Counsel, MECG recommends that the Commission authorize a return on equity of 9.25%. Such a position reflects the fact that the analysis provided by Empire is inherently unreliable and is fraught with many of the same defects that has previously caused the Commission to find Mr. Hevert's recommendations to be "too high." Furthermore, as explained in the section addressing Empire's request to implement a weather normalization mechanism, the Commission is tasked to consider the reduction in Empire's business risk as a result of implementing such a mechanism. To the extent that the Commission authorizes such a mechanism, the Commission should consider an explicit 10-15 basis point reduction in the return on equity that would have otherwise been authorized in this matter.

b. Capital structure – what capital structure should be used for determining rate of return?

Position: As reflected at page 5 of the direct testimony of David Murray, MECG recommends that the Commission utilize a capital structure consisting of 46% common equity and 54% long term debt. Such a capital structure is consistent with merger conditions agreed to by Empire and its parent company and recognizes a capital structure that allows Empire to earn a reasonable return on equity while also minimizing the cost of capital for ratepayers. Specifically, such a capital structure avoids concerns that Liberty Utilities has manipulated the capital structure of its regulated subsidiaries in order to maximize corporate profits.

c. Cost of debt – what cost of debt should be used for determining rate of return?

Position: MECG recommends that Empire's embedded cost of debt is 4.65%.

2. **Rate Design, Other Tariff and Data Issues**:

z. How should production plant-related costs be allocated to each rate class?

Position: In this case, Empire and MECG both assert that the Commission should utilize the Average & Excess ("A&E") methodology for allocating fixed production plant related costs to the various rate classes. The A&E methodology has been adopted by all of the Missouri electric utilities as well as by the vast majority of the state public utility commissions. In contrast, Staff has proposed the Highest Hours approach that has never been tried in any state and was only recently suggested in a publication. While Empire and MECG both agree that the Commission should utilize the A&E approach, MECG suggests that the Commission should rely on the six highest monthly peaks (6NCP) variation, while Empire waters down this cost causation approach and utilizes a 12 months approach. Therefore, MECG recommends that the Commission adopt the A&E 6NCP fixed production cost allocator.

aa. How should plant accounts 364, 366 and 368 be classified?

Position: The Commission should adopt the minimum size approach, advocated by Empire and MECG, for classifying Account 364, 366, and 368 distribution costs as demand or customer related. Staff's zero intercept approach leads to illogical results and should be rejected.

bb. How should primary and secondary distribution plant facility costs be allocated to each rate class?

Position: Once the Commission has classified distribution costs as either demand or customer-related, it must then determine how to allocate these costs to the various customer classes. All the parties agree that the customer-related portion of these distribution costs should be allocated on the basis of each class' number of customers. In contrast, the parties differ on the manner in which the demand-related portion of distribution costs should be allocated. MECG proposes that the Commission allocate the demand-related portion of these costs based upon each class' single largest monthly peak (i.e., 1NCP). This methodology is consistent with the way that Ameren has allocated these costs as well as the manner in which Empire has historically allocated such costs.

cc. How should General Plant facility costs be allocated to each rate class?

Position: Empire and MECG have both allocated these costs (consisting of various general plant and Administrative & General costs) on the basis of an allocator that reflects the manner in which such costs are incurred. In contrast, Staff has simply labeled these costs as "miscellaneous and unassignable costs" and then allocated the costs using an energy allocator that is punitive to high load factor classes, like the large commercial and industrial class. As the evidence indicates, the energy allocator is totally unrelated to the manner in which these costs are incurred and should be rejected in favor of the allocators recommended by Empire and MECG.

r. How should any revenue requirement increase or decrease be allocated to each rate class?

Position: As it has done in the last two Empire rate cases, the Commission should take steps to further reduce the residential subsidy. It is apparent, however, given that the residential subsidy continues to increase, that steps taken in recent cases have not gone far enough to address this subsidy. Given this, MECG recommended that, much as it has done in previous cases, the Commission eliminate 25% of the existing residential subsidy.[7] Such a movement would lead to a 4.2% increase for the residential class and improve the competitiveness of rates for all commercial and industrial rate classes.

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[7] Maini Direct, page 35.

Such a shift is not punitive. The Non-Unanimous Stipulation provides for no rate change. Therefore, if the stipulated no rate change is approved by the Commission, the revenue neutral shift would only result in a residential increase of 4.2%. In its original filing, Empire sought an increase for the residential class of 5.8%. Thus, even with the partial elimination of the residential subsidy, residential customers will still see a smaller increase than they were initially expecting from this case.

e. How should the rates for each customer class be designed?

Position: While the previous issue seeks to correct the significant interclass subsidy that exists in rates, this issue seeks to correct for the intraclass subsidy in the rates of the LP, GP and SC-P rate classes. Specifically, MECG proposes that any rate decrease for the LP, GP and SC-P rate classes be reflected by reducing the energy blocks of each class. In this way, all other charges (customer and demand charges) used for the collection of fixed costs would remain at current levels. On the other hand, in the unlikely event of a rate increase, energy charges should remain at current levels and the demand charges proportionally increased. In its rebuttal testimony, Empire agreed with MECG's proposal. "The Company supports MECG's recommendation to apply approved increase for the LP class to the billing demand and facility charges and apply any approved decreases to the energy charge. This approach better aligns recovery of demand-related costs through demand charges and energy-related costs through energy-related charges."

4. **WNR and SRLE Adjustment Mechanisms**:

a. Should the Commission approve, reject, or approve with modifications Empire's proposed Weather Normalization Rider?

b. Is it lawful for the Commission authorize Empire to implement a Sales Reconciliation to Levelized Expectations ("SRLE") mechanism, such as those Staff and Empire are proposing in this case?

c. Should the Commission adopt Staff's Sales Reconciliation to Levelized Expectations Proposal ("SRLE") or approve the SRLE with modifications as suggested by the Company?

Position: The Commission should approve the WNR / SRLE mechanism set forth in the Non-Unanimous Stipulation. Section 386.266.3 provides statutory authority for the Commission to establish a mechanism authorizing "periodic rate adjustments outside of general rate proceedings to adjust rates of customers in eligible customer classes to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both." Recognizing that a significant portion of the residential fixed costs are collected through the residential energy charge, the utility is particularly susceptible to under-recovering its fixed costs as a result of weather and conservation. Therefore, the implementation of the WNR / SRLE serves to break the linkage between the recovery of residential fixed costs and the residential class' consumption of electricity which may ultimately reduce the frequency of rate cases that have otherwise been caused by Empire's inability to fully recover fixed costs from the residential class.

12. **<u>Tax Cut and Jobs Act of 2017 Federal Income Tax Rate Reduction</u>**:

a. How should the Commission treat the 2017 TCJA regulatory liability the Commission established in Case No. ER-2018-0366 when setting rates for Empire in this case?

<u>Position</u>: Section 393.137, implemented in 2018, provides two things. First, the statute authorizes the Commission to adjust a utility's rates to prospectively account for the 2017 change in the federal corporate tax rate. Second, the statute required the Commission to defer, as a regulatory liability, the financial impact of the tax reduction for the period from January 1, 2018 through the date on which rates were prospectively changed (the "stub period"). The statute then mandates that the Commission include these stub period benefits in rates in the utility's subsequent general rate proceeding.

In Case No. ER-2018-0366, the Commission held that Empire fell within the scope of Section 393.137. Given this, the Commission prospectively changed Empire's rates to account for the reduction in the federal corporate tax rate. In addition, consistent with the statute, the Commission ordered Empire to create a regulatory liability for the benefits that occurred during the stub period. "Having found that section 393.137.3 applies to Empire, the Commission must comply with that statute by ordering Empire to establish a regulatory liability to account for its excess earnings during the period of January 1 through August 30, 2018."

In this case, the Non-Unanimous Stipulation Signatories have complied with Section 393.137. Specifically, the Signatories have included an amortization of the stub period benefits, as required by the statute, while preserving the vast majority of these benefits in Empire's next rate case when a significant investment with wind is included in rates.

25. **<u>Asset Retirement Obligations</u>**:

a. Should Asset Retirement Obligations be included in rate base as a regulatory asset and amortized?

<u>Position</u>: In its Direct Testimony, Empire sought to include certain costs in rate base that it classified as an Asset Retirement Obligation ("ARO"). Historically, the Commission has not allowed for the recovery of ARO's on the basis that, absent a legal obligation for these costs to be incurred, these future costs were speculative and not known and measureable. During settlement discussions, the parties received a better understanding of the costs in question. In fact, unlike an ARO which addresses future speculative costs, the costs in question had already been incurred and were related to asbestos and ash pond remediation associated with certain Empire generating units. Given this, the Signatories included a provision in the Non-Unanimous Stipulation which provides for the treatment of such costs as a regulatory asset, but <u>not</u> as an Asset Retirement Obligation. Given that these costs have been incurred, and are known and measureable, MECG asserts that they should be included in rates in the manner set forth in the Non-Unanimous Stipulation. (See Meyer Supplemental Surrebuttal, pages 2-4).

III. CLASS COST OF SERVICE

z. How should production-related costs be allocated to each rate class?
aa. How should plant accounts 364, 366 and 368 be classified?
bb. How should primary and secondary distribution plant facility costs be allocated to each rate class?
cc. How should General plant facility costs be allocated to each rate class?

A. INTRODUCTION

In this case, class cost of service studies were conducted by Staff, MECG and Empire. While the methodologies differed to some degree, each of the studies reached largely the same conclusion. Specifically, the studies all show that the residential class is paying rates that are significant below its cost of service. In contrast, in order to compensate for this subsidization of residential rates, all of the commercial and industrial rate classes are paying rates that exceed cost of service.

Earned Return by Customer Class

	Empire[8]	MECG[9]	Staff[10]
RG – Residential	2.90%	2.62%	5.46%
CB – Commercial	8.23%	8.16%	11.31%
SH – Small Heating	7.39%	7.12%	11.31%
GP – General Power	11.44%	12.19%	11.11%
SC-P Praxair	9.63%	15.28%	11.38%
Total Electric Bldg.	11.46%	11.37%	11.11%
PFM - Feed Mill	10.59%	10.56%	-36.92%
LP - Large Power	8.34%	9.52%	10.88%
MS – Miscellaneous	-5.21%	-4.94%	28.70%
SPL – Municipal Ltg.	1.77%	1.99%	28.70%
PL – Private Ltg.	26.95%	26.48%	28.70%
LS – Special Ltg.	-6.47%	-7.18%	28.70%
Total Company	6.11%	6.11%	6.11%

[8] Exhibit 350, Maini Direct, page 31 (based upon Exhibit 26, Lyons Direct, Schedule TSL-9). Empire subsequently agreed with certain adjustments to "firm up" the revenues for the interruptible SC-P class and to more appropriately allocate the interruptible credits for this class. This has the effect of increasing the earned return for the SC-P class. (See, Exhibit 28, Lyons Rebuttal, page 10).
[9] Exhibit 350, Maini Direct, page 31.
[10] Exhibit 121, Lange Rebuttal, page 17.

Given the unanimity of this conclusion, MECG asserts that the Commission could simply order revenue shifts to address the residential subsidy without addressing each and every sub issue concerning the class cost of service studies. By ordering revenue shifts, the Commission would continue the progress that it has made in each of the last two Empire rate cases to address the residential subsidy. Nevertheless, in the event that the Commission deems it appropriate to resolve each of these sub issues, MECG provides the following discussion.

B. CLASS COST OF SERVICE ISSUES

In this case, class cost of service studies were presented by 3 parties: Empire, Staff and MECG. "The purpose of a CCOS is to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service."[11] By allocating each cost in a rational manner to the individual rate classes, one can determine the cost of service for each rate class. In the case at hand, class cost of service issues surrounding the allocation of: (1) fixed production-related costs; (2) distribution plant accounts 364, 366 and 368; (3) primary and secondary distribution plant costs; and (4) general plant costs have arisen.

1. FIXED PRODUCTION RELATED COSTS

In general, utilities incur three categories of costs: (1) customer-related costs: costs associated with connecting customers to the distribution system, metering usage and other customer support functions (i.e., meter reading, billing, postage and customer service expenses); (2) energy-related costs: costs that tend to change with the amount of electricity sold (i.e., fuel, fuel handling, and interchange power costs); and (3) demand-related costs: costs associated with meeting maximum electricity demands.

[11] Exhibit 26, Lyons Direct, page 8.

It is well established that the electric industry is very capital intensive. As Mr. Lyons recognizes, "[p]roduction plant is the largest component of the Company's rate base, representing 44.4 percent of total utility plant."[12] Therefore, the single largest issue within an electric class cost of service study involves the allocation of the utility's investment in generating units.

While there are different methods utilized for allocating generation fixed costs, the difference in these methodologies generally concerns the extent to which the methodology treats production plant as an energy-related cost (focused on meeting system energy usage) or a demand-related cost (focused on meeting system peak demand). The evidence indicates, however, that production plant investment is both an energy and demand related costs. In fact, the need to meet a class' energy needs as well as its peak demand drives the utility decision as to the amount of capacity the utility must add as well as the type of capacity added.

The various production allocators fall along a continuum with a pure energy allocator at one end of the spectrum and a 1 NCP pure demand allocator at the other end of the spectrum.[13] The various other production allocators fall within this continuum.

Energy Based ◄──────────────────────► Demand Based

^	^	^	^
Energy Only	Highest Hours	Average & Excess	1NCP

[12] *Id.* at page 20.

[13] In general, production allocators that rely more heavily on class energy usage are beneficial to low load factor classes, like the residential class, that use the system in a more inefficient manner. (See, Exhibit 28, Lyons Rebuttal, page 24). In contrast, production allocators that rely more heavily on class demand are beneficial to high load factor classes, like the industrial classes, that use the system in a more efficient manner.

a. Average & Excess Approach

Recognizing that both class peak demand and energy usage are important to a utility's decision regarding the amount and type of capacity to be added, Empire, MECG and of the Missouri electric utilities rely upon the Average & Excess ("A&E") production allocator methodology. "Like Empire and all of the Missouri utilities, I recommend the A&E demand method."[14] The widespread acceptance of the A&E methodology is understandable when one recognizes the logic implicit in this approach.

> The approach used in this study to allocate production plant was the Average and Excess (A&E) method since it is consistent with how costs are incurred by the Company, ***allocating a portion of production plant based on energy consumption and the remaining portion based on peak demands***.[15]

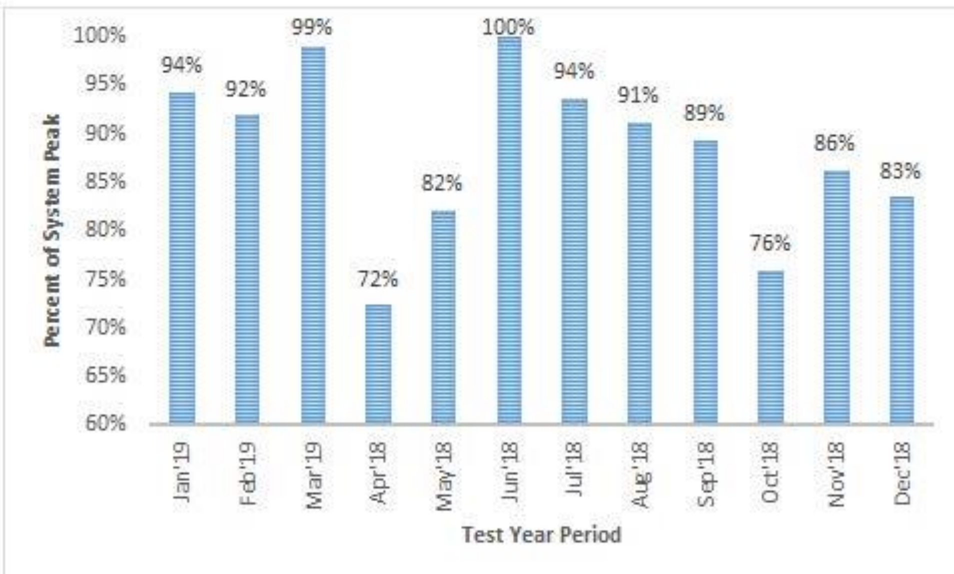
As the name implies, A&E makes a conceptual split of the production plant investment into an "average" component and an "excess" component. The "average" demand, which reflects class energy consumption, is simply each class' total annual kWh usage divided by the total number of hours in the year. This, therefore, is the amount of capacity that would be required to meet the class' energy needs if the class used energy at the same rate for each hour of the year. The excess component, which reflects the class' peak demand, is simply the difference between the system peak demand and the system average demand.[16] As one can see then, both the class energy usage and its peak demands are critical components to the A&E calculation.

While the class peak demand is a necessary component of the A&E methodology, not all monthly peaks influence the utility's decision to add capacity. Rather, only the largest monthly peaks should be considered. As MECG points out, unlike other utilities

[14] Exhibit 350, Maini Direct, page 19.
[15] Exhibit 26, Lyons Direct, page 21 (emphasis added).
[16] Exhibit 350, Maini Direct, page 18; Exhibit 26, Lyons Direct, pages 21-23.

which experience simply a summer peak, Empire typically experiences both a winter and a summer peak. Specifically, Empire experiences a winter peak during the months of January through March as well as a summer peak during the months of June through August.

Figure 4: Liberty-Empire Missouri's Monthly Peak Demands As a Percent of Annual Peak



Source: Exhibit 350, Maini Direct, page 17.

Given that Empire experiences two distinct peaks, covering a period of six individual months, MECG relied upon these 6 monthly peaks for calculating the excess component of the A&E allocator. As MECG points out:

> 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 calculated the A&E methodology.[17]

[17] Exhibit 351, Maini Rebuttal, page 7.

In contrast to MECG's assertion that only the highest 6 monthly peaks should be incorporated into the A&E calculation, Empire relied on all 12 monthly peaks.[18] Given this, Empire considers peaks in April and October which represent only 72% and 76% of the annual peak. Therefore, as MECG points out, Empire's 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."[19]

The fact that these other months are not critical to Empire's decision to add generation is best highlighted by the fact that Empire, in performing its Integrated Resource Plan, does not rely upon all 12 monthly peaks, but rather only considers two peaks - the highest winter and highest summer peaks.[20] For this reason, MECG recommends that the Commission rely upon the 6NCP variation of the A&E methodology to allocate fixed production plant-related costs.

The Commission is well versed in the A&E approach. At various times, the Commission has expressly utilized this approach. Specifically, in a recent Ameren case, Ameren proposed the use of the A&E approach.[21] Ultimately, the Commission adopted Ameren's approach. "After carefully considering all the studies, the Commission finds that AmerenUE's class cost of service study, modified to allocate revenues from off-system sales on the basis of class energy requirements, is the most reliable of the submitted studies."[22]

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[18] In all other ways, Empire's A&E calculation mirrors that of MECG.
[19] Exhibit 351, Maini Rebuttal, page 7.
[20] *Id.*
[21] "The studies presented by AmerenUE and MIEC used versions of the Average and Excess Demand Allocation method (A&E)." *Report and Order*, Case No. ER-2010-0036, issued May 28, 2010, page 82.
[22] *Id.* at page 87.

Additionally, the A&E approach has seen widespread acceptance throughout the electric utility industry. As mentioned previously, the A&E approach has been adopted by all of the Missouri electric utilities.[23] In addition, the public utility commission of virtually every vertically integrated state relies upon the A&E approach.

► Louisiana: "In light of all the relevant evidence, the commission deems it appropriate to allocate the rate increase under the average and excess method proposed by Gulf States. This method reflects the theoretical justifications for a rate design that reflects an allocation of embedded costs but tends somewhat to spread the impact of the cost allocation. This approach furthers the overall interests historically considered by the commission in designing rates and is consistent with the purposes of PURPA. ***In addition, it reflects the concern of the commission that the rates assigned to industrial customers in Louisiana not reach a level at which these firms would be placed in an untenable competitive position***."[24]

► Oklahoma: "The allocation of production demand-related costs to the various retail customer classes in the class COSS is based on a 4CP Average & Excess (4CP A&E) methodology. The peak demands for the summer months of June through September for the years of 2006 to 2009 are consistently the highest monthly peak demands incurred on the system. By using the 4CP A&E method, PSO ensured that all customers who benefit from the use of the Company's generation system will be allocated a reasonable share of the cost of developing and operating that system."[25]

► Texas: "The ALJs begin by examining the final decision in the ETI case in Docket No. 39896. In that document, the utility proposed to allocate capacity-related production and transmission costs to the retail classes based on A&E/4CP. The utility had used the same method in its last contested rate proceeding. In the Final Order approving ETI's previous application, the Commission found that the continued use of the A&E/4CP

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[23] Exhibit 350, Maini Direct, page 19.

[24] Re: Gulf States Utilities Company, Louisiana Public Service Commission, Docket No. U-14495, issued November 17, 1980 (emphasis added). *See also*, Re: Gulf States Utilities Company, Louisiana Public Service Commission, Docket No. U-17282, issued March 1, 1991. ("The company has proposed to redesign its rates for the residential, commercial and industrial classes. Any design of rates must begin with the development of a cost of service study. Consistent with the Commission's past practice, the company utilized the Average and Excess Demand Method to allocate costs.").

[25] Re Public Service Company of Oklahoma, Oklahoma Corporation Commission, Cause No. PUD 201000050, issued January 5, 2011. *See also*, Re: Oklahoma Gas & Electric Company, Oklahoma Corporation Commission, Cause No. PUD 201100087, issued July 9, 2012 ("A 4CP Average and Excess allocation method using the above adjustments will be used for allocation of costs between Oklahoma jurisdiction customer classes."); Re: Public Service Company of Oklahoma, Oklahoma Corporation Commission, Cause No. PUD 200800144, issued January 14, 2009 ("The allocation of production demand-related costs to the various retail customer classes in the class cost-of-service was based on a 4CP A&E methodology."); Re: Oklahoma Gas & Electric Company, Oklahoma Corporation Commission, Case No. PUD 201000037, issued July 29, 2010; Re: Oklahoma Gas & Electric Company, Oklahoma Corporation Commission, Case No. PUD 900000898, issued February 25, 1994.

method was reasonable for allocating transmission costs and that the A&E/4CP method was "devoid of any double counting problem." The "double counting problem" is a reference to an error in the A&P calculation method by which a part of the demand data is counted twice. The Commission has been aware of the flaw since at least 1988, when an examiner's report rejected the use of another method for the same reason. Accordingly, because of the A&P method's flaws, we narrow the scope of our analysis by rejecting Mr. Johnson's recommendation that SWEPCO use the A&P method.

The continued use of the A&E 4CP allocator is the most reasonable methodology for allocating production and transmission plant among classes. The A&E 4CP allocator sufficiently recognizes customer demand and energy requirements and assigns cost responsibility to peak and off-peak users. It best recognizes the contribution of both peak demand and the pattern of capacity use throughout the year."[26]

►Arkansas: Recently the General Assembly passed Act 725. Codified at 23-4-422(b)(2), that legislation mandates the utilization of the Average & Excess method for the allocation of fixed production costs.

> (A) For the retail jurisdiction rate classes, ensure that all electric utility production plant, production related costs, all nonfuel production-related costs, purchased capacity costs, and any energy costs incurred resulting from the electric utility's environmental compliance are classified as production demand costs.
>
> (B) ***Ensure that production demand costs are allocated to each customer class pursuant to the average and excess method*** shown in Table 4-10B

[26] Re: Southwestern Electric Power Company, Texas Public Utility Commission, PUC Docket No. 40443, issued May 20, 2013 (citations omitted, emphasis added); *See also*, Re: Southwestern Electric Power Company, Texas Public Utility Commission, PUC Docket No. 40443, issued October 10, 2013 ("SWEPCO proposed the use of the Texas retail load factor in its A&E / 4CP methodology for allocating capacity-related production costs. Because SWEPCO's generation is built to meet system needs based on analysis of the system loads, it is reasonable to allocate costs using the system load factor. The appropriate load factor for use in the A&E / 4CP methodology is the system load factor."); Re: Homeowner's United, Texas Public Utility Commission, PUC Docket No. 40627, issued April 29, 2013 ("Austin Energy's use of the modified A&E 4CP for production cost allocation under the terms of the agreement is reasonable."); Re: Entergy Texas, Inc. Texas Public Utility Commission, PUC Docket No 39896, issued September 14, 2012 ("The Average and Excess (A&E) 4 CP method for allocating capacity-related production costs, including reserve equalization payments, to the retail classes is a standard methodology and the most reasonable methodology."); Re: Reliant Energy, Incorporation, Texas Public Utility Commission, PUC Docket No. 21665, issued May 31, 2000 ("In Docket No. 12065, the most recent docket addressing Applicant's rate design, the Commission approved the use of the Average & Excess 4 CP (A&E 4CP) to allocate Applicant's costs. Development of demand allocations using the generation-related base revenues by class resulting from the A&E 4CP is reasonable and appropriate and should be approved."); Re: Entergy Texas, Inc. Texas Public Utility Commission, PUC Docket No 16705, issued October 14, 1998; Re: Southwestern Electric Power Company, Texas Public Utility Commission, PUC Docket No. 36961, issued November 17, 2009; Re: Entergy Gulf States, Inc., Texas Public Utility Commission, PUC Docket No. 31315, issued February 9, 2006.

> on page 51 of the 1992 National Association of Regulatory Utility Commissioners Manual, as it existed on January 1, 2015, using the average of the four (4) monthly coincident peaks for the months of June, July, August, and September for each class for the coincident peak referenced in Table 4-10B of the manual, as it existed on January 1, 2015, or any subsequent version of the manual to the extent it produces an equivalent result.

► Colorado: "Public Service proposed continued use of the AED allocation method for the allocation of Production, Transmission, and Distribution Substation fixed capacity costs among the various rate classes.

* * * * *

We agree with Public Service that the AED method should be used to allocate Production, Transmission, and Distribution Substation costs. This method has a long precedent of acceptance by this Commission. The testimony regarding this issue has convinced us that the method proposed by the OCC is not an accepted methodology and may cause problems by mixing two methods. Their hybrid method could result in a double counting of costs because the average demand is inherently a part of any measure of system peak."[27]

► District of Columbia: "Contrary to claims by WMATA and the District, the Commission is not required to "reinvent the wheel" or turn every rate case into an endless morass by requiring *de novo* justification of well-settled policies like AED (NCP) in every case. In short, we are simply not persuaded that WMATA and the District have carried their heavy burden to justify overthrowing the traditional AED(NCP) method. ***The old AED(NCP) method has value as a tried-and-true benchmark, against which the Commission can measure its progress towards marginal cost based rates. We adhere to that method***."[28]

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[27] Re: Public Service Company of Colorado, Colorado Public Utilities Commission, Docket No. 04S-164E, issued April 11, 2005 (emphasis added); *See also*, Re: Aquila, Inc. dba Aquila Networks – WPC, Colorado Public Utilities Commission, Docket No. 03S-539E, issued December 30, 2004 ("We adopted the use of AED allocation method using non-coincident peak to calculate the excess portion of transmission and generation plant and associated expenses."); Re: Black Hills / Colorado Electric Utility Company, L.P., Colorado Public Utilities Commission, Docket No. 12AL-1052E, issued May 14, 2013 ("It is also noted that the Commission approved a 4CP-AED allocator for the allocation of Public Service's production plant costs in Decision No. C10-0286 in Docket No. 09AL-299E issued March 29, 2010. While no policy directives are provided in that Decision, nonetheless, this approach is the Commission's most recent consideration of the issue."); Public Service Company of Colorado, Colorado Public Utilities Commission, Docket No. 09AL-2993, issued March 29, 2010.

[28] Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 912, issued June 26, 1992, 13 DC PSC 512 (citations omitted). *See also*, Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 541, issued April 15, 1970, 83 P.U.R.4th 113; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 596, issued November 16, 1973, 3 P.U.R.4th 65; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 905, issued October 23, 1991; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 929, issued March 4, 1994, 150 P.U.R.4th 528; Re: Potomac Electric Power Company, District of Columbia Public Service Commission,

► FERC: "The average and excess demand method was clearly delineated in Re Wisconsin Michigan Power Co., as follows: "Under the average-excess demand method, capacity costs (C) are divided into two parts in accordance with the system load factor (L). The portion equal to LC is allocated to customer classes on an energy use or average demand basis, and the balance (1 L)C is allocated on the basis of excess demands (the maximum demand of a load less its average demand). The effect of the average-excess method is to emphasize the extent of use of capacity, resulting in allocation of an increasing proportion of capacity costs to a customer as his load factor increases. . . . ***The average and excess demand method accomplishes this result and is accordingly adopted in this proceeding***."[29]

► Hawaii: "The AED method allocated production demand costs on the basis of each class' average demand weighted by system load factor and the peak demand in excess of weighted average demand. In our opinion, this method distinguishes between the cost to serve the average demand and the cost to serve the excess demand. The AED method recognizes such cost-related factors as class and system load factors, diversity of demand, and peak class demand whereas the PR and NCD method are based solely on a single load characteristic which can lead to unstable results. We believe that no single method of allocating demand costs can be claimed to be correct or best for all utilities, but ***the AED method is reasonable*** and an equivalent form of this method has been used and approved by this commission for all Hawaiian Electric Company, Inc., HELCO, and MECO rates cases"[30]

Other state utility commissions that have adopted the Average & Excess method for allocating fixed production plant-related costs include the Pennsylvania Public Utilities

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Case No. 1087, issued September 27, 2012, 300 P.U.R.4th 166; Re: Potomac Electric Power Company, District of Columbia Public Service Commission, Case No. 1103, issued March 26, 2014, 313 P.U.R.4th 340 (emphasis added).

[29] Re: Public Service Company of Oklahoma, Federal Power Commission, Docket No. E-8242, issued February 17, 1977, 19 P.U.R.4th 190 (emphasis added).

[30] Re: Hawaiian Electric Company, Inc., Hawaii Public Utilities Commission, Docket No. 3705, issued June 26, 1981, 44 P.U.R.4th 234. *See also,* Re: Hawaiian Electric Company, Inc., Hawaii Public Utilities Commission, Docket No. 4536, issued September 16, 1983, 56 P.U.R.4th 398 (""We agree with HECO that although there is no single best method of allocating demand costs for all utilities, the AE method is reasonable for HECO. . . . The AE method takes into consideration class and system load factors, diversity of demand, and class peak demand."); *See also,* Re: Maui Electric Company Ltd., Hawaii Public Utilities Commission, Docket No. 1739, issued March 28, 1968 ("In the average and excess demand method used by the applicant, both the maximum loads and the extent of use of equipment are taken into account in the allocation process. In other words, in the average excess demand method, the allocation takes into consideration the average use of capacity and the responsibility for the capacity required to meet system loads. Used capacity costs are assigned to the various classes of service in proportion to their respective use and the remaining capacity costs, representing the portion of demand costs associated with the unused portion of capacity, is apportioned to the various classes of service in the ratio that the individual group demands, in excess of used demands, bear to total demand.").

Commission,[31] Maryland Public Service Commission,[32] and Connecticut Department of Public Utility Control.[33]

B. Highest Hours Approach

In contrast to the A&E approach that has been adopted by Empire, MECG, all Missouri electric utilities and virtually every state utility commission, Staff advocates for an approach that has never been adopted by a single utility or public utility commission. Rather, Staff's Highest Hours approach was only recently postulated in a Regulatory Assistance Project publication.[34]

Given its constantly changing approach to allocating fixed production costs, it is apparent that Staff's Highest Hours approach is simply its production allocator *du jour*. Specifically, at the beginning of the last decade, Staff argued vehemently on behalf of the Peak & Average approach.[35] Shortly thereafter, Staff advocated for the Base / Intermediate / Peak approach to allocating fixed production costs.[36] Just last year, Staff again changed its approach to what it termed a "functionalized approach."[37] Now, Staff has again changed its approach to an allocator that it read about in a recent publication called the Highest Hour approach.[38]

Under Staff's misplaced approach, Staff sorts Empire's highest hourly peaks for the year and then allocates fixed production plant related costs based upon each class'

[31] Pa. Publ. Util. Comm'n v. PPL Gas Utilities Corporation, Docket No. R-00061398, issued February 9, 2007.
[32] Re: Potomac Electric Power Company, Maryland Public Service Commission, Case No. 9286, issued July 20, 2012; Re: Potomac Electric Power Company, Maryland Public Service Commission, Case No. 9336, issued July 2, 2014.
[33] Re: The Connecticut Light and Power Company, Connecticut Department of Public Utility Control, Docket No. 03-07-02RE09, issued December 8, 2006; Re: The United Illuminating Company, Connecticut Department of Public Utility Control, Docket No. 05-06-04RE02, issued December 19, 2006.
[34] Exhibit 104, Staff Class Cost of Service Report, page 26.
[35] See, Case No. ER-2010-0036, *Report and Order*, issued May 28, 2010, at pages 85-86.
[36] See, Case No. ER-2016-0285, *Report and Order*, issued May 3, 2017, at page 50.
[37] Exhibit 104, Staff Class Cost of Service Report, page 26.
[38] *Id.*

contribution to the peak in each of these hours.[39] Demonstrating the completely arbitrary nature of its approach, Staff considered utilizing the highest 12, 51, 100, 135, and 310 hourly peaks before ultimately settling on the top 100 highest peaks.[40]

MECG asserts that Staff's approach is flawed. Unlike the well-tested A&E approach, the Highest Hours approach is simply an academic theory at this point and is completely arbitrary in application. The arbitrariness is demonstrated by the fact that, by choosing a higher or lower number of hourly peaks, Staff can actually manipulate the approach to create the result that it desires. That is, by focusing on a higher number of peaks, Staff can easily lessen the impact of the summer air conditioning / winter space heating loads that are largely driven by the residential class. In fact, MECG suggests that Staff's decision to consider 100 hours reflects this desire.

Ultimately, as Empire suggests within its IRP, MECG asserts that generation capacity is built to meet the single largest peak in the year. Therefore, all other peaks are necessarily subsumed within that single annual peak. Given this, it is unnecessary to consider 100 hours as Staff suggests. With this in mind, MECG posits that a more reliable version of the approach would focus on those hourly peaks within 90% of the annual peak. By focusing only on those peaks that truly drive the decision to add generation capacity the Highest Hours approach ultimately produces results that are comparable to MECG's A&E approach.[41]

C. CONCLUSION

As can be seen, the Commission is tasked with choosing between two different approaches to allocating fixed production costs. First, the Commission can adopt the

[39] Exhibit 351, Maini Rebuttal, page 11.
[40] Exhibit 104, Staff Class Cost of Service Report, page 27.
[41] Exhibit 351, Maini Rebuttal, page 13 as compared to Exhibit 350, Maini Direct, page 20.

Highest Hours approach that has not been adopted by any utilities or state utility commissions and is inherently arbitrary and can be easily manipulated to produce desired results. On the other hand, the Commission can utilize the well tested A&E approach that has been adopted by all Missouri utilities, virtually every electric utility and by a large majority of the public utility commissions. Furthermore, because this approach is driven entirely by class load profile, it removes a significant amount of the discretion as well as the arbitrariness of the Highest Hours approach. MECG urges the Commission to utilize the A&E 6NCP approach.

2. DISTRIBUTION PLANT ACCOUNTS 364, 366 AND 368

In addition to its preferred method for allocating fixed production costs, Staff also deviates from Empire / MECG in the manner in which it allocates the distribution plan costs in Accounts 364, 366 and 368.

Distribution plant costs associated poles and towers, overhead conductors and devices, underground conduit, underground conductors and devices and line transformers are booked in Accounts 364-368.[42] These costs must then be classified as either customer or demand-related.[43] In general, there are two methods for segregating the customer-related portion of these costs from the demand-related portion: (1) the minimum size approach and (2) the zero intercept approach.

> The Minimum-size Method assumes that a minimum size distribution system can be built to serve minimum demand requirements of customers. . . . The approach is consistent with the methodology described in the NARUC manual:
>
> > Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The

[42] Exhibit 350, Maini Direct, page 22.
[43] *Id.*

minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility.[44]

In contrast to the minimum size approach utilized by both Empire and MECG, Staff advocated for the zero intercept approach.

> The concept behind a Zero-Intercept Cost study is to seek to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component.[45]

While the NARUC allocation manual finds that both approaches are acceptable, it does state that the differences between the two methodologies should be "relatively small."[46] Contrary to the expected small differences, the minimum size and zero intercept approaches in this case result in dramatic differences. For instance, under Empire's minimum size approach, 53.1% of the costs in Account 364 are classified as customer related while only 22.6% of such costs are classified as customer related under Staff's zero intercept approach.[47] Still again, Empire's methodology classifies 43% of Account 368 costs as customer related while Staff's methodology only classified 9.8% of such costs as customer related.[48]

Further evidence of a problem with Staff's methodology is found in the fact that "Staff's regression analysis [for Account 368] shows that the 'no-load' number is

[44] Exhibit 26, Lyons Direct, pages 17-18.
[45] Exhibit 104, Staff Class Cost of Service Report, page 28.
[46] Exhibit 351, Maini Rebuttal, page 14.
[47] *Id.* at page 15. See also, Exhibit 28, Lyons Rebuttal, page 25.
[48] *Id.*

negative, which suggests that a negative percentage of costs are customer-related. Such a result is not reliable."[49]

In its rebuttal testimony, Empire witness Lyons provides greater insight into the problems with Staff's zero-intercept approach. Specifically, for Account 364, "Staff's methodology does not consider the cost of anchors and guys."[50] Inclusion of such costs would have resulted in higher customer-related costs.[51] Similarly, in Account 366, "Staff's methodology does not consider the cost of vaults and pedestals."[52] Finally, Mr. Lyons points out that, for Account 368, Staff's methodology considered "limited data": a 15 kVa overhead transformer cost, and a 25 kVA underground transformer cost.[53] "This would help to explain Staff's study results which show a negative zero-intercept."[54]

In its surrebuttal testimony, Staff attempted to excuse the numerous problems in its classification of distribution costs on the basis that data was "limited" which precluded a more "robust" analysis.[55]

Given the obvious problems with Staff's zero-intercept approach, the Commission should adopt the minimum size approach for classifying distribution-related costs as advocated by Empire and MECG.

3. PRIMARY AND SECONDARY DISTRIBUTION PLANT COSTS

In the previous issue the Commission was asked to decide the best method for classifying distribution costs as either customer or demand-related. Once the costs have

[49] Exhibit 351, Maini Rebuttal, page 15.
[50] Exhibit 28, Lyons Rebuttal, page 26.
[51] *Id.*
[52] *Id.*
[53] *Id.*
[54] *Id.*
[55] Exhibit 135, Kliethermes Surrebuttal, page 3.

been classified as customer or demand related the Commission must decide the best way to allocate the customer and demand-related costs to the various classes. All parties agree that the customer-related portion of these distribution costs should be allocated on the basis of the number of customers.[56] The parties disagree, however, on the appropriate method for allocating the demand-related portion of distribution costs.

MECG asserts that the distribution system must be sized to meet the customer's single largest peak within the year. "[W]hen 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 levels, whenever the maximum demands occur."[57]

Given that the distribution system is sized to meet the customer's single largest peak, no matter when it occurs, it necessarily will meet any other peaks. In other words, all other peaks are necessarily subsumed within the single largest peak. "By sizing [the distribution system] in this manner, the distribution infrastructure necessarily accommodates all demands lower than the maximum demands."[58] Recognizing then that the distribution system is sized to meet a class' single largest peak, the demand portion of these distribution costs should be allocated to each class based upon the class' contribution to the single largest peak.[59]

In contrast, Empire proposes that the demand-related portion of these distribution costs should be allocated among the customer classes based upon each class' contribution to the average of the six largest peaks occurring in the months of December through

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[56] Exhibit 26, Lyons Direct, page 25. Exhibit 104, Staff Class Cost of Service Report, page 28.
[57] Exhibit 351, Maini Rebuttal, page 10.
[58] *Id.*
[59] *Id.*

February.[60] By considering six peaks rather than a single peak, Empire dampens the cost causative factor that drives the sizing of the distribution system.

As MECG further points out, Empire's use of 6 monthly peaks to allocate the demand-related portion of distribution costs represents a radical shift in its approach. In previous cases, Empire agreed with MECG and allocated such costs based upon the single largest peak.[61] Furthermore, not only has Empire previously allocated such costs based upon a single largest peak, as recommended by MECG, Ameren also allocates the demand related portion of these distribution costs in this manner.[62]

Finally, Empire's six peak allocation approach contradicts the manner in which distribution costs are collected from demand-metered classes. Specifically, Empire collects its distribution costs from these classes by using a ratcheted facilities demand charge.[63] The use of a ratcheted facilities demand charge means that Empire collects its distribution costs from these customers based upon the single largest peak that occurred in the previous 12 months. "[T]he 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."[64] Recognizing that Empire collects the demand-related portion of distribution plant based upon a customer's single largest peak, it is logical that these costs are allocated between classes in a similar manner. "Each

[60] Exhibit 26, Lyons Direct, pages 25-26.
[61] Exhibit 351, Maini Rebuttal, pages 9-10.
[62] Exhibit 351, Maini Rebuttal, page 10.
[63] *Id*. See also, Exhibit 355.
[64] *Id*.

class' single non-coincident peak demand is therefore a more reasonable indicator to reflect the cost causing characteristic of building the distribution-related infrastructure."[65]

In contrast, Staff proposes that the demand-related portion of distribution costs be allocated using the sum of coincidental peak demands. As Empire points out, however, Staff's allocator does not reflect "an understanding of what drives distribution costs."[66]

Given the problems with the Staff and Empire allocators, MECG urges the Commission to allocate the demand-related portion of distribution costs on the basis of each class' contribution to the single largest peak.

4. GENERAL PLANT COSTS

In its class cost of service study, Staff designates approximately $188.0 million of several cost categories as "miscellaneous and unassignable costs." Such costs include General Plant, Administrative and General Costs and Materials and Supplies. Given its claimed inability to properly assign these costs, Staff simply allocated them to the customer classes using the energy allocator.[67]

As Empire witness Lyons points out, however, the use of the energy allocator for such costs is irrational. "[C]ustomer energy usage does not drive the costs of General Plant and A&G expenses."[68] Given this, Empire allocated such costs on a rational basis that reflects the manner in which such costs are incurred.

> General Plant facilities are generally used by the Company employees. Accordingly the General Plant costs were allocated based on a composite of labor-related O&M expenses. The Company's approach is generally consistent with the allocation method for these costs described in the NARUC manual.[69]

[65] *Id.*
[66] Exhibit 28, Lyons Rebuttal, page 27.
[67] Exhibit 351, Maini Rebuttal, pages 15-16.
[68] Exhibit 28, Lyons Rebuttal, page 29.
[69] *Id.* (citing to NARUC Electric Utility Cost Allocation Manual, page 105).

Similarly, Empire utilized an approach to allocating A&G costs that best reflects how those costs are actually incurred.

> Labor related A&G expenses (such as Accounts 920 through 926) are allocated based on a composite of labor-related O&M expenses, while Plant-related A&G expenses are allocated based on a composite Total Plant allocation. The Company's approach is generally consistent with the allocation method for these costs described in the NARUC manual.[70]

Interestingly, in several recent Empire cases, Staff did not have a problem with finding a rational method for allocating such costs. For instance, in Empire's last rate case, Staff allocated General Plant on the basis of the gross production, transmission and distribution plant allocator. Similarly, materials and supplies were not allocated in the last case based upon the energy allocator, but instead on the basis of net plant.[71]

Again, like many of the other problems in Staff's class cost of service study, Staff's decision to classify these costs as miscellaneous and unassignable and allocate them on the basis of the energy allocator is beneficial to residential customers and detrimental to large commercial and industrial customers. For instance, by using class energy to allocate general plant, the residential class is only allocated 39% of these costs. In contrast, the residential class is allocated 70.6% of these costs in Empire and MECG's analysis.[72] Still again, by using class energy to allocated A&G costs, Staff has allocated only 39.9% of these costs to the residential class. In contrast, the residential class is allocated 68.8% of such costs under the Empire and MECG studies.[73]

[70] (citing to NARUC Electric Utility Cost Allocation Manual, pages 106-107).
[71] Exhibit 351, Maini Rebuttal, Schedule KM-2.
[72] Exhibit 28, Lyons Rebuttal, page 30.
[73] *Id.*

IV. REVENUE ALLOCATION

d. How should Empire's revenue requirement be allocated amongst Empire's customer rate classes (Class revenues responsibilities)?

q. What, if any, revenue neutral interclass shifts are supported by the class cost of service study?

r. How should any revenue requirement increase or decrease be allocated to each rate class?[74]

In recent Empire rate cases the Commission has recognized the importance of competitive industrial rates.

> Competitive industrial rates are an important factor in helping to retain and expand industry within the utility's service area. Business retention and expansion result in positive impacts on local economy and employment. Further, if businesses relocate or expand in Empire's service area, it has the potential of lowering costs for customers as the fixed costs are spread over larger amount of billing determinants. The converse is also true – if businesses shift operations from Empire's area, the remaining customers bear the burden of the same fixed costs but over a smaller amount of billing determinants thereby increasing rates for all customers. Thus, the Commission should be cognizant of how its decisions affect industrial rates.[75]

At the time that the Commission raised its concern, Empire's industrial rates were 16.7% above the national average.[76] Given this concern, the ultimately Commission ordered the elimination of 25% of the residential subsidy. Specifically, quantifying the residential subsidy as 8.1%, the Commission ordered a revenue neutral shift of an additional 2% to the residential class. Importantly, this was <u>in addition to</u> the overall increase of 3.9%. Therefore, the residential class received an increase of 5.9%.

> Attempting to completely eradicate the 8.1% residential rate class discrepancy in this rate case would be too punitive to the customers in that class. A revenue neutral adjustment of 25% of the 8.1% needed adjustment would increase the residential rates by approximately 2%. This 2% increase, in additional to the 3.9% revenue requirement increase, agreed to by the parties in the Revised Agreement, would raise the average

[74] These three issues are redundant in that they represent various parties characterization of the issue.
[75] *Report and Order*, Case No. ER-2014-0351, issued June 24, 2015, page 18.
[76] *Id.* at page 17. See also, Exhibit 350, Maini Direct, page 9.

> residential customer's monthly bill by approximately 5.9%. . . . A 2% revenue neutral adjustment for the residential class is not punitive to the residential class and helps to eliminate any residential subsidy in a shorter timeframe.[77]

In the next case, the Commission again took steps to eliminate a portion of the residential subsidy. Specifically, approving a stipulation, agreed to by all parties including Public Counsel, the Commission approved a revenue neutral shift of $3.0 million to the residential class.

> There shall be a $3 million revenue neutral shift to the residential class, allocated as follows: -$2 million to GP; -$525,000 to CB; -$340,000 to LP; and -$135,000 to the Praxair class.[78]

Thus, for at least the past five years, the Commission has been very cognizant of Empire's residential subsidy and the need to eliminate that subsidy in order to make Empire's industrial rates more competitive.

While the Commission has taken steps in recent cases, the residential subsidy persists. Specifically, all three class cost of service studies[79] prepared in this case definitively show that residential rates are not covering the residential cost of service. Specifically, these studies show that, while Empire was earning an overall rate of return of 6.11%, it was only earning 2.90%, 2.62% and 5.46% from the residential class under the Empire, MECG and Staff class cost of service studies.[80] In contrast, under the 3 studies, Empire was earning significantly above 6.11% from <u>each</u> of the commercial and industrial rate classes. In other words, this rate case was driven <u>entirely</u> by the fact that Empire is not recovering its costs from the residential class.

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[77] *Report and Order*, Case No. ER-2014-0351, issued June 24, 2015, pages 18-19.
[78] *Report and Order*, Case No. ER-2016-0023, issued August 10, 2016, Attachment A, page 9.
[79] Class cost of service studies were prepared by Empire, MECG and Staff. While it did not take the time to prepare a class cost of service study, in its rebuttal testimony Public Counsel "aligned" itself with the results of Staff's study. (Exhibit 208, Marke Rate Design Rebuttal, page 5.
[80] See, Table 1.

TABLE 1: Earned Return by Customer Class

	Empire[81]	MECG[82]	Staff[83]
RG – Residential	2.90%	2.62%	5.46%
CB – Commercial	8.23%	8.16%	11.31%
SH – Small Heating	7.39%	7.12%	11.31%
GP – General Power	11.44%	12.19%	11.11%
SC-P Praxair	9.63%	15.28%	11.38%
Total Electric Bldg	11.46%	11.37%	11.11%
PFM - Feed Mill	10.59%	10.56%	-36.92%
LP - Large Power	8.34%	9.52%	10.88%
MS – Miscellaneous Svc.	-5.21%	-4.94%	28.70%
SPL – Municipal Ltg.	1.77%	1.99%	28.70%
PL – Private Ltg.	26.95%	26.48%	28.70%
LS – Special Ltg.	-6.47%	-7.18%	28.70%
Total Company	6.11%	6.11%	6.11%

As mentioned, the conclusions reached by MECG are supported by the studies presented by both Staff and Empire. In its testimony, Staff found that, while the commercial and industrial classes are paying rates above cost of service, the residential class is not. Specifically, even after applying its 5% deadband,[84] Staff recommends that steps be taken to address the residential subsidy. Specifically, while at the time it was assuming an overall rate reduction, Staff recommended that the entirety of the revenue reduction be allocated to the commercial and industrial classes.[85] Certainly then, despite

[81] Exhibit 350, Maini Direct, page 31 (based upon Lyons Direct, Schedule TSL-9). Empire subsequently agreed with certain adjustments to "firm up" the revenues for the interruptible SC-P class and to more appropriately allocate the interruptible credits for this class. This has the effect of increasing the earned return for the SC-P class. (See, Exhibit 26, Lyons Rebuttal, page 10).
[82] Exhibit 350, Maini Direct, page 31.
[83] Exhibit 121, Lange Rebuttal, page 17.
[84] As Staff points out, "[t]ypically Staff does not recommend revenue responsibility shifts for classes within a 5% plus or minus "deadband" of contribution to cost of service at an equal rate of return. This deadband is due to the inherent inaccuracy of class cost of service studies at a high level of precision in general, despite the appearance of a high level of precision in the results as presented." (Exhibit 104, Staff Class Cost of Service Report, page 32).
[85] In its direct testimony, Staff recommended that any rate reduction be assigned to the CB/SH, GP/TEB, and LPS rate schedules. (Exhibit 104, Staff Class Cost of Service Report, page 32). In its rebuttal testimony, Staff corrected an error in its class cost of service study and, as a result, agreed that the SC-P rate class should also receive a portion of any rate reduction. (Exhibit 121, Lange Rebuttal, page 18).

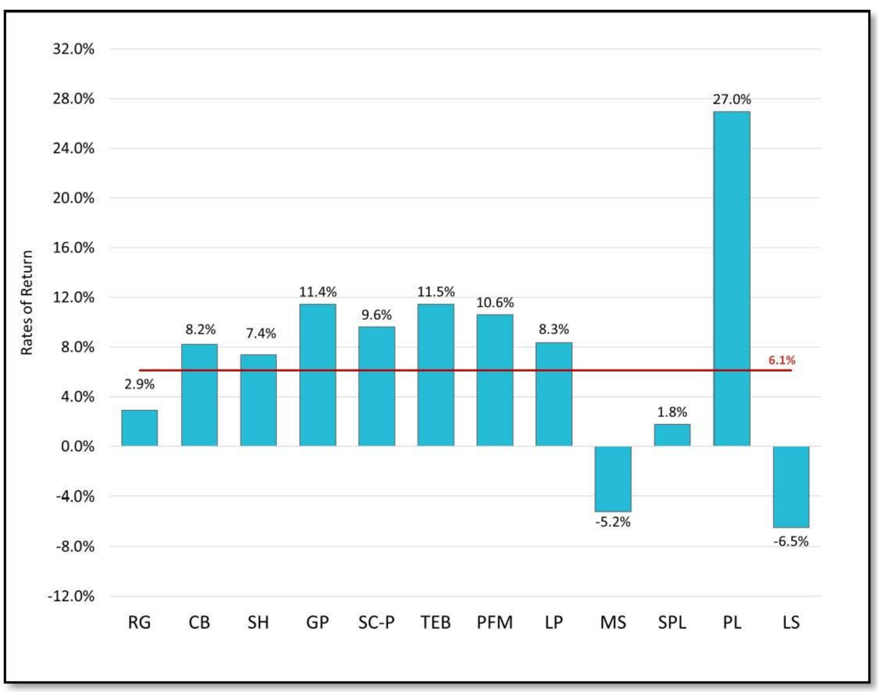
the fact that the Non-Unanimous Stipulation is recommending no rate change, Staff's evidence still supports the need to address the residential subsidy.

Empire's evidence is equally clear. As Mr. Lyons points out,

> The results of the Company's CCOS show that the current rate design produces a disparity in class rates of return ("ROR"). The Residential, Miscellaneous Service, Municipal Street Lighting, and Special Lighting rate classes produce RORs that are less than the system or overall ROR, indicating their rates recover less than their cost of service. The remaining commercial and industrial ("C&I") and Lighting rate classes produce RORs that are more than the system ROR, indicating their rates recover more than their cost of service.[86]

Graphically, Empire's class cost of service study demonstrates that, while the commercial and industrial classes are producing returns well above the system average, the residential class is producing a dismal.

Figure 4: Class vs. Overall Rates of Return at Current Base Rates



Source: Exhibit 26, Lyons Direct, page 11. It should be noted that, after making corrections to firm up the load associated with the SC-P class, the rate of return for this class increased to 12.78%. (Exhibit 28, Lyons Rebuttal, page 34).

[86] Exhibit 26, Lyons Direct, pages 2-3.

Given the undeniable inequity in rates, Empire proposed steps to reduce the residential subsidy and move all classes closer to cost of service.

> The results of the CCOS support a movement toward a more equitable rate structure where class RORs move closer to the system ROR. To meet that objective, the proposed rate increases for the Residential and Miscellaneous Service, Municipal Street Lighting and Special Lighting rate classes are higher than the overall rate increase.[87]

The existence of the residential subsidy should not be surprising. As indicated, the Commission has taken steps in both of the last two cases to address the residential subsidy. Furthermore, while Empire's industrial rates were 16.7% above the national average just five years ago, Empire's industrial rate has now increased to 21.1% above the national average.[88] In fact, the dire nature of Empire's industrial rates is best realized by comparing Empire's industrial rate to that of other Midwest electric utilities. Specifically, of the 95 electric utilities operating in 28 Midwest and Central states, Empire's industrial rates are 12th highest.

continued on next page

[87] *Id.* at page 3.
[88] Exhibit 350, Maini Direct, page 9 (citing to the EEI Typical Bills and Average Rates Report).

INDUSTRIAL RATES

Utility	State	Rate	Utility	State	Rate
KCPL	Kansas	10.05	PacifiCorp	Idaho	6.87
Indiana Michigan Power	Michigan	9.79	El Paso Electric	Texas	6.86
Northwestern Wisc. Electric	Wisconsin	9.40	El Paso Electric	N.Mexico	6.84
Duke Energy - Ohio	Ohio	9.04	Mississippi Power	Mississippi	6.82
Tucson Electric Power	Arizona	9.01	Louisville Gas & Electric	Kentucky	6.69
Montana Dakota Utilities	N. Dakota	8.99	Westar - KGE	Kansas	6.68
Montana Dakota Utilities	S. Dakota	8.89	Toledo Edison	Ohio	6.67
Indianapolis Power & Light	Indiana	8.88	GMO	Missouri	6.64
Black Hills Power	Wyoming	8.61	Minnesota Power Company	Minnesota	6.59
Black Hills Power	Colorado	8.51	Otter Tail Power	Minnesota	6.59
Empire	Kansas	8.45	Entergy Mississippi	Mississippi	6.55
Empire	Missouri	8.37	DTE Electric	Michigan	6.55
Arizona Public Service	Arizona	8.33	American Electric Power	Kentucky	6.50
Madison Gas & Electric	Wisconsin	8.28	Cheyenne Light, Fuel & Power	Wyoming	6.38
Black Hills Power	S. Dakota	8.24	Dayton Power & Light	Ohio	6.37
Westar - KPL	Kansas	8.16	Ameren	Missouri	6.36
Northern States Power	Minnesota	8.15	Southwestern Electric Power	Texas	6.31
We Energies	Wisconsin	8.07	Public Service Company - Col.	Colorado	6.30
Consumers Energy	Michigan	7.91	Superior Water, Light & Power	Wisconsin	6.30
South Indiana Gas & Electric	Indiana	7.91	Northern States Power	Michigan	6.29
KCPL	Missouri	7.85	Alabama Power	Alabama	6.17
Nevada Power	Nevada	7.85	PacifiCorp	Wyoming	6.15
AEP - Columbus	Ohio	7.72	American Electric Power	Tennessee	6.12
Wisconsin Power & Light	Wisconsin	7.68	Kentucky Utilities	Kentucky	5.96
AEP - Ohio Power	Ohio	7.67	Southwestern Electric Power	Arkansas	5.92
Northern States Power	Wisconsin	7.62	PacifiCorp	Utah	5.91
Empire	Oklahoma	7.61	Wisconsin Public Service	Wisconsin	5.83
Montana Dakota Utilities	Wyoming	7.59	Entergy Arkansas	Arkansas	5.80
Duke Energy - Kentucky	Kentucky	7.53	Upper Mich. - Wisc. Pub. Serv.	Michigan	5.72
Interstate Power & Light	Iowa	7.52	MidAmerican	Iowa	5.67
CLECO Power	Louisiana	7.49	Upper Michigan - We Energies	Michigan	5.51
Duke Energy - Indiana	Indiana	7.49	Public Service Company - N.Mex.	N.Mexico	5.49
Empire	Arkansas	7.45	Idaho Power	Idaho	5.45
Northern States Power	S. Dakota	7.38	MidAmerican	Illinois	5.35
Northwestern Energy	Montana	7.29	Sierra Pacific	Nevada	5.24
Entergy New Orleans	Louisiana	7.21	Avista	Idaho	5.17
Otter Tail Power	N. Dakota	7.17	Upper Peninsula	Michigan	5.11
Northern Indiana Pub. Serv.	Indiana	7.16	Entergy Gulf States	Louisiana	5.08
Southwestern Electric Power	Louisiana	7.12	Southwestern Public Service	N.Mexico	5.01
Northern States Power	N. Dakota	7.11	OG&E Electric	Arkansas	5.00
AEP - Indiana Michigan	Indiana	7.04	Public Service Company - Ok.	Oklahoma	4.95
Otter Tail Power	S. Dakota	7.00	Entergy Louisiana	Louisiana	4.89
Montana Dakota Utilities	Montana	7.00	MidAmerican	S. Dakota	4.85
Unisource Electric	Arizona	6.93	Entergy Texas	Texas	4.76
Northwestern Energy	S. Dakota	6.92	OG&E Electric	Oklahoma	4.73
Black Hills Power	Montana	6.90	Cleveland Electric Illuminating	Ohio	4.30
Ohio Edison	Ohio	6.88	Southwestern Public Service	Texas	4.16
Commonwealth Edison	Illinois	6.88			

Source: Exhibit 350, Maini Direct, Schedule 2, pages 2-3.

Real world experience from Walmart supports the uncompetitive nature of Empire's industrial rates. In his surrebuttal testimony, Steve Chriss from Walmart indicates that the EEI data is consistent with Walmart's. Given its operations in all 50 states and the District of Columbia, Walmart is "able to easily benchmark our utility cost in one market against other utilities in that market as well as against regional and national benchmarks."[89] Based upon its operational experience through the United States, Mr. Chriss concludes:

> **[redacted]**[90]

Given the residential subsidy as well as Empire's increasingly uncompetitive industrial rates, MECG urges the Commission to take steps to reduce the residential subsidy. Specifically, MECG recommends that the Commission eliminate 25% of the residential subsidy.[91] Such a movement would lead to a 4.2% increase for the residential class and improve the competitiveness of <u>all</u> commercial and industrial classes.

	Revenue Shift (in thousands)	% Shift
RG – Residential	+$9,030	4.2%
CB – Commercial	-$841	-1.9%
SH – Small Heating	-$101	-1.0%
GP – General Power	-$4,310	-5.1%
SC-P – Praxair	-$239	-5.4%
TEB – Total Electric Bldg.	-$1,674	-4.6%
PFM – Feed Mill	-$3	-4.5%
LP – Large Power	-$1,846	-3.0%
MS – Miscellaneous Svc.	+$1	7.5%
SPL – Municipal Ltg.	+$259	11.9%
PL – Private Ltg.	-$445	-10.9%
LS – Special Ltg.	+$77	58.8%

Source: Exhibit 350, Maini Direct, page

[89] Exhibit 353, Chriss Surrebuttal, page 5.
[90] Exhibit 353, Chriss Surrebuttal, page 7.
[91] Exhibit 350, Maini Direct, page 35.

Consistent with the Commission's finding from previous cases, the recommended 4.2% shift is not punitive to the residential class. Recognizing that, through the Non-Unanimous Stipulation, Empire has agreed to no rate change. Therefore, MECG's proposed revenue neutral shift would only result in a residential increase of 4.2%. In its original filing, however, Empire sought an increase for the residential class of 5.8%.[92] Therefore, even after the proposed revenue neutral shifts, residential customers would still see a smaller rate increase than they were initially expecting from this case.

In the final analysis, the Commission must take steps to address the residential subsidy and the competitiveness of industrial rates. As the Commission previously recognized, the uncompetitive industrial rates makes it difficult to attract industry to the Empire service area and places pressure on existing industry to either relocate or shift production to lower cost facilities in other states. Ultimately, such a situation threatens employment in the area. Given this, the Commission should follow the logic of previous Commissions and address the residential subsidy.

[92] Richard Direct, Schedule SDR-9.

V. LARGE POWER / GENERAL POWER / SC-P RATE DESIGN

2e. How should the rates for each customer class be designed?
t. What, if any, changes to the CB, SH, GP and TEB customer charge are supported by the class cost of service study?
u. What, if any, changes to the CB, SH, GP and TEB customer charge should be made in designing rates resulting from this rate case?
w. How should any GP and TEB revenue requirement increase or decrease be apportioned to the demand (kW) and energy (kWh) rates?
x. How should any LP revenue requirement increase or decrease be apportioned to the demand (kW) and energy (kWh) rates?
y. What, if any, changes to the current SC-P energy (kWh) rates should be made to align with Market Prices?

While the previous issue seeks to mitigate the significant inter-class subsidy that exists in Empire rates, the proposal for the design of Large Power / General Power / SC-P rates seeks to address the intra-class subsidy existing in the rates of those classes. Specifically, MECG proposes that any rate decrease for the LP, GP and SC-P rate classes be implemented by reducing the class energy charges.[93] In this way, demand charges would remain at current levels. Similarly, any rate increase for these classes should be implemented by increasing demand charges and leaving energy charges at current levels. Bottom line, the Commission should seek to reduce energy charges.

Generally, proper ratemaking mandates that costs be collected in a manner that reflects the manner in which those costs are incurred. Thus, fixed costs (those costs that are incurred regardless of usage) should be collected through demand charges (per kW). In this way, a customer pays its share of fixed costs regardless of usage. Similarly, variable costs should be collected through energy charges (per kWh). As such, a

[93] In the Non-Unanimous Stipulation, the Signatories agreed that "[t]here will be no changes to the customer charges in this proceeding." (See, Non-Unanimous Stipulation, provision 5). Public Counsel did not oppose this provision. The GP, LP, TEB and SC-P rate schedules all include customer, demand and energy charges. (See, Exhibit 355). Given that the GP, LP, TEB and SC-P customer charges will not change, any change in the revenue requirement for these classes must be apportioned to the energy or demand charges. Through this section of the brief, MECG advocates that any revenue requirement decrease for the GP, LP and SC-P classes be collected by reducing energy charges. Similarly, any increase in the revenue requirement for these classes should be collected by increasing demand charges.

customer that has no usage will still pay for the fixed costs of service, but will avoid any of the variable costs.

Intra-class subsidies to the detriment of high load factor customers are created when fixed costs, which should be collected through per-kW demand charges, are instead collected through per-kWh energy charges. As MECG witness Chriss points out:

> ***The shift in demand-related costs from per kW demand charges to per kWh energy charges results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers***. Two customers can have the same level of demand and cause the utility to incur the same amount of fixed cost, but because one customer uses more kWh than the other, that customer will pay more of the demand cost than the customer that uses fewer kWh. This results in a misallocation of cost responsibility as higher load factor customers overpay for the demand-related costs incurred by the Company to serve them. In other words, higher load factor customers are paying for a portion of the demand-related costs that are incurred to serve lower load factor customers simply because of the manner in which the Company collects those costs in rates.[94]

Currently, Empire collects a significant amount of fixed costs, in the LP, GP and SC-P rate classes, through energy charges. As Empire readily acknowledges, while demand costs [fixed costs] represent 53% of the LP class cost of service, only 32% of the LP class revenue requirement is collected through demand charges.[95] Similarly, while energy costs represent only 45% of the LP class' cost of service, Empire collects 68% of its LP revenues through energy charges.

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[94] Exhibit 353, Chriss Surrebuttal, pages 15-16 (emphasis added). In his testimony, Mr. Chriss provides an example with associated rates that shows the problem of collected fixed costs through energy charges. (See, Exhibit 353, pages 16-18).
[95] Exhibit 26, Lyons Direct, pages 35-36.

Figure 13: LP Current Revenues vs CCOS Breakdown by Cost Classification

LP Class Revenues By Cost Classification		Total LP Class		Demand Related		Customer Related		Energy Related
Class Cost of Service								
Revenue Requirement $	$	74,849,688	$	39,473,259	$	1,361,331	$	34,015,098
Breakdown %		**100%**		**53%**		**2%**		**45%**
Current Rate Revenues								
Demand Charges	$	20,495,057	$	20,495,057				
Customer Charge		135,820				135,820		
Energy Charges		43,572,079						43,572,079
Current Rate Revenues	$	64,202,957	$	20,495,057	$	135,820	$	43,572,079
Breakdown %		**100%**		**32%**		**0%**		**68%**

Source: Exhibit 28, Lyons CCOS Rebuttal, page 35.

Clearly then, a significant portion of the fixed costs for the LP class are inappropriately collected on a usage basis through energy charges.

Given this, MECG recommends that the Commission implement any rate reduction for the LP and GP classes by allocating the reduction "equally between both blocks of the energy charge to further correct the over recovery [of fixed costs] through the energy charges."[96] In this way energy charges are decreased while other charges [including the demand and facilities demand] would remain at current levels.[97]

In its rebuttal testimony, Empire agreed with MECG's proposal. "The Company supports MECG's recommendation to apply approved increase for the LP class to the billing demand and facility charges and ***apply any approved decreases to the energy charge***. This approach better aligns recovery of demand-related costs through demand charges and energy related costs through energy-related charges."[98]

In its testimony, Staff did not disagree with MECG's proposal, but suggested that the SC-P energy charges needed to account for SPP market prices of energy.[99] Staff's

[96] Exhibit 350, Maini Direct, page 36.
[97] *Id.*
[98] Exhibit 28, Lyons CCOS Rebuttal, pages 34-35 (emphasis added).
[99] Exhibit 104, Staff Class Cost of Service Report, pages 21-23.

concern centers on ensuring that the SC-P energy charges remain above the SPP market prices. Given this, Staff suggests that any SC-P revenue requirement reduction may nevertheless necessitate an increase in energy charges.

Staff's concern is misplaced for multiple reasons. ***First***, the evidence indicates that the load weighted and loss adjusted local marginal price for energy in the SPP market is approximately $0.03 / kWh.[100] As reflected in Exhibit 355, however, the SC-P energy charges are all well above this threshold. In fact, even a 5% rate reduction for the SC-P class would allow SC-P energy charges to stay above Staff's suggested threshold.

ENERGY CHARGE, per kWh:	Summer Season	Winter Season
On-Peak Period	$ 0.05412	$ 0.03838
Shoulder Period	$ 0.04371	
Off-Peak Period	$ 0.03373	$ 0.03184

Second, the evidence indicates that Empire will be immediately filing another rate case to reflect its capital 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."[101] Given that demand charges will likely increase in the next case to account for these increased fixed costs, MECG questions the logic of reducing demand charges in this case, as Staff appears to propose, just to then increase these charges in the next case.[102]

Given this, MECG suggests that Staff's suggestion is misplaced and urges the Commission to reject Staff's concern with the SC-P energy charges.

[100] Exhibit 351, Maini Rebuttal, page 24.
[101] *Id.*
[102] *Id.* at pages 24-25.

VI. OTHER RATE DESIGN ISSUES

a. Should the GP and TEB rate schedules be fully consolidated?

Position: In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will submit a rate analysis for the alignment of GP / TEB rates in its next rate case."[103] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

b. Should the CB and SH rate schedules be partially consolidated?

Position: In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will submit a rate analysis for the alignment of CB / SH rates in its next rate case."[104] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

c. Should "grandfathered" multifamily customers taking service through a single meter be given the option of being served on the CB/SH rate schedule?

Position: In the non-unanimous stipulation, the Signatories agreed that "[w]hen the Company files its next rate case, the Company will include testimony regarding whether or not it proposes to change its tariffs to allow mastermetered apartments to be served under CB / SH."[105] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

[103] Non-Unanimous Stipulation, provision 14.
[104] Non-Unanimous Stipulation, provision 15.
[105] Non-Unanimous Stipulation, provision 18.

f. What should be the amount of the residential customer charge?

Position: In the non-unanimous stipulation, the Signatories agreed that "There will be no changes to the customer charges in this proceeding."[106] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

g. Should Empire continue its Low-Income Pilot Program as is, or modify it?

Position: In the non-unanimous stipulation, the Signatories agreed that "[t]he Company's Low-Income Pilot Program will remain in place with no changes made in this case, and the Company will track all costs until the next rate case." Furthermore, the Signatories agreed that "[t]he Company, Staff, and OPC agree to meet at least twice prior to the filing of Empire's next rate case to discuss the Company's Low Income Pilot Program and whether or not modifications are warranted."[107] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

h. Should Empire be ordered to consolidate the PFM rate schedules into the GP/TEB rate schedule in a future proceeding?

Position: In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will propose the elimination of the Feed & Grain [PFM] rate in its next general rate case."[108] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

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[106] Non-Unanimous Stipulation, provision 5.
[107] Non-Unanimous Stipulation, provisions 21 and 22.
[108] Non-Unanimous Stipulation, provision 16.

i. Should Empire be ordered to incorporate shoulder months into the Special Contract / Praxair rate structures in the next rate proceeding?

Position: In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will work with parties to explore modification of the rate structures of all rate schedules to subdivide the current "Winter" billing season into a "Peak Winter" and two "Shoulder Month" seasons, to reflect at a minimum the difference in the cost of market energy among current "Winter" months to the extent it is consistent with reasonable rate design principles."[109] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

j. Should Empire be ordered to work to incorporate shoulder months into the rate structures of all non-lighting rate schedules?

Position: In the non-unanimous stipulation, the Signatories agreed that "[t]he Company will work with parties to explore modification of the rate structures of all rate schedules to subdivide the current "Winter" billing season into a "Peak Winter" and two "Shoulder Month" seasons, to reflect at a minimum the difference in the cost of market energy among current "Winter" months to the extent it is consistent with reasonable rate design principles."[110] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

k. Should Empire be ordered to retain each of the following: Primary costs by voltage; Secondary costs by voltage; Primary service drops; Line extension by rate schedule and voltage; Meter costs by voltage and rate schedule?

Position: In the non-unanimous stipulation, the Signatories agreed that "[p]rior to the next rate case, the Company will identify and provide the data required to determine: primary

[109] Non-Unanimous Stipulation, provision 17.
[110] Non-Unanimous Stipulation, provision 17.

distribution costs by voltage; secondary distribution costs by voltage; primary voltage service drops; line extension by rate schedule and voltage; and, meter costs by voltage and rate schedule. If the required data is not readily available, the Company will identify and implement the actions necessary to obtain it as quickly as possible."[111] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

l. Should Empire be ordered to use of AMIs for near 100% sample load research as soon as is practical, but no more than 12 months after 90% of AMI are installed?

Position: In the non-unanimous stipulation, the Signatories reached multiple agreements with regard to the deployment of AMI and the use of the data resulting from such deployment.[112] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

m. Should Empire be ordered to retain individual hourly data for future bill comparisons?

Position: In the non-unanimous stipulation, the Signatories agreed that Empire will "[r]etain individual hourly data for use in providing bill comparison tools for customers to compare rate alternatives"[113] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

n. Should Empire be ordered to retain coincident peak determinants for use in future rate proceedings?

Position: In the non-unanimous stipulation, the Signatories agreed that Empire will

[111] Non-Unanimous Stipulation, provision 12.
[112] Non-Unanimous Stipulation, provision 13a.
[113] Non-Unanimous Stipulation, provision 13b.

"[r]etain coincident peak determinants for use in future rate proceedings."[114] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue.

o. How should the amount collected from customers related to the SBEDR charge be billed, and should there be a separate line item on customers' bills?

Position: MECG takes no position on this issue.

p. By when should Empire move customers served on CB/SH that exceed the demand limits of those schedules to the appropriate rate schedule.

Position: MECG takes no position on this issue.

s. How should any residential revenue requirement increase or decrease be apportioned to the energy (kWh) rates?

Position: The residential schedule only provides for a customer and energy charges.[115] In the non-unanimous stipulation, the Signatories agreed that "[t]here will be no changes to the customer charges in this proceeding."[116] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue. Given that the residential customer charge will not change, any change in the residential revenue requirement must be apportioned to the energy (kWh) rates.

v. How should any CB and SH revenue requirement increase or decreasebe apportioned to the energy (kWh) rates?

Position: The CB and SH rates schedules only provides for a customer and energy charges.[117] In the non-unanimous stipulation, the Signatories agreed that "[t]here will be

[114] Non-Unanimous Stipulation, provision 13c.
[115] See, Exhibit 355.
[116] Non-Unanimous Stipulation, provision 5.
[117] See, Exhibit 355.

no changes to the customer charges in this proceeding."[118] This provision was not opposed by Public Counsel. MECG continues to support this provision as a reasonable resolution of this issue. Given that the CB and SH customer charges will not change, any change in the CB and SH revenue requirement must be apportioned to the energy (kWh) rates.

[118] Non-Unanimous Stipulation, provision 5.

VII. RETURN ON EQUITY

A. INTRODUCTION

It is well established that public utility commissions have several basic objectives. Foremost among these objectives is to ensure adequate earnings for the utility while preventing excessive (monopoly) profits.[119] Absent regulatory controls, the utility will inevitably seek to extract monopoly profits from the many (the ratepayers of Missouri) for the benefit of the few (the Empire shareholders scattered across the nation).

The attempt to extract monopoly profits in this case is best seen in Empire's request for an inflated return on equity. Rather than seeking that level of return that is "sufficient to ensure confidence in the financial soundness of the utility,"[120] Empire seeks to bolster its corporate profits. The Supreme Court has pointed out, however, that the utility has no "right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures."[121]

In considering the appropriate return on equity, the Commission should focus on the nature of this issue. Unlike other costs (i.e., fuel costs, investment, salaries, etc.) that can be directly tied to the provision of utility service, the return on equity is simply the profit that the utility is permitted to earn. With this in mind, permitting Empire to earn its recommended 9.85% return on equity as opposed to the 9.25% return on equity recommended by Staff and Public Counsel does <u>not</u> result in a more reliable level of service. Rather, it simply makes Empire's rates more unjust and unreasonable.

Of course, the Commission must be cognizant of authorizing a return that permits the attraction of capital. Clearly, in this regard, authorizing Staff's recommended 9.25%

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[119] Phillips, Charles F. Jr., *The Economics of Regulation*, Rev. ed. (1969) at page 124.
[120] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692-693 (1923).
[121] *Id.*

return on equity, especially in conjunction with the risk shifting WNR / SRLE mechanism, will meet that capital attraction goal. Frankly, the authorization of a higher return on equity serves no other purpose that to transfer wealth from Missouri ratepayers, at a time of a pandemic, to shareholders in other states or even other countries.

Furthermore, for large commercial / industrial customers, the authorization of an inflated return on equity also serves to increase rates that are already uncompetitive with those available in other states. As previously pointed out, Empire's industrial rates are already 21.1% above the national average industrial rate.[122] The authorized return on equity provides the Commission an opportunity to either address this fundamental economic development problem or to ignore this problem and grant higher profits to out of state shareholders.

B. OVERVIEW OF THE RECOMMENDATIONS

Demonstrating its desire to extract monopoly profits from its customers, Empire's witness Robert Hevert recommends a return on equity of 9.95% while simultaneously acknowledging that a return of 9.80% is reasonable.

> My analyses indicate that an ROE in the range of 9.80 percent to 10.60 percent represents the range of equity investors' required return for investment in a vertically integrated utility such as Liberty-Empire in the current and expected capital market environment. Based on the quantitative and qualitative analyses discussed throughout my Direct Testimony, and taking into consideration the Commission's decisions in prior proceedings, I propose an ROE of 9.95 percent.[123]

As this brief demonstrates, Mr. Hevert's 9.95% recommendation is inflated in that it is: (1) significantly above the national average authorized return on equity and (2) based upon modeling that is fundamentally flawed. Specifically, as pertains to the low

[122] Exhibit 350, Maini Direct, page 9 (citing to EEI Typical Bills and Average Rate Report, Summer 2019).
[123] Exhibit 36, Hevert Direct, page 2.

cost of capital, Staff points out that the national average authorized return on equity for 2019 was only 9.39%.[124] Therefore, Empire's proposed return on equity is significantly inflated. As pertains to flawed modeling, the Commission has repeatedly pointed our specific concerns with Hevert's methodology. In fact, as a result of his flawed analysis, the Commission, in two recent Ameren decisions, concluded that Mr. Hevert's recommendation was "too high" and rejected his recommendation.[125] Despite the clarity of the Commission's prior criticism, Mr. Hevert continues to present the same flawed analysis in furtherance of inflated returns. For the same reasons as it has done in other cases, the Commission should disregard Mr. Hevert's recommendation in this case.

In contrast both Staff and OPC present a more reasoned analysis. As these analyses both demonstrate, Empire's current investment credit rating would be fully supported by a 9.25% return on equity.[126] Furthermore, a 9.25% return on equity is consistent with the continued low cost of capital for utilities that has been prevalent for almost a decade.[127] For these reasons, MECG urges the Commission to authorize Empire a return on equity of 9.25%.

C. HEVERT'S FLAWED MODELING AND INFLATED ANALYSIS

Historically, the Commission has considered the national average return on equity in its consideration of an appropriate return on equity.

> The Commission mentions the average allowed return on equity not because the Commission should, or would slavishly follow the national average in awarding a return on equity to Ameren Missouri. However, Ameren Missouri must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides

[124] Exhibit 108, Chari Rebuttal, pages 6-7.
[125] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 69-70.
[126] See, Exhibit 101, Staff Direct Report, page 18 and Exhibit 210, Murray Direct, page 2.
[127] As Mr. Murray points out, "utility bond yields are at their lowest levels in at least 60 years." Exhibit 211, Murray Rebuttal, page 10.

> a reasonableness test for the recommendations offered by the return on equity experts.[128]

As a reasonableness test then, the national average return on equity demonstrates that Mr. Hevert's recommended return on equity is inflated.

> Mr. Hevert's recommended authorized ROE of 9.95% is too high. An authorized ROE of 9.95% is 56 basis points ("bps") higher than the 2019 national average authorized ROE of 9.39%. There were six fully litigated vertically integrated electric cases in the U.S.A. in 2019, of which five utilities were authorized 9.50% or less, and one was authorized 10.00%. Even the one case, involving DTE Electric Co., which was awarded a 10.00% authorized ROE was unique; the utility was authorized a capital structure with a far lower common equity ratio than the other five cases. It is therefore, implausible for Mr. Hevert to recommend such a high authorized ROE for Empire.[129]

The reason that Mr. Hevert's recommended return is so far above the national average return on equity is found in his modeling. Mr. Hevert's methodologies are flawed in several ways.

<u>First</u>, Mr. Hevert relies upon inflated growth rates. As mentioned, on at least two previous occasions, the <u>Commission</u> has found that Mr. Hevert's growth rate assumptions and return on equity recommendations were "too high."

> However, Hevert's estimation of an appropriate ROE is ***<u>too high</u>***. MIEC's witness, Michael Gorman explains that Mr. Hevert relied on long-term sustainable growth rate estimates in his DCF models that are higher than the growth outlook of the economy as a whole. As he explained, it is not rational to expect that utilities can grow faster than the demand of the economies they serve.[130]

Still again,

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[128] *Report and Order*, Case No. ER-2012-0166, issued December 12, 2012, page 67.

[129] Exhibit 108, Chari Rebuttal, pages 6-7. Specifically, while DTE was authorized a return on equity of 10.00%, that return was applied to a capital structure that consisted of only 37.94% common equity. In contrast, the other authorized returns for 2019 were applied to capital structures which included 49.46% to 53.00% common equity. (See, Exhibit 108, Chari Rebuttal, page 7, footnote 6).

[130] Case No. ER-2012-0166, *Report and Order*, issued December 12, 2012, at pages 69-70. (emphasis added).

> Hevert's recommended return on equity is higher than the other recommendations in large part because he over-estimates future long-term growth in his various DCF analyses, making them ***too high*** to be reasonable estimates of long-term sustainable growth. When Hevert's long-term growth rates are adjusted to use more sustainable growth estimates based on published analyst's projections, his multi-stage DCF analysis produces a rate of return more in line with the estimates of LaConte and Gorman.[131]

Thus, the Commission has repeatedly criticized Mr. Hevert's heavy reliance on inflated growth rates in his modeling.

In this case, Mr. Hevert has once again ignored the Commission's previous criticism and relied on inflated growth rates in his DCF modeling. Specifically, Staff points out that, while Mr. Hevert utilized a growth rate of 5.8%, the expected long-term GDP growth rate is only 4.1%.

> Mr. Hevert assumes, in his constant growth DCF model, that his electric proxy group's dividends will grow perpetually, at an average of 5.80%, a growth rate that is about 170 bps higher than the estimated long-term growth rate for the general economy. ***Assuming that utilities will grow at a higher rate than the overall economy is unrealistic, because it runs counter to basic economic principles: in the long run, companies will grow at a rate consistent with the long-term growth rate of the overall economy***. Dr. Roger A. Morin ("Dr. Morin"), in his book New Regulatory Finance posits, "It is useful to remember that eventually all company growth rates, especially utility service growth rates, converge to a level consistent with the growth rate of the aggregate economy [GDP growth rate]." (Roger A. Morin, New Regulatory Finance, page 302).[132]

Recognizing that Mr. Hevert continues to rely on inflated growth rates, the Commission should disregard his recommendation.

[131] Case No. ER-2011-0028, *Report and Order*, issued July 13, 2011, at page 23. (emphasis added).
[132] Exhibit 108, Chari Rebuttal, page 7 (emphasis added). In his testimony, Mr. Chari points out that, while Mr. Hevert uses a growth rate of 5.8%, the long-term GDP growth rate is only 4.1%. See, Exhibit 108, Chari Rebuttal, page 7, footnote 7.

Second, Mr. Hevert uses his growth rate in an inappropriate fashion in his DCF approach. Specifically, while the DCF approach has a long-term focus, Mr. Hevert relies exclusively on analyst short-term growth rates.

> Mr. Hevert also uses his analysts' growth rate inappropriately. ***Analysts' growth estimates have a short-term projection horizon of between one to five years. The constant growth DCF model assumes a long-term growth rate, which means that analysts' growth forecasts are unsuitable for exclusive use in the constant growth DCF model***. FERC, in Opinion 569 acknowledged the unsuitability of exclusive use of analysts' growth forecasts in the constant growth DCF, "[T]he Commission's current policy is to require the DCF analysis of an individual company to include a projection of the long-term growth in dividends based on the growth in gross domestic product (GDP)." (FERC Opinion 569, line 135). FERC requires that analysts' growth estimates be given two-thirds weight and long-term GDP growth rate, one-third weight when calculating the growth rate for use in the constant-growth DCF. Mr. Hevert simply takes analysts' growth forecasts and plugs them into his constant growth DCF model without long-term growth consideration. ***Analysts' growth forecasts are simply inappropriate for exclusive use in the constant-growth DCF***.[133]

Third, Mr. Hevert has relied on several methodologies that have been summarily rejected by FERC. Specifically, Mr. Hevert utilized the constant growth DCF, the CAPM, the empirical capital asset pricing model ("ECAPM") and a Bond Plus Risk Premium model. In addition, Mr. Hevert presents an Expected Earnings analysis.[134] The problem is that the risk premium approach as well as the Expected Earnings methodologies have both been deemed unreliable by FERC.

> Recently, FERC ruled that expected earnings model does not satisfy the requirements of the *Hope* case and therefore decided not to rely on that approach anymore. At the same time, FERC ruled risk premium models less reliable than the DCF and CAPM models and so decided to also stop relying on them for COE [cost of equity] estimation.[135]

[133] Exhibit 108, Chari Rebuttal, pages 7-8 (emphasis added).
[134] Exhibit 108, Chari Rebuttal, page 4.
[135] Exhibit 108, Chari Rebuttal, page 2 (citing to FERC Opiinion 569, page 117, line 200).

Recognizing that the FERC has deemed these approaches unreliable, the Commission should reject them as well. Given this, Mr. Hevert's analysis should focus solely on his DCF (range of 8.09% - 10.04%) and CAPM (range of 8.66% - 9.76%) analyses. That said, as has been shown, Mr. Hevert's DCF analysis is flawed in that it is based upon inflated growth rates.

Fourth, while FERC continues to utilize the CAPM methodology, concerns with the quantification of market risk premiums ("MRP"), an essential input in the CAPM model, are prevalent. Predominant among such concerns is the inclusion of companies that do not pay dividends. In a recent opinion, FERC "reaffirmed its position that only dividend paying companies are to be used in the constant growth DCF ex-ante MRP method, noting that DCF analysis can only be performed on companies that pay dividends."[136] As Staff points out, however, Mr. Hevert nevertheless included numerous companies that do not pay dividends.

> Mr. Hevert's ex-ante (forecasted) MRPs of 12.15% and 12.25% are too high compared to Staff's and Mr. Murray's MRP estimates, as well as estimates from industry professionals. For example, Aswath Damodaran, estimated MRPs in the range 5.36% to 5.96% between the months of January and June 2019. Dr. Morin in his Regulatory Finance book estimates that reasonable average MRPs for the U.S. range from 5% to 8%.13. Duff and Phelps' estimates are 4.50% (geometric) and 6.00% (arithmetic). Staff took a closer look at how Mr. Hevert calculated his constant growth DCF forward-looking MRPs and discovered a significant flaw that led to his unreasonably high MRPs. ***The principal flaw in Mr. Hevert's MRP is that he included companies that do not pay dividends. The constant growth DCF model assumes dividend payment. Staff discovered 84 companies that do not pay dividends within the S&P 500 company list that Mr. Hevert used to develop his recommendation. This flaw inflated Mr. Hevert's MRPs***.[137]

[136] Exhibit 108, Chari Rebuttal, page 10 (citing to FERC Opinion 569).
[137] Exhibit 108, Chari Rebuttal, pages 9-10 (emphasis added).

In fact, Staff demonstrated that by correcting this simple manipulation, Mr. Hevert's CAPM results would decline from a range of 8.66% - 9.76% to a range of 6.02% - 7.60%. Similarly, Mr. Hevert's ECAPM range would decline from a range of 10.19% - 11.05% to a range of 6.88% - 8.50%.[138]

Fifth, Mr. Hevert further seeks to inflate his return on equity recommendation to account for Empire's alleged "small size".[139] As Staff points out, however, this is misplaced since Empire is now part of Algonquin Power.

> In his estimation of the size premium, Mr. Hevert assumed that Empire is a standalone company. This is a wrong assumption because since Empire merged with Algonquin Power and Utility Corporation ("APUC"), it ceased to be a standalone company. Empire no longer issues its own debt; it now relies on Liberty Utilities Corporation ("LUCo") and ultimately, APUC for all its financing. Empire is now a private company with all its stocks held and traded by APUC. This means that any size premium for Empire, if at all, should be based on APUC's market capitalization of $8.2 billion.[140]

As has been shown, Mr. Hevert routinely recommends a return on equity that state utility commissions have found to be "too high." As this brief has shown, the reason underlying Hevert's inflated recommendation is found in his faulty analysis and reliance on inflated data. Just as FERC has rejected many of the assumptions utilized by Mr. Hevert, this Commission should also reject his recommendation.

D. OPC / STAFF ANALYSIS

In contrast to Mr. Hevert's problematic analysis, Staff and Public Counsel conducted DCF and CAPM analyses that ultimately lead both to recommend a return on equity of 9.25%. Unlike the problems in Mr. Hevert's analysis, however, both utilize more reasonable growth assumptions in the DCF analysis. In fact, recognizing the

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[138] *Id.* at page 10.
[139] Exhibit 20, Hevert Direct, page 23.
[140] Exhibit 108, Chari Rebuttal, page 12.

undeniable limitations of the constant growth DCF analysis, Public Counsel instead utilized the multi-stage DCF approach. Specifically, while the constant growth DCF assumes a single growth rate to be realized in perpetuity, the multi-stage DCF allows for the utilization of different growth rates to be utilized at different points in time.

> I used the multi-stage version because it ***<u>allows for a modeling of changes in dividend growth due to varying capital expenditure cycles occurring within the electric utility industry</u>***. As I observed in the pending Ameren Missouri rate case, Case No. ER-2019-0335, some companies are currently in a higher capital expenditure cycle due to policy initiatives related to grid modernization and investment in renewables. During such cycles, companies will typically retain a higher percentage of their earnings in order to reinvest capital back into their systems. Although the utility may still increase its dividends during this capital spend cycle, it is typically at a slower rate than the utility's expected earnings growth. At the point in time at which the investment cycle ends, a company's DPS will grow faster than its EPS until the company achieves a payout ratio (DPS/EPS) consistent with a sustainable growth rate. From this point in time forward into perpetuity, the constant-growth DCF (more specifically the constant-growth DDM) can be used to estimate the value of perpetual cash flows.[141]

Thus, both the Public Counsel and Staff return on equity methodologies avoid the problems that are so prevalent in Empire's analysis.

That said, however, the upper end of Staff's recommended return on equity range (9.05% - 9.80%)[142] is problematic. Specifically, while Staff's discounted cash flow and CAPM analysis both support a return on equity of 9.25%, Staff artificially ratchets its return on equity range to 9.80%. Staff accomplishes this by starting with the Spire decision from 26 months ago and then engaging in several machinations to eventually extend its range to 9.80%.

> In the Spire Missouri rate cases, the Commission authorized Spire Missouri an ROE of 9.80%. At the time, Staff estimated a 6.96% COE for the gas proxy group, using market data from the period April, May, and

[141] Exhibit 210, Murray Direct, page 34.
[142] Exhibit 101, Staff Direct Report, page 18.

> June 2017. Staff's updated COE for the gas proxy group, using market data from the period September, October, and November 2019, is 6.21%, indicating that the COE for the gas proxy group has decreased approximately 75 basis point ("bps") since the Spire rate cases decision. Staff's current COE estimated for Staff's electric proxy group of 6.39% implies that the COE for the electric proxy group is 18 bps higher than for the gas proxy group.[143]

The problem with Staff's artificial expansion of its return on equity range to include consideration of the decision in the Spire case is obvious – it assumes that the ordered return on equity in that case was correct. In this regard, Staff clearly believes that the Commission was wrong. Specifically, while Staff recommended an analysis-based return on equity of 9.25% in that case,[144] the Commission ultimately ordered a return on equity of 9.80% which appeared to blindly mirror the national average return on equity from the previous year.[145] Thus, Staff clearly believed that the return on equity in that case was significantly inflated.

Nevertheless, in an apparent attempt to fulfill the perception that the Commission now desires a higher return on equity than is justified by the various ROE methodologies, the Staff uses that Spire decision to artificially inflate the upper end of its return on equity range.

> To be frank, the Commission went in the wrong direction in that case. Also, I note the Commission indicated that it believed it was authorizing an ROE consistent with average allowed ROEs for gas distribution companies. In fact, the average allowed ROE for gas companies then was closer to 9.6% after eliminating the 11.88% outlier that was included in the average at that time. For this reason, the relevant benchmark for this case is the approximate 9.5% allowed ROEs the Commission initially authorized other Missouri vertically-integrated electric utility companies in 2015.[146]

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143 Exhibit 101, Staff Direct Report, page 5.
144 *Amended Report and Order*, Case No. GR-2017-0215, issued March 7, 2018, at page 29.
145 *Id.* at page 33.
146 Exhibit 211, Murray Rebuttal, pages 32-33.

MECG suggests that the Commission should decide a return on equity for Empire that is based upon the objective analyses conducted in this case. With this in mind, the Commission should not artificially inflate the return on equity for an electric utility simply because of a two year old gas decision.

E. EFFECT OF WNR / SRLE MECHANISM

In 2018, the General Assembly authorized the Commission to implement a weather normalization mechanism for Empire. The purpose of this mechanism is to insulate the electric utility from variations in residential usage caused by weather or conservation. Because of the significant amount of fixed costs collected through the residential energy charge, such variation in usage inevitably results in the utility not fully recovering its fixed costs. Given that the mechanism shifts the risk of usage variation caused by weather and conservation from the utility to the customers, it represents a significant reduction in the utility's business risk. For this reason, Section 386.266.8 tasks the Commission with considering this reduction in business risk when it establishes the appropriate return on equity for Empire.

The fact that a weather normalization mechanism reduces Empire's business risk is undeniable. As Moody's recognized:

> On a positive note, Missouri Senate Bill 564, passed in June 2018, is expected to provide more supportive regulatory framework, thereby reducing regulatory lag and opening the possibility of greater spend in Missouri. The bill provides the ability for electric utilities to update their rates in between general rate cases to account for changes in customer usage due to weather or conservation. . . . These mechanisms should work towards shortening regulatory lag, a credit positive. Empire intends to utilize the decoupling mechanism now available to electric utilities.[147]

[147] Exhibit 211, Murray Rebuttal, pages 33-34.

It is further undeniable that a reduction in business risk should be reflected in the authorized return on equity. That is, the more risky a company is, the higher the return on equity that is expected by investors. Similarly, the less risky a company is, as a result of a weather normalization mechanism or other regulatory device, the lower the return that is expected by investors.

In this case, OPC witness Murray quantified the impact of approving the weather normalization mechanism as equivalent to a 10 to 15 basis point reduction in the allowed ROE. "A 1% reduction in the allowed common equity ratio is equivalent to an approximate 10 to 15 basis point reduction (0.10% to 0.15%) in the allowed ROE."[148]

Given this, MECG urges the Commission to demonstrate that it has met the statutory expectation and make an explicit 10-15 basis point reduction in the return on equity that would have otherwise been approved in this matter.

F. CONCLUSION

For all the foregoing reasons, MECG recommends that the Commission authorize a return on equity of 9.25% for this case.

[148] *Id.* at page 35.

VIII. CAPITAL STRUCTURE

As reflected at page 5 of the direct testimony of David Murray, MECG recommends that the Commission utilize a capital structure consisting of 46% common equity and 54% long term debt. Such a capital structure is consistent with merger conditions agreed to by Empire and its parent company and recognizes a capital structure that allows Empire to earn a reasonable return on equity while also minimizing the cost of capital for ratepayers. Specifically, such a capital structure avoids concerns that Liberty Utilities has manipulated the capital structure of its regulated subsidiaries in order to maximize corporate profits.[149]

[149] Exhibit 210, Murray Direct, pages 8-14.

IX. COST OF DEBT

MECG recommends that Empire's embedded cost of debt is 4.65%. (Exhibit 210, Murray Direct, pages 14-15).

X. WNR / SRLE ADJUSTMENT MECHANISMS

In 2018, the General Assembly passed Section 386.266.3 which provides statutory authority for the Commission to establish a mechanism authorizing "periodic rate adjustments outside of general rate proceedings to adjust rates of customers in eligible customer classes to account for the impact on utility revenues of increases or decreases in residential and commercial customer usage due to variations in either weather, conservation, or both."

The statute continues on to provide that the "eligible customer classes" subject to such a mechanism are "residential and classes that are not demand metered." The reason for limiting the applicability of such a mechanism to residential and non-demand metered classes is obvious from the evidence in this case. Classes that have demand meters[150] are charged demand rates. For Empire, this includes both a demand charge (used to collect generation and transmission costs) as well as a ratcheted facilities demand charge (used to collect distribution costs).[151] For these classes then, fixed costs are ideally collected through the demand charges and variable costs are collected through the energy charge.

In contrast, the residential and other non-demand metered classes are simply charged a customer charge and an energy charge.[152] Given the absence of a demand charge(s) for the collection of fixed costs, a significant amount of the fixed costs for these classes are collected through energy charges. As Mr. Lyons points out, 90.9% of the

[150] Exhibit 355: Schedules General Power; Large Power; Total Electric Building; Special Transmission Service Contract: Praxair; and Special Transmission Service are all served via demand meters and are charged demand charges.
[151] *Id.*
[152] Exhibit 355: Schedules Residential Service; Commercial Service; Small Heating Service; and Feed Mill and Grain Elevator Service are not charged demand charges.

residential revenue requirement is collected through energy charges.[153] This heavy reliance on energy charges, which are collected on a per kWh basis, means that the utility's recovery of fixed costs from these classes is incredibly susceptible to usage variations due to weather and conservation.

> [I]ncreases or decreases in consumption will likely cause utilities to over- or under-collect their cost of service. Warmer than normal weather during the winter, for example, will likely result in sales that are below historical test year sales, reducing the likelihood that utilities recover their Commission-authorized cost of service. Conversely, colder than normal weather during the winter will likely result in sales that are above historical test year sales, increasing the likelihood that utilities recover more than their Commission-approved cost of service.[154]

In an effort to break the linkage between the utility's recovery of fixed costs and these classes' consumption of electricity, the General Assembly authorized the creation of a mechanism that permits changes in rates for these non-demand metered classes to account for usage variation. Based upon this statute (Section 386.266.3), Empire sought approval of a weather normalization rider.

In its testimony, Staff proposed a similar mechanism which it termed a Sales Reconciliation to Levelized Expectations ("SRLE") rider.[155] In its proposed mechanism, Staff suggested that the residential SRLE mechanism be treated separately from the small commercial SRLE mechanism.[156] Staff then attempted to determine that level of monthly usage for both the residential (RG) as well as the CB / SH classes that appears to be relatively constant throughout the year and not susceptible to weather and conservation

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[153] Exhibit 26, Lyons Direct, page 53. Similarly, 89.0% of the Commercial and 92.0% of the Small Heating revenue requirements are collected through energy charges. *Id.*
[154] *Id.* at page 54.
[155] Exhibit 104, Staff Class Cost of Service Report, pages 3-13.
[156] *Id.* at page 3.

variations. For the RG class, this monthly level of usage is 400 kWh per customer.[157] Similarly, for the CB / SH classes, this relatively constant level of monthly usage is 700 kWh per customer.[158]

Staff then determined the level of revenues expected to be recovered from usage above each of these breakpoints and insulated that level of usage from weather / conservation variation. Specifically, residential rates are designed to collect approximately $91 million of revenue requirement[159] associated with monthly usage above 400 kWh.[160] Staff made a similar calculation for the CB / SH mechanism which shows that approximately $17.7 million of CB / SH revenues are to be insulated from weather / conservation variation through the SRLE mechanism.[161]

Staff then proposed that the designated level of revenue to be insulated through the SRLE would be compared to actual level and an annual reconciliation would be performed.[162]

In the Non-Unanimous Stipulation, the Signatories recommend a mechanism that is largely consistent with Staff's SRLE mechanism. Specifically, the recommended SRLE mechanism follows Staff's proposed mechanism and adopts the 400 kWh and 700 kWh monthly breakpoints for the residential and CB / SH rate classes and only uses the

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[157] *Id.* at page 5.
[158] *Id.* at pages 5-8.
[159] *Id.* at pages 8-10.
[160] This level of revenue requirement was based upon Staff's proposed revenue reduction and would necessarily change based upon the ordered revenue requirement.
[161] *Id.* at pages 10-12. Staff suggested certain changes to the CB / SH mechanism to account for the presence of certain large customers served under the CB / SH rate schedules. Specifically, less than 3% of the CB / SH customers account for 17% of the CB / SH usage. A decision by any of these customers to migrate to the General Power rate schedule would result in a significant decrease in revenues for this class. Recognizing that the SRLE mechanism is not designed to protect Empire from lost revenues associated with customer migration,
[162] *Id.* at pages 12-13.

SRLE to insulate the level of revenue requirement expected to be collected from usage above that point.[163]

While the Non-Unanimous Stipulation may different in very slight ways from the mechanism originally recommended by Staff, Staff has subsequently filed the supplemental testimony of Robin Kliethermes which, not only answers Commission questions, but also fills in whatever differences may exist between Staff's originally proposed WNR and that ultimately recommended in the Non-Unanimous Stipulation. Given this, MECG urges the Commission to approve the WNR mechanism set forth in the Non-Unanimous Stipulation.

It is important to recognize that the creation of a weather normalization / SRLE mechanism results in a significant decrease in the utility's business risk. Specifically, the risk associated with usage variation resulting from weather and conservation is shifted from the utility to the customers. Section 386.266.8 directs the Commission to consider this change in the utility's business risk resulting from the creation of such a mechanism. Such a change in risk should be reflected in the return on equity authorized by the Commission in this case. Given the direction of this statute, MECG urges the Commission to consider the reduction in Empire's business risk resulting from the requested SRLE mechanism and make an explicit reduction in Empire's return on equity to account for the shifting of this risk from the utility to customers.

[163] Non-Unanimous Stipulation, Appendix C, page 3.

XI. TAX CUT AND JOBS ACT IMPACT

Section 393.137, implemented in 2018, provides two things. First, the statute authorizes the Commission to adjust a utility's rates to prospectively account for the 2017 change in the federal corporate tax rate. Second, relevant to the issue in this case, the statute requires the Commission to defer, as a regulatory liability, the financial impact of the tax reduction for the period from January 1, 2018 through the date on which rates were prospectively changed (the "stub period benefits"). The statute then mandates that the Commission include these stub period benefits in rates in the utility's subsequent general rate proceeding.

> The commission shall also require electrical corporations to which this section applies, as provided for under subsection 1 of this section to defer to a regulatory asset the financial impact of such federal act on the electrical corporation for the period of January 1, 2018, through the date the electrical corporation's rate are adjusted on a one-time basis as provided for in the immediately preceding sentence. The amounts deferred under this subsection shall be included in the revenue requirement used to set the electrical corporation's rates in its subsequent general rate proceeding through an amortization over a period determined by the commission.[164]

In Case No. ER-2018-0366, the Commission held that Empire fell within the scope of Section 393.137.[165] Given this, the Commission prospectively changed Empire's rates to account for the reduction in the federal corporate tax rate.[166] In addition, consistent with the statute, the Commission ordered Empire to create a

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[164] Section 393.137.3

[165] *Report and Order*, Case No. ER-2018-0366, issued August 15, 2018, at pages 12-13 ("After considering the facts and the applicable law, the Commission finds that Empire did not have a "general rate proceeding" within the meaning of section 393.137 pending before the Commission on June 1, 2018. For that reason, section 393.137 does apply to Empire.").

[166] *Id.* at page 14 ("Empire's rates should be adjusted prospectively to reflect a reduction in its annual base rate revenue requirement of $17,837,022. That reduction shall take effect on August 30, 2018, as allowed by the authority granted to the Commission in section 393.137.3.").

regulatory liability for the stub period tax benefits. "Having found that section 393.137.3 applies to Empire, the Commission must comply with that statute by ordering Empire to establish a regulatory liability to account for its excess earnings during the period of January 1 through August 30, 2018."[167]

Given that this is the "subsequent general rate proceeding", the Commission is required to amortize these stub period tax benefits into rates. In this case, the Signatories to the Non-Unanimous Stipulation have complied with Section 393.137. Specifically, the Signatories have included an amortization of the stub period benefits, as required by the statute, while preserving the vast majority of these benefits until Empire's next rate case when a significant investment in wind will be included in rates. The relevant portion of the stipulation provides:

> An amortization of the balance of the stub period amortization of \$11,728,453, in the amount of \$5,000 monthly, is included in the revenue requirement for this case. The amortization balance, and the appropriate amortization period, will be reevaluated in the next general rate case.[168]

Recognizing that the provision from the Non-Unanimous Stipulation is consistent with Section 393.137 and has been agreed to by representatives of all of Empire's stakeholder groups, MECG asks that the Commission adopt this provision as a fair and reasonable resolution of this issue.

[167] *Report and Order*, Case No. ER-2018-0366, issued August 15, 2018, at page 22.
[168] *Global Stipulation and Agreement*, page 2, provision 3(b).

XII. ASSET RETIREMENT OBLIGATION

An Asset Retirement Obligation ("ARO") "is an obligation, legal or non-legal, associated with the retirement of a tangible, long-lived asset for the cost of returning a piece of property to its original condition."[169] This definition is generally consistent with the Instruction 25A of the Uniform System of Accounts.

> An asset retirement obligation represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine or promissory estoppel.[170]

In its direct filing, Empire sought to include certain amounts in rate base that it termed an "asset retirement obligation."[171] Initially, Staff opposed recovery of the asset retirement obligation on the basis that it was not known whether there was a legal obligation to incur these costs and that the costs were not known and measureable.

> First, Empire has included two "expected" ARO settlements which at this time are estimated amounts. If any rate treatment of an ARO is to be considered, the amount should be known and measurable, not estimated. Also, Empire's direct workpapers do not indicate if the AROs in question are legal or non-legal obligations. Staff's position is that non-legal ARO obligations should not be included. Staff is awaiting a response to a data request to determine if the AROs are legal or non-legal obligations.[172]

After the filing of rebuttal testimony the parties gained a better understanding of the nature of these costs and that, unlike an ARO which represents a future obligation, these costs have already been incurred. As MECG witness Meyer pointed out, "during the negotiation of this rate case it was discovered that the $9.2 million of claimed ARO costs ***were already incurred*** by Empire to address an environmental issue (asbestos

[169] Exhibit 106, Bolin Rebuttal, page 2.
[170] *Id.* at pages 2-3 (citing to Uniform System of Accounts Instruction 25A).
[171] Exhibit 4, Richard Corrected Direct Testimony, page 14.
[172] Exhibit 106, Bolin Rebuttal, page 3.

removal) at Asbury and to address the operation of certain ash ponds at Iatan, Asbury and Riverton generating units."[173]

Staff also agreed that, since these expenditures have already been incurred and were not a future obligation, they should be included in rates.

> In her testimony, Empire witness Ms. Richard stated that the amounts deemed to be AROs in this case were not accrued liabilities, as Staff earlier had thought, but in fact represented actual recent cash expenditures for various environmental activities at several of its power plants. Following the filing of surrebuttal testimony, Staff had subsequent discussions over the phone with Empire representatives concerning the nature of the costs in question. Based upon the evidence now available to it, Staff has verified that the amounts sought in rates by Empire as AROs represent recent cash expenditures, and that the costs were both prudent and necessary. As such, Staff now takes the position that these costs should be eligible for rate recovery by Empire.
>
> Recognizing that these costs have already been incurred and were therefore known and measureable, it became apparent that these costs did not constitute an asset retirement obligation.[174]

Given that these costs were not associated with a potential future obligation and were known and measureable, the Signatories to the Non-Unanimous Stipulation agreed that they should be included in rate base as a regulatory asset. Specifically, the Non-Unanimous Stipulation provides that "the costs for removal of asbestos at Asbury should be treated as cost of removal and charged against the Asbury accumulated depreciation reserve. It was also decided that similar treatment should be afforded the costs for working on the Iatan and Asbury ash ponds. For the Riverton ash pond which has already been retired, the costs were captured in a regulatory asset to be amortized in the next rate case."[175]

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[173] Exhibit 354, Meyer Supplemental Surrebuttal, page 3 (emphasis added).
[174] Exhibit 154, Oligschlaeger Sur-Surrebuttal Testimony, page 2.
[175] Exhibit 354, Meyer Supplemental Surrebuttal, page 3

Respectfully submitted,

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing pleading by email, facsimile or First Class United States Mail to all parties by their attorneys of record as provided by the Secretary of the Commission.

____
David L. Woodsmall

Dated: May 6, 2020