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Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
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MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

SURREBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

UNION ELECTRIC COMPANY,
d/b/a AMEREN MISSOURI

CASE NO. ER-2024-0319

Jefferson City, Missouri
February 2025

TABLE OF CONTENTS OF
SURREBUTTAL TESTIMONY OF

SARAH L.K. LANGE

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d/b/a AMEREN MISSOURI

CASE NO. ER-2024-0319

EXECUTIVE SUMMARY 1

Updated CCoS Study Results and Interclass Revenue Responsibility Recommendation 1

CLASS COST OF SERVICE STUDIES 7

Relevance of Ameren Missouri and Derivative Direct-Filed Study 7

Change in Ameren Missouri Position on Market Prices 7

Errors in Ameren Missouri Direct CCoS Study 10

Allocation of Production, Transmission, and Market Energy Costs, Expenses, and Revenues 11

Has Anything Changed? 17

Production Allocation Approaches 19

Production Allocation Case History and Timeline of Material Changes 28

Production Allocation Examples 34

Distribution Allocation 42

Poles 44

Distribution Assignment of Customer-Specific Facilities 46

RATE MODERNIZATION PROCESS AND REASONABLENESS OF RESULTS ...47

Unbundled Results Request 54

RATE DESIGN 55

LGS/SPS Rate Design 55

Residential Customer Charge 56

Cost Basis of Residential Differential 60

TOU & AMI 61

SUMMARY OF STAFF RECOMMENDATIONS 62

CONCLUSION 64

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CASE NO. ER-2024-0319

EXECUTIVE SUMMARY

Q. Please state your name and business address.

A. My name is Sarah L.K. Lange, and my business address is 200 Madison Street, Jefferson City, Missouri 65102.

Q. Are you the same Sarah L.K. Lange who provided direct class cost of service (CCoS) and rate design testimony in this matter, filed December 17, 2024, and rebuttal testimony, filed January 17, 2025?

A. Yes.

Q. What areas will you be addressing in this testimony?

A. I will respond to Ameren[1] witnesses Phillips, Bowden, Hickman, and Wills, and MECG[2] witness Maini and MIEC[3] witness York concerning CCoS and rate design issues.

Updated CCoS Study Results and Interclass Revenue Responsibility Recommendation

Q. Did Mr. Hickman alert you to errors in your CCoS study and inputs?

A. Yes. In his rebuttal testimony Mr. Hickman correctly identified that I had inadvertently:

[1] Union Electric Company, d/b/a Ameren Missouri ("Ameren" or "Ameren Missouri").
[2] Midwest Energy Consumers Group (MECG).
[3] Missouri Industrial Energy Consumers (MIEC).

(1) pulled the wrong number for total lighting customers into my workpaper,[4]
(2) included an error in my Poles allocation formula related to the SGS class,[5] and
(3) misapplied the ampacity rating of #4 copper wire to #4 aluminum wire in my Overhead Conductors and Devices classification.[6]

Q. Have you updated your CCoS study to correct for these items?

A. Yes. Also, while I do not agree with Mr. Phillips or others concerning the propriety of my treatment of equipment serving only one customer that is recorded to the substations, poles, and overhead conductors and devices accounts, because the impact of my treatment in this case is negligible, I have excluded the assignment of that equipment in my updated CCoS Study.

Q. What are your corrected study results and revenue responsibility recommendations?

A. While my study results show that the LGS, SPS, and LPS classes[7] are undercontributing to overall return by a magnitude greater than 5%, I do not recommend that any changes in revenue responsibility of the classes be made in this case.

Corrected Study Table 1

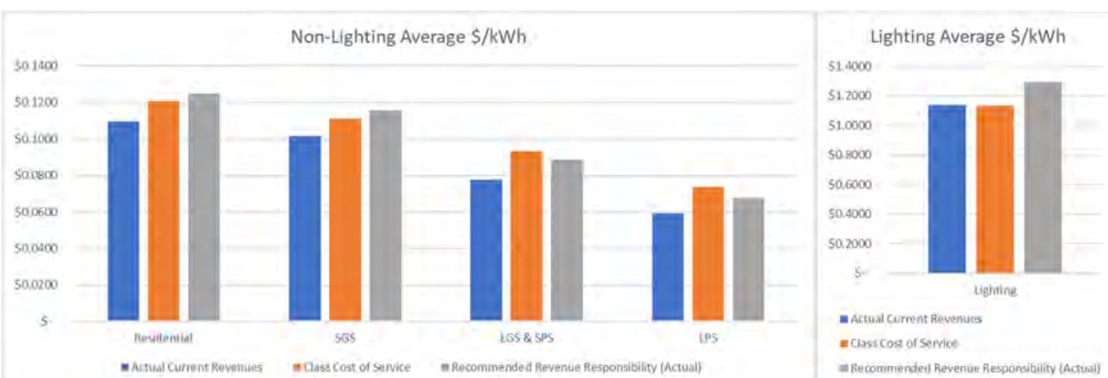
	Residential	SGS	LGS & SPS	LPS	Lighting	System Average/
Actual Current Revenues	$ 1,447,291,019	$ 329,249,326	$ 830,584,205	$ 220,665,241	$ 41,999,473	$ 2,869,789,264
Current Revenues for Study	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419	$ 2,869,789,264
Class Cost of Service	$ 1,596,665,700	$ 360,210,889	$ 998,638,104	$ 274,654,003	$ 41,864,173	$ 3,272,032,870
Study Difference ($)	$ 154,511,018	$ 32,130,046	$ 167,992,874	$ 47,595,915	$ 13,754	$ 402,243,606
Difference as % of Studied Rev.	10.71%	9.79%	20.22%	20.96%	0.03%	14.02%
Return Provided on Allocated Ratebase (Study revenues)	**4.85%**	**4.96%**	**2.92%**	**2.40%**	**7.08%**	**4.15%**
Under/Over Contribution %	**3.39%**	**3.76%**	**-5.95%**	**-7.82%**	**14.41%**	**0.00%**
Interclass Revenue	$ -	$ -	$ -	$ -	$ -	$ -
Recommended Revenue	$ 1,644,294,090	$ 374,066,248	$ 947,072,502	$ 258,883,653	$ 47,716,378	$ 3,272,032,870
Recommended $/kWh	**$ 0.1243**	**$ 0.1154**	**$ 0.0884**	**$ 0.0695**	**$ 1.2901**	**$ 0.1057**
% Increase (Actual)	13.97%	13.97%	14.02%	14.42%	13.97%	14.02%
% Increase (Studied)	14.02%	14.02%	14.02%	14.02%	14.02%	14.02%

[4] Hickman rebuttal, page 17.
[5] Hickman rebuttal, page 12.
[6] Hickman rebuttal, pages 14-16. Mr. Hickman found that I erroneously applied the ampacity of # 4 aluminum wire to #4 copper wire, discussed at pages 14-15 of his rebuttal testimony. For purposes of my study updates corrected in this testimony I will use his value of $03908 for the zero-intercept classification.
[7] Large General Service (LGS), Small Primary Service (SPS), and Large Power Service (LPS) classes.

As illustrated below, while my main study results indicate that the lighting class is overcontributing to revenue requirement, my alternate allocation results show that the lighting class is undercontributing to revenue requirement. Lighting is incredibly infrastructure intensive, so allocation of administrative and overhead expenses based on previously-allocated ratebase tend to overallocate revenue responsibility to lighting customers, however, lighting loads are generally counter to other system loads so production capacity costs tend to be underallocated to lighting customers. Because company-owned lighting schedules did not receive increases in File No. ER-2022-0337, it is reasonable to forgo a revenue responsibility shift from the Lighting class in this case. In the alternative, a modest $500,000 revenue responsibility shift from the Lighting class proportionately to the LGS, SPS, and LPS classes is supported by the evidence in this case and would also be reasonable.

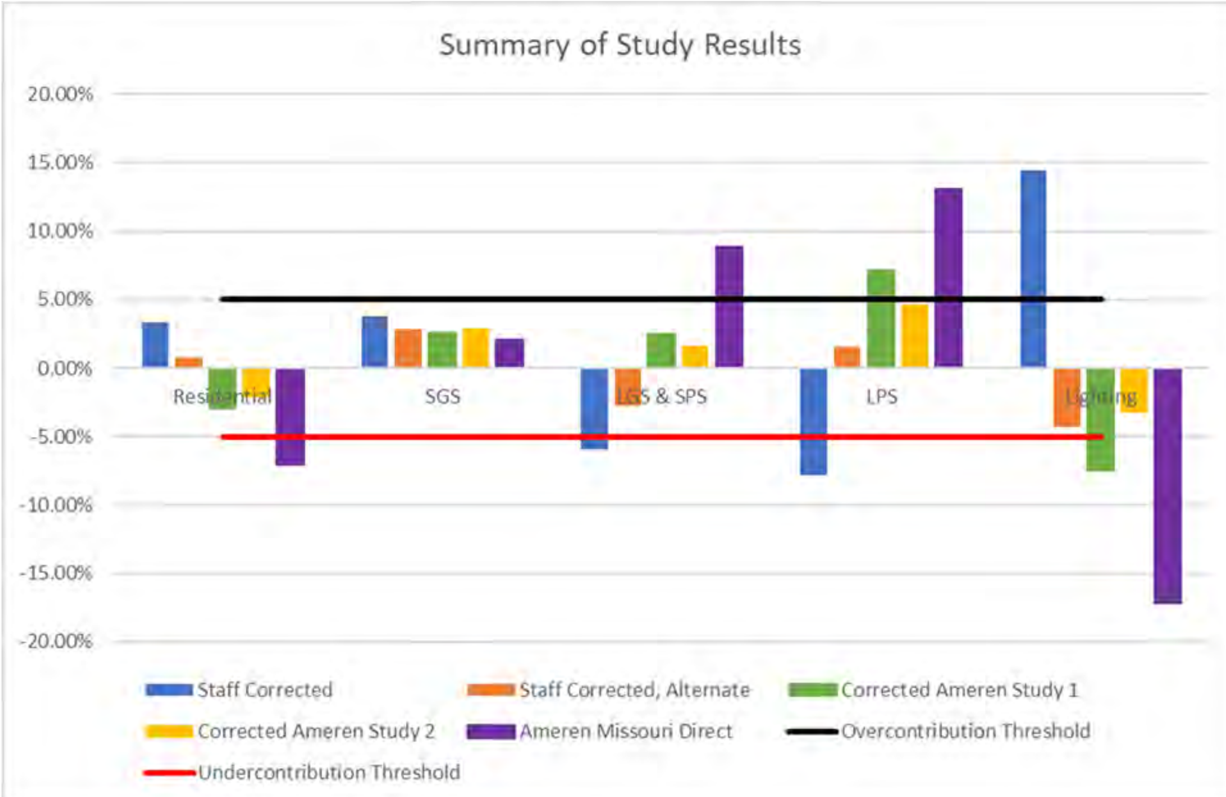
Q. Can you provide an illustration of these results and your recommendations?

A. Yes:



Q. Can you provide a summary of the CCoS study results available in this case?

A. Yes:



The "Staff Corrected" (blue) results are those discussed above, reflecting the Staff direct revenue requirement and the classifications and allocations described in my direct testimony, except that I have corrected the lighting customer count, the poles allocator, and the overhead conductor and device classifier; this study also reflects the removal of the assignment for single-customer poles, conductors, and substations. Its results are summarized below:

Energy Sales Allocation of Administrative and Overhead Costs and Expenses - Recommended Study						
	Total	Residential	SGS	LGS & SPS	LPS	Lighting
Non A&O Net Expense	$ 1,791,400,231	$ 884,570,020	$ 198,824,014	$ 537,574,040	$ 144,058,969	$ 26,373,189
Reallocate on Retail Revenue	$ 23,341,521	$ 11,729,810	$ 2,668,456	$ 6,756,079	$ 1,846,784	$ 340,392
Administrative & Overhead	$ 488,269,339	$ 210,501,563	$ 51,566,616	$ 168,767,381	$ 56,845,253	$ 588,526
Total Net Expense	$ 2,303,011,090	$ 1,106,801,393	$ 253,059,085	$ 713,097,500	$ 202,751,006	$ 27,302,107
Retail Revenue for Study Purposes	$ 2,869,789,264	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419
Revenue for Return	$ 566,778,173	$ 335,353,290	$ 75,021,757	$ 117,547,731	$ 24,307,082	$ 14,548,313
Non A&O Net Ratebase	$ 11,819,480,554	$ 6,112,635,465	$ 1,316,139,597	$ 3,388,586,650	$ 798,939,779	$ 203,179,062
Reallocate on Retail Revenue	$ 2,664,730	$ 1,339,106	$ 304,638	$ 771,292	$ 210,834	$ 38,860
Administrative & Overhead	$ 1,849,155,217	$ 797,203,577	$ 195,291,142	$ 639,149,458	$ 215,282,196	$ 2,228,843
Total Net Ratebase	$ 13,671,300,501	$ 6,911,178,149	$ 1,511,735,377	$ 4,028,507,400	$ 1,014,432,809	$ 205,446,765
Return at Current Revenues	4.15%	4.85%	4.96%	2.92%	2.40%	7.08%

The "Staff Corrected, Alternate" (orange) study is a comparison study where administrative and overhead costs are allocated to the classes on the same basis as previously assigned costs, and where administrative and overhead expenses are allocated to the classes on the same basis as previously assigned expenses. It is otherwise the same as the "Staff Corrected" study. Its results are summarized below:

Net Expense and Net Rate Base Allocation of Administrative and Overhead Costs and Expenses - Comparison Study						
	Total	Residential	SGS	LGS & SPS	LPS	Lighting
Non A&O Net Expense	$ 1,791,400,231	$ 884,570,020	$ 198,824,014	$ 537,574,040	$ 144,058,969	$ 26,373,189
Reallocate on Retail Revenue	$ 23,341,521	$ 11,729,810	$ 2,668,456	$ 6,756,079	$ 1,846,784	$ 340,392
Administrative & Overhead	$ 488,269,339	$ 241,155,925	$ 54,213,000	$ 146,455,939	$ 39,256,994	$ 7,187,481
Total Net Expense	$ 2,303,011,090	$ 1,137,455,755	$ 255,705,470	$ 690,786,058	$ 185,162,747	$ 33,901,062
Retail Revenue for Study Purposes	$ 2,869,789,264	$ 1,442,154,683	$ 328,080,843	$ 830,645,231	$ 227,058,088	$ 41,850,419
Revenue for Return	$ 566,778,173	$ 304,698,928	$ 72,375,373	$ 139,859,173	$ 41,895,341	$ 7,949,358
Non A&O Net Ratebase	$ 11,819,480,554	$ 6,112,635,465	$ 1,316,139,597	$ 3,388,586,650	$ 798,939,779	$ 203,179,062
Reallocate on Retail Revenue	$ 2,664,730	$ 1,339,106	$ 304,638	$ 771,292	$ 210,834	$ 38,860
Administrative & Overhead	$ 1,849,155,217	$ 956,314,417	$ 205,910,997	$ 530,144,806	$ 124,998,762	$ 31,786,234
Total Net Ratebase	$ 13,671,300,501	$ 7,070,288,989	$ 1,522,355,232	$ 3,919,502,748	$ 924,149,375	$ 235,004,157
Return at Current Revenues	4.15%	4.31%	4.75%	3.57%	4.53%	3.38%

The "Corrected Ameren Study 1" (green) starts with the Ameren Missouri direct CCoS Study and Ameren Missouri's direct revenue requirement, it is then adjusted in the following manner:

(1) The renewable energy resources are allocated to the classes on the basis of class energy/RESRAM requirements,[8]
(2) Correction of the A&E[9] allocator calculation to reflect individual LGS and SPS non-coincident peaks,[10]
(3) Removal of the unexplained and inappropriate Handy Whitman adjustments to the CPR values that Mr. Hickman relied upon in his direct classifications,[11]
(4) Backing out Mr. Hickman's application of his minimum-classified account percentages to the balances in the high-voltage Taps accounts,[12]
(5) Applying the Staff-determined customer classifications for the Poles account (51%), the Overhead Conductor and Device account, adjusted to Mr. Hickman's zero-intercept

[8] Sarah L.K. Lange Rebuttal testimony, pages 5 - 16.
[9] Average and Excess ("A&E").
[10] Sarah L.K. Lange Rebuttal testimony, pages 23 - 25.
[11] Sarah L.K. Lange Rebuttal testimony, pages 29 - 30.
[12] Sarah L.K. Lange Rebuttal testimony, page 30.

value for wire (10%), the Underground Conduit account (14%), and the Underground Conductor and Device Account (30%).

These corrections do not address Ameren Missouri's failure to appropriately functionalize and allocate production infrastructure recorded in distribution accounts, nor the unreasonable use of the A&E allocator in this case for remaining production infrastructure based primarily on summer peaks, nor the failure to recognize the full expense of serving load and the full revenue of participation in the integrated energy markets.[13] These results do not allocate or assign any customer-specific infrastructure except for the services and line transformer allocations to secondary customers.

The "Corrected Ameren Study 2" (gold), starts with the "Corrected Ameren Study 1" results, and reduces net revenue from selling energy into the wholesale market by $115,000,000 consistent with the rebuttal testimony of Andrew Meyer, regarding market prices. This adjustment will be described in greater detail in the indicated testimony section.

The "Ameren Missouri Direct" (purple), is the Ameren Missouri direct-filed study in this case, which is substantially identical to the MECG study results derived from that study.

The numerical results of all of these studies are provided below:

	Residential	SGS	LGS & SPS	LPS	Lighting
Staff Corrected	3.39%	3.76%	-5.95%	-7.82%	14.41%
Staff Corrected, Alternate	0.80%	2.82%	-2.72%	1.58%	-4.29%
Corrected Ameren Study 1	-2.89%	2.59%	2.53%	7.10%	-7.45%
Corrected Ameren Study 2	-2.17%	2.88%	1.60%	4.62%	-3.29%
Ameren Missouri Direct	-7.03%	2.05%	8.89%	13.04%	-17.14%

[13] Sarah L.K. Lange Rebuttal testimony, pages 16 – 23.

CLASS COST OF SERVICE STUDIES

Relevance of Ameren Missouri and Derivative Direct-Filed Study

Q. Are the Ameren Missouri (and derivative) direct study results relevant at this time, even if they were reasonable?

A. No. While the Ameren Missouri (and derivative) direct study results are not reasonable, they are also no longer relevant given a significant reduction in revenues which Ameren Missouri allocated on the basis of energy due to a change in Ameren Missouri's position on market prices for use in production modeling.

Further, a number of errors in Ameren Missouri's direct study have not been addressed. These errors are in addition to differences in potential opinions and approaches to selection of appropriate classification and allocation approaches.

Q. Is Staff aware of any changes in the Staff revenue requirement recommendation near the scale of the change in Ameren Missouri's position on market prices?

A. No.

Change in Ameren Missouri Position on Market Prices

Q. Did Mr. Hickman update his study for consistency with the position of Ameren Missouri witness Andrew Meyer, accepting the Staff approach to market price normalization?[14]

A. No. Ameren Missouri's change in position on market price normalization to the Staff position is expected to have a net increase of approximately $115,000,000 in the Ameren Missouri revenue requirement, based on the quantifications related to this issue in Ameren Missouri's direct and Staff's direct.[15]

[14] Rebuttal testimony of Andrew Meyer, page 2.
[15] This change in position will also increase the calculated Net Base Energy Cost used in the Ameren Missouri FAC, thus the overall impact to ratepayers of this change is negligible once the operation of the FAC is considered.

Q. What would be wrong with continuing to rely on Ameren Missouri's direct study results?

A. Ameren Missouri has conceded that its direct revenue requirement calculation included a level of revenue for its generation based on market prices that it has deemed to be "abnormally high due to geopolitical events and supply chain concerns impacting almost the entirety of the commodity markets."[16] Including the benefit of those revenues as an offset to the costs of obtaining energy for its customers warps the CCoS study results to an extent that they are simply not useful in this case.

Q. Is the Staff direct study similarly no longer useful?

A. As I indicated above, I made corrections to the Staff study, and this corrected study is a better representation of reasonable cost allocations than that provided in direct. However, the scope of the corrections to my study does not approach the impact of this change in Ameren Missouri's position. I am not aware of any changes in Staff's revenue requirement calculation that would approach the impact of the Ameren Missouri position correction.

Q. Have you evaluated the impact of the change on the Ameren Missouri study?

A. Yes. The Ameren Missouri direct study results, modified only to address Allocator 35, with the additional $115,000,000 revenue requirement, is shown below:

	Residential	SGS	LGS/SPS	LPS	Lighting
@ Full Rate of Return	$ 549,859	$ 113,917	$ 252,313	$ 57,964	$ 20,202
Increase $	$ 374,988	$ 51,502	$ 67,925	$ 7,810	$ 15,782
Increase %	25.71%	15.58%	8.13%	3.55%	37.46%
@ Current Rate of Return	$ 263,383	$ 54,567	$ 120,858	$ 27,765	$ 9,677
Increase $	$ 88,512	$ (7,849)	$ (63,530)	$ (22,390)	$ 5,257
Increase %	6.07%	-2.37%	-7.60%	-10.19%	12.48%

[16] Andrew Meyer rebuttal, page 2.

The original Ameren Missouri direct study results, modified only to address Allocator 35, are as follows.

	Residential		SGS		LGS/SPS		LPS		Lighting	
@ Full Rate of Return	$	549,859	$	113,917	$	252,313	$	57,964	$	20,202
Increase $	$	325,370	$	39,404	$	27,983	$	(5,161)	$	15,410
Increase %		22.31%		11.92%		3.35%		-2.35%		36.58%
@ Current Rate of Return	$	326,982	$	67,743	$	150,042	$	34,469	$	12,013
Increase $	$	102,492	$	(6,771)	$	(74,288)	$	(28,655)	$	7,222
Increase %		7.03%		-2.05%		-8.89%		-13.04%		17.14%

Q. What does a comparison of these results show?

A. Comparing these results shows that the undercontribution claimed by Ameren Missouri and various intervenors for the residential, and lighting classes decreases with the corrected revenue requirement, and that the overcontributions claimed for the LGS, SPS, and LPS classes decrease as well. Further, the overcontribution of the Small General Service (SGS) increases.

Q. Can you show the impact of the revenue requirement correction on the corrected Ameren Missouri study results that you supplied in your rebuttal testimony?

A. Yes. These results were presented in the executive summary of this testimony as "Corrected Ameren Study 2." The results with the new market price position are shown below:

	Residential		SGS		LGS/SPS		LPS		Lighting	
@ Full Rate of Return	$	519,912	$	112,914	$	278,049	$	65,023	$	18,359
Increase $	$	302,566	$	49,304	$	131,469	$	23,717	$	10,950
Increase %		20.74%		14.92%		15.73%		10.79%		25.99%
@ Current Rate of Return	$	249,038	$	54,086	$	133,186	$	31,146	$	8,794
Increase $	$	31,692	$	(9,524)	$	(13,394)	$	(10,160)	$	1,385
Increase %		2.17%		-2.88%		-1.60%		-4.62%		3.29%

The results, presented in the executive summary as "Corrected Ameren Study 1" are shown below:

	Residential		SGS		LGS/SPS		LPS		Lighting	
@ Full Rate of Return	$	519,912	$	112,914	$	278,049	$	65,023	$	18,359
Increase $	$	252,948	$	37,207	$	91,527	$	10,747	$	10,578
Increase %		17.34%		11.26%		10.95%		4.89%		25.11%
@ Current Rate of Return	$	309,173	$	67,146	$	165,346	$	38,667	$	10,917
Increase $	$	42,209	$	(8,561)	$	(21,176)	$	(15,609)	$	3,137
Increase %		2.89%		-2.59%		-2.53%		-7.10%		7.45%

Q. What do these results indicate?

A. These results are consistent directionally with the impact on the original Ameren Missouri study – namely, that the Residential, SGS, and Lighting classes are contributing more under the revised revenue requirement, and that the LGS, SPS, and LPS classes are contributing less under the revised revenue requirement.

Errors in Ameren Missouri Direct CCoS Study

Q. Did the rebuttal of Ameren Missouri, MECG, MIEC, or any other party attempt to adjust the Ameren Missouri study to correct the Underground accounts classifier per Ameren Missouri response to Consumers Council of Missouri ("CCM") Data Request 7 indicating a formula error in its direct filing or the mismatch in the classifier entered from one Ameren Missouri workpaper to the next?

A. No.[17]

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[17] Ameren Missouri's response to CCM Data Request 7 indicating a formula error in its direct filing. Review of this error indicated a mismatch in the classifier entered from one Ameren Missouri workpaper to the next, discussed in Sarah L.K. Lange Rebuttal testimony, pages 27-29. Subsequent to rebuttal filing, Ameren Missouri provided a supplemental response to CCM Data Request 7, indicating another error in the calculation.

Q. Did the rebuttal of Ameren Missouri, MECG, MIEC, or any other party attempt to adjust the Ameren Missouri study to correct for the inclusion of production infrastructure in distribution accounts?

A. No.

Q. Did the rebuttal of Ameren Missouri, MECG, MIEC, or any other party attempt to adjust the Ameren Missouri study to correct for the application of the minimum-classification percentage to the Taps high voltage subaccount balances within the Poles and Overhead Conductor and Device accounts?

A. No.

Q. Are these objective errors or oversights, as opposed to potential areas of disagreement in professional opinion, such as Ameren Missouri's decisions concerning the allocation of the PISA revenue requirement, Ameren Missouri's decisions concerning allocation of renewable resource costs or revenues, or other topics addressed in your direct testimony?

A. Yes.

Allocation of Production, Transmission, and Market Energy Costs, Expenses, and Revenues

Q. What is the most important testimony in this case concerning the cost causation of production costs, expenses, and revenues?

A. The two most important testimonies on this issue are:

> Ameren Missouri operates in a "buy all – sell all" RTO wholesale market. As a function of the MISO market, all the generation which is cleared for a given hour is sold into the market. At the same time, the Company must purchase from the MISO market all the energy needed to meet its load obligations. FERC Order 668 requires that these sales and purchases be netted against each other in each given hour. When the

> volume of purchases exceeds the volume of sales in a given hour, a net purchase is recorded. When the opposite occurs, a net sale is recorded.[18]

And,

> The RES law itself imposes a new obligation on utilities to provide a specific kind of energy – renewable energy – leading them to make specific types of investments at a significant scale (in renewable energy resources like High Prairie) and which would otherwise be at the discretion of utility management to undertake.[19]

Q. Does Ameren Missouri match its generation to the load of Ameren Missouri retail customers?

A. No. This has been a well-established fact for roughly 20 years. As further explained by Andrew Meyer:

> The Company's fuel costs (which includes significant coal costs), off-system sales, and spot market prices for fuel commodities and energy are inextricably linked together. The volume of coal (and natural gas) which Ameren Missouri consumes in any given year is a function of the market dispatch of its generating units. That dispatch in the Midcontinent Independent System Operator ("MISO") market is a function of the offer price of the unit (based on its incremental fuel cost) and the market price available to the unit for a given hour.
>
> Any volatility or uncertainty in either the incremental fuel cost or the market price available to the units will necessarily result in volatility and uncertainty in the unit output, which impacts fuel consumption, net purchased power expense, and net off-system sales revenues.[20]

Despite these clear and well-established realties, Ms. Maini, Mr. Brubaker, Ms. York, Mr. Wills, Mr. Hickman, and Mr. Phillips, on behalf of Ameren Missouri, formerly of Brubaker and Associates and MIEC, fail to acknowledge the impact of Ameren Missouri's participation

[18] Andrew Meyer direct, pages 20-21. See also Mr. Meyer's direct testimony at page 8, supporting the Ameren Missouri FAC positions in this case, states, "I will discuss how the Company's fuel costs are a function of unit dispatch, which itself is a function of spot fuel and spot energy market prices."
[19] Wills' rebuttal at pages 3-4.
[20] Meyer direct, pages 12-13.

in the integrated energy market on its cost-causation with regard to the cost of wholesale energy and the revenue from energy production and sales.

Q. Did Mr. Phillips express apparent confusion with the allocation of production, market, and transmission costs, expenses, and revenues, described in your direct testimony?

A. Yes. His rebuttal testimony discussed his confusion, and likely introduced confusion to readers of that testimony. However, despite the confusion Mr. Phillips expresses at pages 10-17 of his rebuttal testimony, he apparently understands the method as his description at page 18 line 8 – page 19 line 3 is relatively accurate. Similarly, Ms. Maini explains the method at pages 3 - 5 of her rebuttal, and Ms. York does the same at page 7 line 20 through page 9 line 2 of her rebuttal.

Pages 12 – 19 of my direct testimony provide an explanation of the allocation of these costs and expenses, and the rationale for the approaches taken. In light of Mr. Phillips apparent confusion, and due to the misrepresentations of the approach he provides in his rebuttal testimony, I have prepared a "walk-through" of the allocation, using only four plants, Callaway Nuclear, Labadie Coal, Boomtown Solar, and Atchison Wind at a greater level of detail than was presented in my direct testimony.

Q. Is the way you treated production, transmission, and market energy costs, expenses, and revenues, "new," as alleged by Mr. Phillips and others?

A. No. I treated these costs, expenses, and revenues very similar to how they were treated in the last rate case, with one exception. In ER-2022-0337 I used the customer loads in each of the 247 MISO-identified RA hours. In that case, Mr. Brubaker, on behalf of MIEC testified as follows:

> Q. ARE LOADS DURING RA HOURS USED FOR ANY COST ALLOCATION OR CAPACITY RESPONSIBILITY ALLOCATION PURPOSE?
>
> A. No, they are not. They are used solely to define the availability of generation resources owned by or available to MISO members.
>
> Q. HOW IS CAPACITY RESPONSIBILITY DETERMINED?
>
> A. The capacity responsibility of each load serving entity ("LSE") equals its expected load at the time of the MISO peak demand plus a reserve margin percentage that is established by MISO based on reliability considerations.
>
> Q. DOES MISO NOW LOOK AT LOADS AND RESOURCES DURING SPRING, SUMMER, FALL AND WINTER PERIODS?
>
> A. Yes. [21]

In this case (ER-2024-0319) I did not use the MISO RA Hours to allocate Type 1 Capacity, rather I used the Ameren Missouri peak load in each of the four seasons used by MISO to determine capacity responsibility.

Q. Was that treatment a new approach in that case?

A. No. That treatment was effectively an adaptation of the approach taken under the Staff's detailed Base Intermediate Peak (BIP) allocation, which I have used since 2014 in cases when relevant data was available.[22] Additional discussion of the use of production allocators before the Missouri Commission is described below.

Q. What causes the difference in CCoS Study results related to production and energy?

A. The real differences in CCoS Study results are caused by differences in the calculations and allocations of fuel, generation revenues, wholesale energy expense, and

[21] File ER-2022-0337, Rebuttal of Maurice Brubaker on behalf of MIEC, page 4.

[22] The Detailed BIP itself was a refinement of the NARUC-described BIP, which incorporated aspects of the "Capacity Utilization" method developed by Dr. Michael Proctor on behalf of Staff, and the "E8760" and "Plant Stratification" allocations which have been in use since before 2006 in various jurisdictions.

capacity revenue. The following reconciliation of the direct revenue requirements of the parties makes the differences obvious:

	Staff Direct Position	Ameren Direct Position	Difference
Sales Revenue - Energy	$ 144,794,262	$ 260,770,026	$ (115,975,764)

As discussed above, Ameren Missouri has changed its position on market energy prices, and that difference in net sales revenue is expected to evaporate. However, even if the same amounts are used, there is significant difference in the allocation of the revenue from the sales of Ameren Missouri's generators into the integrated marketplace. Namely, Staff allocates fuel costs and energy revenues based on how plant costs were allocated, and separately allocates wholesale energy costs to the classes based on class load and market energy prices for each hour. However, Ameren Missouri nets these three distinct amounts and then simply allocates them to the classes on the basis of annual energy usage.

Q. Does the 1994 NARUC Manual recognize that it may be appropriate to allocate fuel costs consistent with plant allocation, as opposed to simply allocating fuel cost on the basis of annual energy in every case?

A. Yes. As described in the NARUC Manual at page 64:

> Fuel expense data can be obtained from the FERC Form 1. Aggregate fuel expense data by generation type is found in Accounts 501, 518, and 547. **Annual fuel expense by fuel type for specified _generating stations can be found on pages 402 and 411 of Form 1**.
>
> Fuel expense is **almost** always classified as energy-related. It is allocated using appropriate time-differentiated allocators; e.g., on-peak KWH and off-peak KWH, or non-time-differentiated energy allocators (total KWH) calculated by incorporating adjustments to reflect different line and transformation losses at different levels of the utility's transmission and distribution system. Depending on the cost of service method used, **it may be necessary to directly assign fuel expense to classes that are directly assigned the cost responsibility for specific generating units.** [Emphasis added.]

Q. What causes the differences in the ratebase allocators used by Staff and Ameren Missouri (and the derivative studies)?

A. The differences are attributable to:

1. Less ratebase is allocated on the basis of energy in the Staff study,
2. Difference in peak selection
    a. The four peaks used in the Staff study were found by:
        i. Identifying the four MISO resource adequacy seasons,
        ii. Identifying the hour in each MISO resource adequacy season with the highest load for Ameren Missouri retail customers
        iii. Finding each class's share of the load in that hour.
    b. The peaks used in the Ameren Missouri study were found by:
        i. Compiling a table of each class's peak load for any given hour in each calendar month,
        ii. Selecting the four largest peaks for each class, regardless of the month or hour of occurrence.
    c. The peaks used in the MECG study were found by:
        i. Compiling a table of each class's peak load for any given hour in each calendar month,
        ii. Selecting the peaks for each class, regardless of the hour of occurrence, for each of the months of June, July, August, and September.
3. Differences in peak netting:
    a. In the Staff study, the "excess," demand for each class is calculated net of generation of allocated renewable resources in the hour of that peak,
    b. In the Ameren and derivative studies, the "excess" demand for each class is calculated net of the total energy the class consumed in the year, divided by 8,760.

Q. Is more production ratebase allocated based on demand using Staff's approach in this case, or Ameren Missouri's approach in this case?

A. Staff's approach allocates more production ratebase on the basis of class demands than does Ameren Missouri's approach (or the derivative studies). The two allocations are illustrated below, using Staff's production rate base amounts for consistency:

Staff Production Rate Base Allocation						
	Residential	SGS	LGS & SPS	LPS	Lighting	Total
Production Type 1	$ 2,000,959,614	$ 389,203,809	$ 1,108,045,719	$ 277,988,447	$ 5,132,568	$ 3,781,330,158
Production Type 2	$ 777,539,168	$ 190,473,947	$ 623,383,728	$ 209,971,887	$ 2,173,865	$ 1,803,542,595
	$ 2,778,498,782	$ 579,677,757	$ 1,731,429,447	$ 487,960,334	$ 7,306,433	$ 5,584,872,753
Class Allocation of Ratebase	**49.75%**	**10.38%**	**31.00%**	**8.74%**	**0.13%**	100.00%
% Allocated on Demand	72.0%	67.1%	64.0%	57.0%	70.2%	**67.7%**
% Allocated on Energy	28.0%	32.9%	36.0%	43.0%	29.8%	**32.3%**
Ameren Missouri Production Rate Base Allocation						
	Residential	SGS	LGS & SPS	LPS	Lighting	Total
Demand-Allocated Rate Base	$ 1,412,174,835	$ 278,306,540	$ 493,329,570	$ 62,699,140	$ 2,807,353	$ 2,249,317,439
Energy-Allocated Rate Base	$ 1,438,018,974	$ 350,616,838	$ 1,157,581,664	$ 375,899,201	$ 13,438,637	$ 3,335,555,314
	$ 2,850,193,810	$ 628,923,378	$ 1,650,911,234	$ 438,598,341	$ 16,245,990	$ 5,584,872,753
Class Allocation of Ratebase	**51.03%**	**11.26%**	**29.56%**	**7.85%**	**0.29%**	100.00%
% Allocated on Demand	49.5%	44.3%	29.9%	14.3%	17.3%	**40.3%**
% Allocated on Energy	50.5%	55.7%	70.1%	85.7%	82.7%	**59.7%**

Staff's approach allocates about 68% of production ratebase on the basis of demand, while the Ameren and derivative study allocates about 40% of ratebase on the basis of demand.

Has Anything Changed?

Q. At page 6 of his rebuttal testimony, Mr. Phillips testifies:

> Generally speaking, while Ameren has a stated policy goal to reduce carbon from its system and add renewable energy resources as part of its strategy to facilitate the carbon reduction, the fact is that Ameren's system planning and operations has not materially changed and continues to include, in additional to zero carbon resources, significant additions of dispatchable resources as needed for resource adequacy and firm, reliable energy production as it has in the past. Thus, the drastic change as proposed by Staff (which I will discuss below) is unwarranted. Furthermore, the A&E approach currently utilized is what is known as an "Energy Weighted" allocation method. This results in an allocation of production demand related costs that already considers both demand and energy components. I also agree that the allocation of production energy related costs should continue to be allocated using energy.

What are the problems with these assertions?

A. There are several. First, Mr. Phillips implies that under Staff's method in this case, Staff will in future cases wrongly allocate Ameren Missouri generation plants that are dispatchable. In fact, those dispatchable resources, when added, will be classified as "Type 1," and allocated on demand, consistent with the many CTs, coal plants, and the nuclear plant classified as Type 1 and allocated on demand in this case.

Second, a lot has changed in how Ameren's system planning and generation build out has occurred. This will be detailed below.

Finally, Mr. Phillips acknowledges that the A&E approach considers both energy and demand and references "energy related costs," when the real difference between the Staff and Ameren study results in this case is related not to the allocation of costs, but to the allocation of generation revenues and net generation revenues, sometimes referred to as "off-system sales."

Q. What are off-system sales?

A. Mr. Meyer includes the following at page 23 of his direct testimony, "In the context of this proceeding, I use the term "net off-system sales revenue" in reference to the revenues and costs from transactions resulting from Ameren Missouri's wholesale market exposure, after netting out the costs and revenues associated with purchasing energy from the MISO market to meet the Company's load requirements." The expected $115,000,000 change in the Ameren Missouri revenue requirement is due to a reduction in Ameren Missouri's calculation of off-system sales for the test period.

Q. What has changed with Ameren Missouri's system planning and generation resources?

A. A lot has changed. How much depends on the starting perspective.

Mr. Wills testifies in this case that "The RES law itself imposes a new obligation on utilities to provide a specific kind of energy – renewable energy – leading them to make specific types of investments at a significant scale (in renewable energy resources like High Prairie) and which would otherwise be at the discretion of utility management to undertake."[23] As discussed above and in my Rebuttal, Ameren Missouri has testified that its recent ratebase additions have been for anything but summer capacity. MEEIA[24] has had modeled impact on peaks and energy. Renewable PPAs which would be allocated on energy under the Ameren Missouri approach have been replaced with renewable ratebase, and renewable ratebase has ballooned.

Additional developments are discussed with the rate case history discussion, below.

Q. Ms. York of Brubaker and Associates, on behalf of MIEC, criticizes Staff's CCoS direct testimony for not explaining "in its direct testimony why it is necessary or reasonable to abandon the Company's long-standing cost allocation methods in this case."[25] Mr. Phillips makes similar assertions throughout his testimony. Why did your direct testimony not include full criticism of the Ameren Missouri direct CCoS study?

A. Under the Commission's rules and the procedural orders in this case, criticism of Ameren Missouri's direct position was included in my rebuttal testimony.

Q. Are Ameren Missouri proposed allocations in this case "long-standing?"

A. No. A history of Commission use of production allocators and other relevant information is provided below.

Production Allocation Approaches

Q. Does Missouri statute recognize that renewable production may be allocated differently than nuclear or fossil production?

A. Yes. Section 393.1620 RSMo requires that "[i]n determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall

[23] Wills' rebuttal at pages 3-4.
[24] Missouri Energy Efficiency Investment Act (MEEIA).
[25] York rebuttal, pages 7, 10, 17, and 23.

only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual." While the energy-weighted method Staff uses for Type 2 resource allocation is in the NARUC manual, the reservation of the statute for renewable resources to be allocated in a manner NOT contained within the manual clearly recognizes that different resources may be reasonably assigned or allocated using different approaches.

Q. In support of the A&E allocator and in rejecting Staff's seasonal approach, Ms. York testifies that "Generally speaking, having capacity sufficient to meet the summer peak loads has historically been sufficient to meet loads in other seasons,"[26] and Ms. Maini testifies that "Ameren Missouri's participation in the MISO market does not invalidate the fact that the primary reasons it built or acquired generation capacity is sized to meet system peak demands and the type of capacity that was built is primarily a function of the load characteristics of the system?"[27] Is this consistent with MISO and with Ameren Missouri's representations in seeking Certificates of Convenience and Necessity ("CCN")?

A. No. As the representations made by Ameren Missouri within CCN filings were provided in my rebuttal, I will not restate them here, but to summarize, Ameren Missouri has represented – and the Commission has authorized - recent renewable additions due to "energy needs," winter capacity needs, participant renewable programs, and the Missouri Renewable Energy Standard requirements.

[26] York rebuttal, pages 10-11.
[27] Maini rebuttal, page 9.

Q. Ms. York testifies that "Staff's functionalized revenue requirement for production Type 1 and Type 2 resources amounts to $1.563 billion. However, it ultimately allocates only about $437.447 million of that revenue requirement using its recommended Type 1 and Type 2 production cost allocators."[28] Is this accurate?

A. This is both accurate and misleading. Staff allocated all of the ratebase, fuel (as applicable), and expenses associated with production resources using the production cost allocators described; however, Staff ALSO allocated the revenues produced by those plants and that fuel (as applicable) using those allocators. The revenue nets against the costs and expenses.

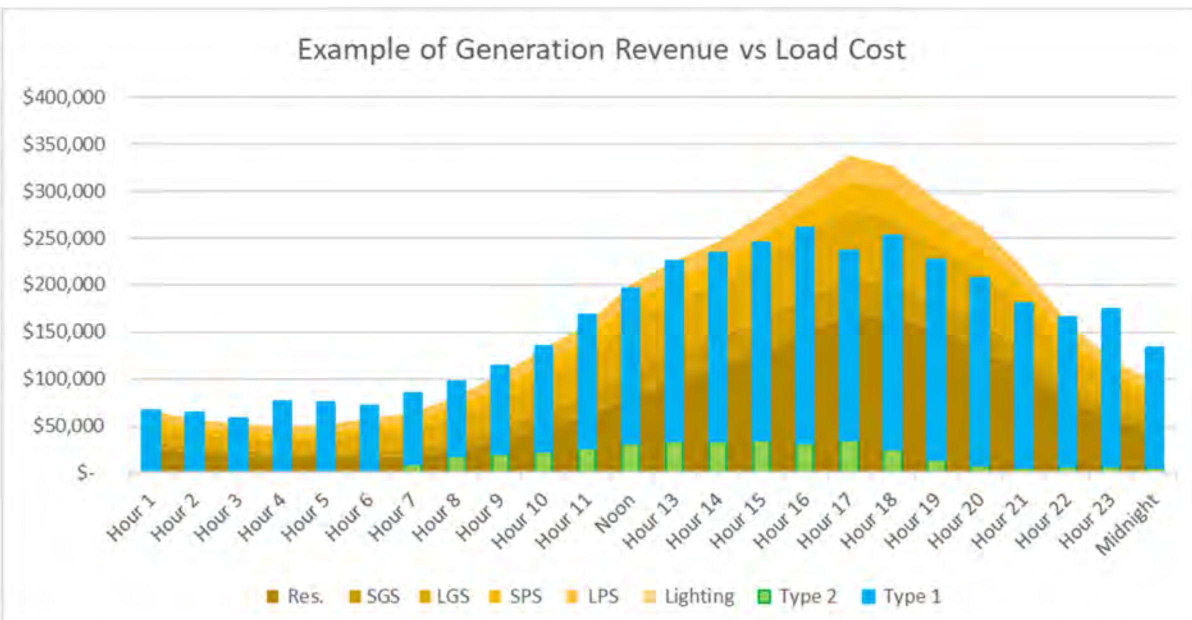
Ms. Maini's similar allegation that "Since Staff nets out the day ahead generator revenues to calculate the net revenue requirements, the ultimate result is that $1,001,326,330 in fixed expenses is allocated on the basis of the load weighted energy allocator instead of being allocated on the basis of Staff's capacity-based Type 1 Resource Allocator,"[29] is similarly inaccurate.

Q. Is Ms. York's testimony at page 132 that "The DA LMP effectively is the incremental energy cost, that is the energy cost on the margin, and not the average energy cost Ameren Missouri and the other Missouri utilities are regulated on the basis of their actual or embedded cost, not on the basis of incremental or marginal cost," misleading?

A. Yes, her testimony is misleading and inaccurate. MISO calculates the marginal cost of energy for each time and location, known as the Day Ahead ("DA") Locational Marginal Price ("LMP"). That price is then the price for Ameren Missouri to sell all of the energy it generates (except for the small amount of generation that interconnects at the distribution

[28] York rebuttal, page 12.
[29] Maini rebuttal, page 8.

voltages). And, that price is then the price for Ameren Missouri to buy all of the energy that its customers use (except for the small amount interconnected at the distribution voltages). These are two sets of separate and distinct transactions which occur. Each of these transactions has very different cost (or revenue) causation, and the attribution of that causation should be appropriately reflected in a CCoS study. An example day (actual DA load costs and production-modeled revenues for July 3, 2023) is provided below. The gold area is the cost of load. The blue and green bars are the generation revenues. They do not follow the same curve. They do not have the same causation. They should be allocated separately.



Q. Mr. Phillips testifies that "if market prices increase, even more demand related costs will be reallocated to energy,"[30] and "if gas prices were to rise, Ameren's fuel cost would not change much but off-system sales revenue is likely to increase, thus reducing net energy related costs. In this situation, Staff's proposed method would increase the overall

[30] Phillips rebuttal, page 15.

amount of production revenue requirement allocated on energy. This makes no sense."[31] Does Mr. Phillips' conclusion that "this makes no sense" consider the changes that would also occur in the wholesale cost of energy to serve load if market prices increase?

A. No. It is true that changes in fuel costs, sales revenues, and costs of load would each cause a change in the results of a CCoS study. In Mr. Phillips scenario, if gas prices were to rise, Ameren Missouri's fuel costs would go up a little, and Ameren Missouri's generation revenue would go up some. What Mr. Phillips does not mention is that Ameren Missouri's load costs would also go up some. It is hard to guess whether the increase in sales revenue would equal, exceed, or fail to offset the increased costs to serve load on a company-wide basis. In any event, each of those costs and revenues should be separately allocated in a reasonable CCoS Study.

Q. At page 5 of her rebuttal testimony, Ms. Maini implies that the annual cost of purchasing energy for Ameren Missouri's load in the MISO integrated energy market is part of the revenue requirement for Type 1 and Type 2 resources. Is this accurate?

A. No. Generation does not require purchasing energy to serve load.

Q. Ms. Maini criticizes your approach on Type 1 resources at page 6 of her rebuttal with the statement "Specifically, Staff did not explain why participation in the MISO market necessitated sub functionalization." Have you provided this explanation?

A. Yes. In my direct testimony I explained at pages 14 to 19 that the historic view of plant operation has shifted from simple "Base," "Intermediate," and "Peak" uses, as Ameren Missouri has installed significant renewable energy plants which do not fit into those categories

[31] Phillips rebuttal, page 16.

and as changes in the regional generation mix have resulted in changes in how legacy plants operate. In my rebuttal testimony, I expanded on the explanation of Ameren Missouri's deployment of plants for purposes other than capacity, with discussion of recent CCNs motivated by "energy needs," winter capacity needs, participant renewable programs, and the Missouri Renewable Energy Standard requirements. Historically, the value of a utility's energy purchases and sales at a given time and location were set by bilateral contracts or estimated through modeling. Today, the MISO market published prices provide clear, transparent, and objective prices for each transaction, at each location, at each time throughout the year.

Q. Ms. Maini criticizes your approach of separately allocating integrated energy costs to the classes from allocating production revenue requirements at page 6 of her rebuttal testimony.[32] Do you agree?

A. No. The cost causation of the cost of load is the cost of load, not the cost of generation. For example, consider if the table below represented the total load and cost of load for Ameren Missouri in a particular hour:

	Load in MW	Load LMP	Cost of Load
Residential	50		$ 1,500
SGS	10		$ 300
LGS/SPS	10	$ 30.00	$ 300
LPS	20		$ 600
System Total	90		$ 2,700

[32] "Inconsistency between allocating day ahead generator revenues and day ahead load costs to classes. Assume for argument's sake that Staff's approach for netting out day ahead generator revenues to calculate the revenue requirement is reasonable, Staff inherently utilizes the seasonal demand based allocator to allocate the energy based generator revenues while allocating the costs of purchasing energy for native load from the day ahead market using a load weighted energy allocator. Since both transactions are from the day ahead energy market, the allocation should be consistent, and energy based."

And consider if Ameren Missouri owned only two plants, the operation of which is represented below for the same hour:

	Generation in MW	Fuel Cost	Variable O&M	Total Variable Cost	Generation LMP	Generation Revenue	Net Revenue
Labadie	1000	$ 15.00	$ 3.00	$ 18,000	$ 31.00	$ 31,000	$ 13,000
Atchison	100	$ -	$ 0.50	$ 50	$ 29.00	$ 2,900	$ 2,850

If Ameren Missouri's load in the first table increased in that hour, that would not change the inputs and outputs of the second table any more so than a change in load in Illinois, Iowa, or Mississippi would change the inputs and outputs of the second table.

Q. Ms. Maini alleges at page 7 of her rebuttal testimony that netting the revenue for selling energy produced by a generator from the cost of owning and operating that generator is not reasonable. Do you agree?

A. No. Her allegation that "Staff has not provided evidence that the Company's decision to build or acquire capacity was based on the level of profitability in the MISO energy market,"[33] misattributes the purpose of Staff's allocation approach, which is to reflect how these plants operate. Further, there is plenty of evidence as summarized in my rebuttal that the recent building spree was motivated by everything except summer resource adequacy requirements – namely the Missouri RES, "energy needs," and desires of large customers. Similar inaccurate testimony is offered by Ms. York.[34]

[33] Maini rebuttal, page 7.

[34] "Q IS IT REASONABLE TO BIFURCATE THE COMPANY-OWNED PRODUCTION RESOURCES BETWEEN TYPE 1 AND TYPE 2? A No. Staff's approach, which attempts to allocate different resources in different ways, is not only complicated, but unnecessary. It also ignores the fact that particular resources are not built for particular customer classes or segments of load, but rather that each utility constructs a portfolio consisting of various kinds of resources that have been acquired with the objective of meeting customer requirements reliably and in a reasonable least cost manner." York rebuttal, page 9.

Ms. Maini's footnote at page 7 states "In general, utilities buy all their load requirements from the MISO market and sell all their generators' energy output in the MISO market. Instead of decoupling the "buy all" from the "sell all" as Staff did, it is conventional for utilities in regulated states to net them out." While acknowledging exactly how and why Staff's allocators were designed and implemented, she simply states that it is "conventional" to ignore this reality.

The crux of Ms. Maini's argument that Staff's method did not produce the results she desires is that "Given that the netting out of generator revenues and costs to serve load end up with the same embedded costs we started with, adding another layer of day ahead generator revenues and load weighted costs only makes the methodology more complex and does not aid in determining cost causation,"[35] however, that minor bit of complexity is exactly needed to reflect cost causation, and the costs Ameren Missouri incurs and the revenues Ameren Missouri obtains occur within the MISO integrated market.

Q. Does the usage of Ameren customers cause Ameren Missouri to turn on its power plants?

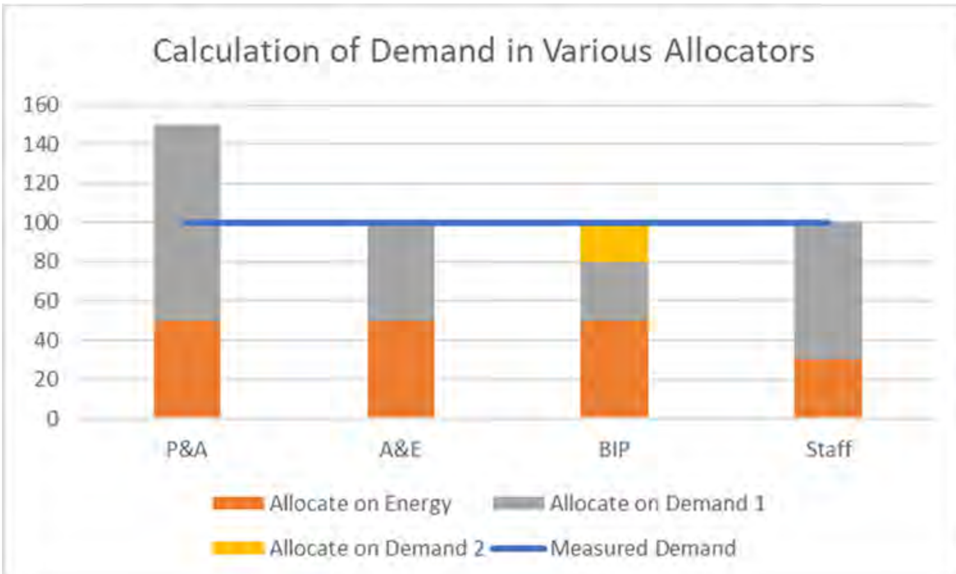
A. No. MISO dispatch instructions, which are predicated on efficiently serving the entire MISO footprint load given the operating parameters of all participating generation resources, is the driving force of the increases and decreases in production from Ameren Missouri's power plants.

Q. At page 17 of his rebuttal testimony, Mr. Phillips alleges that Staff's demand allocation of Type 1 resources fails to recognize the demand-satisfying contribution of Type 2

[35] Maini rebuttal, page 8.

resources, which he characterizes as similar to that used in the Peak and Average cost allocation method.[36] Can you provide an example to demonstrate the inaccuracy of his testimony?

A. Yes. In the P&A, the peak is the peak – unadjusted. In the Staff approach in this case, the BIP, and the A&E, the actual demand of the class is reduced by the energy-allocated portion.



Note, Staff's allocation does not use "average demand" for any purpose. Staff's allocation does subtract out the energy generated by a class's share of Type 2 resources (what Mr. Phillips is apparently referring to as "average demand,") when calculating the class peak in the designated demands hours used to allocate Type 1 costs, expenses, and revenues.

Q. Ms. Maini criticizes your approach on Type 2 resources at page 6 of her rebuttal with the statement "Staff determination of the capacity value of Type 2 resources consisted of

[36] Phillips rebuttal, page 17, "Fundamentally, by implementing this reallocation of costs based on market prices, what Staff is proposing is analogous to an even more extreme version of the Peak and Average ("P&A") approach that the Commission has previously rejected as it double counts the energy component within the demand component of the energy-weighted allocator. The method as proposed by Staff in this case suffers from the same deficiency."

identifying the generation produced at each of the four seasonal peak hours. MISO does not use this method." Do you agree?

A. I agree that my netting approach did not exactly mirror the MISO valuation of the renewable capacity assigned to the classes. However, my production allocation is a much better match to the rapidly developing complexities of Missouri's electric utilities and their requirements under FERC-approved RTO tariffs regarding resource adequacy. Ignoring these complexities is not consistent with the public interest. However, I believe Ms. Maini's recommended seasonal demand calculation approach could be reasonable, although my approach was also reasonable. If data is readily available in future cases I will make reasonable effort to review both approaches.

Production Allocation Case History and Timeline of Material Changes

Q. Mr. Phillip states in his rebuttal testimony, at page 14:

> This begs the question that if Ameren has been a participant in the MISO (including in its energy market, which began operations in 2005) since 2004, why is Staff only now attempting to incorporate a merchant generation, buy-all, sell-all approach into cost allocation? It is illogical to attempt to reallocate production demand related costs based on MISO generator revenues when the fundamental operations of Ameren within the MISO energy markets haven't changed in roughly the past two decades Ameren has participated in the market. To do so now would lead to an unforeseeable and inequitable shift in revenue responsibility among customer classes when Staff has failed to demonstrate that cost causative factors have fundamentally changed.

Has the Average and Excess method ever been a preferred method of production cost allocation, and what relevant circumstances have changed, and when?

A. The Commission has relied on a version of the Average and Excess method of production allocation for class cost of service to some extent or another in three cases since roughly 1980.

1. In Ameren Missouri ER-2010-0036, Staff and OPC provided Average and Peak-based studies, and the Commission found that "Since the class cost of service studies offered by Staff and Public Counsel are unreliable, the Commission must choose between the Average and Excess method studies submitted by AmerenUE and MIEC." (R&O page 86)

2. In Ameren Missouri ER-2021-0240, the Commission found:

> For purposes of this case, the Commission finds that Ameren Missouri's class cost of service study offers a reasonable estimation of class cost of service. However, under the particular circumstances of this case, the Commission believes that aside from Ameren Missouri's proposed adjustment to more closely balance the company-owned and customer-owned branches of the Lighting class, no class rate adjustments need to be made and the necessary rate increase should be allocated to all customer classes on an equal percentage basis. In making that determination, the Commission is not relying on the relatively minor differences between the cost studies prepared and submitted by the parties. Rather the Commission is exercising its discretion to look beyond the numbers contained in those cost studies to reach a deeper conclusion that the people who are members of the residential rate class have already faced enough challenges in recent years, including an 8.81 percent electric rate increase that will result from this case, and should not, at this time, have to endure an even larger rate increase to address the imbalance described in Ameren Missouri's class cost of service study.

This result was consistent with Staff's recommendation.

3. In Ameren Missouri ER-2014-0258, both the A&E 4NCP and Detailed BIP were implicitly relied upon, "The Commission will once again reject the Office of Public Counsel's P&A study because it has the effect of double counting average demand. Also, because the results of the A&E and BIP studies are similar, the Commission does not need to decide which particular study is most appropriate."

The Base Intermediate and Peak method and the Detailed Base Intermediate and Peak method were relied upon in Evergy ER-2012-0174, Empire ER-2014-0351, and KCPL ER-2016-0285. It was relied upon to the same extent as the A&E in ER-2014-0258.

Historically, throughout the 1980s and into the 1990s, in orders discussing class cost of service, the Commission largely relied upon a Staff-developed production allocation method known as "Capacity Utilization/Time of Use." Staff provided CCoS results using this method in cases where hourly load data was available. In cases where hourly load data was not available during this time period, the Commission largely relied upon a method known as Peak and Average or Average and Peak. Various materials during that time discussed that the Average and Peak method produces results similar to the Capacity Utilization method, so it was viewed as a reasonable surrogate when hourly load data for classes was unavailable or unreliable.

Q. Was the Detailed BIP conceptually similar to the method you used in this case for production allocation?

A. Yes. The current production allocation is effectively a hybrid of the Detailed BIP method[37] and the Alternative Market-Based study, both initially presented in 2014.

Q. When did Staff develop the Detailed BIP method?

A. The Detailed BIP method was first presented in Ameren Missouri Case No. ER-2014-0258. In that case, Staff also included an "Alternative Market-Based" study, described in the CCoS and Rate Design Report at page 32 as follows:

> Staff's alternative market-based production study consists of a review of three years' of Ameren Missouri's day-ahead energy purchases to serve the retail classes. The annual average cost of energy to serve a given class is assigned directly to that class. While no separate normalizations are conducted, for purposes of this CCS alternative study, it is assumed that the use of three-years' of data, averaged, will smooth most significant anomalies. Staff then applies an adder determined by multiplying the average annual energy usage of each class by an amount to reflect the cost to Ameren Missouri as a Load Serving Entity ("LSE") in MISO for

[37] A succinct description of the Detailed BIP was provided by the Commission in its Evergy Metro Report and Order in ER-2016-0285, "Because KCPL participates in the Southwest Power Pool's Day-Ahead, Real-Time, and Ancillary Services integrated markets ("SPP IM"), its generation is dispatched as part of the larger SPP fleet. SPP's dispatch is ordered according to security-constrained economic merit, which results in price signals stacking in a manner consistent with those experienced by a utility with a generation fleet that includes the relative amounts of each base, intermediate, and peak generation units assumed in the NARUC Manual.

Unlike other common CCoS methods, Staffs BIP method most reasonably assumes that some plants will run virtually year round (base), only part of the year (intermediate), and rarely during the year (peak). Among the submitted studies, Staff's BIP study also best accounts for KCPL's participation in the SPP integrated energy market through its recognition of the variability of fuel costs."

> the ancillary service associated with each MWh of energy purchased in the Day-Ahead market.
>
> Staff used the class load at the time of Ameren system peak to allocate the remaining production and transmission-related expenses and revenues. This is appropriate under this alternative market study, in that the intent of the study is to segregate Ameren Missouri's costs as an LSE from Ameren Missouri's net revenues as an owner of generation and seller of energy into the MISO energy market. It is therefore appropriate to allocate the net cost of plant on the basis of the capacity requirements of each retail class, and it is appropriate that the net sales revenues follow the allocation of the generating facilities to the retail classes.

Q. Why did Staff move away from the Detailed BIP and incorporate elements of the Alternative Market-Based study into its allocation in recent cases, including Ameren Missouri's ER-2022-0337 and the current case?

A. The increasing percentage of ratebase that has a capacity cost but little or no energy cost, and is not dispatchable during peak load hours, and has been added for either RES[38] compliance, energy needs, or participant renewable generation has driven the change. As Staff noted in its CCoS and Rate Design Report in Ameren Missouri's ER-2016-0179, at page 16, "Ameren Missouri also has wind resources, as well as solar and hydroelectric investment, including pumped storage at Taum Sauk. Staff did allocate these expenses and costs to the classes using the BIP allocators; however, Staff did not assign these expenses and costs in allocator development."

Q. Can you present a timeline of these items and other relevant changes in circumstances?

A. Yes:

[38] Renewable Energy Standard (RES).

1981	Commission relies on the Average and Peak (AP) method of production allocation for CCoS for Arkansas Power & Light in ER-81-364.
1985	Commission order in Union Electric Company case EO-85-17/ER-85-160 relies on Staff's "TOU/AP" study.
2005	MISO Day 2 Energy Market begins, Ameren Missouri ceases operation under its Joint Dispatch Agreement
2007	Ameren Missouri operates as its own Balancing Authority under NERC
2007	In KCPL (Evergy Missouri Metro) ER-2007-0291, the Commission relied on Staff's study, which was an Average and Peak production allocation
2008	Missouri RES passes as a voter-approved initiative petition
2009	MISO takes over as balancing authority and implemented Ancillary Services Market
2009	Ameren Missouri FAC begins
2009	In AmerenUE ER-2008-0318, the Commission finds the Peak and Average method "is inherently flawed as it double counts the average demand of customer classes, resulting in customers with higher load factor, in other words industrials, being allocated an inequitable share of production plant investment." 271 P.U.R.4th 475, 78
2010	In Ameren Missouri ER-2010-0036 Staff and OPC provided Average and Peak-based studies, and the Commission found that "Since the class cost of service studies offered by Staff and Public Counsel are unreliable, the Commission must choose between the Average and Excess method studies submitted by AmerenUE and MIEC." (R&O page 86)
2011	Missouri RES begins at 2% of energy sales sourced from renewable energy
2011	MISO Capacity Auction begins implementation
2013	MISO Voluntary Capacity Auction replaced with annual Planning Reserve Auction
2013	Commission relies on a Base Intermediate Peak (BIP) study in KCPL ER-2012-0174
2014	Missouri RES requires 5% of energy sales sourced from renewable energy
2014	In ER-2014-0258 Staff files its "Detailed BIP" study and "Alternative Market-Based Study"
2015	In Ameren Missouri ER-2014-0258 the Commission decided "because the results of the A&E and BIP studies are similar, the Commission does not need to decide which particular study is most appropriate. Therefore, all the specific sub-issues involving the difference between those studies are moot and do not need to be addressed in this case."
2015	Commission relies on Staff Detailed BIP in Empire ER-2014-0351
2017	Commission relies on Staff Detailed BIP in KCPL ER-2016-0285

2018	Missouri RES requires 10% of energy sales sourced from renewable energy
2019	In EA-2019-0181 Ameren Missouri testifies that RES compliance is the need for the Atchison and High Prairie windfarms.
2021	Missouri RES requires 15% of energy sales sourced from renewable energy
2021	Ameren Missouri RESRAM begins
2022	In ER-2021-0240 the Commission found "For purposes of this case, the Commission finds that Ameren Missouri's class cost of service study offers a reasonable estimation of class cost of service." The Commission did not implement the specific study result
2022	In EA-2022-0244 Ameren Missouri testifies that RES compliance is the need for the Huck Finn Solar Project.
2023	MISO Seasonal Capacity Requirements implemented
2023	In EA-2023-0286, Ameren Missouri testifies that the Cass County, Split Rail, Bowling Green, and Vandalia solar projects are needed to support an energy need and to support large employers desiring renewables.
2023	In EA-2022-0245 the Commission finds that the Boomtown Solar project is needed due to winter capacity needs, energy needs, and the ability to offer larger customers an option to purchase renewable energy.

Q. Is Staff recommending that the Commission order in this case that A&E is not an acceptable study method, that the Staff approach is the only proper study method, or anything else of the sort?

A. No. Staff recommends the Commission allow parties to the various electric utilities' rate case proceedings to continue to offer the allocation methods that those parties believe provide the most reasonable allocation of costs, expenses, and revenues that the data in a given case and the industry conditions at a given time will allow. To the extent that the purpose of a CCoS study is to objectively determine cost causation, continuing changes in the electric utility industry and the statutory and regulatory framework require flexibility and responsiveness. This is not to say that policy considerations cannot be relied upon by analysts or the Commission to deviate from CCoS results, however, consideration of movement towards more transparent electric pricing requires the most reliable CCoS study as possible for a starting point.

Production Allocation Examples

Q. Could you provide the approximate revenue requirements for several Ameren Missouri production plants, and walk through these issues?

A. Yes. Using Staff's direct accounting schedules and production cost modeling, the approximate[39] revenue requirements are set out below:

Approximate Net Revenue Requirements of Sample Production Facilities **Staff Direct**	**Callaway Nuclear**	**Labadie Coal**	**Boomtown Solar**	**Atchison "Outlaw" Wind**
Capital	$ 3,743,756,132	$ 1,973,847,496	$ 969,714,032	$ 517,276,003
Reserve	$ 2,094,783,383	$ 728,398,893	$ 1,571,745	$ 69,119,080
Net Ratebase	$ 1,648,972,749	$ 1,245,448,603	$ 968,142,287	$ 448,156,923
Cost of Capital & Income Tax	$ 164,897,275	$ 124,544,860	$ 96,814,229	$ 44,815,692
Depreciation Expense	$ 96,148,726	$ 74,803,187	$ 37,721,876	$ 18,311,388
Maintenance	$ 73,596,085	$ 22,895,017	$ 12,265,948	$ 12,265,948
Operation	$ 73,927,058	$ 17,289,297		
Fuel	$ 69,465,971	$ 283,658,702		
Revenue Requirement	$ 478,035,115	$ 523,191,063	$ 146,802,053	$ 75,393,029
kWh generated	*9,468,431*	*16,726,218*	*334,487*	*944,951*
Value of kWh generated	$ 283,849,039	$ 532,846,053	$ 10,647,908	$ 27,923,219
Net Revenue Requirement	$ 194,186,076	$ (9,654,990)	$ 136,154,145	$ 47,469,809

Q. If these were Ameren Missouri's only plants, how would they be allocated under Staff's method?

[39] Note, this does not include all ratebase additions and offsets which are recorded outside of the production plant accounts, or amounts like property taxes or insurance which are recorded outside of the operations and maintenance expense accounts. Also, because some expenses are combined for multiple plants, approximations of the amounts attributable to these specific plants were made. Finally, production tax credits are not included in these amounts.

A. First, Boomtown's[40] and Atchison's[41] costs, expenses, and revenues would be allocated to each class based on that class's approximate Renewable Energy Standard ("RES") requirement share.[42] Both of these are "Type 2," production facilities, and therefore it is reasonable to allocate the costs, expenses, and revenues associated with these facilities to the classes on the basis of class energy requirements, and allocation on the basis of energy best reflects the winter capacity contributions of these plants, interest in meeting real or perceived "energy needs," and in the case of Boomtown, support of the renewable solutions program:

continued on next page

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[40] In its Report and Order in at page 31, EA-2022-0245, effective April 22. 2023, the Commission found, inter alia, that the project was needed due to:

1. A need for winter capacity additions, Report and Order in EA-2022-0245, page 11.
2. Concern that waiting to add renewable resources could result in Ameren Missouri falling sort of meeting "energy needs," Report and Order in EA-2022-0245, page 12.
3. That other benefits of the project included "Offering its larger customers an option to purchase renewable energy is one way for Ameren Missouri to help prevent these customers from leaving, or seeking to expand outside, the Ameren Missouri service territory," and that "Real business investment decisions are being made based on renewable energy access, and states that can provide access to renewables are succeeding in some of the largest economic development opportunities in the country." Report and Order in EA-2022-0245, page 16.

[41] Atchison was indisputably pursued by Ameren Missouri, from the perspective of Ameren Missouri, for purposes of RES compliance, see Direct Testimony of Matt Michels, EA-2019-0181, pages 2-5.

> Q. Does Ameren Missouri need the Project to satisfy any resource requirement other than the requirements of the RES?
>
> A. No. Ameren Missouri has sufficient generation resources to meet its resource adequacy obligations under the Midcontinent Independent System Operator, Inc. ("MISO") Module E tariff and to provide its customers with safe and reliable electric service at a reasonable cost. This is consistent with the analysis and findings in the Company's 2017 IRP. But for the need to comply with the RES, Ameren Missouri would not pursue the Project.

[42] As discussed in my rebuttal testimony, the RES requirement is actually set based on metered usage, while Staff allocated these RES compliance costs based on usage adjusted to transmission voltage. This underallocates compliance costs to the SPS and LPS classes, and overallocates costs to other classes.

Staff Allocation of Boomtown	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 41,738,329	$ 10,224,648	$ 33,463,260	$ 11,271,298	$ 116,693
Depreciation Expense	$ 16,262,569	$ 3,983,845	$ 13,038,341	$ 4,391,653	$ 45,467
Maintenance	$ 5,288,068	$ 1,295,419	$ 4,239,652	$ 1,428,025	$ 14,785
Operation	$ -	$ -	$ -	$ -	$ -
Fuel	$ -	$ -	$ -	$ -	$ -
Revenue Requirement	$ 63,288,966	$ 15,503,912	$ 50,741,253	$ 17,090,976	$ 176,945
kWh generated	*144,203*	*35,326*	*115,613*	*38,942*	*403*
Value of kWh generated	$ 4,590,502	$ 1,124,536	$ 3,680,386	$ 1,239,650	$ 12,834
Net Revenue Requirement	$ 58,698,464	$ 14,379,376	$ 47,060,867	$ 15,851,327	$ 164,111

Staff Allocation of Atchison	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 19,320,839	$ 4,733,030	$ 15,490,276	$ 5,217,529	$ 54,018
Depreciation Expense	$ 7,894,364	$ 1,933,884	$ 6,329,222	$ 2,131,847	$ 22,071
Maintenance	$ 5,288,068	$ 1,295,419	$ 4,239,652	$ 1,428,025	$ 14,785
Operation	$ -	$ -	$ -	$ -	$ -
Fuel	$ -	$ -	$ -	$ -	$ -
Revenue Requirement	$ 32,503,270	$ 7,962,334	$ 26,059,150	$ 8,777,401	$ 90,874
kWh generated	*407,385*	*99,797*	*326,617*	*110,013*	*1,139*
Value of kWh generated	$ 12,038,195	$ 2,948,999	$ 9,651,494	$ 3,250,875	$ 33,657
Net Revenue Requirement	$ 20,465,076	$ 5,013,334	$ 16,407,656	$ 5,526,526	$ 57,217

Q. What's next?

A. Next, we turn to data from Ameren Missouri to identify the hour of its retail load coincident peak for each MISO resource adequacy season:

Season	Peak Value	Date/Hour of Peak	Residential	SGS	LGS & SPS	LPS	Lighting
Summer	6,096,467	7/25/23 16:00	3,027,160	720,972	1,873,161	475,174	-
Summer	6,173,511	8/25/23 15:00	3,222,842	669,062	1,808,641	472,966	-
Fall	**5,189,088**	**9/4/23 15:00**	**2,757,979**	**510,932**	**1,516,096**	**404,081**	**-**
Fall	4,311,853	10/2/23 16:00	1,864,099	477,086	1,532,361	438,308	-
Fall	4,454,515	11/27/23 7:00	1,996,457	532,675	1,515,434	409,847	102
Winter	5,290,232	12/19/23 6:00	2,553,185	573,552	1,741,214	394,228	28,053
Winter	**5,715,620**	**1/17/24 6:00**	**3,129,311**	**569,699**	**1,604,894**	**382,357**	**29,358**
Winter	5,413,579	2/29/24 6:00	2,877,977	517,859	1,608,294	393,849	15,600
Spring	4,539,005	3/19/24 6:00	2,165,170	484,242	1,485,922	373,908	29,763
Spring	3,844,605	4/15/24 16:00	1,625,270	408,269	1,376,024	435,043	-
Spring	**4,851,706**	**5/21/24 16:00**	**2,307,090**	**500,467**	**1,574,148**	**470,001**	**-**
Summer	**6,220,382**	**6/25/24 14:00**	**3,130,697**	**689,253**	**1,908,046**	**492,386**	**-**

Then, we find the amount of energy that Boomtown, Atchison, and other Type 2 generation produced in each of those peak hours:

Season	Hour of Peak	Boomtown Generation During Peak	Atchison Generation During Peak	Other Type 2 Generation During Peak
Summer	6/25/24 14:00	148.30	120.34	662.17
Fall	9/4/23 15:00	142.21	231.09	568.43
Winter	1/17/24 6:00	-	130.08	276.76
Spring	5/21/24 16:00	142.89	42.75	638.94

Then, each class's share of the Type 2 Generation during each peak hour is subtracted from each class's demand that was measured for that peak hour. As an example, we will run through the calculation using only the Winter peak which occurred the morning of January 1, 2024, an hour during which Boomtown was not generating energy, but Atchison and other renewable generation was generating:

	Residential	SGS	LGS & SPS	LPS	Lighting
Demand of each Class	3,129.31	569.70	1,604.89	382.36	29.36
Boomtown Generation	-	-	-	-	-
Atchison Generation	56.08	13.74	44.96	15.14	0.16
Other Type 2 Generation	119.32	29.23	95.66	32.22	0.33
Net Demand of each Class	**2,953.91**	**526.73**	**1,464.27**	**334.99**	**28.87**

The calculation is illustrated below, using the LGS & SPS combined coincident peak demand and combined allocation of Type 2 Resources, including Boomtown and Atchison:

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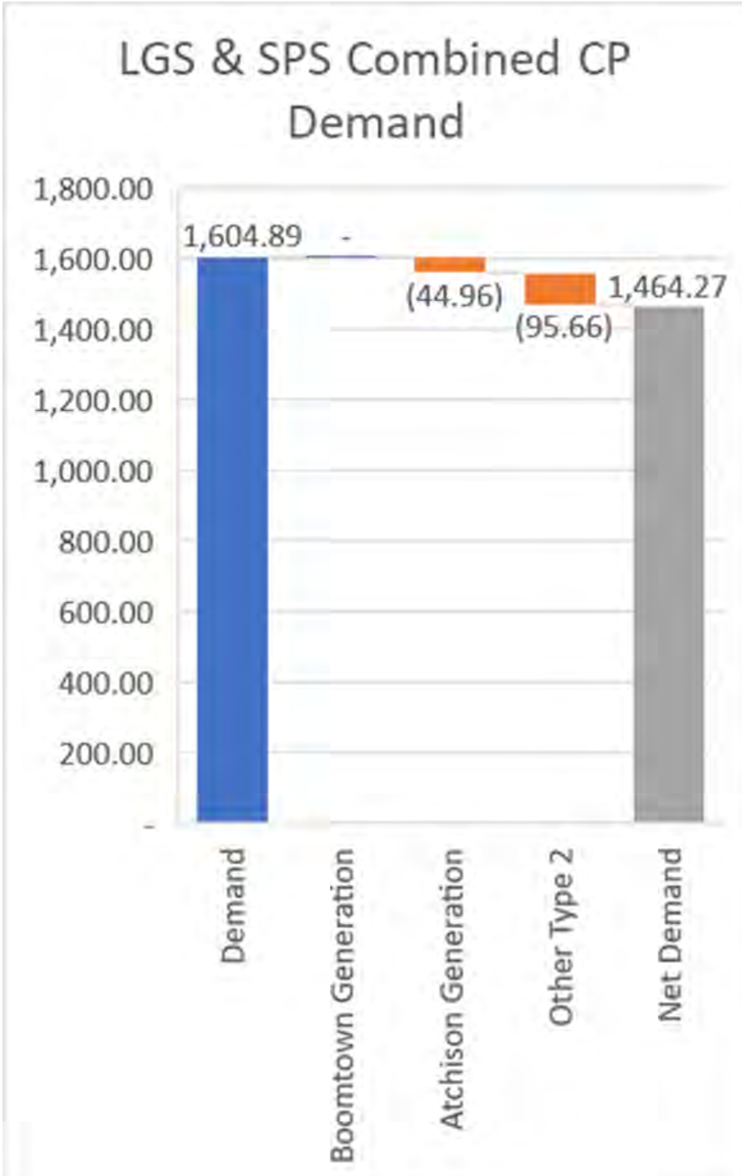


Q. What is allocated with the net demand values calculated above?

A. The net demand for all seasons for each class are summed, and the resulting allocator is used to allocate the costs, expenses, and revenues associated with the Production Type 1 generation facilities, Callaway and Labadie:

Staff Allocation of Callaway	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 87,258,392	$ 16,972,506	$ 48,319,959	$ 12,122,596	$ 223,822
Depreciation Expense	$ 50,878,847	$ 9,896,372	$ 28,174,526	$ 7,068,474	$ 130,507
Maintenance	$ 38,944,707	$ 7,575,080	$ 21,565,910	$ 5,410,493	$ 99,895
Operation	$ 39,119,847	$ 7,609,146	$ 21,662,896	$ 5,434,825	$ 100,345
Fuel	$ 36,759,182	$ 7,149,976	$ 20,355,660	$ 5,106,864	$ 94,289
Revenue Requirement	$ 252,960,974	$ 49,203,079	$ 140,078,951	$ 35,143,252	$ 648,858
kWh generated	*5,010,392*	*974,564*	*2,774,541*	*696,082*	*12,852*
Value of kWh generated	$ 150,203,881	$ 29,215,943	$ 83,176,475	$ 20,867,459	$ 385,281
Net Revenue Requirement	$ 102,757,093	$ 19,987,136	$ 56,902,476	$ 14,275,793	$ 263,577

Staff Allocation of Labadie	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 65,905,178	$ 12,819,122	$ 36,495,464	$ 9,156,046	$ 169,050
Depreciation Expense	$ 39,583,467	$ 7,699,324	$ 21,919,628	$ 5,499,235	$ 101,534
Maintenance	$ 12,115,315	$ 2,356,533	$ 6,708,942	$ 1,683,151	$ 31,076
Operation	$ 9,148,946	$ 1,779,548	$ 5,066,294	$ 1,271,041	$ 23,468
Fuel	$ 150,103,160	$ 29,196,352	$ 83,120,700	$ 20,853,467	$ 385,023
Revenue Requirement	$ 276,856,065	$ 53,850,880	$ 153,311,029	$ 38,462,939	$ 710,151
kWh generated	*8,850,983*	*1,721,592*	*4,901,295*	*1,229,645*	*22,703*
Value of kWh generated	$ 281,965,178	$ 54,844,646	$ 156,140,237	$ 39,172,736	$ 723,256
Net Revenue Requirement	$ (5,109,113)	$ (993,766)	$ (2,829,208)	$ (709,797)	$ (13,105)

Q. Can you show how these plants are allocated if the Ameren method and allocators are applied to the same revenue requirement and revenues values used in your examples above?

A. Yes:

continued on next page

Ameren Missouri Allocation of Boomtown	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 49,408,344.21	$ 10,902,438.51	$ 28,618,682.08	$ 7,603,138.33	$ 281,625.57
Depreciation Expense	$ 19,251,049	$ 4,247,934	$ 11,150,741	$ 2,962,422	$ 109,730
Maintenance	$ 6,259,826	$ 1,381,292	$ 3,625,864	$ 963,285	$ 35,681
Operation	$ -	$ -	$ -	$ -	$ -
Fuel	$ -	$ -	$ -	$ -	$ -
Revenue Requirement	$ 74,919,219	$ 16,531,665	$ 43,395,287	$ 11,528,846	$ 427,037
kWh generated	*144,203*	*35,160*	*116,081*	*37,695*	*1,348*
Value of kWh generated	$ 4,590,508	$ 1,119,255	$ 3,695,284	$ 1,199,962	$ 42,899
Net Revenue Requirement	$ 70,328,711	$ 15,412,410	$ 39,700,004	$ 10,328,884	$ 384,137

Ameren Missouri Allocation of Atchison	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 22,871,319	$ 5,046,782	$ 13,247,702	$ 3,519,523	$ 130,366
Depreciation Expense	$ 9,345,066	$ 2,062,081	$ 5,412,921	$ 1,438,053	$ 53,267
Maintenance	$ 6,259,826	$ 1,381,292	$ 3,625,864	$ 963,285	$ 35,681
Operation	$ -	$ -	$ -	$ -	$ -
Fuel	$ -	$ -	$ -	$ -	$ -
Revenue Requirement	$ 38,476,211	$ 8,490,156	$ 22,286,488	$ 5,920,861	$ 219,313
kWh generated	*407,386*	*99,328*	*327,939*	*106,491*	*3,807*
Value of kWh generated	$ 12,038,211	$ 2,935,149	$ 9,690,562	$ 3,146,797	$ 112,500.01
Net Revenue Requirement	$ 26,438,000	$ 5,555,007	$ 12,595,925	$ 2,774,064	$ 106,813

Ameren Missouri Allocation of Callaway	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 84,153,966.08	$ 18,569,403	$ 48,744,309	$ 12,949,923	$ 479,674
Depreciation Expense	$ 49,068,710	$ 10,827,495	$ 28,421,957	$ 7,550,874	$ 279,690
Maintenance	$ 37,559,156	$ 8,287,798	$ 21,755,304	$ 5,779,741	$ 214,086
Operation	$ 31,871,308	$ 7,770,841	$ 25,655,880	$ 8,331,183	$ 297,845
Fuel	$ 29,948,052	$ 7,301,914	$ 24,107,690	$ 7,828,442	$ 279,872
Revenue Requirement	$ 232,601,193	$ 52,757,452	$ 148,685,140	$ 42,440,164	$ 1,551,167
kWh generated	*4,082,014*	*995,274*	*3,285,954*	*1,067,041*	*38,147*
Value of kWh generated	$ 122,372,518	$ 29,836,787	$ 98,507,868	$ 31,988,265	$ 1,143,601
Net Revenue Requirement	$ 110,228,674	$ 22,920,665	$ 50,177,272	$ 10,451,899	$ 407,566

Ameren Missouri Allocation of Labadie	Residential	SGS	LGS & SPS	LPS	Lighting
Cost of Capital & Income Tax	$ 63,560,444	$ 14,025,239	$ 36,815,970	$ 9,780,916	$ 362,292
Depreciation Expense	$ 38,175,190	$ 8,423,732	$ 22,112,128	$ 5,874,539	$ 217,597
Maintenance	$ 11,684,283	$ 2,578,252	$ 6,767,861	$ 1,798,021	$ 66,600
Operation	$ 7,453,733	$ 1,817,364	$ 6,000,132	$ 1,948,411	$ 69,657
Fuel	$ 122,290,461	$ 29,816,779	$ 98,441,813	$ 31,966,815	$ 1,142,834
Revenue Requirement	$ 243,164,111	$ 56,661,367	$ 170,137,904	$ 51,368,701	$ 1,858,980
kWh generated	*7,210,979*	*1,758,176*	*5,804,720*	*1,884,955*	*67,388*
Value of kWh generated	$ 229,719,691	$ 56,010,103	$ 184,920,579	$ 60,048,893	$ 2,146,786
Net Revenue Requirement	$ 13,444,420	$ 651,264	$ (14,782,675)	$ (8,680,192)	$ (287,806)

Q. What should an observer notice from review of these results?

A. The Ameren approach and allocators as applied to the Labadie values results in the LGS, SPS, and LPS, and Lighting classes being allocated a negative net revenue requirement, while the Residential and SGS classes carry a significant positive revenue requirement. Recall, the overall Labadie revenue requirement in the first table was negative, meaning that the market revenues received from Labadie exceeded not only the cost of the fuel burned for generation, but also the capital costs, depreciation expense, and other costs approximated in this example. It is also worth noting that under the Ameren Missouri approach the Boomtown facility is predominately allocated to Residential customer, although it is the resource for the Renewable Solutions program, which is dedicated to Ameren Missouri's largest customers.

Q. Considering these four plants together, does the Staff approach or the Ameren approach allocate more costs and expense to the Residential class?

A. The Staff approach allocates more costs to the Residential Class than does the Ameren approach, if the same revenue requirement components are used:

	Residential	SGS	LGS & SPS	LPS	Lighting
Staff Revenue Requirement $	$ 625,609,275	$ 126,520,205	$ 370,190,383	$ 99,474,569	$ 1,626,828
Ameren Revenue Requirement $	$ 589,160,733	$ 134,440,639	$ 384,504,819	$ 111,258,573	$ 4,056,496
Staff Revenue Requirement %	51%	10%	30%	8%	0.13%
Ameren Revenue Requirement %	48%	11%	31%	9%	0.33%

Q. Considering these four plants together, does the Staff approach or the Ameren approach allocate less revenues to the Residential class?

A. The Ameren approach allocates less revenue to the Residential class.

	Residential	SGS	LGS & SPS	LPS	Lighting
Staff Sales Revenue $	$ 448,797,755	$ 88,134,125	$ 252,648,592	$ 64,530,720	$ 1,155,028
Ameren Sales Revenue $	$ 368,720,928	$ 89,901,294	$ 296,814,293	$ 96,383,918	$ 3,445,787
Staff Sales Revenue %	52%	10%	30%	8%	0.14%
Ameren Sales Revenue %	43%	11%	35%	11%	0.40%

Q. When revenue requirement and revenues are netted, how do the net allocations to the classes for these four plants compare?

	Residential	SGS	LGS & SPS	LPS	Lighting
Staff Net RR $	$ 176,811,520	$ 38,386,080	$ 117,541,792	$ 34,943,849	$ 471,800
Ameren Net RR $	$ 220,439,805	$ 44,539,345	$ 87,690,526	$ 14,874,655	$ 610,709
Staff Net RR %	48.03%	10.43%	31.93%	9.49%	0.13%
Ameren Net RR %	59.88%	12.10%	23.82%	4.04%	0.17%

The Ameren approach results in significantly less allocation to the LGS, SPS, and LPS classes, and significantly more allocation to the Residential and SGS classes. This result is unreasonable.

Q. You have illustrated these allocations and results using the values provided above derived from Staff's direct revenue requirement filing – what is significant about the differences between Ameren's and Staff's direct positions on these revenue requirement values?

A. It is my understanding that Ameren Missouri is accepting Staff's position on excluding 2022 for purposes of calculating normalized hourly market prices for use in production modeling. If Ameren Missouri had excluded 2022 from its direct production modeling, then its sales revenues – allocated to the classes on the basis of energy – would be about $115 million less.

Distribution Allocation

Q. At page 15 of her rebuttal Ms. York discusses that it is not necessary to know the specific cost of running a 34 kV line, only the average cost of a 34 kV line per mile. Does Ameren provide the average cost of a 34 kV line per mile in its study?

A. No. The Ameren Missouri study is based on the cost of adjusting its embedded cost components to a common year that exceeds the book value, and then running a complete two conductor primary voltage system at the cost of those components to be allocated to each customer at the exact same amount. The balance of the costs is then allocated on the basis of demand, except that higher voltage customers are exempted from the costs Ameren Missouri represents as serving lower voltage customers. Ameren Missouri has not been able to provide costs within each mass property account for the infrastructure that operates at a given voltage, nor to provide average, typical, or example costs of infrastructure within an account that operates at a given voltage.

Q. Does Ms. York's rebuttal testimony at page 15 imply that the Ameren Missouri classification study acknowledges or specifically addresses plant by voltage of operation?

A. Yes. However, Ameren Missouri does not actually do so.

Q. Ms. York implies at pages 16-17 of her rebuttal testimony that Staff's CCoS study is deficient because it relies on Ameren Missouri's Continuing Property Record ("CPR"), and explicitly alleges this at page 19. Does she acknowledge that Ameren Missouri's study relies on the Ameren Missouri CPR, and does not include the clean up that Ameren Missouri indicated was necessary?

A. Ms. York does not acknowledge that the Ameren Missouri CCoS study relies on the same CPR, nor does she adjust the Ameren Missouri distribution classification to address the errors in the CPR that were acknowledged by Ameren Missouri in response to Staff data requests. Additional issues with Ameren Missouri's retirement recording process were the subject of an issue in ER-2022-0337, and are the subject of ongoing corrective actions.

Poles

Q. In his rebuttal testimony at page 12 Mr. Hickman notes an error in your testimony regarding your discussion of the poles classification and allocation procedure. Do you agree with Mr. Hickman?

A. I agree that the study results included an error in the treatment of the SGS poles allocation,[43] and that my direct testimony at page 28 lines 14-16 should be corrected to read "In general, the Residential class was allocated more of each pole size through the minimum-system allocation than indicated by demand responsibility."

Q. Could you provide updated distribution classification and allocation tables consistent with this correction?

A. Yes:

Min. Sys. Poles <40'		Min Sys $	Demand Alloc. Poles <40'	Demand $	Difference in Quantity	Difference in Cost	Hold at Min	Min + Demand
Residential	360,049	$ 180,344,195	237,758	$ 119,090,099	(122,291)	$ (61,254,096)	$ 180,344,195	
SGS	47,835	$ 23,960,098	54,426	$ 27,261,541	6,591	$ 3,301,443		$ 51,221,639
LGS/SPS	3,741	$ 1,873,740	126,593	$ 63,409,025	122,852	$ 61,535,285		$ 65,282,765
LPS Combined	22	$ 11,047	8,746	$ 4,380,558	8,724	$ 4,369,511		$ 4,391,605
Lighting	18,211	$ 9,121,705	2,335	$ 1,169,562	(15,876)	$ (7,952,143)		$ 10,291,267
	429,858	$ 215,310,785	429,858	$ 215,310,785	0	$ 0		
Min. Sys. 40' Wood Poles		Min Sys $	Demand Alloc. Poles <40'	Demand $	Difference in Quantity	Difference in Cost	Hold at Min	Min + Demand
Residential	246,215	$ 343,107,229	157,733	$ 219,805,231	(88,482)	$ (123,301,998)	$ 343,107,229	
SGS	32,712	$ 45,584,405	36,419	$ 50,750,867	3,707	$ 5,166,462		$ 96,335,272
LGS/SPS	2,558	$ 3,564,816	90,268	$ 125,790,522	87,710	$ 122,225,707		$ 129,355,338
LPS Combined	15	$ 21,017	7,943	$ 11,068,741	7,928	$ 11,047,724		$ 11,089,759
Lighting	12,453	$ 17,354,165	1,590	$ 2,216,270	(10,863)	$ (15,137,895)		$ 19,570,435
	293,953	$ 409,631,632	293,953	$ 409,631,632	0	$ -		
Min. Sys. Poles 40'+		Min Sys $	Demand Alloc. Poles <40'	Demand $	Difference in Quantity	Difference in Cost	Hold at Min	Min + Demand
Residential	147,190	$ 205,112,882	91,669	$ 305,765,004	(55,521)	$ 100,652,121	$ 205,112,882	
SGS	19,555	$ 27,250,807	20,846	$ 69,531,523	1,290	$ 42,280,716		$ 96,782,329
LGS/SPS	1,529	$ 2,131,082	54,878	$ 183,046,128	53,348	$ 180,915,046		$ 185,177,210
LPS Combined	9	$ 12,564	7,580	$ 25,283,560	7,571	$ 25,270,996		$ 25,296,125
Lighting	7,445	$ 10,374,491	756	$ 2,521,544	(6,689)	$ (7,852,947)		$ 12,896,035
	175,728	$ 244,881,826	175,728	$ 586,147,759	0	$ 341,265,933		

[43] Given the compressed schedule for preparation of a CCoS study, I had used a "plug" to set up my study and apparently failed to fully update the formulas when actual values became available.

Poles	Total Min Sys Poles	Min Sys $	Total Demand Alloc Poles	Demand $	Hold at Min	Min + Demand	Allocated	With Additional Demand Costs
Residential	753,453	$ 728,564,306	487,160	$ 644,660,335	$ 728,564,306		$ 728,564,306	$ 832,536,639
SGS	100,102	$ 96,795,310	111,691	$ 147,543,931	$ -	$ 244,339,241	$ 244,339,241	$ 268,135,472
LGS/SPS	7,828	$ 7,569,638	271,738	$ 372,245,675		$ 379,815,313	$ 379,815,313	$ 439,851,970
LPS Combined	46	$ 44,629	24,269	$ 40,732,860		$ 40,777,489	$ 40,777,489	$ 47,346,980
Lighting	38,109	$ 36,850,361	4,681	$ 5,907,377		$ 42,757,737	$ 42,757,737	$ 43,710,493
	899,539	$ 869,824,244	899,539	$ 1,211,090,177	$ 728,564,306	$ 707,689,779	$ 1,436,254,086	<allocated
							$ 1,631,581,554	<poles $
							$ 195,327,468	<additional demand

Poles	Customer-Classified Allocation	Transmission Customer-Classified	Demand Allocation	Total	Composite Demand
Residential	$ 728,564,306	$ -	$ 103,972,333	$ 832,536,639	13.65%
SGS	$ 96,795,310	$ -	$ 171,340,162	$ 268,135,472	22.49%
LGS/SPS	$ 7,569,638	$ -	$ 432,282,332	$ 439,851,970	56.75%
LPS Combined	$ 44,629	$ -	$ 47,302,351	$ 47,346,980	6.21%
Lighting	$ 36,850,361	$ -	$ 6,860,132	$ 43,710,493	0.90%
	$ 869,824,244	$ -	$ 761,757,310	$ 1,631,581,554	
	Customer Counts	Customer Assigned	Composite		

Note, these tables also reflect removal of the assignment of designated Taps-account infrastructure to customers exclusively served by that infrastructure.

Q. Do you agree with Mr. Hickman's further criticisms concerning your poles allocation?

A. No. For example, Mr. Hickman goes on to state that "In one of the three size breakouts, the Residential Minimum System allocation in dollars is less than the Residential 'Demand $' allocation." It is true that for poles in excess of 40' and for non-wooden 40' poles there are more dollars allocated on demand than dollars allocated under the minimum system approach, however more poles are allocated on minimum system than on demand. This is because for the demand allocation, the actual cost of the pole is allocated, while for the minimum system, the cost of the minimum pole is allocated.

Q. Mr. Hickman states that building allocators that as interim steps involve different total dollar values than the actual CPR values for poles is “not grounded in logic and supports an inability to trust Staff’s pole allocations.”[44] Do you agree?

A. No. The poles allocation process used by both Staff and Ameren Missouri essentially involves allocating all poles on the basis of customer counts first, and then allocating all poles again on the basis of the use of each height of poles used by the various voltage levels. Mr. Hickman ignores this step by failing to net out the ability of the minimum system to meet demand. Allocating more dollars than are in the CPR and then scaling the results back to apply to the actual plant balance is a simple and reasonable step in the allocation process.

Distribution Assignment of Customer-Specific Facilities

Q. In his rebuttal testimony at page 30, Mr. Phillips alleges that “Staff has significantly increased the direct assignment of costs to classes rather than rely on system averages, ratios, etc. typically used in CCOSS and ratemaking.” Mr. Hickman also states his disagreement with this assignment in his rebuttal testimony from pages 2 – 12. How much of the distribution system was assigned to classes in your CCoS Study?

A. My direct study assigned four substations and two overhead circuits. This amounted to $35 million dollars out of net distribution rate base of $5.8 billion, or 0.604%. While I do not agree with these criticisms, it is such a small issue that I have simply removed the assignment in the study presented in this surrebuttal testimony.

Q. Mr. Phillips testifies that “Based on our current experience with client engagements in multiple state jurisdictions and research, electric utilities in at least twenty-six

[44] Hickman rebuttal, page 14.

states have adopted to varying degrees a customer component of the distribution system. Some specific examples excluding Ameren), are presented in Table 2 below,"[45] and includes Evergy's Missouri Metro rate case, ER-2022-0129. What did the Commission find in that case regarding customer components of the distribution system and what other findings did the Commission make with regard to the "minimum system," as alleged in that table?

A. The Report and Order section on Rate Design/Class Cost of Service begins at page 58 and ends at page 75. There is no discussion of distribution allocations or class cost of service anywhere in those pages (or elsewhere in the Report and Order). While there is discussion of the residential customer charge level, that discussion on pages 65-66 reports the Staff and company valuations of the residential customer charge. The Staff customer charge valuation did not include costs or expenses associated with Poles, Overhead Conductors and Devices, Underground Conduit, or Underground Conductors and devices, and the R&O at pages 75-76 orders use of the Staff valuation. There is nothing within this case to support an assertion that this case supports the use or adoption of the minimum system distribution approach. I have not reviewed the other ultra-jurisdictional cases in Mr. Phillips table, but I find the inclusion of the Evergy case in this table as "adopting" the minimum system approach to be misleading at best.

<u>RATE MODERNIZATION PROCESS AND REASONABLENESS OF RESULTS</u>

Q. Mr. Wills presents Edison Electric Institute's, ("EEI"), a utility lobbying organization, cent per kWh average realized rate data for the year 2023 in his rebuttal

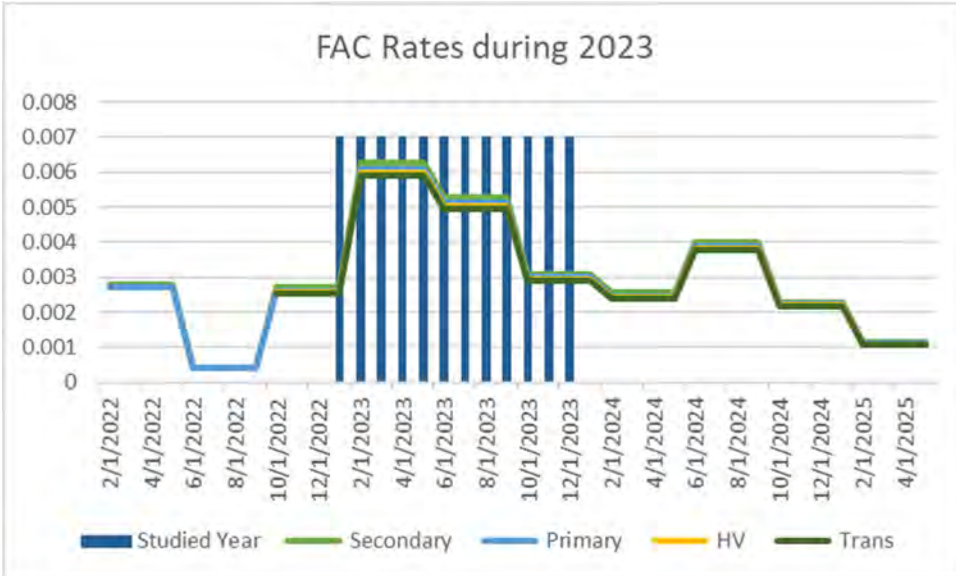
[45] Phillips rebuttal, page 29.

testimony at page 16. Is EEI data reliable for evaluating the reasonableness of rate designs, cost studies, or setting just and reasonable rates for a particular utility?

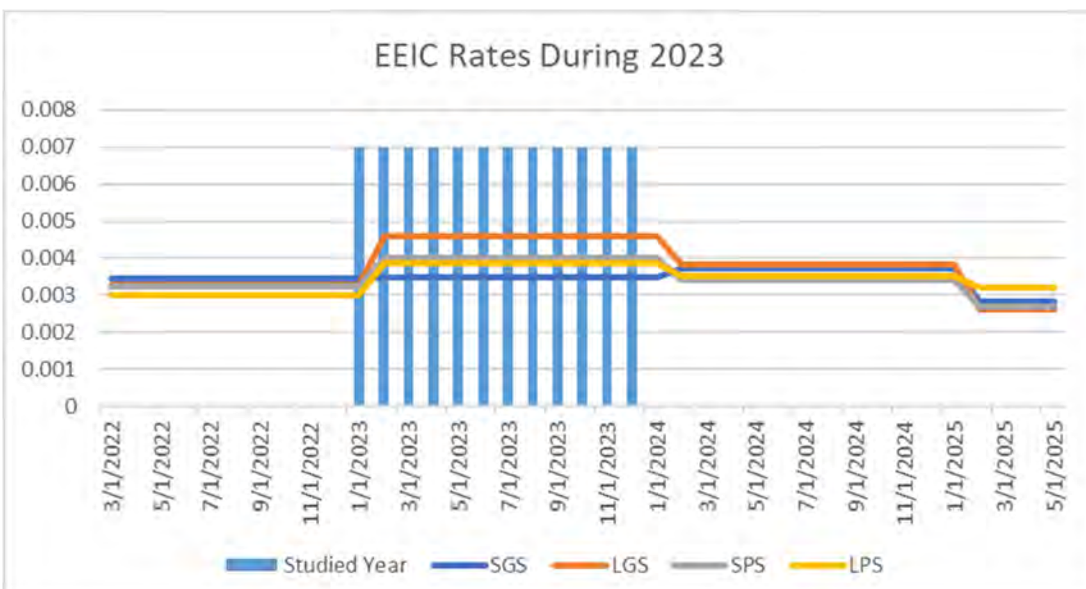
A. EEI data is not particularly useful. My understanding is that the particular EEI product that Mr. Wills reproduced is derived by dividing the FERC Form 1 reported sales revenue by business sector by the EEI reported sales kWh by business sector. The customer composition by business sector varies among utilities. Also, these revenues per kWh include riders such as the Fuel Adjustment Clause, ("FAC"), Energy Efficiency Investment Charge ("EEIC"), and the Renewable Energy Standard Rate Adjustment Mechanism ("RESRAM"). These riders change independently of the base rates which are subject to this case. Finally, the Commission is obligated to set just and reasonable rates without undue discrimination based on the cost of service of the utility it regulates, not based on vague calculations about average realized bills from two years prior.

Q. When Mr. Wills testifies in his rebuttal at page 19 that he is representing the impact of Staff's recommended rate increases on the EEI averaged realized bill amounts, did he remove the revenue associated with the FAC, EEIC, and RESRAM?

A. No, he did not. During 2023, the FAC reached a high of 0.6080 cents per kWh for customers served at primary voltage, 0.5980 cents per kWh for customers served at substation voltage and 0.5900 cents per kWh for customers served at transmission voltage. Note, the FAC will rebase to essentially zero with the implementation of new rates in this pending rate case.

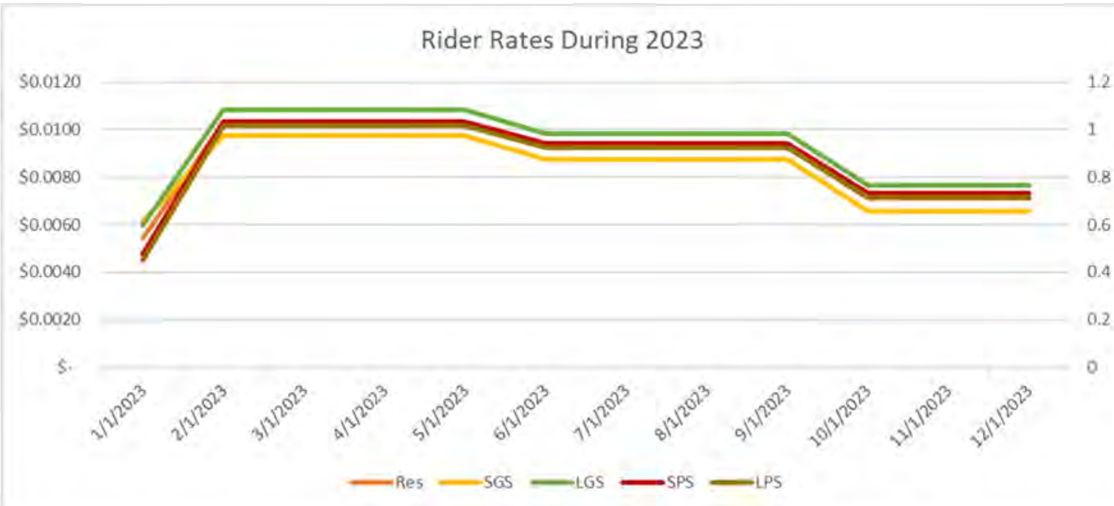


During 2023, the EEIC rates for the LGS class experienced an elevation of over a tenth of a cent over historic levels, and the SPS and LPS class experienced an elevation of nearly a tenth of a cent over historic levels. The 2023 levels for LGS were 0.194 cents higher than the current EEIC rate, and the SPS and LPS levels were 0.132 and 0.066 cents higher than the current respective EEIC rates.



The RESRAM rate, which will rebase in this rate case, was 0.035 cents per kWh in 2023.

Together, the riders in place during 2023 were around 1 cent per kWh.



When Mr. Wills applies a percentage increase to the EEI average revenue per kWh value, he is inflating the results by the percentage applied, at a minimum. To the extent that the sum of the rider rates which will be in place exceeds the sum of the rider rates in place during 2023, the results reported by Mr. Wills are further exaggerated, particularly for classes which consume higher levels of energy per customer.

Q. How have Ameren Missouri's base rates changed over the past 10 years?

A. I have summarized the approximate annual bills for the indicated years, the average billed $/kWh, and calculated the change in bills for a variety of usage profiles for each rate plan. I did not include SPS as the experienced changes and relative rates are essentially identical to that of LGS.

Large Power Service				2015	2020	2025	2015	2020	2025	
	Energy/Month	Demand	LF	Annual Bill	Annual Bill	Annual Bill	$/kWh	$/kWh	$/kWh	% Change
Low with Low LF	540,000	5,000	0.15	$ 985,876	$ 933,952	$ 1,039,825	$ 0.152	$ 0.144	$ 0.160	5%
Low with High LF	3,060,000	5,000	0.85	$ 1,938,436	$ 1,869,376	$ 2,078,065	$ 0.053	$ 0.051	$ 0.057	7%
Med with Low LF	1,620,000	15,000	0.15	$ 2,948,916	$ 2,792,048	$ 3,105,185	$ 0.152	$ 0.144	$ 0.160	5%
Med with Med LF	4,860,000	15,000	0.45	$ 4,173,636	$ 3,994,736	$ 4,440,065	$ 0.072	$ 0.068	$ 0.076	6%
Med with High LF	9,180,000	15,000	0.85	$ 5,806,596	$ 5,598,320	$ 6,219,905	$ 0.053	$ 0.051	$ 0.056	7%
Big with Low LF	3,780,000	35,000	0.15	$ 6,874,996	$ 6,508,240	$ 7,235,905	$ 0.152	$ 0.143	$ 0.160	5%
Big with Med LF	11,340,000	35,000	0.45	$ 9,732,676	$ 9,314,512	$ 10,350,625	$ 0.072	$ 0.068	$ 0.076	6%
Bigh with High LF	21,420,000	35,000	0.85	$ 13,542,916	$ 13,056,208	$ 14,503,585	$ 0.053	$ 0.051	$ 0.056	7%

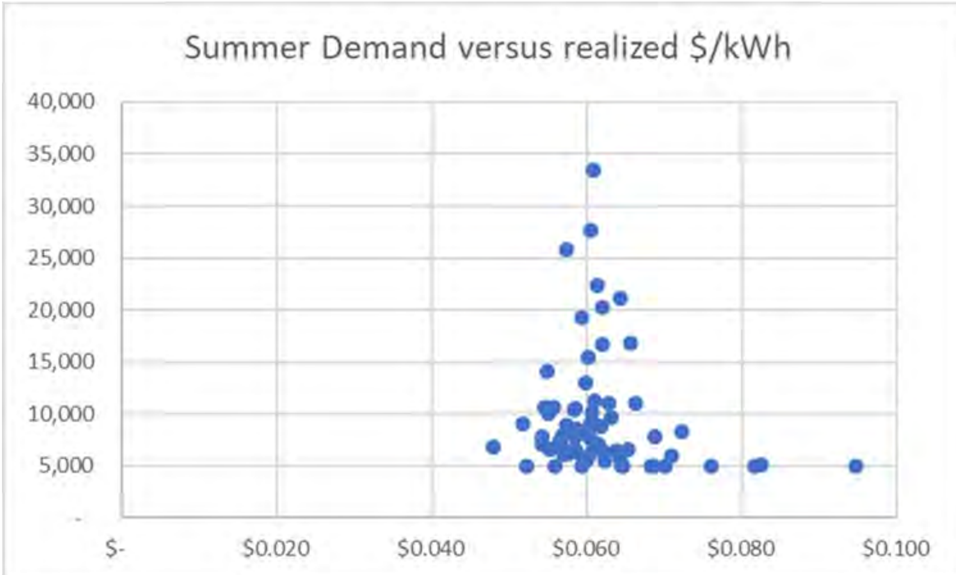
Large General Service				2015	2020	2025	2015	2020	2025	
	Energy/Month	Demand	LF	Annual Bill	Annual Bill	Annual Bill	$/kWh	$/kWh	$/kWh	% Change
Low with Low LF	13,500	125	0.15	$ 17,934	$ 17,653	$ 20,265	$ 0.111	$ 0.109	$ 0.125	13%
Low with High LF	76,500	125	0.85	$ 57,087	$ 54,335	$ 62,363	$ 0.062	$ 0.059	$ 0.068	9%
Med with Low LF	75,600	700	0.15	$ 95,303	$ 93,598	$ 107,381	$ 0.105	$ 0.103	$ 0.118	13%
Med with Med LF	226,800	700	0.45	$ 207,742	$ 198,877	$ 228,176	$ 0.076	$ 0.073	$ 0.084	10%
Med with High LF	428,400	700	0.85	$ 314,559	$ 299,018	$ 343,129	$ 0.061	$ 0.058	$ 0.067	9%
Big with Low LF	378,000	3,500	0.15	$ 472,057	$ 463,418	$ 531,596	$ 0.104	$ 0.102	$ 0.117	13%
Big with Med LF	1,134,000	3,500	0.45	$ 1,034,253	$ 989,812	$ 1,135,573	$ 0.076	$ 0.073	$ 0.083	10%
Bigh with High LF	2,142,000	3,500	0.85	$ 1,568,339	$ 1,490,514	$ 1,710,337	$ 0.061	$ 0.058	$ 0.067	9%

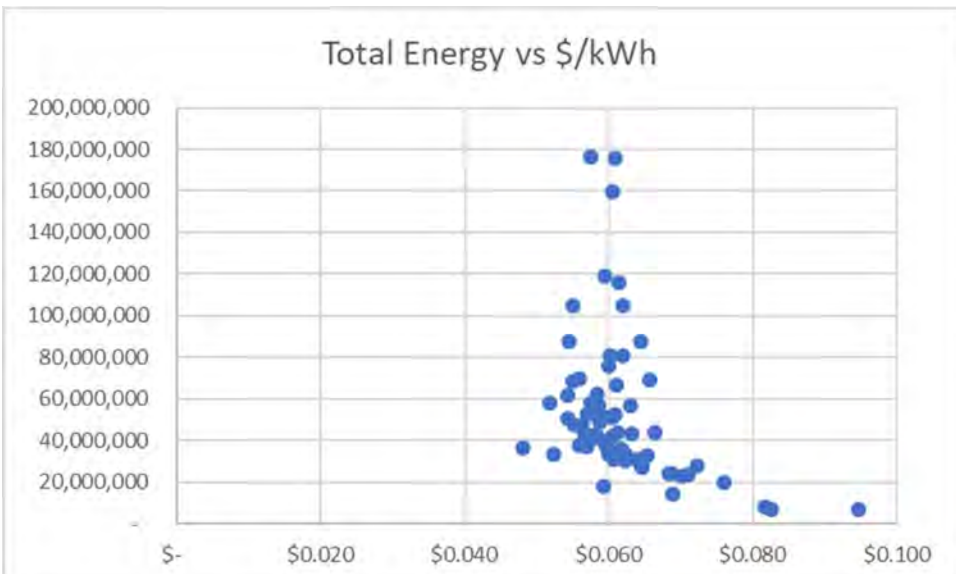
Small General Service				2015	2020	2025	2015	2020	2025	
	Energy/Month	Demand	LF	Annual Bill	Annual Bill	Annual Bill	$/kWh	$/kWh	$/kWh	% Change
Low	800	-	-	$ 984.64	$ 958.20	$ 1,101.12	$ 0.103	$ 0.100	$ 0.115	12%
Medium 1	1200	-	-	$ 1,366.42	$ 1,326.84	$ 1,524.29	$ 0.095	$ 0.092	$ 0.106	12%
Medium 2	2000	-	-	$ 2,140.88	$ 2,074.68	$ 2,382.72	$ 0.089	$ 0.086	$ 0.099	11%
High	10000	-	-	$ 10,198.76	$ 9,851.88	$ 11,309.64	$ 0.085	$ 0.082	$ 0.094	11%

Residential				2015	2020	2025	2015	2020	2025	
	Energy/Month	Demand	LF	Annual Bill	Annual Bill	Annual Bill	$/kWh	$/kWh	$/kWh	% Change
Low	800	-	-	$ 875.68	$ 990.56	$ 1,134.20	$ 0.091	$ 0.103	$ 0.118	30%
Medium	1200	-	-	$ 1,179.84	$ 1,351.68	$ 1,554.36	$ 0.082	$ 0.094	$ 0.108	32%
High	2000	-	-	$ 1,788.16	$ 2,073.92	$ 2,394.68	$ 0.075	$ 0.086	$ 0.100	34%

Q. Have you reviewed the range of individual experienced $/kWh for current LPS class customers?

A. Yes:

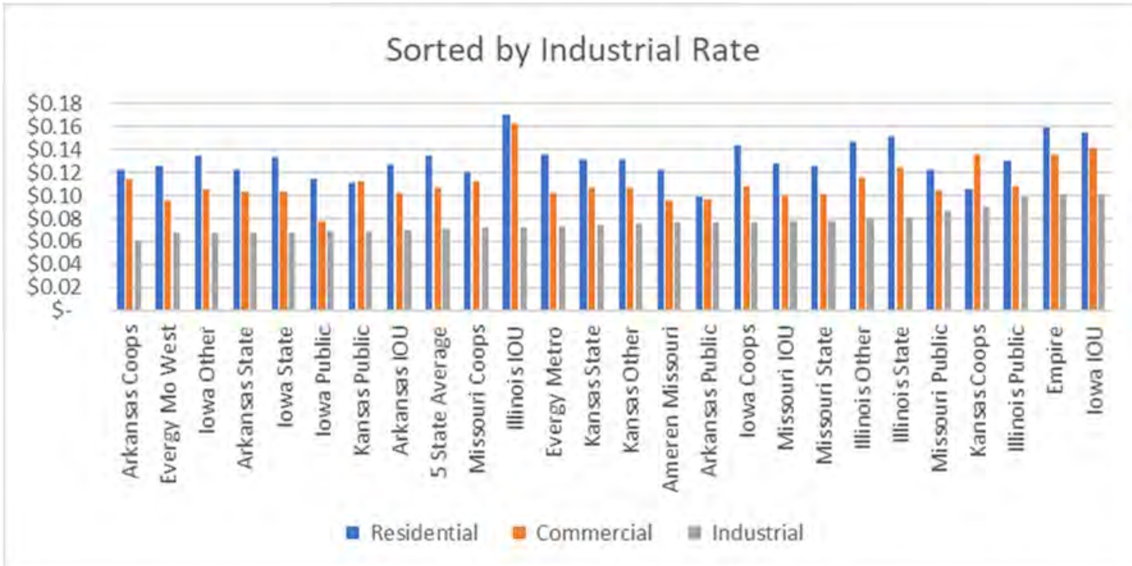


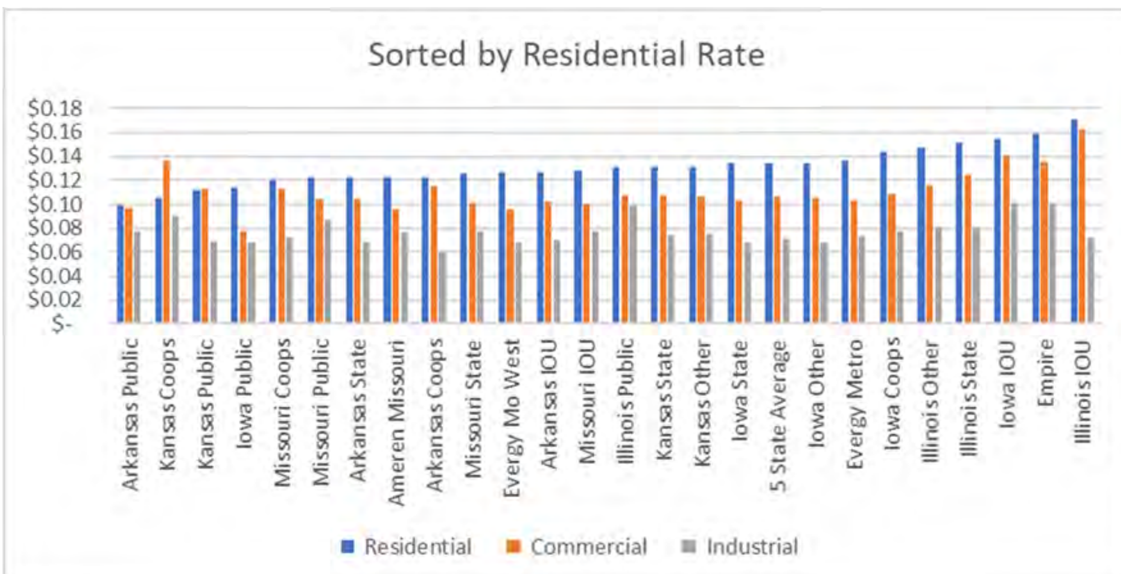


Significant variety in realized rates exist depending on the usage characteristics of customers within the class.

Q. Have you reviewed the average $/kWh for Missouri and neighboring states for the year 2023?

A. Yes:





Q. Evergy Missouri West has a lower average $/kWh for industrials than Ameren Missouri. Are Evergy Missouri West's rates lower than Ameren Missouri?

A. No. A comparison of the same usage and demand profiles on Ameren Missouri's LPS rates and Evergy Missouri West's LPS rates indicates that Ameren Missouri's rates would be lower for each profile:

Evergy West Large Power Service Comparision				Evergy West	Ameren Missouri	Evergy West	Ameren Missouri	
	Energy/Month	Demand	LF	Annual Bill	Annual Bill	$/kWh	$/kWh	% Difference
Low with Low LF	13,500	125	0.15	$ 33,851	$ 1,039,825	$ 0.209	$ 0.160	30%
Low with High LF	76,500	125	0.85	$ 63,486	$ 2,078,065	$ 0.069	$ 0.057	22%
Med with Low LF	75,600	700	0.15	$ 152,308	$ 3,105,185	$ 0.168	$ 0.160	5%
Med with Med LF	226,800	700	0.45	$ 231,680	$ 4,440,065	$ 0.085	$ 0.076	12%
Med with High LF	428,400	700	0.85	$ 318,261	$ 6,219,905	$ 0.062	$ 0.056	10%
Big with Low LF	378,000	3,500	0.15	$ 729,139	$ 7,235,905	$ 0.161	$ 0.160	1%
Big with Med LF	1,134,000	3,500	0.45	$ 1,125,998	$ 10,350,625	$ 0.083	$ 0.076	9%
Bigh with High LF	2,142,000	3,500	0.85	$ 1,558,904	$ 14,503,585	$ 0.061	$ 0.056	7%

However, because Evergy Missouri West sells a lot of energy at or below cost to Nucor, the average industrial revenue divided by the average industrial energy sales are lower for Evergy Missouri West than for Ameren Missouri.

Unbundled Results Request

Q. Mr. Phillips alleges that he could not find my unbundled CCoS results. Is this literally accurate, are they easily calculated, and what is the problem, if any?

A. The full allocation of costs by classification was included in my workpapers, and many were provided in my testimony. Mr. Phillips' request is that I provide study results on the basis of simple demand and simple energy calculations for each function, but those calculations are not applicable or particularly useful.

Q. Mr. Phillips requests that the Commission order "that if parties file alternative CCOSS that are not based on the same CCOSS model filed by the utility initiating the rate review, those parties should be required to file sufficient detail including, but not limited to a fully unbundled, breakdown of costs at each step (Functionalization, Classification, and Allocation) within the cost allocation process to ensure full understanding and transparency of alternative models by all parties to the case, as well as the Commission."[46] What is your response?

A. Staff typically receives approximately 10 business days to prepare a CCoS Study, have those results reviewed internally, write up the CCoS study testimony, prepare revenue allocation and rate design recommendations based on CCoS study results, have those recommendations reviewed internally, and write up the rate design testimony. While some preliminary work such as distribution classification is started before those 10 days, that preliminary work must be adjusted to final customer numbers and account balances which may not be finalized until the revenue requirement filing. Further, as explained in my direct testimony, the participant renewable programs and proliferation of non-traditional accounting authorizations has significantly complicated the conduct and presentation of CCoS studies.

This request to add further requirements to CCoS study presentation will not improve transparency, as the details it seeks are simplified to the point of irrelevance and, more importantly, inaccuracy. Staff opposes this additional requirement to be imposed on Staff or any other party that submits its own independent CCoS study.

RATE DESIGN

LGS/SPS Rate Design

Q. In preparing this testimony did you observe a new issue to address in the preparation of rates for compliance tariffs in this case?

A. Yes. The LGS seasonal energy charge is $0.0001 less than third block, but the SPS seasonal energy charge is $0.0001 higher than third block. While Staff recommends

[46] Phillips rebuttal, page 20.

elimination of the seasonal energy charges as part of the rate modernization process, in the interim, each seasonal energy charge should ideally be set equal to the third block winter energy rate in the respective class.

Residential Customer Charge

Q. Dr. Bowden testifies that "Staff makes a cost of service argument to support their proposal to keep the monthly residential customer charge at $9.00. In order to maintain costs at this level, Staff uses a narrow definition of customer-related costs to estimate a cost of service based residential customer charge."[47] Is this accurate?

A. No. Dr. Bowden has reversed the order of Staff's analysis. Staff studied the plant and expenses that change with the addition or the subtraction of a customer, and concluded that the revenue requirement of those items – if line transformers are included – is $8.16 per customer per month. Without line transformers, the cost is only $4.29 per customer per month. Line transformers are an area where significant improvement in the company distribution study and in the information provided in rate cases and the rate modernization process is needed. Primary line transformers are included in the Ameren Missouri line transformer accounts, and Ameren Missouri is unable to provide an estimate of the relationship between customer class or customer size and the count of customers per line transformer or the size or cost of the line transformer. However, Staff does not recommend reducing the residential customer charge in this case.

Q. Dr. Bowden testifies that the "the large gap between the Company's current residential customer charge and the Company's estimate of residential customer related costs,

[47] Bowden rebuttal, page 64.

increasing the customer charge is good policy."[48] What is the causation of the large gap between Mr. Hickman's estimated $31 per customer per month and the current $9.00 customer charge?

A. The high customer charge calculated by Ameren Missouri is a direct product of the unreasonable inclusion of the minimum-classified distribution system costs, which were, in turn, unreasonably calculated.

Q. Did Dr. Bowden's testimony alert you to any errors in your direct testimony?

A. Yes. Dr. Bowden noted that my CCoS testimony in the footnote on page 47 stated that I did not include incremental costs associated with meter reading in my customer charge calculation, and upon review I can confirm that the referenced statement was a drafting error. Meter reading expense was fully included in my calculation of $8.16 and $4.29. For clarity, the costs and expenses that are included in my calculation are set out below:

Account Number	Plant Account Name	Total Gross Plant	Total Net Plant	Amount of Net Plant Allocated to Residential Class	Included in Customer Charge Calculation
360	Land/Land Rights - DP	$ 40,789,309	$ 40,789,309	$ 19,986,859	
361	Structures & Improvements - DP	$ 17,949,046	$ 10,162,353	$ 8,823,640	
362	Station Equipment - DP	$ 1,717,438,958	$ 1,350,688,838	$ 842,894,595	
364	Poles, Towers, & Fixtures - DP	$ 1,675,080,470	$ 423,896,192	$ 951,317,769	
365	Overhead Conductors & Devices - DP	$ 2,407,605,988	$ 1,824,401,652	$ 1,297,529,008	
366	Underground Conduit - DP	$ 796,365,227	$ 628,441,032	$ 445,163,614	
367	Underground Conductors & Devices - DP	$ 1,091,546,216	$ 747,785,385	$ 675,414,737	
368	Line Transformers - DP	$ 627,683,838	$ 393,544,258	$ 467,456,536	$ 467,456,536
369.01	Services - Overhead - DP	$ 263,559,548	$ (42,574,749)	$ 209,305,285	$ 209,305,285
369.02	Services - Underground - DP	$ 208,147,538	$ 47,066,727	$ 163,464,144	$ 163,464,144
369.091	Services - 369.091 - DP			$ -	
370	Meters - DP	$ 44,516,051	$ 23,529,687	$ 29,812,724	$ 29,812,724
370.1	AMI Meters - DP	$ 275,251,645	$ 239,792,083	$ 184,338,035	$ 184,338,035
371	Meter Installations - DP	$ 164,613	$ (10,443)	$ 110,243	$ 110,243
373	Street Lighting and Signal Systems - DP	$ 259,452,981	$ 165,345,999		
		$ 9,425,551,428	$ 5,852,858,323	$ 5,295,617,189	$ 1,054,486,967

[48] Bowden rebuttal, page 65.

Account Number	Expense Account Name	Total Jurisdiction Labor Expense	Total Jurisictional Non-Labor Expense	Amount of Expense Allocated to Residential Class	Included in Customer Charge Calculation
	Depreciation with Plant Above			$ 794,842,758	$ 16,785,789
580	Supervision & Engineering - DE	$ 8,001,278	$ 990,558	$ 4,439,007	
581	Load Dispatching - DE	$ 1,149,110	$ 122,993	$ 628,000	
582	Station Expenses - DE	$ 1,148,622	$ 952,613	$ 1,037,318	
583.1	Overhead Line Expenses - DE	$ 2,980,237	$ 1,736,448	$ 2,569,939	
583.2	Install, Remove & Replace Line Transformers - Overhead	$ 4,481,030	$ 4,524,580	$ 6,706,770	$ 6,706,770
584.1	Underground Line Expenses - DE	$ 999,303	$ 1,380,476	$ 1,412,443	
584.2	Install, Remove & Replace Line Transformers - Underground	$ 1,843,447	$ 855,736	$ 2,010,169	
585	Street Lighting & Signal System Expenses - DE	$ 1,816,423	$ 816,949	$ -	
586	Meters - DE	$ 3,310,076	$ 69,314	$ 2,263,202	$ 2,263,202
587	Customer Install - DE	$ 585,833	$ 17,844	$ 339,168	
588	Miscellaneous - DE	$ 7,286,249	$ 23,481,103	$ 17,286,216	
589	Rents - DE	$ -	$ 417,712	$ 234,686	
590	S&E Maintenance - DE	$ 1,410,238	$ (39,285)	$ 676,800	
591	Structures Maintenance - DE	$ 378,691	$ 450,257	$ 409,227	
592	Station Equipment Maintenance - DE	$ 8,403,447	$ 4,219,101	$ 6,231,384	
593	Overhead Lines Maintenance - DE	$ 19,729,527	$ 39,533,938	$ 32,290,369	
594	Underground Lines Maintenance - DE	$ 2,466,284	$ 2,403,610	$ 2,890,372	
595	Line Transformers Maintenance - DE	$ 927,656	$ 432,695	$ 1,013,098	$ 1,013,098
596	Street Light & Signals Maintenance - DE	$ 361,327	$ 396,605	$ -	
597	Meters Maintenance - DE	$ 707,114	$ 85,658	$ 530,925	$ 530,925
598	Misc. Plant Maintenance - DE	$ 725,002	$ 2,400,182	$ 1,755,842	
901	Supervision - CAE	$ 1,156,968	$ (18,611)	$ 639,570	
902	Meter Reading Expenses - CAE	$ 799,995	$ 5,212,795	$ 5,252,080	$ 5,252,080
903	Customer Records & Collection Expenses - CAE	$ 17,089,351	$ 21,481,368	$ 33,690,930	
905	Misc. Customer Accounts Expense	$ 96	$ 113,543	$ 99,262	
		$ 87,757,305	$ 112,038,182	$ 919,249,535	$ 32,551,864

Q. Why is the company calculation so much higher than Staff's calculation?

A. Mr. Hickman chose to include significant amounts of plant within the accounts for Poles, Overhead Conductors and Devices, Underground Conduit, and Underground Conductors and Devices, as well as the associated depreciation and a consistent percentage of those expenses in the customer charge.

Q. Are there two fundamentally different ways of thinking about customer charges?

A. Yes. One approach is to say that anything that doesn't change due to changes in energy consumption belongs in the customer charge. In addition to Mr. Hickman's residential customer charge calculation includes $1,682,076,000 of net ratebase, approximately 11.99% of Ameren Missouri's $14 billion total ratebase. He achieves this massive amount by including all plant that he allocates on the basis of class customer counts, which is based on his significantly overstated minimum system study, then he grosses this amount up by incorporating an additional $302,885,000 of intangible and general plant.

Q. Has the Commission entered orders on this issue before?

A. Yes. I recall the Commission last addressing the residential customer charge causation decision in an Evergy Missouri Metro case, ER-2014-0370. In that case the Commission relied upon Staff's customer charge calculation which did not include portions of the poles, overhead conductors and devices, conduit, and underground conductors and devices accounts, and rejected the company calculation which did include portions of those accounts.

Q. Why would the company inflate the residential customer charge?

A. Generally, speaking, the higher the customer charge, the more stable or positive the revenue stream is for the utility. In other words, a higher customer charge gives the utility greater certainty in its cost recovery, which provides greater financial upside for a utility with consistent residential customer growth. As averaged for calendar years 2016-2023, Ameren Missouri gained 462.2 residential customers per month.[49] This additional customer growth provides $1,247,850 in additional revenue over the course of 2 years at the current $9 customer charge. If the customer charge increased to $10, that is an additional $1,386,500 of stable revenue collected through the residential customer charge. This is particularly relevant if customer growth is in the form of apartments, condos, or other non-detached facilities. The incremental cost Ameren Missouri experiences on a per-customer basis for these customers is below the average cost for a detached home. In turn, new construction, particularly of

[49] Over the same time period, Commercial customer growth was approximately 70.9 customers/month, and Industrial customer growth was approximately -7.0625 customers/month.

apartments, condos, or other non-detached facilities will likely have lower average energy consumption than a detached home or existing construction.

Q. How much revenue would be associated with what Bowden characterizes as the cost based $31 per month?

A. Setting aside energy charge revenue, Ameren Missouri would receive $12,478,500 in customer charge revenue for adding 11,092 residential customers over 24 months. That result is simply out of alignment with the actual fixed cost recovery, and is a direct consequence of Ameren Missouri's decision to include over half of its entire distribution system as a cost to be recovered through the residential customer charge.

Q. Should costs that do not vary with the number of residential customers be included in the residential customer charge?

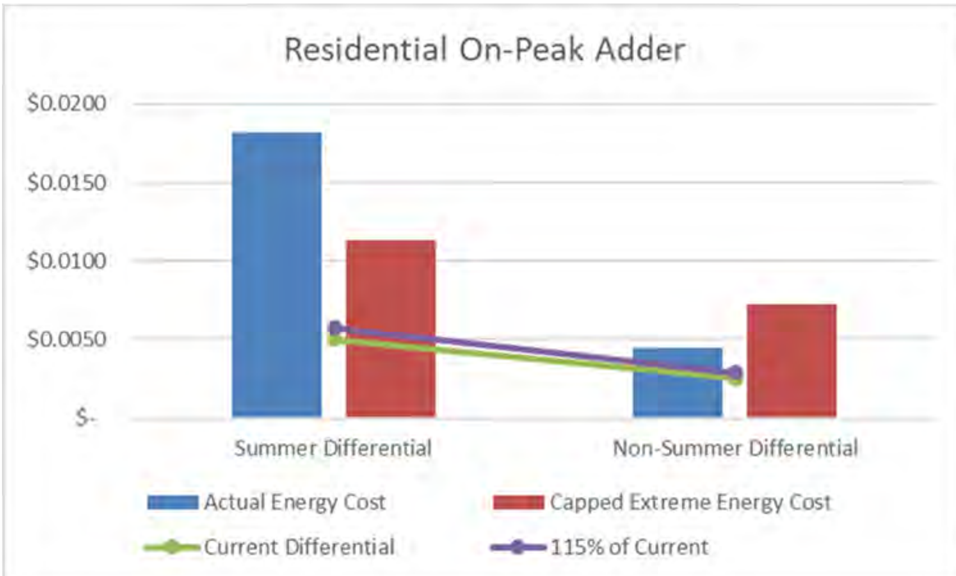
A. Generally, no.

Cost Basis of Residential Differential

Q. Dr. Bowden testifies in his rebuttal testimony at pages 65-66 that keeping the current on-peak adjustment is preferable because (1) AMI rollout is wrapping up and (2) "To the best of my understanding, the level of the charge recommended by Staff is not directly linked to any cost-based measure." He continues that "However, it makes sense to me to consider what the cost is intended to represent or what it is intended to achieve before we start changing it." What is the rate intended to represent?

A. The rate is intended to represent the differential between wholesale costs of energy within the time periods.

Staff reviewed the load LMPs for the test year and update period in this case, and observed that the actual differentials by season exceed both the current differential and 115% of the current differential. The values are provided below:



	Summer Differential	Non-Summer Differential
Actual Energy Cost	$ 0.0182	$ 0.0045
Capped Extreme Energy Cost	$ 0.0113	$ 0.0072
Current Differential	$ 0.0050	$ 0.0025
115% of Current	$ 0.0058	$ 0.0029

TOU & AMI

Q. Mr. Wills testifies at page 22 of his rebuttal testimony that Staff acknowledges that the proposal it put forth, regarding if the Commission desires to make the Smart Saver and Overnight Saver service rates available to net metering customers is not cost based. Is this accurate, and is the proposal, discussed as the "Evergy proposal" by Mr. Wills on the same page, cost based?

A. Yes, it is accurate. Neither the Staff proposal nor the proposal referenced from the Evergy case are cost based because the Ameren Missouri Smart Saver and Overnight Saver rates are not cost-based. Staff did not join in the related portion of the Evergy stipulation because Staff determined that the proposal does not comply with relevant Missouri statute.

<u>SUMMARY OF STAFF RECOMMENDATIONS</u>

Q. How does Staff recommend increases to revenue requirement be allocated to the classes?

A. Staff recommends all classes receive an equal percentage increase to current revenues.

Q. How does Staff recommend increases to revenue requirement be designed within the classes?

A. Rider B, the residential customer charge, and the low-income charges should be held constant. Various additional charges for time-based rate participation should be eliminated. Within the LGS and SPS classes a small misalignment in the tail-block and seasonal energy charges should be corrected.

All other rate schedule elements, including the residential Evening-Morning Savers on-peak adder should be increased by the same percent within a class.

Q. Should the Commission specifically order any CCoS study or method in this case?

A. No. The Commission should acknowledge if it is relying on any particular submitted study in its order, but should not limit the range of study approaches or methods available to the parties as circumstances and data availability vary case to case. Staff's study reasonably allocates the costs and revenues of Ameren Missouri's generation assets and the cost of energy to serve load. Staff's study, to the extent possible, classifies distribution costs using methods that recognize the demand-serving ability of the customer-classified distribution system for the overhead system. Staff's study does overallocate the cost of the underground distribution system to classes taking service at secondary voltage, and does overallocate customer-specific substation, transmission, and distribution costs to classes taking service at secondary voltage, namely Residential, SGS, LGS, and lighting. However, the Ameren Missouri and derivative studies make no attempt to account for customer-specific costs, demand-serving capability of customer-classified plant, and over-classifies customer-classified plant. Further, the Ameren Missouri and derivative studies do not take the integrated energy market or resource adequacy requirements into consideration when allocating production plant, fail to reasonably allocate renewable resource costs consistent with the Missouri RES or cost causation, and result in a fundamentally unfair relationship between the allocated costs of renewable energy and the allocation of the revenues and RECs proceeding from that renewable energy.

Q. Should the Commission order revenue adjustments to exactly match any submitted CCoS Study result?

A. No, CCoS Study results should only be used as a guide in setting rates. Before any deviations from the CCoS results for any policy considerations, the limitations of the precision of CCoS results in alignment of cost causation and revenue responsibility must be recognized. Staff recommends that CCoS Studies be viewed as accurate to a precision of +/-5% of calculated under- and over-contribution at current system average rate of return. This recognizes that CCoS Studies are of a snapshot in time and are not fully updated to final revenue requirements. Calculation of the tolerance band on over/under contribution eliminates the impact of a parties' recommended rate of return from the study.

Q. Should specific rate modernization updates be ordered, as requested by MECG?

A. Staff is not opposed to keeping the Commission informed of progress in the working docket.

CONCLUSION

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service	)))	Case No. ER-2024-0319

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI COUNTY OF COLE	)))	ss.

COMES NOW SARAH L.K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Surrebuttal / True-Up Direct Testimony of Sarah L.K. Lange*; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L.K. Lange

SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 4th day of February 2025.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: April 04, 2025
Commission Number: 12412070

D Suzie Mankin

Notary Public