Exhibit No. 235

Staff – Exhibit 235
Sarah L.K. Lange
Rebuttal
File No. ER-2024-0189

Exhibit No.:	
Issue(s):	*TOU Revenue Adjustment, TOU Revenue Tracker, Class Cost of Service, Rate Design*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case No.:	*ER-2024-0189*
Date Testimony Prepared:	*August 6, 2024*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRY ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

REBUTTAL TESTIMONY

OF

SARAH L.K. LANGE

EVERGY MISSOURI WEST, INC.,

d/b/a Evergy Missouri West

CASE NO. ER-2024-0189

Jefferson City, Missouri
August 6, 2024

** Denotes Confidential Information **

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REBUTTAL TESTIMONY

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EVERGY MISSOURI WEST, INC.,
d/b/a Evergy Missouri West

CASE NO. ER-2024-0189

Q. Please state your name and business address.

A. My name is Sarah L.K. Lange, 200 Madison Street, Jefferson City, MO 65101.

Q. Are you the same Sarah L.K. Lange who provided revenue requirement direct and rate design direct testimony in this matter?

A. Yes.

EXECUTIVE SUMMARY

Q. What is the purpose of your direct testimony?

A. My testimony will:

1. Address an error in my direct-recommend rate design for Small General Service ("SGS"), Large General Service ("LGS"), and Large Power Service ("LPS") customers which came to my attention due to a data request Staff received from Every Missouri West ("EMW") on July 26,

2. Provide testimony supporting Staff Expert Kim Cox's recommend rejection of EMW adjustment to revenues related to Time of Use ("TOU") rate structures,

3. Recommend rejection of EMW's requested residential revenue tracker,

4. Address the reasonableness of EMW's Class Cost of Service ("CCoS") study and the Midwest Energy Consumer's Group ("MECG") derivative CCoS study and related interclass revenue responsibility requests, and

5. Respond to the rate design recommendations of EMW and MECG.

CORRECTED RATE DESIGN RECOMMENDATIONS FOR SGS, LGS, AND LPS CUSTOMERS

Q. Could you summarize your direct recommendation for the rate structures and designs for SGS, LGS, and LPS customers?

A. Yes. Staff recommends lessening the reliance on hours-use rate structures, that a time-based overlay be incorporated, and that end-use rate distinctions and related discounts be eliminated. In describing this recommendation, my Rate Design direct testimony included the steps of the rate calculation process for each class of customers at each voltage level, using a 10% overall increase for illustration of the math.

Q. Did your underlying workpaper and therefore your testimony include an error?

A. Yes. EMW brought to my attention that I made a formula error on the very last step of the calculation. I appreciate EMW alerting me to this error, where I added an amount that I should have subtracted. This change only impacts the "New Rates" column of the calculation set out for each class.

Q. What are the corrected "New Rates" for each class and voltage level using the example 10% increase?

A. The corrected "New Rates," using the purely illustrative 10% increase, are set out in the table below:

	Starting Rates			New Rates		
	SGS	LGS	LPS	SGS	LGS	LPS
Sec. NonDemand-Summer-Block 1	$ 0.13902			$ 0.1554		
Sec. NonDemand-Nonsummer-Block 1	$ 0.08734			$ 0.0913		
Sec. NonDemand-Nonsummer-Seasonal	$ 0.04480					
Discounted-Nonsummer-Block 1	$ 0.06504					
Discounted-Nonsummer-Seasonal	$ 0.04480					
Secondary-Summer-Block 1	$ 0.09747	$ 0.08973	$ 0.05445	$ 0.1090	$ 0.1007	$ 0.0631
Secondary-Summer-Block 2	$ 0.07334	$ 0.06790	$ 0.04287	$ 0.0820	$ 0.0762	$ 0.0497
Secondary-Summer-Block 3		$ 0.04751	$ 0.03759		$ 0.0533	$ 0.0436
Secondary-Nonsummer-Block 1	$ 0.07080	$ 0.06836	$ 0.05083	$ 0.0803	$ 0.0781	$ 0.0604
Secondary-Nonsummer-Block 2	$ 0.06390	$ 0.06266	$ 0.03999	$ 0.0686	$ 0.0716	$ 0.0475
Secondary-Nonsummer-Block 3		$ 0.04291	$ 0.03507		$ 0.0477	$ 0.0416
Secondary-Nonsummer-Seasonal	$ 0.04480	$ 0.03753	$ 0.03274			
Primary-Summer-Block 1	$ 0.09144	$ 0.08701	$ 0.05279	$ 0.1022	$ 0.0976	$ 0.0612
Primary-Summer-Block 2	$ 0.06880	$ 0.06584	$ 0.04154	$ 0.0769	$ 0.0739	$ 0.0481
Primary-Summer-Block 3		$ 0.04606	$ 0.03642		$ 0.0517	$ 0.0422
Primary-Nonsummer-Block 1	$ 0.06953	$ 0.06588	$ 0.04930	$ 0.0788	$ 0.0752	$ 0.0586
Primary-Nonsummer-Block 2	$ 0.06276	$ 0.06038	$ 0.03879	$ 0.0675	$ 0.0690	$ 0.0461
Primary-Nonsummer-Block 3		$ 0.04132	$ 0.03400		$ 0.0447	$ 0.0403
Primary-Nonsummer-Seasonal	$ 0.04305	$ 0.03659	$ 0.03193			
Substation-Summer-Block 1			$ 0.05132			$ 0.0595
Substation-Summer-Block 2			$ 0.04041			$ 0.0468
Substation-Summer-Block 3			$ 0.03540			$ 0.0410
Substation-Nonsummer-Block 1			$ 0.04850			$ 0.0576
Substation-Nonsummer-Block 2			$ 0.03816			$ 0.0453
Substation-Nonsummer-Block 3			$ 0.03345			$ 0.0397
Substation-Nonsummer-Seasonal			$ 0.03159			
Transmission-Summer-Block 1			$ 0.05234			$ 0.0607
Transmission-Summer-Block 2			$ 0.04119			$ 0.0477
Transmission-Summer-Block 3			$ 0.03611			$ 0.0418
Transmission-Nonsummer-Block 1			$ 0.04727			$ 0.0562
Transmission-Nonsummer-Block 2			$ 0.03719			$ 0.0442
Transmission-Nonsummer-Block 3			$ 0.03259			$ 0.0387
Transmission-Nonsummer-Seasonal			$ 0.03132			

Q. Did Staff inform EMW and intervenors of this error promptly?

A. Yes. I provided a corrected workpaper on 7/30/2024, prior to the technical conference scheduled in this matter on 8/2/2024.

Q. Are the above rates the only rates these customers would pay?

A. No. The rates above are only the energy rates. Customer charges, demand charges, and facilities charges, as applicable, should each be increased by an equal percent. Also, the Staff-recommended time-based overlay would be included in rate structures for customers in the Small General Service ("SGS"), Large General Service ("LGS"), and Large Power Service ("LPS") classes:

		Super Off-Peak	Off-Peak	On-Peak
Time Periods	Summer	Midnight - 6:00 am	6:00 am - 2:00 pm; 6:00 pm - Midnight	2:00 pm - 6:00 pm
	Non-Summer	Midnight - 5:00 am	11:00 am - 5:00 pm	5:00 am - 11:am pm; 5:00 pm - 8:00 pm
Approximate Overlay Values	Summer	$ (0.030)	$ -	$ 0.030
	Non-Summer	$ (0.020)	$ -	$ 0.003

TOU REVENUE ADJUSTMENT REQUEST AND TOU REVENUE TRACKER REQUEST

Q. What is the difference between EMW's requested Time of Use ("TOU") revenue adjustment, and EMW's requested TOU revenue tracker?

A. EMW's requested TOU revenue adjustment is proposed by its witness Marisol Miller, and reduces test year revenues in this rate case by $3.1 million for purposes of (1) calculating the overall revenue requirement, (2) performing a class cost of service study, and (3) establishing new rates in compliance tariffs.

The TOU tracker is requested by its witness Ron Klote, and is for authority to track and defer the differences going forward between each residential customer's actual bill, and what that customer's bill would have been had that customer used exactly the same amount of energy at exactly the same time each month, but had that customer been on one of the rate plans which are no longer available.

Q. At page 11 of her direct testimony, Ms. Miller testifies that the calculation of the TOU revenue adjustment is "uncertain," and states that the proposed tracker mechanism will "ensure actual revenue impacts are tracked and considered." Would the TOU revenue tracker do so?

A. No. As explained more fully below, the requested tracker reconciles to recalculated bills, which is not only an improper basis for any potential revenue tracking, but also compounds the errors the revenue adjustment will introduce. Each of these requests are inappropriate on their own, and are also inappropriate if combined.

TOU Revenue Adjustment Requested by EMW

Q. What is the TOU revenue adjustment requested by EMW?

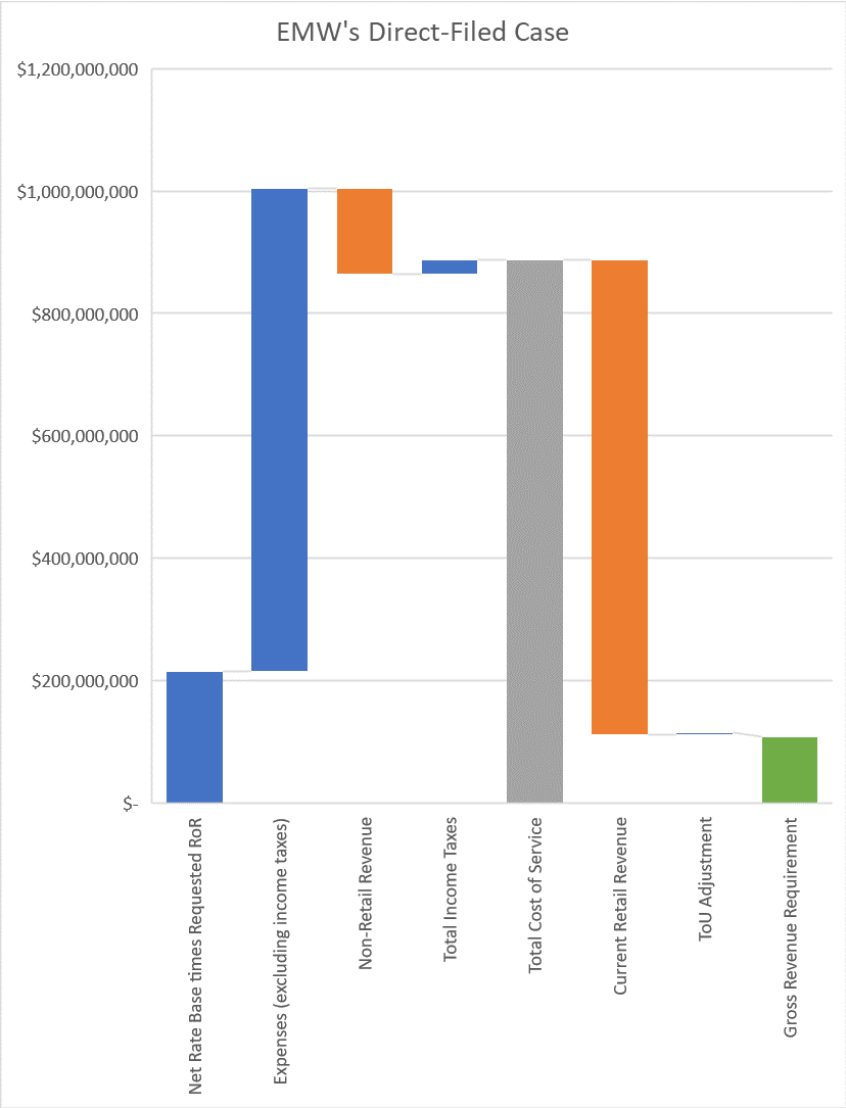
A. At page 5 of her direct testimony, Ms. Miller testifies that "The Company adjusted test year revenues to reflect an expected revenue decrease resulting from the implementation of Time of Use ("TOU") rates that began in October 2023." At page 10, she quantifies the adjustment as a reduction of $3.1 million to revenues.[1]

Q. What is the effect of a $3.1 million reduction to adjusted test year revenues on EMW's case?

A. EMW has requested a "Gross Revenue Requirement," in this case of $108,904,216. The illustration below, with dollar values in the table that follows, sets out how the EMW requested increase is built up, and how the $3.1 million adjustment offsets the current retail rate revenue that is considered when calculating the gross revenue requirement:

continued on next page

[1] As discussed in section Class Cost of Service – TOU Revenue Adjustment, this adjustment is handled differently in Ms. Miller's class cost of service study.



Net Rate Base times Requested RoR	$	214,189,841
Expenses (excluding income taxes)	$	789,679,018
Non-Retail Revenue	$	(139,978,951)
Total Income Taxes	$	23,534,321
Total Cost of Service	*$*	*887,424,229*
Current Retail Revenue	$	(775,421,849)
ToU Adjustment	$	3,098,164
Gross Revenue Requirement	*$*	*108,904,216*

In other words, EMW is requesting an additional $3.1 million increase from customers due to the TOU revenue adjustment.

Q. Is this adjustment reasonable?

A. No. First, the quantification of the adjustment is unreasonable. Second, the manner in which the adjustment was applied was unreasonable, and third, the concept of the adjustment undermines the apparent policy goals of EMW's promulgation of optional rates in prior Evergy rate cases. As a preface to this discussion, explaining EMW's adjustment, how it was calculated, and how it was applied, is extraordinarily difficult, as the calculation and application are unreasonable and illogical.

$3.1 million quantification

Q. How was the $3.1 million adjustment quantified?

A. Ms. Miller calculates the $3.1 million as 26% of $11.6 million, plus 74% of $71,362.

Q. What is the relevance of the 26% and 74% weighting?

A. Ms. Miller's direct testimony at page 10 states "The resulting revenue impact estimates for the Default and Best Fit scenarios were then averaged together based on the number of customers who self-enrolled into a TOU rate." The 26% figure reflects the count of customers who had opted into any time-based rate plan prior to October 13, 2023. The 74% figure reflects the remaining customers who had not opted into any time-based rate plan prior to October 13, 2023.

$11.6 million Quantification

Q. How was the $11.6 million value calculated?

A. $11.6 million is the result of Ms. Miller factoring up and "normalizing" the "Best Fit" results of the "Batch Rate Analysis Tool" ("BRAT") discussed in my revenue

requirement direct testimony in this case at pages 7 – 12. The BRAT is an analysis that EMW directed be undertaken by Oracle. This analysis relied on:

1. the actual weather and customer usage in place for the months of July 2022 – June 2023;
2. the "Best Fit" analysis calculated that if every ratepayer knew ahead of time how much energy they would use in which time period for the next twelve months; and
3. calculated which rate plan would produce the lowest bills during the months of July 2022 – June 2023, and then took service on that rate plan for 12 months.

According to Evergy, the BRAT analysis concluded that the revenue produced by those customers would be $9.277 million less than the revenue those customers would have produced on the now-discontinued blocked rates, MORG and MORH, and the preexisting time based rate plan, MORT.

Best Fit	**Total**	
Current Rate Total $	$ 348,557,727	
Best Fit Rate Total $	$ 339,280,627	
Revenue Impact	$ (9,277,100)	Perfect knowledge, lowest bill
	24.27%	Factor up for excluded customers
	$ (11,529,012)	
	0.78%	Normalization Adjustment
	$ (11,618,454)	

Q. Was Ms. Miller's factoring up of the Best Fit results reasonable?

A. Not in particular. In her direct testimony at page 10 she states, "While the Oracle's revenue estimates were calculated using a majority of Residential customers' kWh's within the test year period, there were minor exclusions as previously described. The revenue estimates were further adjusted to more completely reflect the full test year of kWh's. This was done by comparing the total actual kWh's in the test year to kWh's in Oracle's analysis to

calculate a % differential and then grossing up the Oracle kWh's to reflect the full kWh of the Residential population." However, the calculation Ms. Miller made to incorporate customers excluded in Oracle's analysis factored up the Best Fit results to include energy consumed by customers who are not Advanced Metering Infrastructure ("AMI") metered, although through discovery EMW stated that the adjustment would not reflect the energy consumed by net metering, parallel generation, or subscriber solar customers (Schedule SLKL-r1, Staff DR[2] 256). Further, EMW is not aware of what rate plan the excluded customers were previously served on. (Schedule SLKL-r2, Staff DR 255). It was not reasonable for EMW to adjust for customers who cannot be take service on a rate plan other than the PRKA rate plan.

Q. Was Ms. Millers normalizing the Best Fit results reasonable?

A. No. In her direct testimony at page 10 she states "Once the full test year kWh's were reflected in revenues, the revenue impacts were further adjusted for weather, a 365-day year, energy efficiency, and customer growth." As detailed as this testimony sounds, her process simply multiplied her factored up results by an additional 0.78%, which she calculated as the change from her starting total residential revenue at current rates to her adjusted total residential revenue at current rates. In no sense is it accurate to state or imply that $3.1 million figure has been weather normalized or adjusted for energy efficiency.

$71,362 Quantification

Q. How was the $71,362 value calculated?

A. The BRAT calculated the revenue EMW would have received if all residential customers had taken service on the low-differential default time-based rate as $56,981 less than

[2] Data Request ("DR").

the revenue EMW actually billed on the rate plans customers were served on during the months of July 2022 – June 2023. She then factored up and normalized this value using the process described above to come to the total $71,362.

Default Peak Adjustment Rate	**Total**	
Current Rate Total $	$ 348,557,727	
Default Rate Total $	$ 348,500,746	
Revenue Impact	$ (56,981)	All take service on default rate plan
	24.27%	Factor up for excluded customers
	$ (70,813)	
	0.78%	Normalization Adjustment
	$ (71,362)	

Q. Is this quantification reasonable?

A. Excluded customers, with the exception of those who do not have AMI meters, will be served on the Default rate plan. The Default rate plan is not designed to substantially prompt changes in customer behavior. Customers are placed on the Default rate plan without taking any action. While the "normalization" adjustment remains questionable, and ideally greater care could be taken in the excluded customer calculation, and more detailed weather normalization procedures will occur in the future, the $71,362 calculation is a reasonable estimate of what customers would have been billed if on the default rate plan for the period of the months of July 2022 – June 2023.

Q. Is estimating what customers would have been billed if on the default rate plan for the period of the months of July 2022 – June 2023 a reasonable exercise in this case?

A. Yes. This approach is consistent with Staff's direct-filed calculation of residential customers on the Default rate for the test year, as updated.

26%/74% Relevance and Use in Ms. Miller's $3.1 Million Adjustment

Q. Where does the 26% weighting factor come from?

A. Ms. Miller calculated that 26% of all residential customers took service on a time-based rate plan as of October 13, 2023. She concludes that the percentage of customers who took service on a time-based rate plan as of October 13, 2023 is a reasonable estimate of the percentage of bill changes that would result from customers having perfect foreknowledge of the rate plan that would produce the lowest bills during the months of July 2022 – June 2023, and then took service on that rate plan for 12 months, as calculated by the "Best Fit" adjustment, after factoring up and her normalization adjustment.

Q. Is this a reasonable conclusion?

A. It is not, for a number of reasons. First, as discussed above, any reliance on the "Best Fit" calculation is unreasonable. Second, it overstates the number of customers willing to take a chance on picking a riskier rate plan, even if they did have perfect foreknowledge. Third, it assumes that customers who are willing to take a chance guessed right every single time.

Q. How does the 26% overstate the number of customers willing to take a chance on picking a riskier rate plan?

A. Ms. Miller's 26% calculation includes customers who voluntarily opted into what is now the Default rate plan, prior to defaulting onto that rate plan. Essentially, these are customers who opted out of highly-differentiated rate plans. Using the figures from her direct workpaper, only 15% of customers actually opted into a time-based rate other than the Residential Peak Adjustment ("RPKA") rate plan, while 11% of customers opted into the RPKA rate plan:

Miller Workpaper, Active Customers on ToU Rates as of October 13, 2023				
Marketing Name (Tariff Code/Billing Code)	**Count**	**%**	**%**	**% of Customers**
Nights & Weekends Max (RTOU3/MORT3)	12,947	16%	58%	15%
Nights & Weekends (RTOU/MORT)	7,284	9%		
Summer Peak (RTOU2/MORT2)	25,693	33%		
Default (RKPA/MORPA)	32,973	42%	42%	11%

Q. What would you infer about a customer opting into the RPKA rate plan prior to October of 2023?

A. I would infer that a customer opting into the RPKA rate plan was effectively opting out of the RTOU2 rate plan, which had been ordered to be the default residential rate plan at the time these customers would have opted into the RPKA rate plan.

Q. The BRAT report relied on customer usage data for the period of July 2022 – June 2023. Would a customer using the online bill comparison tool between July and October of 2023 have seen similar results to those calculated in the BRAT?

A. While actual customer usage for the months of July 2022 – September 2022 would have been replaced by current usage for those months in 2023, customers making rate plan decisions from July of 2023 – October of 2023 would have reviewed bill information identical to that relied on in the BRAT for 8 – 12 months.

Q. As calculated in the BRAT, was the RPKA the "Best Fit" rate plan for most residential customers during the studied time period?

A. No. As calculated in the BRAT, the RPKA was the "Best Fit" rate plan for only 19% of residential customers, while the RTOU3 rate plan was the "Best Fit" rate plan for 59% of customers and the RTOU2 rate plan was the "Best Fit" rate plan for 21% of customers. The fact that most customers who selected a time-based rate plan prior to October of 2023 selected the RPKA rate plan supports my inference that customers were opting

out of the highly-differentiated RTOU2 rate plan, as opposed to signaling a willingness to aggressively manage their energy consumption and pursue high risk / high reward rate plan options.

Q. Is this inference supported by more current rate plan enrollment information?

A. Yes. Customers have predominately selected the current Default rate plan, the RPKA rate plan. Only about 16% of EMW's residential customers are currently opted-into a more differentiated rate plan, and for each of the highly-differentiated rate plans, more than half of the current participation count had already opted into that rate plan by October of 2023, based on the numbers which were provided in Evergy's July response to DR 2.1 in ET-2024-0061:

		Jun-24		Oct-23		Growth in Participation October - June	
Rate Code	EMW Plan Name	Aggregated Customer Count	% of Customer Count	Aggregated Customer Count	% of Customer Count	Customer Count Change	Change in %
MORG	Missouri West Residential General						
MORGS	Missouri West Residential General Solar						
MORH	Missouri West Residential Heating						
MORHS	Missouri West Residential Heating Solar	31	0.010%	259,780	80.95%	(259,811)	-80.94%
MORN	Missouri West Residential General Net Meter						
MORNH	Missouri West Residential Heating Net Meter						
MORNO	Missouri West Residential Other Use Net Meter						
MORO	Missouri West Residential Other Use						
MORPA	Missouri West Residential Peak Adjustment Service						
MORPANM	Missouri West Residential Peak Adj. Service Net Meter	255,842	83.84%	24,072	7.50%	231,770	76.33%
MORPAPG	Missouri West Residential Peak Adjustment Service Parallel Generation						
MORPAS	Missouri West Residential Peak Adj. Solar						
MORT	Missouri West Residential Time of Use	7,528	2.467%	6,826	2.127%	702	0.340%
MORT2	Missouri West Residential Time of Use - Two Period	25,418	8.329%	20,501	6.388%	4,917	1.941%
MORT3	Missouri West Residential High Differential TOU	16,349	5.357%	9,749	3.038%	6,600	2.320%
MORTEV	Missouri West Residential Separately Metered EV TOU	3	0.001%	0	0.000%	3	0.001%
		305,171	100%	320,928	100%	(15,757)	0%

Ms. Miller's decision to extrapolate her adjusted "Best Fit" revenue difference on an assumption that 26% of customers are actively seeking the lowest possible rate plan is simply unreasonable, even if the remainder of that calculation were reasonable, which it is not. There is nothing to support the concept that 59% of customers will opt into the RTOU3 rate plan nor that 21% of customers will opt into the RTOU2 rate plan, even if those rate plans were the best fit rate plan for that percentage of customers going forward, which they may or may not be.

Q. Even if ratepayers were pretty sure which rate plan would produce their lowest bill for them over a future year, is it reasonable to assume that each ratepayer would select that option?

A. No. More differentiated rate plans are essentially higher risk / higher reward. Many customers will select bill predictability and risk aversion over the possibility of saving money on their energy bill.

Q. Has EMW discouraged customers from exploring rate plan options?

A. Yes. EMW fostered a perception that customers are unable to run Heating, Ventilation and Air Conditioning ("HVAC") equipment or major appliances from 4pm – 8pm on the more-differentiated time-based rate plans, or at a minimum conveyed that these plans require significant behavioral changes:

EMW's website has included the following language:

Summer Peak Time Based Plan
Only has peak pricing during the summer months

Formerly called the Standard Peak Saver plan. Under this rate, the time of day you use energy affects your bill. Customers who can reduce energy usage during summer (June-Sept.) peak hours of 4-8 pm on weekdays should consider this rate plan. Customers who shift energy usage to off-peak times on weekdays in the summer are rewarded with discounted rates.

Nights & Weekends Plan
Three time periods, overnight and weekend discount

Pay a lower price for energy during off-peak times and on weekends. It's as easy as shifting energy use away from 4-8 pm to save. This plan is designed for those who can make a larger effort to shift their energy use to overnight hours or weekends to avoid the higher prices during peak times. This means you can save more if you can plan to avoid the peak times.

Q. Does the BRAT report directly contradict these statements?

A. Yes. The BRAT report indicates that for the studied time period, only 19% of customers were "best fit" on the RPKA rate plan, meaning that 81% of customers would have paid a lower bill on a more-differentiated rate plan *without* any changes in time of usage.

Q. If the $3.1 million adjustment is based on customers making a decision that EMW has discouraged them from making, even if the customers had the prognostication to make that decision, is it reasonable?

A. No. The proposed $3.1 million adjustment will unreasonably understate revenues.

Q. Does EMW acknowledge that this adjustment is ill-conceived?

A. Yes. As Ms. Miller acknowledges at page 11:

> [T]he estimated revenue impact of $3.1M is inexact. It is fully expected that actual revenue impacts will be different. The Company did not attempt to precisely estimate an annual or seasonal revenue amount nor did it attempt to modify existing TOU pricing with that goal because it would have required that the Company attempt to predict not only which TOU rate a customer would select based on the many options available to them, but also how each customer would modify their usage and behavior in response to those price signals. There is no data that currently exists to reliably predict or estimate that outcome. Instead, the Company utilized the Oracle analysis with the assumption that customers will move to a given TOU rate based on their lowest measured bill. This may or may not be true. And, dependent on multiple factors, including weather, customers future bill comparisons may result in a different impact and as such, a different TOU rate choice. The $3.1M estimate was the best estimate that the Company could offer and was more appropriate than no adjustment.

Q. Do you agree that the $3.1 million estimate is more appropriate than no adjustment?

A. No.

Updated BRAT

Q. Did EMW represent that it would provide an updated BRAT report to Staff for the 12 months ending June 2024 as soon as it was available?

A. Yes. In its April 19 filing in EW-2023-0199, Staff stated "Evergy is planning to update the Behavior Rate Analysis Tool (BRAT) reports around the same time Staff files

direct in the West rate case. Evergy used the October version to claim a need for a $3.1 million revenue adjustment in the rate case. It is Staff's understanding that Evergy expects this report to be completed sometime around the end of June/beginning of July; Staff requests that Evergy provide Staff the BRAT report as soon as it is completed, rather than waiting until Evergy's next quarterly update in this working docket. The provision of this report prior to the filing of Staff's direct testimony in ER-2024-0189 is essential so Staff can evaluate appropriate revenue adjustments in its direct case." Based on informal discussions with Evergy management, Staff understood EMW would provide the update BRAT as soon as it was available.

On July 19, 2024, Evergy filed in EW-2023-0199 stating "In the April TOU presentation, Evergy shared that it would provide the findings of winter bill impact on heating customers from the BRAT analyses at our next quarterly report, after the analyses was completed, likely in 12-14 weeks. Evergy received the winter bill impact analyses on heating customers from Opower and we are in the process of reviewing the results. Evergy will be prepared to file the results by August 4, 2024, and is available to discuss the filing with the Commissioners upon request." Had EMW provided the new BRAT 12 – 14 weeks from the April 2, 2024 presentation in the working docket as it represented it was going to do, Staff would have received the updated report sometime around June 25 – July 9.

Q. Has Staff received the updated BRAT information to date?

A. No. While EMW filed its "Heating Customer TOU Analysis" in EW-2023-0199 on August 1, 2024, no workpapers have been provided at this time, and the filed document contains minimal information. The filed document is attached as Schedule SLKL-r4.

Introduction of errors into revenue and billing determinant quantification and the undermining of apparent policy goals

Q. What is the second problem with the $3.1 million adjustment?

A. The second problem is how EMW incorporated the adjustment into its revenue requirement calculation workpapers. In its revenue requirement workpaper "CONFIDENTIAL - Billed Revenue - MO West TYE202306," on tab, "Revenue Summary," at cell w31, EMW simply reduced its total revenues by $3,098,164, without attributing that reduction to any rate plans or customer classes. As explained above, this adjustment simply increases the gross revenue requirement.[3]

Q. What is the problem with increasing revenue requirement to address an assumed revenue reduction?

A. Assuming the revenue reduction quantification was accurate – which it is not – this would properly be addressed through recalibration of specific rates to the appropriate total value, not through an across-the-board adjustment in rates. However, this recalibration would come with its own issues, namely that such recalibration undermines the apparent policy goals of EMW's promulgation of optional rates in prior Evergy rate cases.

Q. Can you provide an example to illustrate the systemic error problem?

A. Yes. Consider a class with two rate options. "Rate A" charges $0.10/kWh for each kWh sold. "Rate B" is designed where on peak usage is charged at three-times the rate of off-peak usage. The rates were designed based on the total class determinants of 2,000 kWh

[3] In her CCoS workpaper, Ms. Miller applied the adjustment proportionate to her calculated test year revenues for the residential rate plans that have been discontinued, as she did not study the time-based rate plans created in ER-2022-0130. Her CCoS results are generally presented in her testimony on a class basis. She studies residential class revenues of $411,065,976, reflected in her workpaper "CONFIDENTIAL_Evergy(MO West) 2024 CCOS Model – Direct," on tab "inputs," at cell range O10:O16.

generating total revenues of $200. Therefore, f all customers take service on either Rate A or Rate B, $200 in revenue will be generated.

				Revenues under Either Rate Option		
	Rate A	Rate B	Total Determinants	Rate A Revenues		Rate B Revenues
On Peak	$ 0.10	$ 0.15	1,000	$ 100.00	OR	$ 150.00
Off Peak	$ 0.10	$ 0.05	1,000	$ 100.00		$ 50.00
			2,000	$ 200.00		$ 200.00

In the first example, half of the customers take service on Rate A, and half of the customers take service on Rate B, and the determinants for each rate option follow the same usage profile:

	Rate A	Rate B	Rate A Determinants	Rate B Determinants	Rate A Revenues	Rate B Revenues	Total Revenues
On Peak	$ 0.10	$ 0.15	500	500	$ 50.00	$ 75.00	
Off Peak	$ 0.10	$ 0.05	500	500	$ 50.00	$ 25.00	
			1,000	1,000	$ 100.00	$ 100.00	$ 200.00

Total revenues in this example remain $200.00.

In this next example, customers who use more energy off peak migrate to Rate B, while customers with more on-peak usage choose Rate A. Total revenues are reduced by $25 to $175.00:

	Rate A	Rate B	Rate A Determinants	Rate B Determinants	Rate A Revenues	Rate B Revenues	Total Revenues
On Peak	$ 0.10	$ 0.15	750	250	$ 75.00	$ 37.50	
Off Peak	$ 0.10	$ 0.05	250	750	$ 25.00	$ 37.50	
			1,000	1,000	$ 100.00	$ 75.00	$ 175.00

The above is the scenario that EMW requests the Commission to assume will occur, and requests be addressed through the removal of their estimation of the $25.00 revenue shortfall – the $3.1 million adjustment. The mechanism for how this occurs through a rate case is to

increase revenue requirement for the amount of the shortfall. In this example, the effect of the revenue adjustment is to increase Rate A and Rate B to collect an additional $25.00 (12.5%), resulting in the rates set out below:

				Revenues under Either Rate Option		
	Rate A	Rate B	Total Determinants	Rate A Revenues		Rate B Revenues
On Peak	$ 0.1125	$ 0.1688	1,000	$ 112.50	OR	$ 168.75
Off Peak	$ 0.1125	$ 0.0563	1,000	$ 112.50		$ 56.25
			2,000	$ 225.00		$ 225.00

(Again, note that the rates are designed so that either Rate A or Rate B will collect $225 in revenue, not that each Rate A and Rate B will collect $225 for total revenue of $250.)

The relief EMW requests is to adjust revenues but not determinants, essentially to address a shift EMW asks the Commission to assume will occur in determinants. The result is that customers on Rate A are overcharged, and customers on Rate B contribute less than before, but more than initially:

	Rate A	Rate B	Rate A Determinants	Rate B Determinants	Rate A Revenues	Rate B Revenues	Total Revenues
On Peak	$ 0.1125	$ 0.1688	750	250	$ 84.38	$ 42.19	
Off Peak	$ 0.1125	$ 0.0563	250	750	$ 28.13	$ 42.19	
			1,000	1,000	$ 112.50	$ 84.38	$ 196.88

Q. If customers on rate A are overcharged, and customers on rate B are undercharged, all else being equal, what would a reasonable customer do?

A. A reasonable customer would leave rate A for rate B, all else being equal.

Q. Does this address the under-recovery, or make it worse?

A. Systematically overcharging customers on Rate A will eventually drive customers to rate B, propagating the problem.

Q. If there is a problem of customers on highly-differentiated rate plans under-contributing, is the solution to adjust residential revenues as proposed by the EMW?

A. No. If there is a real problem, which there is no evidence of at this point, adjustments to residential revenues exacerbate the problem.

Q. What would be the proper steps to address the problem, if there is systemic under-recovery of revenue from customers on a highly-differentiated rate plan?

A. The first step would be to determine whether systemic under-recovery of revenue from customers on a highly-differentiated rate plan is a problem or if that is the intent of the Commission in adopting highly-differentiated rate plans. The intent of highly-differentiated rate plans is to induce changes in customer usage patterns. The results of changes in usage patterns of customers in highly-differentiated rate plans is that a given customer's bill is lower than it otherwise would be for the same usage on a different rate plan. The intent of highly-differentiated rate plans is to decrease load at times associated with driving system costs while increasing load at times with low energy costs and adequate system capacity, therefore reducing average costs. For policy makers who favor highly-differentiated rate plans as a motivator of customer behavior, systemic under-recovery of revenue from customers on a highly-differentiated rate plans should be viewed as a feature, not a bug, and to increase rates to counter such under-recovery would effectively be to pull the rug out from under ratepayers who acted in reliance on the design of the rate plan.

Q. If a policy maker chose to view systemic under-recovery of revenue from customers on a highly-differentiated rate plan as a bug, not a feature, which customers should bear the costs of compensating the utility for any under-recoveries?

A. The customer receiving the benefit of the bill reduction should bear that cost. However, the incorporation of this cost would effectively erase the bill reduction that drove the customer benefit motivating the behavior change in the first place.

TOU Revenue Tracker Requested by EMW

Authority Requested

Q. Mr. Klote's direct testimony at page 39 states "The deferral would capture, beginning January 1, 2024, the time TOU implementation was complete and continue through the rates effective date of the Company's next general rate case in which TOU rates are effective for the entire test period in that general rate case, the difference in revenues between the new TOU rates and the previous traditional blocked residential rates for all residential customers that are placed on TOU rates. The Company will utilize a third-party, Oracle, to model and quantify the differences in revenues." Is this request reasonable?

A. No. First, as described in my revenue requirement direct testimony at pages 13 – 14, to the extent that EMW experiences revenue shortfalls or overages associated with customer usage on time-based rates, that is a function of the time-based rates, or of Evergy's own decision to make customer optionality a centerpiece of its brand, and the level of variability of the default RPKA rate revenues is comparable to the level of variability of the discontinued usage-blocked rate structures.

Second, EMW's proposed method of calculating the balance to be tracked is ill-defined, apparently too costly, and unreasonable.

Balance Calculation

Q. How does EMW propose to calculate the tracker balance?

A. EMW requests a tracker balance defined as the difference in the sum of customer bills on current rate plans versus bills for the same energy usage on discontinued rate plans.

Q. Mr. Klote testified that "The Company will utilize a third-party, Oracle, to model and quantify the differences in revenues."[4] How much will it cost for this calculation to be made?

A. Staff does not know, and EMW appears to have abandoned this position, although it is not clear what EMW's new position is.

Staff's DR 262 (Confidential Schedule SLKL-r3) referenced Mr. Klote's testimony, and asked, "(A) Please provide any contracts or preliminary contract documents for the performance of this work by Oracle," and "(B) Please identify the cost of the work to be performed by Oracle." EMW's response was that ** [redacted] ** and ** [redacted] **

Staff followed up with DR 262.1, issued April 3, 2023, which requested "(A) Please provide the estimated set up cost as referenced in Evergy's response to DR 262. (B) Please provide the estimated annual cost as referenced in Evergy's response to DR 262. (C) Please describe the other cost-effective options as referenced in Evergy's response to DR 262. (D) Please provide the cost estimates of the other cost-effective options as

[4] Klote direct at page 39

referenced in Evergy's response to DR 262. If these would include setup costs and annual costs or other variations in cost, please provide and describe."

EMW's response of April 25 stated ** [redacted] **

In response to a request from Staff to provide an answer to the questions posed in DR 262.1, EMW's counsel, Mr. Steiner, stated:[5]

> It is my understanding that the Company has discussed the level of effort with Oracle, however that estimate was specific to running Opower's BRAT analyses and modeling that was used to support Marisol Miller's adjustment for the test year. Oracle has provided an estimate for set up of the modeling and an annual cost – which was specific to BRAT. The response that "Evergy is evaluating the cost of this effort in relation to other cost-effective options" is related to that Evergy identified in its testimony (Miller) that the BRAT analyses is limited in capturing all customer activity that would be needed to support the deferral mechanism. Evergy is evaluating other cost effective options that would not be as limiting as BRAT – again as described in Miller's testimony. Evergy should be receiving a cost estimate from another vendor and can supplement the DR at that time.

Following a discovery conference on May 7, 2024, EMW provided a supplemental response to DR 262.1 on May 23, 2024, which stated, ** [redacted]

[5] Email from Roger Steiner to Travis Pringle, sent May 2, 2024 12:57 PM.

[redacted] **

Q. Could you summarize the testimony and known facts concerning EMW's proposed request to track differences in revenues in the range of $70,000 per year?[6]

A. Yes, EMW has changed its position from its direct testimony to use Oracle to calculate the tracker balance at an ** [redacted] ** cost using a method that has significant flaws to using ** [redacted] ** and an unknown method at a cost of ** [redacted] ** per year.

Q. Mr. Klote testified that EMW requests to track "the difference in revenues between the new TOU rates and the previous traditional blocked residential rates for all residential customers that are placed on TOU rates." Further, in the May 24 response to DR 262, EMW stated that "[t]he comparison would be with the general service rate. The goal of the

[6] See Lange revenue requirement direct at page 13, "Based on the Oracle analysis requested by EMW, as supplemented by analysis performed by Marisol Miller, for the period of July 2022 – June 2023, had all EMW customers been on the RPKA rate plan, Evergy Missouri West's residential revenues would have been $71,362 less than the rates on which customers actually took service. A reduction of 0.78%. "

deferral is to reflect actual individual bill differences from class level revenue pricing established for TOU rates (reflect non-revenue neutral impacts of current and forward periods as incurred for TOU rates that were implemented)."

Even if the tracker were reasonable, is this a reasonable basis for the tracked balance?

A. No. Comparison to the general service rate, when roughly half of the customers were previously on a discounted rate, is facially unreasonable. The calculation proposed in Mr. Klote's testimony is also unreasonable for several reasons. First, as discussed in my direct testimony at page 12:

> Q. Would it be reasonable to establish a counterfactual of what energy costs and revenues would have existed but-for a customer's participation on a particular rate plan?
>
> A. No. There is not a manner to calculate what revenue Evergy would have received by assuming customers on highly-differentiated rate plans were not on highly differentiated rate plans. Attempting to base such a counterfactual on what energy usage those customers would have had under different circumstances would not be reasonable, nor reliable, nor feasible, much less all three.

Second, the "traditional" blocked residential rates no longer exist, and the new time-based rate plans are all designed to recover less revenue than the former general service rate plan and to recover more revenue than the former discounted rate plans.

Q. Why would it be necessary to establish a counter-factual of what energy costs and revenues would have been but-for a customer's participation on a particular rate plan?

A. Highly-differentiated time-based rates are designed to induce changes in customer usage, and cost-based time-based rates have the latent benefit of inducing changes in customer usage. Consider a hypothetical with two available rates:

Blocked Rate	
0-600 kWh	$ 0.10
600 + kWh	$ 0.05

Time Based Rate	
On-Peak	$ 0.40
Off-Peak	$ 0.05

Consider a customer who uses an average of 30 kWh of energy in a day, which results in 900 total kWh for the month:

Blocked Rate			
Rate		Usage	Charge
0-600 kWh	$ 0.10	600	$ 60.00
600 + kWh	$ 0.05	300	$ 15.00

This customer's bill on the blocked rate will be $75, no matter what time of day the customer uses energy. If that customer used 85.7 kWh on peak, and 814.3 kWh off peak, that customer would have the exact same bill of $75 for 900 kWh of usage under the Time-Based rate plan:

Time Based Rate			
Rate		Usage	Charge
On-Peak	$ 0.40	85.7	$ 34.29
Off-Peak	$ 0.05	814.3	$ 40.71

However, that customer may decide to precool their home in summer to take advantage of the time-based rate,[7] and simultaneously that customer's usage goes up, and their bill goes down:

Time Based Rate - with Precooling			
Rate		Usage	Charge
On-Peak	$ 0.40	80.0	$ 32.00
Off-Peak	$ 0.05	825.0	$ 41.25
New Usage Level:		905.0	
New Bill Amount:			$ 73.25

[7] Or to preheat their home in winter, or to use a thermal storage water heater, or to run the dryer overnight and briefly rerun it in the morning to fluff clothing, or any number of other load shifting measures that increase net energy usage while reducing peak usage and building off peak load.

EMW's plan would not be to track that $1.75 bill reduction. EMW's request is to track the difference to what that customer's bill *would have been* if the customer had been on a rate that no longer exists:

Time Based Rate - with Precooling			
Rate		Usage	Charge
0-600 kWh	$ 0.10	600.0	$ 60.00
600 + kWh	$ 0.05	305.0	$ 15.25
New Usage Level:		905.0	
New Bill Amount:			$ 75.25

EMW is not requesting that the Commission track the difference between the residential revenue requirement ordered in this case and the residential revenues in a given year; EMW is requesting the difference between the revenues it receives after inducing changes in customer usage, and what the bills would have been if customers made changes, but paid old rates. This will result in over-recovery:

What EMW Requests	
Customer Bill on Blocked Rate with Precooling	$ 75.25
Customer Bill on Time Based Rate with Precooling	$ 73.25
Difference:	$ (2.00)

Not What EMW Requests	
Customer Bill on Blocked Rate	$ 75.00
Customer Bill on Time Based Rate with Precooling	$ 73.25
Difference:	$ (1.75)

Q. Would you expect net changes in induced usage to be small?

A. No. Accretive electrical vehicle charging usage that may be induced by highly differentiated rates could easily double the usage of a customer. Transitioning to heat pumps or other non-gas non-LP heating could significantly increase net usage.

Q. Has EMW proposed a reasonable method to control for induced energy usage in calculating its requested tracker balance?

A. No. Staff DR 262 part E requested that EMW "Please explain how usage changes such as precooling, preheating, electrification, and EV charging will be excluded from the requested deferral calculation." EMW's response was that "None of these usage changes will be excluded from the deferral calculation."

Q. Given the significant bill difference between the discounted heating rates and the general service rates, how would EMW's proposed calculation address customers who began taking service after the discontinuance of those rate plans?

A. Staff DR 262 parts C and D attempted to address this concern. EMW's responses contradicted prior responses in concluding that "The deferral mechanism would then be expected to track the overall revenue change from the end of the True up (June 2024) to the next rate case."

> Question part D: Please explain whether Evergy proposes to include in this deferral the usage of customers who begin taking service after January 1, 2024, and if so, what "previous traditional blocked residential rate," would be with regard to such customers for purposes of calculating the deferral.
>
> Response: Starting in January 2024 and through June 2024, revenue actuals will reflect that majority of Residential customers have transitioned to TOU rates and those impacts will be reflected in True Up revenues. "Previous traditional blocked residential rate" refers to the original blocked rates that most Residential customers were on during the Test Year. True up period actuals will be used to adjust the Test Year, when customers were on the original blocked rates that were in place prior to the move of majority of Residential customers to TOU rates. The deferral mechanism would then be expected to track the overall revenue change from the end of the True up (June 2024) to the next rate case.
>
> Question part C: Please describe what is meant by "the previous traditional blocked residential rates," as used by Mr. Klote. This response should include, but not be limited to, clarification of the date(s) at which

the "previous," rate code will be established, and clarification of whether each customer's "previous," rate code and actual usage will be used in this calculation.

Response: "Previous traditional blocked residential rate" refers to the original blocked rates that most Residential customers were on during the Test Year, prior to the TOU transition. Actual usage will be used in the calculation.

Staff is unable to discern how EMW proposes to address customers who began taking service after rate plan RPKA became the default residential rate plan.

CLASS COST OF SERVICE

Q. Has any party provided a reliable Class Cost of Service ("CCoS") study in this case?

A. No. EMW is overdue for a comprehensive study of its distribution and customer-related costs, and any CCoS study done at this time is necessarily unreliable. Additional concerns with the EMW and derivative MECG study are described below. Correction of only three of these issues produces CCoS results that indicate that no shifts in revenue responsibility among the major classes – Residential, SGS, LGS, and LP -- are appropriate in this case:

	MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Electric Vehicle	Lighting
EMW Study Results	4.64%	2.64%	9.29%	7.58%	5.94%	-59.93%	10.46%
Adjusted EMW Study Results	5.33%	5.64%	7.07%	4.37%	2.78%	-45.72%	11.58%

TOU Revenue Adjustment

Q. How does the TOU Revenue Adjustment affect EMW's CCoS results?

A. The TOU Revenue Adjustment reduces EMW's calculation of the dollars that the residential class has available to contribute to EMW's requested rate of return.

Q. Could you provide an example?

A. Yes. Consider a hypothetical utility with the following CCoS Study results:

	Class A	Class B	Class C
Revenue	$ 100.00	$ 100.00	$ 100.00
Allocated Expense	$ 90.00	$ 90.00	$ 90.00
Net Income	$ 10.00	$ 10.00	$ 10.00
Allocated Rate Base	$ 100.00	$ 100.00	$ 100.00
Return on Ratebase	10.00%	10.00%	10.00%

Now. Observe the results of the CCoS Study if $5 of revenue is removed from Class A:

	Class A	Class B	Class C
Revenue	**$ 95.00**	$ 100.00	$ 100.00
Allocated Expense	$ 90.00	$ 90.00	$ 90.00
Net Income	**$ 5.00**	$ 10.00	$ 10.00
Allocated Rate Base	$ 100.00	$ 100.00	$ 100.00
Return on Ratebase	**5.00%**	10.00%	10.00%

Q. To spell out the obvious, what impact does EMW's improper removal of $3.1 million of residential revenue have on the EMW CCoS results?

A. EMW's residential revenues reviewed in its CCoS are understated, which understates the rate of return provided by the residential class, and skews CCoS results.

Inclusion of Crossroads Transmission Revenue Requirement

Q. How did EMW include Crossroads transmission revenue requirement in its CCoS study?

A. EMW included $16.49 million of revenue requirement in this case associated with Crossroads transmission expenses. As an expense, the inclusion of Crossroads transmission revenue requirement is a one-for-one reduction to the rate of return dollars calculated for each customer class. EMW allocated Crossroads transmission expense using its A&E 4NCP allocator, discussed below.

Q. Can you provide an example of the impact on a given class of increasing allocated expense?

A. Yes. Using the same hypothetical CCoS from above, the table below shows the results if Class C allocated expense were increased by $5:

	Class A	Class B	Class C
Revenue	$ 95.00	$ 100.00	$ 100.00
Allocated Expense	$ 90.00	$ 90.00	**$ 95.00**
Net Income	$ 5.00	$ 10.00	**$ 5.00**
Allocated Rate Base	$ 100.00	$ 100.00	$ 100.00
Return on Ratebase	5.00%	10.00%	**5.00%**

Q. Have you calculated what rate of return each customer class would contribute under EMW's study if it were adjusted to provide results that do not include Crossroads transmission expense?

A. Yes. This adjustment alone produces the results provided below:

	MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Electric Vehicle	Lighting
Rate Base	$ 2,830,914,746	$1,724,853,520	$389,720,193	$292,036,170	$347,973,280	$1,329,405	$57,098,749
Net Operating Income at Present Rates	$131,252,484	$ 45,464,639	$ 36,209,413	$ 22,122,724	$ 20,668,554	$ (796,695)	$ 5,973,234
EMW Study Results	**4.64%**	**2.64%**	**9.29%**	**7.58%**	**5.94%**	**-59.93%**	**10.46%**
Relative Rate of Return	1.00	0.57	2.00	1.63	1.28	(12.93)	2.26
Crossroads allocator		0.578	0.142	0.119	0.159	0.000	0.003
Crossroads Expense	$16,491,398	$ 9,533,485	$ 2,336,513	$ 1,960,490	$ 2,618,619	$ 486	$ 41,805
New Net OI	$ 147,743,882	$ 54,998,125	$ 38,545,926	$ 24,083,214	$ 23,287,172	$ (796,209)	$ 6,015,039
New RoR 1	**5.22%**	**3.19%**	**9.89%**	**8.25%**	**6.69%**	**-59.89%**	**10.53%**

Minimum System Study

Q. Did EMW reasonably classify and allocate the revenue requirement related to its distribution system?

A. No. As discussed below, EMW's study is not consistent with the National Association of Regulated Utility Commission ("NARUC") manual, the Realistic Achievable Potential ("RAP") manual, or reasonable ratemaking practice.

Q. Did Evergy provide information in this case as to its quantification of the cost of a mile of overhead line operating at a secondary voltage versus the cost of a mile of overhead line operating at primary voltage, and comparable information for the cost of underground lines?

A. Yes. Evergy's workpapers for its minimum system study included:

	Miles	2024 $/Mile
Overhead Secondary	2,544	$ 107,987
Overhead Primary	7,139	$ 242,568
Underground Secondary	1,127	$ 162,509
Underground Primary	3,570	$ 257,751

EMW's DR response indicated that the infrastructure for secondary line that it priced out would operate at 120/240 voltage. The cost for a minimum system operating at 120/240 volts, in 2024 dollars, based on EMW's work can therefore be calculated by multiplying out the total miles of line, overhead and underground respectively, which provides the amount to classify for allocation on customer count under a minimum system classification approach. Since the minimum system meets the demand needs for all customers served at 120/240, those customers should not get further allocation based on demand or energy.

Q. How are those results applied to correct the EMW CCoS study?

A. The revised minimum system amounts and the adjusted demand allocator for customers over 120/240[8] were used to reallocate the distribution accounts 364 – 368. Ideally, all of the class non-coincident peaks ("NCP") (the factor Evergy selected) should be adjusted to remove the demand served by 120/240, but that information was not available. Evergy's initial allocation and the revised allocation are:

[8] To calculate the allocator for these simplified adjustments to the EMW CCoS, I assumed res, lighting, and SGS no-demand were served at 120/240.

		Total	Residential	mall General Servic	arge General Servic	arge Power Service	Electric Vehicle	Lighting
Revised	Total Expense	$ 88,367,893	42.67%	20.33%	17.25%	19.55%	0.09%	0.10%
Revised	Net Ratebase	$ 1,112,236,506	42.11%	20.36%	17.49%	19.83%	0.09%	0.12%
Evergy	Total Expense	$ 88,367,893	68.80%	13.73%	8.94%	8.10%	0.04%	0.38%
Evergy	Net Ratebase	$ 1,112,236,506	67.85%	13.83%	9.32%	8.58%	0.04%	0.39%

Q. Can you summarize these three adjustments to EMW's CCoS?

A. Yes, the sequence of the results presented below is that adjustment for Crossroads transmission expense inclusion is addressed in ROR 1, adjustment for the TOU Revenue Adjustment is addressed in ROR 2, and adjustment for the distribution classification is addressed in ROR 3:

	MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Electric Vehicle	Lighting
Rate Base	$ 2,830,914,746	$1,724,853,520	$389,720,193	$292,036,170	$347,973,280	$1,329,405	$57,098,749
Net Operating Income at Present Rates	$131,252,484	$ 45,464,639	$ 36,209,413	$ 22,122,724	$ 20,668,554	$ (796,695)	$ 5,973,234
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Relative Rate of Return	1.00	0.57	2.00	1.63	1.28	(12.93)	2.26
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Crossroads Expense	$16,491,398	$ 9,533,485	$ 2,336,513	$ 1,960,490	$ 2,618,619	$ 486	$ 41,805
New Net OI	$ 147,743,882	$ 54,998,125	$ 38,545,926	$ 24,083,214	$ 23,287,172	$ (796,209)	$ 6,015,039
New RoR 1	**5.22%**	**3.19%**	**9.89%**	**8.25%**	**6.69%**	**-59.89%**	**10.53%**
Undo ToU adjustment	$ 3,100,000	$ 58,098,125	$ 38,545,926	$ 24,083,214	$ 23,287,172	$ (796,209)	$ 6,015,039
New RoR 2	**5.33%**	**3.37%**	**9.89%**	**8.25%**	**6.69%**	**-59.89%**	**10.53%**
Adjusted RB for Distribution	$ 2,830,914,746	$1,438,629,389	$ 462,447,287	$ 382,939,094	$ 473,116,063	$ 1,828,571	$ 54,050,913
Adjusted NOI for Distribution	$ 150,843,882	$ 81,187,668	$ 32,711,441	$ 16,742,060	$ 13,170,245	$ (836,020)	$ 6,257,873
New RoR 3	5.33%	5.64%	7.07%	4.37%	2.78%	-45.72%	11.58%

Q. With these changes, are EMW's CCoS results reliable?

A. No. Significant work is needed to reasonably allocate distribution revenue requirement, customer service revenue requirement, and production and transmission revenue requirement. The remaining revenue requirement simply reallocates off of these amounts, so misallocations perpetuate.

Q. With these changes, does the EMW study indicate that it is reasonable to reallocate revenue responsibility among the residential, SGS, LGS, LPS, and lighting classes?

A. With these changes, the EMW study results indicate that it may be reasonable for the SGS class to receive a lower-than-average increase, and for the LPS class to receive a

higher-than-average increase. However, because the underlying study is not reliable, Staff does not recommend those shifts be made in this case.

Production and Transmission

EMW Allocation

Q. How does EMW's study account for changes in the wholesale cost of energy over the time of day and course of the year?

A. It ignores any variation and allocates net fuel cost and net wholesale energy revenue on the basis of class energy.

Q. Is this reasonable at this point in time?

A. No. EMW allocates production costs, fuel costs, energy costs, and energy revenues as though the integrated energy market does not exist.

Q. How does EMW allocate transmission revenue requirement?

A. EMW allocates transmission revenue requirement using its production allocator. If the existence of the integrated energy market is not ignored, this approach can be reasonable in some contexts. However, if the integrated energy market is ignored, or studies that predate the market are used, a 12 CP allocator has typically been used for transmission revenue requirement.

MECG Allocation

Q. How did MECG modify the EMW study for its derivative study?

A. MECG adjusted EMW's calculation of an Average & Excess Four Non-coincident Peak ("A&E 4NCP") allocator to an A&E Four Coincident Peak ("A&E 4CP") allocator.

Q. Is this reasonable?

A. No. The use of a CP demand with an A&E is characterized as a "mistake," in the 1992 NARUC Cost Allocation Manual ("NARUC manual").

At page 50, the 1992 NARUC manual includes the following:

> If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

Distribution Treatment in EMW and Derivative CCoS Studies

Q. Was EMW's classification and allocation of its distribution revenue requirement consistent with the 1992 NARUC manual, the Regulatory Assistance Project cost allocation manual, or other industry best practices?

A. No, nor was the treatment in MECG's derivative study reasonable. For example, the classification fails to reasonably allocate the costs of distribution facilities that are essentially service lines for customers served at higher voltages, and the demand-capability of EMW's minimum system was ignored. EMW has provided more detail than in the past concerning the split of its recorded costs between secondary, primary, and high voltages, but more work remains needed.

Q. Could you summarize the relevant authority concerning customer-specific facilities?

A. Yes. The RAP manual at page 156 states,

> 11.3.6 Direct Assignment of Distribution Plant Direct cost assignment may be appropriate for equipment required for particular customers, not shared with other classes, and not double-counted in class allocation of common costs. Examples include distribution-style poles that support streetlights and are not used by any other class; the same may be true for spans of conductor to those poles. **Short tap lines from a**

> **main primary voltage line to serve a single primary voltage customer's premises may be another example, as they are analogous to a secondary distribution service drop**. Beyond some limited situations, it is not practical or useful to determine which distribution equipment (such as lines and poles) was built for only one class or currently serves only one class and to ensure that the class is properly credited for not using the other distribution equipment jointly used by other classes in those locations.
> [Emphasis added.]

The RAP manual at page 142 acknowledges the common division of distribution costs into two categories,

> 'Share distribution,' and '**Customer-specific costs, which include: Service drops connecting a customer (or multiple customers in a building) to the common distribution system (a primary line, a line transformer or a secondary line or network**). • Meters, which measure each customer's energy use by month, TOU period or hour and sometimes by maximum demand in the month. Advanced meters can also provide other capabilities, including measurement of voltage, remote sensing of outages, and remote connection and disconnection. • Street lighting and signal equipment, which usually can be directly assigned to the corresponding rate classes. • In some systems with low customer spatial density, a significant portion of primary lines and transformers serving only one customer.
> [Emphasis added.]

Also, the NARUC manual at page 87, footnote 1, states '**Assignment or 'exclusive use' costs are assigned directly to the customer class or group with exclusively uses such facilities**. The remaining costs are then classified to the respective cost components.' [Emphasis added.]

Q. Could you summarize the relevant authority related to crediting demand-carrying value of the minimum distribution system?

A. Yes. The rationale underpinning a minimum distribution system study is set out at pages 90-91of the NARUC manual stating:

> Classifying distribution plant with the minimum-size method **assumes that a minimum size distribution can be *built to serve the minimum loading requirements of the customer.*** The minimum-size method involves determining the minimum size pole, conductor, cable,

> transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). **[Emphasis added.]**

At page 95 of the NARUC manual:

> Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. **When using this distribution method, the analyst must be aware that the minimum size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.**
>
> When allocating distribution costs determined by the minimum-size method, some cost analysis will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those **customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs**.
>
> Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus the customer cost of a particular piece of equipment has no demand cost in it whatsoever. **[Emphasis added.]**

Discussion of a marginal cost study at page 138 of the NARUC manual provides further context for these issues:

> The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a **hypothetical system that would serve all customers with voltage but not power (or with minimum demand of 0.5 KW)**, yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculations can be based either on the system as a whole or on a sample of areas reflecting different geographical, service and customer density characteristics.

> When applying this approach, it is necessary to **take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum the minimum size stocked by the company or usually installed by the company**. **To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand**. **[Emphasis added.]**

Page 91 the NARUC manual provides the methodologies for determining the minimum size of distribution plant for use in calculating the customer-classified portion of the minimum-size method. The entirety of the entries for Accounts 365 and 367 are set out below:

> 2. Account 365 – Overhead Conductors and Devices
>
> - Determine minimum size conductor currently being installed.
>
> - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. **Balance of plant account is demand component.** (Note: two conductors in minimum system.)
>
> 3. Accounts 366 and 367 – Underground Conduits, Conductors, and Devices
>
> - Determine minimum size cable currently being installed.
>
> - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, based on ratio of cable account.
>
> - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. **Balance of plant account is demand component.**
>
> [Emphasis added.]

Significant context can be established from the discussion of applications of the minimum-intercept method, using the text quoted below from pages 93-94:

> 2. Account 365 – Overhead Conductors and Devices
>
> - **If accounts are divided between primary and secondary voltages**, develop a customer component separately for each. The total

investment assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- **When developing the customer component, consider only the investment in conductors, and not in devices such as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component,** based on the conductor assignment.

- Determine the feet, investment and average installed book cost per foot for distribution conductors by size and type.

- Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

- Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

- Balance of conductor investment is assigned to demand.

- **Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor ratio.**

3. Accounts 366 and 367 – Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one conductor (I/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c able. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

- Determine the feet, investment and average installed book cost per foot for I/c cables by size and type of cable.

> - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.
>
> - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.
>
> - Balance of cable investment is assigned to demand.
>
> - Total dollars in Account 366 and 367 are assigned to customer and demand components based on conductor investment ratio. [Emphasis added.]

While there is discussion of the classification of devices in Account 365 pursuant to the minimum intercept method, under the discussion of Account 365 classification using the minimum size method, there is the simple and clear statement that "Balance of plant account is demand component," unequivocally stating that all devices in Account 365 are classified as demand-related.

For the underground accounts under the minimum intercept method, not all devices are classified as demand-related, however they are not classified as customer-related either; rather, they are reflected on the ratio of minimum-intercept dollars associated with cables to total cable dollars in Account 366. Again, in contrast to the description of the minimum size method, there is the simple and clear statement that "Balance of plant account is demand component," unequivocally stating that all devices in Account 366 are classified as demand-related. For the minimum size method, the ratio of minimum-size cable dollars in Account 366 to total dollars in Account 366 is the basis for the classification of Account 367 dollars.

At pages 90-91, regarding embedded cost of service studies, the NARUC manual states:

> Classifying distribution plant with the minimum-size method **assumes that a minimum size distribution can be *built to serve the minimum loading requirements of the customer*.** The minimum-size method involves determining the minimum size pole, conductor, cable,

> transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). [Emphasis added.]

Discussing marginal costs studies and the minimum-size method, at page 136 the NARUC manual states:

> Most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather than distribution costs and, in reality, this is the only equipment that is directly assignable for all customers, even the smallest ones. Beyond the customers' premises, however, there are distribution costs that may be classified as customer related. For example, some jurisdictions classify line transformers as customer-related often using a proxy based on average load as the allocation factor when this equipment is not uniquely dedicated to individual customers. In addition, **for very large customers, more than merely meters, services, and transformers are directly assignable. Some have entire substations dedicated to them. As noted above in "Transmission," distribution costs of equipment dedicated to individual customers can be directly assigned to them, thus reducing the common distribution costs assignable to the remainder of the class. [Emphasis added.]**

The portion of the discussion quoted above informs this language, found at page 87 of the NARUC Manual:

> Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

Q. What can be done to improve these shortcomings in distribution classification and allocation?

A. The Commission should order EMW to provide the following in its next general rate case:

1. A calculation of each of the following, supported by detailed workpapers:
    a. Reasonable estimates of an average, low range, and high range cost for installation in the most recent 12 months of each of the following:
        i. 1 mile of overhead circuit operating in each voltage "bin;"[9]
        ii. 1 mile of underground circuit, operating in each voltage "bin;" and
        iii. A typical meter and associated transformers operating in each voltage "bin," generally associated with service of customers falling in each demand "bin."[10]
    b. A reasonable estimate of an average, low range, and high range, embedded cost of installation of each of the following:
        i. 1 mile of overhead circuit operating in each voltage "bin;"
        ii. 1 mile of underground circuit, operating in each voltage "bin;" and
        iii. A typical meter and associated transformers operating in each voltage "bin," generally associated with service of customers falling in each demand "bin."
2. The best available information, supported by applicable documentation, of:
    a. A list of the underground circuits operating at each voltage "bin," and the mileage of each circuit;
    b. A list of the overhead circuits operating at each voltage "bin," and the mileage of each circuit;
    c. For each feeder circuit, the number of customers served by that circuit at each voltage "bin," and identification of each circuit fed;
    d. For each feeder circuit, the number of customers served by that circuit at each voltage "bin;" and
    e. For each substation, identification of each interconnected circuit.

RATE DESIGN

Residential Rate Design

Q. What does EMW request for a residential customer charge?

[9] The voltage bins are (1) 110/240, up to 3.9 kV; (2) 4kV up to 12 kV; (3) Primary voltages; and (4) Transmission voltages.
[10] The demand bins are (1) up to 25 kW, (2) 25 kW to 49 kW, (3) Other voltages to be defined based on a high-level study of the costs of metering infrastructure necessary for serving various levels of demand.

A. EMW requests that the residential customer charge reflect its minimum system classification of distribution revenue requirement, and has proposed a residential customer charge increase to $14.99 from the current $12 level.

Q. Is it reasonable to include the minimum system classified distribution system in a customer charge calculation, even if the minimum system classification is reasonable?

A. No. Staff recommends the Commission continue to rely on the basic customer method of cost causation for the residential customer charge, which is recognized as industry best practice in the RAP manual. This approach recognizes that the customer charge should include only (1) the costs and expenses of metering and billing customers, (2) the cost of the infrastructure that varies with the number of customers served, including related income taxes, and (3) the proportionate labor, non-labor, and distribution expense associated with the above infrastructure.

Non-residential Rate Design

Q. Has EMW made progress on rate modernization in this filing?

A. No. While EMW has identified annual billing demand and seasonal energy as impediments to its rate modernization plans, it did not address making progress on those issues in this case.

Q. Has EMW requested changes to its non-residential rates?

A. Yes. EMW has increased reliance on its customer NCP determinants. MECG also recommends increasing the demand charges be disproportionately increased.[11]

Q. What is the customer impact of these changes?

[11] See Direct Testimony of Kavita Maini, page 6, lines 34-37.

A. EMW has not provided customer impacts, nor has EMW provided sample customer data as of the time of this filing for Staff to review customer impacts.

Q. What is the relationship between the customer NCP that EMW uses as the determinant for its demand charge, and EMW's system CP or the SPP CP?

A. Any relationship is coincidental. A customer may experience its monthly NCP at 2 AM, while the system CP may occur at 5 PM. It is not reasonable to correlate a customers NCP to the system CP. A more reasonable approach would be to identify an on-peak period and calculate billing demand based on a customer's maximum usage during that period.

CONCLUSION

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Evergy Missouri West, Inc. d/b/a Evergy Missouri West's Request for Authority to Implement A General Rate Increase for Electric Service	))))	Case No. ER-2024-0189

AFFIDAVIT OF SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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 *Rebuttal 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 31st day of July 2024.

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

Question: 0256
Energy reflected in Miller $3.1 million residential revenue adjustment

Miller direct testimony in ER-2024-0189 at pages 8 - 9 states "Customers with less than 9 months of data (new movers) are not included in the analysis, which is a limiter within the online tool analysis so as to allow a longer history of usage data such that a customer can confidently review their TOU options. Additionally, EV rate, solar subscription, net metering, parallel generation, non-AMI customers are also excluded from Oracle's rate comparison analysis." Ms. Miller's direct testimony at page 10 states "Q: Did EMW further refine the TOU rate revenue impacts calculated from Oracle's rate comparison analysis? A: Yes. While the Oracle's revenue estimates were calculated using a majority of Residential customers' kWh's within the test year period, there were minor exclusions as previously described. The revenue estimates were further adjusted to more completely reflect the full test year of kWh's. This was done by comparing the total actual kWh's in the test year to kWh's in Oracle's analysis to calculate a % differential and then grossing up the Oracle kWh's to reflect the full kWh of the Residential population." Please confirm if Evergy's "full kWh of the Residential population," includes (A) kWh sold to customers who are not AMI-metered, (B) kWh sold to customers who participate in net metering, (C) kWh sold to customers who are parallel generators, and (D) kWh sold through the EV rate.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

A. Presumably, yes. Customers without AMI meters were not differentiated in the billing data rate codes so I cannot answer with certainty. However, customers without AMI meters makes up a very small proportion of residential customers.
B. No, the full kWh of the Residential population only includes the rate codes included in the impact analysis – MORG, MORH, and MORT.
C. No, the full kWh of the Residential population only includes the rate codes included in the impact analysis – MORG, MORH, and MORT.
D. No, the full kWh of the Residential population only includes the rate codes included in the impact analysis – MORG, MORH, and MORT.

Information provided by:
Brandon Lombardino, Sr. Regulatory Analyst, Regulatory Affairs

Question: 0255
Customers Excluded from Oracle Information

Miller direct testimony in ER-2024-0189 at pages 8 - 9 states "Customers with less than 9 months of data (new movers) are not included in the analysis, which is a limiter within the online tool analysis so as to allow a longer history of usage data such that a customer can confidently review their TOU options. Additionally, EV rate, solar subscription, net metering, parallel generation, non-AMI customers are also excluded from Oracle's rate comparison analysis." (A) Concerning these customers who were not included in the Oracle analysis discussed in Ms. Miller's testimony, please identify the number of customers taking service on a general use rate (winter tail block rate of $0.08255) and the number of customers taking service on a discounted rate (winter tail block rate of $0.05297) in the month of July 2022, and in the month of June 2023. (B) If these customers took service on some other rate, please identify the rate(s) and the number of customers taking service on that rate(s). (C) For each rate identified in response to parts A or B, please provide the total kWh usage, by month, for each month July 2022 - December 2023. (D) If any aspect of this information is not available please explain why this information is unavailable and describe the steps necessary to provide the information requested.

RESPONSE: (do not edit or delete this line or anything above this)

Confidentiality: PUBLIC
Statement: This response is Public. No Confidential Statement is needed.

Response:

A. This information is not available.
B. This information is not available.
C. This information is not available.
D. The Company did not perform an analyses of those specific customers who are excluded from the Oracle analysis and therefore cannot provide this detailed information requested.

Information provided by: Kim Winslow, Senior Director Energy Solutions; Marisol Miller, Senior Manager Regulatory

Case No. ER-2024-0189

SCHEDULE SLKL-r3

HAS BEEN DEEMED

CONFIDENTIAL

IN ITS ENTIRETY