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MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2022-0130

DIRECT TESTIMONY

OF

MARISOL E. MILLER

ON BEHALF OF

EVERGY MISSOURI WEST

Kansas City, Missouri
January 2022

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DIRECT TESTIMONY

OF

MARISOL E. MILLER

Case No. ER-2022-0130

Q: Please state your name and business address.

A: My name is Marisol E. Miller. My business address is 1200 Main, Kansas City, Missouri 64105.

Q: By whom and in what capacity are you employed?

A: I am employed by Evergy Metro, Inc. I serve as Senior Manager – Regulatory Affairs for Evergy Metro, Inc. d/b/a as Evergy Missouri Metro ("Evergy Missouri Metro"), Evergy Missouri West, Inc. d/b/a Evergy Missouri West ("Evergy Missouri West"), Evergy Metro, Inc. d/b/a Evergy Kansas Metro ("Evergy Kansas Metro"), and Evergy Kansas Central, Inc. and Evergy South, Inc., collectively d/b/a as Evergy Kansas Central ("Evergy Kansas Central") the operating utilities of Evergy, Inc.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of Evergy Missouri West.

Q: What are your responsibilities?

A: My general responsibilities are to provide support for the Company's regulatory activities in the Missouri and Kansas jurisdictions. Specifically, my duties include oversight of class cost of service, tariff management, load analysis, and rate design. I also manage certain analytical activities for the department including rate change implementation, billing determinant calculation, and retail revenue calculation.

Q: Please describe your education, experience and employment history.

A: I hold a Master of Business Administration degree from Rockhurst University with an emphasis in Management. I also was awarded a Bachelor of Science in Business Administration Magna Cum Laude with an emphasis in Business Finance and Banking/Financial Markets from the University of Nebraska at Omaha. In addition to those academic credentials, the Institute of Internal Auditor's ("IIA") and the Association of Certified Fraud Examiners ("ACFE") have certified me as a Certified Internal Auditor and Certified Fraud Examiner respectively.

I've worked in various roles in Financial Analysis, Financial Reporting, and Internal Auditing. I joined KCP&L (now Evergy) in August of 2006 working as a Senior/Lead Internal Auditor. I led various projects of increasing complexity and most notably was the on-site Internal Auditor for the approximately $2 billion Comprehensive Energy Plan Iatan 2 Construction project.

I have worked in the Regulatory Affairs Department since 2011 holding various positions covering areas including Integrated Resource Planning ("IRP"), Missouri Energy Efficiency Investment Act ("MEEIA")/Demand-Side Management ("DSM"), compliance reporting for multiple areas in transmission and delivery, and rate case support.

Q: Have you previously testified in a proceeding before the Missouri Public Service Commission ("Commission" or "MPSC") or before any other utility regulatory agency?

A: Yes, I provided written testimony before the Kansas Corporation Commission ("KCC") and provided written testimony and testified in a rate case proceeding before the MPSC.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to:

I. Highlight and explain changes impacting rates resulting from rate studies and planning.

a. Real Time Pricing (RTP) Alternative

b. Rate Clean up

i. Residential

1. Eliminate Other Rate (MORO) and transition customers to Residential Standard (MORG)

2. Eliminate the frozen Time of Day rate (MO610)

ii. Non-Residential

1. Eliminate frozen Separately Metered Heat Rate (MOSHS) and transition customers to Standard General Use Rate (MOSGS or MOSDS)

2. Eliminate the frozen Time of Day rate (MO620, MO630, MO640) and transition customers to the applicable Non-Residential Standard Rate

c. Studies underway & Potential plans for the future

i. Bright Lines

ii. Hours Use

II. Explain and support the Company's annualized/normalized revenues;

III. Explain the Electric Class Cost of Service ("CCOS") Study; and

IV. Explain and support the Company's Electric Rate Design.

I. CHANGES RESULTING FROM RATE STUDIES

Q: Were there any studies completed that impacted change to revenues or rate design proposed in this case?

A: Yes. The Company performed a number of studies as part of commitments made in the last general rate case that provided insight into the value of rate consolidation and simplification. The proposals included herein are also part of a broader Rate Modernization Plan ("Rate Plan") that will expand programs and rates offered to our customers. For more details on the Company's Rate Plan goals and objectives, as well as, the studies and commitments completed, please see the Direct testimony of Company witness Bradley D. Lutz. My testimony will focus on the proposals resulting from those studies and reviews.

Q: What proposals are being made as part of this filing that resulted from studies or planning?

A: The following proposals are being made in this filing resulting from studies:

- Real Time Pricing (RTP) alternative (Commercial & Industrial) (frozen)
- Elimination of certain rates or rate provisions
    - Residential
        - Residential Other
        - Residential Time of Day (TOD) (frozen)
    - Non-Residential
        - Separately Metered Heat Rate (Small General Service) (frozen)
        - Time of Day (General Service) (frozen)

Q: Are there other rate changes that you will discuss in your testimony?

A: Yes, I will also discuss studies that are currently underway that explore a potential future change that would impact our Commercial & Industrial classes. The two studies cover the calculation of Hours Use utilized in the energy charge calculation and the establishment of "bright lines" for demands. The intention in discussing these studies now is to collect feedback to inform a future case where these study results will be used to propose potential changes to the energy charge calculation and class demand thresholds.

Q: Can you provide a bit of background and detail on each proposal starting with the proposal for RTP?

A: The Company worked with consulting firm, Concentric Energy Advisors, to design a rate option that leveraged real world examples in the industry, offered price signals that aligned with market pricing, and that worked with Evergy's billing system. The result was an hourly rate that melds the predictability of static time variant rates with a reflection of market energy price fluctuations. The rate will offer flexibility and predictability that will allow customers to modify their operations to take advantage of reduced cost hours. This offering is a result of a rate case commitment in the last general rate cases. For more details on the commitment and background, please see the Direct testimony of Company witness Bradley D. Lutz.

Q: What is the recommendation and what analysis has been performed to support the it?

A: Utilizing the current Class Cost of Service study, functionalized costs were identified for use in a time-sensitive model for replacement of the RTP tariff. Costs which vary by season (summer versus non-summer) and day type (weekday versus weekend) were identified for temporal allocation. Excess production demand costs were slated for allocation to hours within 90% of System peak, and Energy-related costs were slated for allocation based on locational marginal prices. Average production demand costs, which also possess a time element, were slated for application to all hours. Though Transmission demand costs are not temporal, they are covered in normal rates by the regular demand charge and were thus also slated for application equally to all hours. Distribution demand costs and Customer-related costs were deemed non-temporal. These costs are currently handled via the Facilities Demand Charge (variable by kW) and Customer Charge (per customer,) respectively, within the normal general service tariff rates, and were thus treated accordingly in this proposed rate design and excluded from the hourly considerations. Next, system hourly cost patterns were identified. Prior year day-ahead locational marginal price ("LMP") data was analyzed to identify high and low-cost hours by season and day type. System hourly load data was also analyzed to identify the hours that are the drivers of peak demand and associated costs. Utilizing these findings, the identified time-variable costs were allocated by hour. Once the various functional costs were allocated to the different temporal and non-temporal components, rates were designed to be revenue neutral for each rate class. The resulting structure is composed of three distinct components: hourly energy charge variable by season and day type; facilities demand charge; and customer charge. This new structure continues to preserve the time-based components inherent in the current RTP rate structure, provide appropriate price signals for efficient usage, provide a means for customers to modify usage to reduce costs, and will work with the Company's billing system. The new rate will be available on a limited basis to customers meeting specific load requirements typical of current Large Power Service and Large General Service customers. It is intended that the rate will be broadened further to allow for greater participation in a future case leveraging learnings from this initial offering. See the following table for the pricing being offered as part of this proposal, Schedule MEM-3 for RTP Alternative report, and tariff TRP filed in this case.

Table 1- Time Related Pricing

L

Large General Service – level rates:

	Secondary	Primary
Customer Charge ($/month)	**$79.28**	**$260.80**
Facilities Charge ($/kW)	**$2.426**	**$1.571**

Hourly Energy Charge ($/kWh)

Hour Ending	Summer Weekday	Non-Summer Weekday	Summer Weekend	Non-Summer Weekend
1	$0.04170	$0.04970	$0.04147	$0.06012
2	$0.03794	$0.04744	$0.03849	$0.05748
3	$0.03610	$0.04723	$0.03644	$0.05518
4	$0.03540	$0.04778	$0.03558	$0.05578
5	$0.03806	$0.05181	$0.03637	$0.05901
6	$0.04367	$0.06147	$0.03888	$0.06413
7	$0.04945	$0.07851	$0.04094	$0.06964
8	$0.05293	$0.08085	$0.04530	$0.07699
9	$0.05831	$0.07896	$0.05005	$0.08521
10	$0.06122	$0.08201	$0.05297	$0.09233
11	$0.06708	$0.07808	$0.05657	$0.08785
12	$0.07490	$0.07380	$0.06293	$0.08253
13	$0.08168	$0.07128	$0.06900	$0.07906
14	$0.09657	$0.07047	$0.07348	$0.07647
15	$0.11471	$0.06826	$0.08421	$0.07557
16	$0.14165	$0.06702	$0.08981	$0.07592
17	$0.15267	$0.06974	$0.09278	$0.07971
18	$0.13886	$0.07728	$0.08734	$0.08998
19	$0.10803	$0.07873	$0.07805	$0.09179

20	$0.09109	$0.07676	$0.07118	$0.08908
21	$0.07028	$0.07479	$0.05618	$0.08509
22	$0.05714	$0.06495	$0.05153	$0.07547
23	$0.05008	$0.05758	$0.04576	$0.06687
24	$0.04439	$0.04969	$0.04137	$0.05824

Large Power Service – level rates:

Customer Charge ($/month)	**$717.99**
Facilities Charge ($/kW)	
Secondary	**$3.425**
Primary	**$2.992**
Substation	**$0.000**
Transmission	**$0.000**

Hourly Energy Charge ($/kWh)

Hour Ending	Summer Weekday	Non-Summer Weekday	Summer Weekend	Non-Summer Weekend
1	$0.03698	$0.04284	$0.03444	$0.04763
2	$0.03325	$0.04075	$0.03177	$0.04549
3	$0.03142	$0.04055	$0.02993	$0.04362
4	$0.03073	$0.04107	$0.02917	$0.04410
5	$0.03337	$0.04480	$0.02987	$0.04673
6	$0.03894	$0.05377	$0.03212	$0.05089
7	$0.04468	$0.06957	$0.03396	$0.05537
8	$0.04813	$0.07175	$0.03787	$0.06135
9	$0.05348	$0.06999	$0.04212	$0.06802
10	$0.05636	$0.07283	$0.04473	$0.07381
11	$0.06218	$0.06917	$0.04796	$0.07018
12	$0.06995	$0.06520	$0.05366	$0.06585
13	$0.07668	$0.06287	$0.05909	$0.06303
14	$0.08574	$0.06212	$0.06310	$0.06092
15	$0.09586	$0.06006	$0.06716	$0.06019
16	$0.11021	$0.05892	$0.07211	$0.06048
17	$0.10940	$0.06144	$0.07467	$0.06356
18	$0.09744	$0.06843	$0.06965	$0.07190
19	$0.08112	$0.06978	$0.06122	$0.07337
20	$0.07115	$0.06795	$0.05502	$0.07117
21	$0.06026	$0.06612	$0.04761	$0.06793
22	$0.05231	$0.05699	$0.04345	$0.06011
23	$0.04530	$0.05015	$0.03828	$0.05312
24	$0.03966	$0.04283	$0.03435	$0.04610

Q: Can you provide some background on what is being proposed for grandfathered/frozen rates and why?

A: The Company completed a study exploring the consolidation of the MO Metro and MO West rates which was filed on October 31, 2020. The objective of the study was to outline the current state of operations, costs, and rates, the potential obstacles with immediate rate consolidation given the current state, and finally, the steps contemplated to consolidate rates properly. Because of concern with the impact to customers, a careful incremental process and plan was outlined to ensure minimal impact and to allow time for customer adjustment. The proposals for the elimination of grandfathered rates represents a portion of Steps 1, 2, 3 of that plan.

Q: For the elimination of grandfathered rates and rate clean up, what analysis was performed to support those proposals?

A: The Company completed various analyses to understand the impact of the proposals to determine feasibility. The following steps were performed:

- Identified full list of frozen rates/rate provisions
- Determined the number of customers on each and how long the rate had been frozen
- Pulled test year actual[1] billing determinants for all customers in a given frozen rate/provision
- Performed best fit analysis to determine the best rate for each customer
- Performed bill impact analysis comparing the current rate and the new using test year

[1] All bill impact analysis and corresponding analysis that utilizes billing determinants actuals (kwh, kw, and customer count) will be based calculated on an actual basis with no adjustment for weather or growth. Only customers with a full 12 months of data in the test year were analyzed.

- Finalized recommendations
- Developed an approach to contact and educate impacted customers

Q: Are you proposing elimination of all grandfathered/frozen rates at this time?

A: Yes, all frozen rates are being proposed for elimination in this rate case filing, except for certain Lighting rates that have customers still on them. All frozen rates being proposed for elimination are discussed in this Direct testimony with the exception of the frozen Lighting rates with no customers on them.

Q: What is the Company proposing for the Residential Other rate and why?

A: The Company proposes elimination of the Residential Other rate and moving those customers to the Residential Standard rate. The Residential Other rate provides electric service to Residential customers who have dedicated well pumps, barns, machine sheds, detached garages, etc. and whose corresponding usage would not currently qualify under any other Residential rate. The Company views this usage is as largely an extension of Residential usage and believes it should be covered as part of the Residential General use tariff. This will require modification of the tariff language to allow for this change. Those proposed changes are reflected in the tariffs supporting this rate case filing.

Q: What were the results of the customer bill impact analysis?

A: Based on review of 4,079 customers with 12 months of actual usage for the 12 months ending June 30, 2021, 100% of customers could experience a bill decrease ranging from 15% to 30%[2] and greater.

[2] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.

Q: What else is being proposed for the Residential Class and why?

A: The Company is proposing to eliminate the frozen Residential Time of Day rate. This rate has been frozen since 2017 and has no customers on it. The Company began offering a new TOU rate in 2019 that leverages AMI technology and provides various education tools that customers can use to learn more about their electric usage. Residential customers with an AMI meter can choose to participate in this TOU rate or the new 2 period TOU rate being proposed as part of this rate case filing. With several options for TOU rates and no customers on the frozen TOU rate, the Company would like to eliminate this outdated TOU rate from its rate book.

Q: Moving on to Non-Residential proposals, what is being proposed for the Separately Metered Heat rate and why?

A: The Company is proposing eliminating the Separately Metered Heat Rate available to Small General Service customers. This rate has been frozen since June 15, 1995 and has only 48 customers in the test year. Additionally, no other Non-Residential class offers a special end use rate offering for space heat. Given these factors and the Company's Rate Plan aiming for rate simplicity, jurisdictional alignment, and the movement away from end use rates, the timing seems right to propose elimination.

Q: What were the results of the customer bill impact analysis?

A: Based on review of 43 customers with 12 months of actual usage for the 12 months ending June 30, 2021, 100% of customers could experience a bill increase. An average customer would see a $250 annual increase or a 28%[3] increase. However, the majority of this increase is attributable to an error in historical billing related to the customer charge.

[3] Potential impact was measured on an actual basis with no adjustment for rate increase proposed in this case.

The tariff allows the separate meter rate to be billed at a lower fixed charge/customer charge than that of the Standard Small General Use rates. This customer charge of $9.43 was intended to be billed in addition to the Standard Customer Charge of $23.14. Instead, the entire account was billed the lower $9.43 and thus was not adequately covering their intended fixed costs. When this change to the Customer Charge is adjusted for, the average impact of the recommended change is a 9%[3] or an $85 increase annually.

Q: What else is being proposed for the Non-Residential Classes and why?

A: The Company is proposing elimination of the frozen General Service Time of Day Rate. The rate has been frozen since 2017, there is only one customer currently on the rate, and best fit analysis shows that this customer would benefit (bills would decrease) by moving to a standard rate. The Company continues to evaluate rate offerings that might be offered in the future and expects that TOU rate offerings may be expanded to include Non-Residential classes in a future case.

Q: What is the aggregate revenue impact to the proposals discussed above?

A: Table 2 below shows the aggregated impact of each proposal and the movement of customers from eliminated rates to standard rates and the change in customer count, kwh, and calculated revenue based on those specific customers moved by rate code. For example, for rate code MORO, 4079 customers and 15,414,764 kwh were moved from MORO to MORG. The actual revenue impact for this movement resulted in a change in actual revenue from $2,692,423 (MORO) to $2,028,886 (MORG). Table 3 below shows the aggregated impact of all proposals on weather normalized test year revenues. The total aggregated impact of the proposals results in a reduction in test year revenues of approximately $649,353.

Table 2- Aggregated Revenue Impact for Each Proposal (Actual Revenues)

Aggregate Impact of Grandfathered Rate Clean Up										
Actual Revenues										
Rate Class	Proposal	MO West Rates	Total Revenue (Before Changes)	Customer /Bill Count	Customer Count Change (+/-)	Adj Customer Count	Energy Total (KWH)	Switchers (+/-)	Energy Total (KWH)	Total Revenue (excluding FAC & DSIM)
Res	Other to Standard Rate	MORO	$2,692,423	4,079	(4,079)	-	15,414,764	(15,414,764)	-	$0
Res	Other to Standard Rate	MORG	$0	-	4,079	4,079	-	15,414,764	15,414,764	$2,028,886
	Residential Total		*$2,692,423*	*4,079*	*(0)*	*4,079*	*15,414,764*	*-*	*15,414,764*	*$ 2,028,886*
Non Res	General Service Time of Day	MO630	$17,864	1	(1)	-	199,499	(199,499)		0
Non Res	Small General Service	MOSDS	0		1	1		199,499		16,325
Non Res	2 Meter Heat Rate - 1 Meter Heat Rate	MOSHS	$72,303	48	(48)	0	877,534	(877,534)		0
Non Res	Small General Service no demand	MOSGS	0		48	48		877,534		88,105
	Non Residential Total		*$ 90,167*	$ 49	-	49.00	1,077,033	-	$ -	*104,430*
	GRAND TOTAL		*$ 2,782,590*	$ 4,128	$ (0)	$ 4,128	$ 16,491,796	$ -	$ 15,414,764	*$ 2,133,316*

Table 3- Aggregated Weather Normalized Test Year Revenue Impact for All Proposals- By Class

Aggregate Impact of Grandfathered Rate Clean Up									
WN/CG Test Year Revenues									
Rate Class	MO West Rates	Total Revenue (Before Changes)	Customer /Bill Count	Customer Count Change (+/-)	Adj Customer Count	Starting Energy Total (KWH)	Switchers (+/-)	Final Adj Energy Total (KWH)	Total Revenue (excluding FAC & DSIM)
Residential Class	MORG	$ 205,757,460	173,693	4,163	177,856	1,808,600,940	15,262,795	1,823,863,735	$ 207,785,670
	MORO	$ 2,692,611	4,163	(4,163)	-	15,262,797	(15,262,797)	-	$ -
Residential Total		*$ 208,450,072*	*177,856*	*-*	*177,856*	*1,823,863,737*	*(2)*	*1,823,863,735*	*$ 207,785,670*
Small General Service	MOSGS	$ 28,615,376	26,004	47	26,050	219,688,660	898,322	220,586,982	$ 28,705,600
	MOSHS	$ 74,030	47	(47)	-	898,323	(898,323)	-	$ -
	MOSDS	$ 82,934,134	11,085	1	11,086	914,432,271	203,529	914,635,800	$ 82,950,853
Small General Service Total		$ 111,623,540	37,135	1	37,136	1,135,019,254	203,528	1,135,222,782	$ 111,656,453
General TOD	MO630	$ 17,864	1	(1.00)	-	199,499	(199,499)	-	$ -
General TOD Total		$ 17,864	1	(1)	-	199,499	(199,499)	-	$ -
Non Residential Total		*$ 111,641,404*	*37,136*	*0*	*37,136*	*1,135,218,753*	*4,029*	*1,135,222,782*	*$ 111,656,453*
GRAND TOTAL		***$ 320,091,476***	***214,992***	***0***	***214,992***	***2,959,082,490***	***4,027***	***2,959,086,517***	***$ 319,442,123***
*Total revenues are excluding riders									
**Customer/Bill Count is annualized - If there is 1 bill for each month of the test year, or 12 bills, the Customer/Bill Count will equal 12/12 or 1.									

Q: Do Tables 2 and 3 reflect all proposals that have been adjusted for and reflected in the test year revenues in this filing?

A: Yes.

Q: Is there anything else to add with regard to these proposals and the rate clean up being done to facilitate jurisdictional alignment?

A: Yes. Given the expansive nature of the proposed changes and the number of customers being moved and impacted, implementation will be more arduous, requiring careful planning and consideration to ensure minimal customer impact. The Company is expecting that full implementation of these changes and the elimination of rates may not be completed by the effective date of rates and may require extra time for implementation. The Company is still working through various implementation scenarios and is still assessing the expected timeline or how much extra time might be needed, but at this point, it is not expected to be extensive. The Company expects to share implementation plans and needs as the rate case evolves.

Q: What about new plans being introducing around Hours Use?

A: Like the jurisdictional alignment work described above, the review of Hours Use is part of the broader Rate Plan that includes rate clean up and jurisdictional alignment and is in response to stakeholder and customer feedback communicating interest in this charge being simplified to ease understanding and to enable more active management and monitoring by the customer. The Company worked with Concentric Energy Advisors to review the calculation of the energy charge. The Company is introducing the results of that review in this case to inform a future case where these study results will be used to propose potential changes to the energy charge calculation.

Q: What is the recommendation and what analysis has been performed to support the plan?

A: First, a cross jurisdictional review of existing rate classes and rate structures/pricing, including the calculation of the energy charge and demand charge was performed in order to assess differences and similarities. Second, cost data from Class Cost of Service study[4] and billing determinants (energy and demand) from the test year was obtained. Using that data, the "unraveling" of the hours use calculation began and a determination of the customer impacts was ascertained. Given those impacts, in a future rate case, the Company will be proposing a multi-step plan to move from the hours use calculation to a more standard and more transparent energy charge calculation. The proposal will include the flattening of energy charges and the redistribution of some demand costs back into the demand charge. demand charge. This retains the intended price signaling which exists within the current hours use structure, but in a more straightforward manner. The plan will need to be executed over multiple rate cases due to the potential impact to customers. The table below summarizes the proposed C&I rate structures:

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[4] The Class Cost of Service study from the 2018 rate case was the most recent CCOS study available at the time of the Hours Use review.

Table 4- Summary of Future Changes to the Hours Use Rate Structure

Rate Class	Missouri West	Missouri Metro
Large Power Service	- Summer/winter flat demand charge - Summer/winter flat energy charge - Removed Base/Seasonal demand and energy distinction - *No phase-in required*	- Summer/winter flat demand charge - Summer/winter flat energy charge - Assumes customers will remain on off-peak rider under proposed rates. - Removed blocked demand charge - *Three-step phase-in proposed*
Large General Service	- Summer/winter flat demand charge - Summer/winter flat energy charge - Removed Base/Seasonal demand and energy distinction - *Two-step phase-in proposed*	- Summer/winter flat demand charge - Summer/winter flat energy charge - *Three-step phase-in proposed*
Medium General Service	- Not applicable	- Summer/winter flat demand charge - Summer/winter flat energy charge - *Three-step phase-in proposed*
Small General Service	- Summer/winter flat demand charge - Summer/winter flat energy charge - Removed Base/Seasonal demand and energy distinction - *Three-step phase-in proposed*	Secondary Voltage - Summer/winter flat energy charge - Summer/winter demand charge applied to demand in excess of 25kW - *Three-step phase-in proposed* Primary Voltage - Summer/winter flat energy charge - Summer/winter flat demand charge - *Three-step phase-in proposed*

For more details on the proposal and all analysis performed, please see Schedule MEM-4 for the Hours Use Report.

Q: If Evergy is not proposing the elimination of Hours Use in this case, why is it being discussed?

A: Unlike the jurisdictional alignment proposals discussed earlier, the Hours Use study explores a possible avenue for simplification, but with a focus on jurisdictional alignment. Currently, Evergy's Kansas Central jurisdictions calculates the Energy charge in a manner that veers away from the Missouri Metro, Missouri West, and Kansas Metro jurisdictions and offers a flat seasonal differentiated Energy Charge. The Company took inspiration from this method in its undertaking of the Study. Our goal in this rate case is to introduce the concepts being explored to change the calculation of the Energy Charge and determine a path for formal proposal of a change to be included in a future rate case. As such, we hope to collect formal feedback and impressions from stakeholders in this case to help inform how we might modify the proposals being considered to address broader considerations.

Q: What are Bright Lines?

A: Bright Lines, in utility tariff application, are thresholds which define the utility classes. These thresholds could be expressed in terms of energy usage, demand or capacity, or some other measure of a customer's power usage. Based upon where a customer's pertinent determinants fall within said thresholds and/or similarities in load profiles, customer are grouped into a given class over another. In Evergy's Kansas Central jurisdiction existing application, Bright Lines are based upon customer Non-Coincident Peak (NCP) demands. As part of the Rate Plan that includes jurisdictional alignment, the Company is exploring Bright Lines to bring some consistency to how rate classes are defined across its jurisdictions, as well as minimize rate switching across classes.

Q: What is the recommendation and what analysis has been performed to support it?

A: After examining actual revenues in the test year, best-fit Bright lines were determined across jurisdictions, utilizing maximum NCP demand as the defining criteria. These best-fit lines were determined by established maximums that would minimize customer rate switching. An analysis keeping class counts static was done, as well as a more finite analysis keeping absolute switchers to a minimum. In comparing these lines across all three jurisdictions, it was concluded that all three legacy KCP&L jurisdictions were hovering around the 30-200-1,000 maximum demand lines for Small, Medium and Large

General Service classes, respectively. After establishing these baselines, individual customer impacts were investigated using actual test year data for MO West and MO Metro. The largest one or two rates in each class of each jurisdiction (summing at least 90% of all customers in that class,) were evaluated and their results extrapolated to arrive at full class impacts. Based on test year actuals, MO West could experience an increase in total actual revenues of $232,331, and MO Metro could experience an increase in total revenues of $5,626,214. For purposes of revenue effects, no revenue addition was posited for the movement of MO West customers into a new Medium Service class. Average annual customer impacts ranged from -$119.45 to $29.56 for MO West classes, and -$1076.50 to $718.45 for MO Metro classes. With a focus on minimal upfront customer impacts, and an eye toward finitely defining classes for better cost allocations, rate design, and other class-based considerations, as well as a nod toward jurisdictional alignment, the proposal of Bright Line maximum demands of 30 kW (Small) – 200 kW (Medium) – 1,000 kW (Large) is promoted for implementation in a future rate case. Several factors can impact this proposal including the results of this rate case filing, the timing and frequency of future rate cases, significant change in load profiles, and many other unforeseeable. Evergy wishes to alert the Commission now of its intentions of formally proposing this change in a future rate case filing.

Q: Can you provide more detail on the analysis performed to support this recommendation?

A: The following steps and analysis were performed:

1. Pull Test Year data for all customers currently in the Small, Medium, Large, and Large Power classes in all jurisdictions.

- o Monthly kWh (actuals)
- o Monthly kW (actuals)

2. Identify maximum, minimum, and average energy and demand values, by customer.
3. Calculate load factor by customer (based on maximum of energy and demand).
4. Leverage bright lines experience in Kansas Central jurisdiction specific to how Bright Lines were defined.
5. Graph maximum, minimum, and average demands by class, in an attempt to see any patterns, alignments, or natural divisions in and between classes.
6. Evaluated the impact (switchers) of setting existing and new max demand thresholds across jurisdictions/classes to determine cross jurisdictional feasibility with the goal of minimizing impacts.
7. Using actuals, ran individual bill impacts for impacted customers (customers likely to switch) and calculated change to revenue and bills. Any impacts associated with new classes (Medium for Evergy MO West) were assumed to be revenue neutral or 0.

Q: If Evergy is not proposing Bright Lines in this case, why is it being discussed?

A: Similar to Hours Use, the Company hopes to collect stakeholder impressions and feedback to determine a path for formal proposal in a change to be included in a future rate case. We hope that feedback provided during this rate case can help inform how we might modify the proposals being considered to address broader considerations.

Q: Are there other new rates that you've not included in your discussion above?

A: My testimony mainly covered those rates resulting from the specific studies that were performed. There are other new rates or customers programs that are being included in this filing that are covered in the Direct testimonies of Company witnesses Bradley D. Lutz, Kimberly Winslow, and Ryan Hledik.

II. ANNUALIZED/NORMALIZED REVENUES

Q: Were the retail revenues included in this filing prepared by you or under your supervision?

A: Yes, they were.

Q: Will you describe the method used in developing the revenues for this case?

A: Both the weather-normalized kWh sales and customer growth levels by rate class (i.e. Residential, Small General Service, Medium General Service and Large General Service) were developed by Company witness Albert R. Bass, Jr. Mr. Bass explains those figures and other adjustments, including adjustments for COVID, in his Direct Testimony. The test year used by the Company in this case was the 12 months ending June 30, 2021, which we expect will be updated for known and measurable changes through May 31, 2022. The monthly bill frequencies for the 12 months ending June 30, 2021, that contain the billing units for each of the billing blocks for the various rate components, were developed under my supervision. These bill frequencies were developed by collecting the actual usage and customer counts billed in each month of the test period and applying them to the existing rate structures[5]. By applying the existing rates to the usage in each of the billing blocks, the revenues were reproduced, providing a basis for determining the overall revenues to be used in this case. The Company determined monthly revenues by applying the normalized sales and customer levels for each month represented in the test period to the corresponding billing frequency. The normalized sales and customer levels

[5] These actual determinants would reflect the migration of customers that were moved from frozen rates being proposed for elimination in this rate case filing to standard rates.

from this were then multiplied by the rates that took effect on December 6, 2018 to obtain the weather normalized and customer growth adjusted monthly revenues available. The sum of the monthly revenues was compared to the actual revenues for the test year ending June 30, 2021 to determine the revenue adjustment contained in the Summary of Adjustments attached to the Direct Testimony of Company witness Ronald A. Klote as Schedule RAK-4 (adjustment no. R-20).

Q: Were all class revenues developed as described above?

A: Yes, except for the Large Power Class. The Large Power class revenues generally followed the methodology outlined above but were developed on an individual customer basis. Customer growth was accounted for by the annualization of usage for new customers switching (or starting new service) to the Large Power Class or customers leaving the Large Power Class (either due to switching or stopping service) through the end of the test year period.

Q: Have there been any operational change(s) that would impact the calculation of test year revenues?

A: Yes. Historically and in the last general rate case, the Company relied on hourly load research for purposes of determining weather normalization. This hourly load research was prepared utilizing a sample of customers to determine hourly loads by class. As of December 2020, the Company has discontinued load research.

Q: Why did the Company discontinue load research?

A: The Company implemented Advance Metering Infrastructure (AMI) metering and completed implementation of those meters in all Missouri jurisdictions in early 2020. In order to leverage the benefits of AMI technology and broaden the data set used for weather normalization and rate design, it was decided to transition from using a load research sample to full utilization of AMI data available.

Q: Is AMI data better than load research data?

A: The Company's load research data was relied upon for many years to support various analysis requiring customer load analysis and to support general rate cases. Stakeholder feedback was consistently very positive with regards to load research data, the methodology and the analysis. However, the Company would be remiss to not maximize utilization of a broader data set. For more information on how AMI data was utilized in weather normalization, please see the Direct testimony of Company witness, Albert Bass, Jr.

Q: The Company has several riders in place to recover particular costs. How will these mechanisms affect the requested increase in this case?

A: The Demand-Side Investment Mechanism ("DSIM") is separate from the revenue requirement requested in this case and thus the associated DSIM revenues have been removed from the total revenues available. The fuel adjustment clause ("FAC") rider base amount has been re-based within the current revenue requirement. In addition to my testimony on the FAC, please see the Direct Testimony of Linda Nunn for the primary details concerning the continuation of the FAC in this case.

III. ELECTRIC CLASS COST OF SERVICE STUDY

Q: Has the Company performed a CCOS study for this case?

A: Yes, the Company performed a CCOS study representative of the Evergy Missouri West jurisdiction. A summary of the results of the Company's CCOS studies are attached and marked as Schedule MEM-1 and MEM-2.

Q: Was the study prepared by you or under your direct supervision?

A: Yes, it was. The Company utilized the services of 1898 & Co., a Division of Burns & McDonnell Engineering Company, Inc., who performed the primary CCOS modeling using data provided by the Company.

Q: Has the Company filed a CCOS in previous rate cases?

A: Yes. In all rate cases filed since 2005, the Company has filed a CCOS study.

Q: What is the purpose of the CCOS study?

A: The purpose of the CCOS study is to directly assign or allocate each relevant component of the Company's revenue requirement on an appropriate basis in order to determine the contribution that each customer class makes toward the Company's overall rate of return. The CCOS analysis strives to attribute costs in relationship to the cost-causative factors of demand, energy and customer.

Q: Would the CCOS study serve as the basis for the determination of increasing or decreasing overall revenue levels for Evergy Missouri West?

A: No. Determination of the revenue requirement requested in this case is accomplished using the jurisdictional model sponsored by Company witness Ronald A. Klote. The CCOS model uses the information from the jurisdictional model as an input for the primary purpose of evaluating the possible distribution of costs to the respective classes.

Q: What classes are used as a basis for this CCOS study?

A: The primary classes the Company used in its analysis are Residential, Small General Service, Large General Service, Large Power Service, and Lighting.

Q: Do these classes conform to the proposed electric rate tariffs?

A: Generally, they do. The Residential class has several rate classifications available to it that include general use, general use and space heat, and time of use. The Small General Service, and Large General Service classes also have general usage rates and all electric rates, plus they can be specific to the voltage level at which the customer receives service. The Large Power Service class is distinguished by the specific voltage at which the customer receives service. In total, the Company has four classes of service (plus Lighting) but has approximately 48 rates to meet the specific needs of the customer and reporting and billing requirements.

Q: What test year was used for the CCOS study?

A: The study is based on a historical test year of the 12 months ending June 30, 2021, with known and measurable changes projected through May 31, 2022.

Q: What general categories of cost were examined and considered in the development of the CCOS study?

A: An analysis was made of all elements of cost as defined by the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, including investment (rate base) and expense (cost of service) for the purpose of allocating these items to the customer classes. To achieve this allocation, we begin by functionalizing and classifying costs.

Q: Please explain what you mean.

A: In order to make the appropriate assignment of costs to the appropriate class of customer, it is necessary to first group the costs according to their function. The functions used in the CCOS study were production, transmission, distribution, and other costs. The next step was to classify the costs. Costs are classified as customer-related, energy-related, or demand-related.

Q: What do you mean by customer-related, energy-related and demand-related?

A: Customer-related costs are those costs necessary to provide electric service to the customer independent of any usage by the customer. Some examples of these costs include meter maintenance, customer accounting, billing, and a portion of the investment in distribution plant equipment such as the meter and service line, facilities that are all necessary to make service available. Portions of the distribution facility are separated between the customer costs and the demand costs.

Energy-related costs are directly related to the generation and consumption of energy and consist of such things as fuel and purchased power and certain production operation and maintenance costs.

Demand-related costs relate to the investment and expenses associated with the Company's facilities necessary to supply the customer's full load requirements throughout the year. The majority of demand-related costs consist of production plant (generation), transmission plant and the non-customer portion of distribution plant.

Q: After the above classification of plant investment and operating costs into customer- energy- and demand-related components, what was the next step in the CCOS study?

A: The next step was to allocate each of the three categories of cost to each customer class utilizing allocation factors appropriate for each of the above categories of cost.

Q: How are the allocation factors generally determined?

A: Costs are evaluated to determine the cause driving the cost to be incurred and to establish an allocation method that best distributes the cost based on that causation. Customer-related costs are generally allocated on the basis of the number of customers within each class. Data for the development of the customer-related allocation factors came from Company billing and accounting records. Some of the customer-related accounts were allocated based on a weighted number of customers to reflect the weighting associated with serving those customers.

Energy-related allocation factors were derived on the basis of each customer classes' respective energy (kilowatt hour) requirements. Kilowatt-hour ("kWh") sales to each customer class were available from Company records. The sales data was adjusted to reflect COVID, normal weather, a normal 365-day year, rate switchers, energy efficiency programs, customer growth, and system losses in order to assign the Company's total system output.

Q: How are class demand allocation factors generally determined?

A: The data necessary to develop class demand allocation factors (production and transmission) were derived from the Company's AMI data. Such data consisted of the hour-by-hour use of electricity by each customer class throughout the study period.

Q: Was Evergy Missouri West's AMI data used to develop any other allocators?

A: Yes, it was used to develop distribution plant allocators based on customer's non-coincident peak ("NCP") loads within each class.

Q: Are any costs assigned directly to classes?

A: Yes. In instances where the costs are clearly attributable to a specific class, they are directly assigned to that class.

Q: What method do you propose to allocate production plant?

A: Production plant is the single, largest component cost to allocate to the classes within the study. As such, the production allocator has the most impact on the outcome of the CCOS study. After considerable efforts to determine the most appropriate production allocation methodology in the prior rate case, the Company intends to continue to utilize the Energy Weighted approach, specifically the Average & Excess Demand ("AED") allocation method, incorporating a four (4) Coincident Peak ("CP") component (collectively "AED-4CP"). An Energy Weighted approach was viewed to be cost effective, balanced through its incorporation of energy, and less subjective than other methods. Utilization of the AED method is an energy-weighted method of production plant allocation that gives classes a reasonable balance between the energy and capacity function of generating facilities. Use of the AED method is also consistent with the provisions of Section 393.1620(2), RSMo.

Q: Has this allocation method been used before?

A: Yes, the AED-4CP method was used by the Company in the most recent CCOS study filed in its 2018 rate cases.

Q: How were the fuel costs associated with the production plant allocated in the CCOS study?

A: Fuel costs were allocated using a monthly kWh allocator. Based on monthly fuel costs from the Company for the 12 months ended June 30, 2021, each month's fuel costs were allocated to each customer class's corresponding calendar month kWh sales adjusted for losses. These allocated results were summed by rate and major customer class to identify a proxy fuel allocator which was then used to allocate the actual fuel costs shown in the CCOS study. To ensure the allocation was representative of a normal year, an adjustment was made to the fuel costs associated with February 2021 due to the cold weather event that occurred[6].

Q: How were the off-system sales margins that Evergy Missouri West receives from its external sales of energy allocated?

A: They were allocated using an energy allocator.

Q: What method did you use to allocate transmission plant costs?

A: Transmission plant costs were allocated AED-4CP allocation method.

Q: What method did you use to allocate Distribution Plant?

A: Depending on the plant account, distribution plant is allocated using either a demand or customer allocation factor. Accounts 360 through 363 are demand-related and allocated using a Non-Coincident Peak ("NCP") demand allocator based on the use of NCP class demands. Accounts 364 through 368 include both a demand and a customer component and use a minimum system method to distinguish the appropriate split between demand and customer-related costs for each account. The demand components are allocated using the Class NCP allocator and the customer component is allocated using a customer allocator. The remaining distribution plant accounts (369-373) were allocated using a customer allocation factor.

[6] The fuel costs for February 2021 were replaced with the average fuel costs in February for 2018, 2019, and 2020.

Q: What method did you use to allocate Services?

A: Since Account 369 - Services is considered customer-related, these costs were allocated based on the customers receiving service at a secondary voltage.

Q: What method did you use to allocate Meters?

A: Meter costs, recorded to Account 370, are also customer-related and were allocated using an assignment of all meters and metering devices to customer classes.

Q: Did you include any other rate base elements in the study?

A: Yes, multiple rate base elements have been included. Additions to net plant included cash working capital, taxes other than incomes taxes, tax offset from rate base, materials and supplies, prepayments, fuel inventory, and various regulatory assets. The following details their allocation to various functions and classifications:

- The cash working capital component of rate base was developed and allocated on energy, payroll, and plant in service.
- Taxes other than income taxes were developed and allocated on retail revenue and plant in service.
- Tax offset from rate base was allocated on plant in service.
- Materials and supplies were allocated on a mix of production, transmission, and distribution plant allocators.
- Prepayment items were allocated using plant in service and customer allocation factors.
- Fuel inventory was allocated on energy.
- Regulatory assets were allocated on payroll, energy, customer, and demand allocation factors depending on the costs tracked.

- Subtractions to net plant included accumulated deferred taxes, customer advances, customer deposits, gain on SO2 emissions and income eligible weatherization.
- The accumulated deferred taxes were allocated on plant in service.
- Customer advances for construction were allocated on total distribution plant.
- Customer deposits were developed using the data analysis by customer group available from the Company.
- Gain on SO2 emissions allowances were allocated on energy production.
- Income eligible weatherization was allocated by customers.

Q: What revenues did you use for this study?

A: The class revenues were developed under my supervision and were discussed earlier in this testimony. Other sources of revenues such as Miscellaneous Revenues were allocated consistent with the revenue source.

Q: How were Operation and Maintenance ("O&M") Expenses allocated?

A: O&M Expenses were allocated using various methods dependent of the cost causation. O&M for production, transmission and distribution plant were allocated to customer classes following plant. Customer Accounts Expenses, Customer Services and Information Expenses, Sales Expenses, and Administrative and General Expenses were allocated based on the results of individual allocation studies. Administrative & General expenses were primarily allocated on the payroll allocator with the exception of the following:

- Account 924, Property Insurance, which was allocated based on plant in service.
- Account 928, Regulatory Commission expenses, which was allocated on plant in service and energy production.

- Account 929 Duplicate Charges - Credit, which was allocated on customer sales.

Q: What is the next step after the allocations are applied?

A: The next step is to determine the relative return on rate base for each of the classes and rates in the study. The ratio of class revenues less expense (net operating income) divided by class rate base will indicate the rate of return being earned by the Company that is attributable to a particular class. It is necessary to keep in mind that this calculation only represents a snapshot in time. The results of the CCOS study will most likely vary over time. The results of the study will also vary if you apply different allocation factors to the study. By applying different methods to the allocation process, you can change the outcome of the CCOS study.

Q: What were the results of the CCOS study[7]?

A: The jurisdictional rate of return was calculated to be 5.3%. Individual classes' rates of return at current rates vary, and based on the current costs, are shown in the following table.

Table 5- The Relative Rates of Return by Rate Class

Residential	Small General Service	Large General Service	Large Power Service	Thermal Service	Other Lighting	CCN
2.7%	10.4%	9.7%	8.4%	9.7%	6.5%	-67.0%

[7] The results of the CCOS study results summarized here exclude Special Contracts. The full details from the CCOS study inclusive of Special Contracts can be found in the CCOS study workpapers and full model results.

Q: If rates were changed so that Evergy Missouri West earned the same rate of return from each customer class, how much would each class's rates need to change?

A: To achieve the jurisdictional revenue increase of 8.3%, the classes should be adjusted by the percentages in the table below.

Table 6- Rate Increase Needed to Achieve and Equalized Rate of Return

Residential	Small General Service	Large General Service	Large Power Service	Thermal Service	Other Lighting	CCN
23.5%	-12.4%	-9.6%	-4.4%	-8.3%	3.7%	4399%

Q: What general conclusion can be made from these results?

A: The results of the CCOS study show that each class of customers recovers the cost of service to that class and provides a return on investment, except the CCN class. The results also show that Residential class revenue is below the Total Missouri ("MO") Retail rate of return level, while the Small General, Large General, Large Power, Thermal, and Lighting class revenues are above the Total MO Retail rate of return.

Q: Are you proposing changes to the class revenues based on the results of the study?

A**:** Yes.

Q: Are you proposing changes to class revenues that are reflective of an equalized rate of return by class?

A: No. The exact application of changes in rates that aim for an equalized rate of return by class would have been extremely detrimental to our residential customers and not in line with sound rate design principles. Instead, the Company opted for a gradual approach to adjusting revenues and rates. Utilizing the results from the study prepared based on the Average & Excess production allocation the Company has identified the following recommended changes to class revenues[8] based on an overall jurisdictional revenue requirement increase of 8.31[9]:

- Apply a 10.84% (approximately 128% of the jurisdictional rate increase) increase to the Residential class, and
- Apply a 10.50% (approximately 128% of the jurisdictional rate increase) increase to the CCN class, and
- Apply a 7.05% (approximately 75% of the jurisdictional rate increase) increase to the Large Power Service class, and
- Apply a 7.77% (approximately 75% of the jurisdictional rate increase) increase to the Large General Service class, and
- Apply a 4.30% (approximately 50% of the jurisdictional rate increase) increase to the Small General Service class, and
- Apply a 6.39% (approximately 75% of the jurisdictional rate increase) increase to the Thermal class, and
- Apply a 5.03% (approximately 75% of the jurisdictional rate increase) increase to the Lighting class

Application of these proposals to the electric rates is discussed further in the rate design section of this testimony.

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[8] These results exclude Special Contracts.

[9] This change represents the rate increase including Net Fuel. The overall rate increase excluding Net Fuel is 3.89%.

Q: In proposing class revenue shifts, is there an expectation of rate switchers that should be considered and taken into account?

A: Yes. Revenue losses associated with potential rate switching resulting from the above rate changes are possible. The Company plans to size this impact by the True-up and if possible, sooner.

IV. ELECTRIC RATE DESIGN

Q: Are you sponsoring the electric tariffs filed in this case?

A: Yes, I am.

Q: Please summarize the proposed rate design recommendation for the electric tariffs and any additional proposed changes to the tariffs?

A: The Company is requesting an annual aggregate increase over current revenues reflecting impacts before the rebasing of fuel for the fuel adjustment clause, in the amount of $27.7 million (3.89%). The aggregate annual increase over current revenues including the rebasing of fuel for the fuel adjustment clause is $59.8 million (8.31%).

Utilizing the results of the CCOS study, the Company is proposing that an increase of 10.84% be applied to Residential class revenues with a customer charge of $16.00. The $16.00 proposed customer charge is based on the results of the CCOS and is consistent with prior Commission approved customer charges. This proposed amount is ***below*** the recommended CCOS customer charge of $21.58 which represents the customer charge inclusive of the jurisdictional rate increase on an equalized basis. The Company opted to propose a lesser amount to help manage the impact to customers but hopes to make continued progress towards the equalized customer charge in subsequent rate cases, consistent with prior Commission approved customers charges. The proposed customer charge not only considers incremental progress towards the alignment of cost and ratemaking, but also seeks consistency across its Missouri jurisdictions (Evergy Missouri West and Evergy Missouri Metro). The intention of the Company is to offer one customer charge with the same pricing across both its Missouri jurisdictions. The remaining revenue shortfall/increase was then applied equally to remaining Residential bill components.

For the remaining classes (with the exception of CCN), the Company applied approximately 75% of the jurisdictional rate increase[10] or 7.05% for the Large Power Service class, 7.77% for Large General Service class, 6.39% for Thermal, 5.03% for Lighting, except the Small General Service class that where 50% of the jurisdictional increase or 4.30% increase was applied in consideration of the results of the Class Cost of Service study and the C&I class relative rates return. Generally, for the C&I classes, the Company attempted narrow the gap between how costs are incurred and how rates are designed and applied 125% of each class increase to the fixed cost rate components (i.e. customer charges and demand charges) and 75% to the variable cost rate components (i.e. energy charges). The application of the above increases by class by billing component can be found in attached schedule MEM-5. The summary of revenues and proposed increase by class may be found in Schedules MEM-6. For more details on the reasonableness of the rate increase applied to the CCN class, please see the Direct testimony of Company Witness Darrin Ives.

[10] This change represents the rate increase including Net fuel and revenue shifts.

Q: Describe the rate design recommendation for unmetered lighting.

A: The Company's Missouri jurisdictions have established LED streetlights and LED private areas lighting tariffs. As such, all standard municipal street lighting has been converted to LED while the conversion of private area lighting is at the customer's option. In order to highlight the continuing obsolescence of non-LED lighting, the following is reflected in the unmetered Lighting rate design:

- The adder components (i.e., additional poles, wire spans, etc.) that are common between LED and non-LED rates have been equalized.
- Non-LED lighting components were allotted a slightly higher portion of the increase assigned to the Lighting class at 1.92% with the mercury vapor lighting getting the highest percentage increase at 4.00%. As mercury vapor replacements are only available in the used market, the higher increase reflects the lack of availability and reflects favorably towards the energy efficient, LED equivalent.
- LED and traffic lighting received a 0% increase.
- The transitional LED prices in section 2 of the Municipal Street Lighting Service tariff, sheet No. 150 received a pricing adjustment of 22.52% in order to reduce the price differential to the standard LED prices listed in section 1 of the same tariff sheet by approximately one third. Please see the testimony of Company witness Bradley D. Lutz for details on the transitional rates.

Q: Are there any new tariffs being filed as part of this case?

A: Yes, the Company is proposing expansion of Renewables, TOU programs, and rates supportive of Electrification. Company Witnesses Kimberly Winslow and Bradley D. Lutz explain this in detail in both their Direct Testimonies. Finally, the Company is also proposing a Subscription Pricing proposal that is explained by Company witness Ryan Hledik.

- Proposal of New Rates include:
  - Time-Related Pricing tariff (Large C&I Customers)
  - Residential Two Period Time of Use Rate (See Direct Testimonies of Bradley D. Lutz and Kimberly Winslow)
  - Residential Time of Use EV and Time of Use EV+ Meter tariff (See Direct Testimonies of Bradley D. Lutz and Kimberly Winslow)
  - Business EV Charging Service Rate (See Direct Testimony of Bradley D. Lutz)
  - Residential Green Pricing REC Program Rider (See Direct Testimony of Kimberly Winslow)
  - Residential Low Income Solar Subscription Pilot Rider (See Direct Testimony of Kimberly Winslow)
  - Residential Battery Energy Storage Pilot (See Direct Testimony of Kimberly Winslow)
  - Residential Advance Easy Pay Pilot Program (See Direct Testimony of Kimberly Winslow)
  - Residential Subscription Pricing Program (See Direct Testimonies of Bradley D. Lutz, Kimberly Winslow, and Ryan Hledik)
  - Special High Load Factor Market Rate (See Direct Testimony of Bradley D. Lutz)

Q: Please summarize the proposed changes to rules & regulation tariffs and/or other non-base rate tariffs.

There are multiple changes proposed to existing tariffs. Some changes are proposed to better align the rules & regulations with current costs, planned business practices, and are generally minimal in impact. Others are more impactful. The most significant changes have already been highlighted in this Direct Testimony and others and includes:

- Elimination of rates including:
  - Residential Other Rate (MORO)
  - Residential Frozen Time of Day rate (MO610)
  - C&I frozen Separately Metered Heat Rate (MOSHS)
  - C&I frozen Time of Day rate (MO620, MO630, MO640)
  - C&I Real Time Pricing Rate
- Miscellaneous Changes:
  - FAC (See Direct Testimony of Linda Nunn)
  - Income Eligible Weatherization (IEW) Program (See Direct Testimony of Kim Winslow)
  - Solar Subscription Rider Program (See Direct Testimony of Bradley D. Lutz)
  - Emergency Conservation Plan (See Direct Testimony of Bradley D. Lutz)
  - Market Based Demand Response ("MBDR") (See Direct Testimony of Kimberly Winslow)
  - Interconnection Study Requirements and Fees – the Company proposed to institute requirements and fees associated with large systems requesting to

connect to the Company system. Studies are costly and the fees will defray the cost, avoiding subsidy.

Q: Does that conclude your 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-2022-0130

AFFIDAVIT OF MARISOL E. MILLER

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Marisol E. Miller, being first duly sworn on his oath, states:

1. My name is Marisol E. Miller. I work in Kansas City, Missouri, and I am employed by Evergy Metro, Inc. as Senior Manager – Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of Evergy Missouri West consisting of thirty-nine (39) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded, including any attachments thereto, are true and accurate to the best of my knowledge, information and belief.

Marisol E. Miller

Subscribed and sworn before me this 7th day of January 2022.

Notary Public

My commission expires: 4/26/2025

ANTHONY R. WESTENKIRCHNER
NOTARY PUBLIC - NOTARY SEAL
STATE OF MISSOURI
MY COMMISSION EXPIRES APRIL 26, 2025
PLATTE COUNTY
COMMISSION #17279952

Evergy, Inc. - Missouri West
2022 Rate Case - Direct
Test Year 6/30/2021
Cost of Service Summary

Allocation Method: Avg & Excess 4 CP

Sch No.	Line No.	Description	MO West Retail	Residential	Small General Service	Large General Service	Large Power Service	Thermal Service	Lighting	CCN
1	1	**REVENUE REQUIREMENT SUMMARY**								
1	2	Test Year Revenue	$719,045,350	$376,086,292	$116,686,565	$88,729,808	$116,143,926	$460,184	$13,006,951	$33,302
1	3									
1	4	Gross Revenue Requirements	$ 692,345,035	$ 385,687,501	$ 96,929,995	$ 79,222,073	$ 114,132,121	$ 439,412	$ 9,679,764	$ 1,048,074
1	5	Less Other Revenue	($104,791,905)	$ (50,144,205)	$ (15,666,536)	$ (15,026,427)	$ (23,253,072)	$ (89,848)	$ (605,520)	$ (6,298)
1	6	Net Revenue Requirements	$587,553,130	$ 335,543,296	$ 81,263,459	$ 64,195,646	$ 90,879,049	$ 349,563	$ 9,074,245	$ 1,041,777
1	7									
1	8	Net Operating Income	$131,492,221	$40,542,996	$35,423,106	$24,534,162	$25,264,877	$110,621	$3,932,707	($1,008,474)
1	9									
1	10									
1	11	**RETURN AT PRESENT RATES**								
1	12	Rate Base	$ 2,484,954,467	$ 1,513,343,876	$ 342,049,275	$ 252,928,087	$ 300,470,847	$ 1,143,083	$ 60,350,804	$ 1,504,067
1	13	Net Operating Income at Present Rates	$131,492,221	$ 40,542,996	$ 35,423,106	$ 24,534,162	$ 25,264,877	$110,621	$ 3,932,707	$ (1,008,474)
1	14									
1	15	Rate of Return at Present Rates	5.29%	2.68%	10.36%	9.70%	8.41%	9.68%	6.52%	-67.05%
1	16									
1	17	Relative Rate of Return	1.00	0.51	1.96	1.83	1.59	1.83	1.23	(12.67)
1	18									
1	19	**Notes:**								
1	20	Special contracts are excluded								

Evergy, Inc. - Missouri West
2022 Rate Case - Direct
Test Year 6/30/2021
Unit Costs of Service Summary

			Equalized Rate of Return @ 7.1232%		
Sch No.	Line No.	Customer Class	Customer Costs* ($/bill) Monthly	Energy Costs ($/kWh) Annual	Demand Costs ($/kW) Annual
2	1	Residential	$21.58	$0.0395	
2	2	Small General Service	$21.24	$0.0395	$9.2973
2	3	Large General Service	$19.98	$0.0394	$10.4385
2	4	Large Power Service	$61.94	$0.0388	$8.0234
2	5	Thermal Service	$41.51	$0.0395	$12.1559
2	6	Lighting		$0.0395	

* Excluding Local Facilities

Notes:
Allocation Method: Avg & Excess 4 CP

SCHEDULES MEM-3 THROUGH MEM-4 CONTAIN CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC.

ORIGINALS FILED UNDER SEAL.

Evergy - Missouri West
Large Power Service

Case No. **ER-2022-0130**
Status **Direct**

B	C	D	E	F	G	H	I
						7.05%	
					INPUT FOR MODEL		
						8.81%	5.13%
Component	Voltage	Rate code	Season	**Tariff Language**	**Current Rates**	**Rates with Increase**	**Proposed Rates**
Customer Charge	Secondary/Primary/	MOPGS; MOPNS; MOPGSW; MOPGP; MOPNP; MOPSU; MOPSU-I	Summer/Winter	**Customer Charge**	659.84	717.99	717.99
Facilities Charge	Secondary	MOPGS; MOPNS; MOPGSW	Summer/Winter	Secondary Voltage - Rate Code (MOPGS; MOPNS):	3.148	3.425	3.425
Facilities Charge	Primary	MOPGP; MOPNP	Summer/Winter	Primary Voltage - Rate Code (MOPGP; MOPNP):	2.750	2.992	2.992
Facilities Charge	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer/Winter	Substation - Rate Code (MOPSU):	0.000	0.000	0.000
Facilities Charge	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer/Winter	Transmission - Rate Code (MOPTR):	0.000	0.000	0.000
Demand - Summer	Secondary	MOPGS; MOPNS; MOPGSW	Summer	Billing Demand	10.539	11.468	11.468
	Secondary	MOPGS; MOPNS; MOPGSW	Summer	Seasonal Billing Demand	10.539	11.468	11.468
Demand - Winter	Secondary	MOPGS; MOPNS; MOPGSW	Winter	Base Billing Demand	5.488	5.972	5.972
	Secondary	MOPGS; MOPNS; MOPGSW	Winter	Seasonal Billing Demand	0.000	0.000	0.000
Demand - Summer	Primary	MOPGP; MOPNP	Summer	Billing Demand	10.227	11.128	11.128
	Primary	MOPGP; MOPNP	Summer	Seasonal Billing Demand	10.227	11.128	11.128
Demand - Winter	Primary	MOPGP; MOPNP	Winter	Base Billing Demand	5.325	5.794	5.794
	Primary	MOPGP; MOPNP	Winter	Seasonal Billing Demand	0.000	0.000	0.000
Demand - Summer	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	Billing Demand	10.005	10.887	10.887
	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	Seasonal Billing Demand	10.005	10.887	10.887
Demand - Winter	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	Billing Demand	5.211	5.670	5.670
	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	Seasonal Billing Demand	0.000	0.000	0.000
Demand - Summer	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	Billing Demand	9.934	10.809	10.809
	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	Seasonal Billing Demand	9.934	10.809	10.809
Demand - Winter	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	Billing Demand	5.173	5.629	5.629
	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	Seasonal Billing Demand	0.000	0.000	0.000
Energy Charge - Blk 1/ On-Peak	Secondary	MOPGS; MOPNS; MOPGSW	Summer	First 180 Hours Use	0.05359	0.05359	0.05634
Energy Charge - Blk 2/ Off-Peak	Secondary	MOPGS; MOPNS; MOPGSW	Summer	Next 180 Hours Use	0.04219	0.04219	0.04435
Energy Charge - Blk 3/ Shoulder	Secondary	MOPGS; MOPNS; MOPGSW	Summer	Over 360 Hours Use	0.03699	0.03699	0.03889
Energy Charge - Blk 1/ On-Peak	Secondary	MOPGS; MOPNS; MOPGSW	Winter	First 180 Hours Use	0.05002	0.05002	0.05259
Energy Charge - Blk 2/ Off-Peak	Secondary	MOPGS; MOPNS; MOPGSW	Winter	Next 180 Hours Use	0.03936	0.03936	0.04138
Energy Charge - Blk 3/ Shoulder	Secondary	MOPGS; MOPNS; MOPGSW	Winter	Over 360 Hours Use	0.03451	0.03451	0.03628
Energy Charge - Blk 1/ On-Peak	Primary	MOPGP; MOPNP	Summer	First 180 Hours Use	0.05195	0.05195	0.05461
Energy Charge - Blk 2/ Off-Peak	Primary	MOPGP; MOPNP	Summer	Next 180 Hours Use	0.04088	0.04088	0.04298
Energy Charge - Blk 3/ Shoulder	Primary	MOPGP; MOPNP	Summer	Over 360 Hours Use	0.03584	0.03584	0.03768
Energy Charge - Blk 1/ On-Peak	Primary	MOPGP; MOPNP	Winter	First 180 Hours Use	0.04852	0.04852	0.05101
Energy Charge - Blk 2/ Off-Peak	Primary	MOPGP; MOPNP	Winter	Next 180 Hours Use	0.03818	0.03818	0.04014
Energy Charge - Blk 3/ Shoulder	Primary	MOPGP; MOPNP	Winter	Over 360 Hours Use	0.03346	0.03346	0.03518
Energy Charge - Blk 1/ On-Peak	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	First 180 Hours Use	0.05051	0.05051	0.05310
Energy Charge - Blk 2/ Off-Peak	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	Next 180 Hours Use	0.03977	0.03977	0.04181
Energy Charge - Blk 3/ Shoulder	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	Over 360 Hours Use	0.03484	0.03484	0.03663
Energy Charge - Blk 1/ On-Peak	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	First 180 Hours Use	0.04773	0.04773	0.05018
Energy Charge - Blk 2/ Off-Peak	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	Next 180 Hours Use	0.03756	0.03756	0.03949
Energy Charge - Blk 3/ Shoulder	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	Over 360 Hours Use	0.03292	0.03292	0.03461
Energy Charge - Blk 1/ On-Peak	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	First 180 Hours Use	0.05151	0.05151	0.05415
Energy Charge - Blk 2/ Off-Peak	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	Next 180 Hours Use	0.04054	0.04054	0.04262
Energy Charge - Blk 3/ Shoulder	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	Over 360 Hours Use	0.03554	0.03554	0.03736
Energy Charge - Blk 1/ On-Peak	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	First 180 Hours Use	0.04652	0.04652	0.04891
Energy Charge - Blk 2/ Off-Peak	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	Next 180 Hours Use	0.03660	0.03660	0.03848
Energy Charge - Blk 3/ Shoulder	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	Over 360 Hours Use	0.03207	0.03207	0.03372
Seasonal Energy Charge	Secondary	MOPGS; MOPNS; MOPGSW	Summer	First 180 Hours Use	0.05359	0.05359	0.05634
Seasonal Energy Charge 1	Secondary	MOPGS; MOPNS; MOPGSW	Summer	Next 180 Hours Use	0.04219	0.04219	0.04435
Seasonal Energy Charge 2	Secondary	MOPGS; MOPNS; MOPGSW	Summer	Over 360 Hours Use	0.03699	0.03699	0.03889
Seasonal Energy Charge	Secondary	MOPGS; MOPNS; MOPGSW	Winter	First 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 1	Secondary	MOPGS; MOPNS; MOPGSW	Winter	Next 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 2	Secondary	MOPGS; MOPNS; MOPGSW	Winter	Over 360 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge	Primary	MOPGP; MOPNP	Summer	First 180 Hours Use	0.05195	0.05195	0.05461
Seasonal Energy Charge 1	Primary	MOPGP; MOPNP	Summer	Next 180 Hours Use	0.04088	0.04088	0.04298
Seasonal Energy Charge 2	Primary	MOPGP; MOPNP	Summer	Over 360 Hours Use	0.03584	0.03584	0.03768
Seasonal Energy Charge	Primary	MOPGP; MOPNP	Winter	First 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 1	Primary	MOPGP; MOPNP	Winter	Next 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 2	Primary	MOPGP; MOPNP	Winter	Over 360 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	First 180 Hours Use	0.05051	0.05051	0.05310
Seasonal Energy Charge 1	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	Next 180 Hours Use	0.03977	0.03977	0.04181
Seasonal Energy Charge 2	Substation	MOPSU; MOPSU-RTP; MOPSUW	Summer	Over 360 Hours Use	0.03484	0.03484	0.03663
Seasonal Energy Charge	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	First 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 1	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	Next 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 2	Substation	MOPSU; MOPSU-RTP; MOPSUW	Winter	Over 360 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	First 180 Hours Use	0.05151	0.05151	0.05415
Seasonal Energy Charge 1	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	Next 180 Hours Use	0.04054	0.04054	0.04262
Seasonal Energy Charge 2	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Summer	Over 360 Hours Use	0.03554	0.03554	0.03736
Seasonal Energy Charge	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	First 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 1	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	Next 180 Hours Use	0.03139	0.03139	0.03300
Seasonal Energy Charge 2	Transmission	MOPTR; MOPTR-RTP; MOPTRW	Winter	Over 360 Hours Use	0.03139	0.03139	0.03300
Reactive Demand Adj	Secondary/Primary/	MOPGS; MOPNS; MOPGSW; MOPGP; MOPNP; MOPSU; MOPSU-I	Summer/Winter	REACTIVE DEMAND ADJUSTMENT	0.420	0.45701	0.457
Primary Discount	Secondary/Primary/	MOPGS; MOPNS; MOPGSW; MOPGP; MOPNP; MOPSU; MOPSU-I	Summer/Winter	PRIMARY DISCOUNT	-1.00	-1.00	-1.00
				RTP - Special Contract			
Service Charge	Secondary/Primary/	MOPSU-RTP; MOPTR-RTP	Summer/Winter	Service Charge (CBL peak kW > 500 for 3 consecutive months)	296.570	322.71	322.71
		MOPSU-RTP; MOPTR-RTP		Service Charge (all other)	336.860	366.55	366.55
		MOPSU-RTP; MOPTR-RTP		Trans Congestion Charge-Primary	0.04550	0.04950	0.05
		MOPSU-RTP; MOPTR-RTP		Trans Congestion Charge-Secondary	0.04674	0.05086	0.05
		MOPSU-RTP; MOPTR-RTP		Short-term Fixed Power Transaction Fee	223.330	243.01	243.01
		Secondary - Summer	LPS Secondary	Summer	100.000%	3.37%	6.537%
		Secondary Winter	LPS Secondary	Winter	100.000%	2.72%	6.269%
		Primary - Summer	LPS Primary	Summer	100.000%	3.29%	6.638%
		Primary - Winter	LPS Primary	Winter	100.000%	2.57%	6.385%
		Substation - Summer	LPS Substation	Summer	100.000%	2.83%	6.409%
		Substation - Winter	LPS Substation	Winter	100.000%	1.80%	6.026%
		Transmission - Summer	LPS Transmission	Summer	100.000%	3.25%	6.621%
		Transmission - Winter	LPS Transmission	Winter	100.000%	2.13%	6.197%
		Winter Price Below Summer (SUM-WIN)/SUM			18.408%	18.998%	21.497%
		LPS Overall Change				2.887%	6.405%
				Revenue	$ 117,117,854.49	$ 120,498,669.16	$ 124,618,769.06
				Change in Revenue			$ 7,500,914.57
				Proposed change per Revenue Summary			$ 7,501,489.00
							($574)
				EDR Credit	$ (702,245.78)		
				Ex Fac	$ -		
				Forecasted EE Adjustment	$ -		
					$ 116,415,608.71		
				Total Normalized/Annualized Revenues from LPS Billed Revenues	$ 116,415,608.75		

Evergy - Missouri West
Large General Service

Case No. ER-2022-0130
Status Direct

7.77%

INPUT FOR MODEL

	A	B	C	D	E	F	G	H	I
9					JURIS INCREASE (%)			9.71%	5.81%
10	Ref Column	Charge	Voltage	Rate Code	Season	Tariff Language	Current Rates	Rates with Increase	Proposed Rates
11	1								
12	2	Customer Charge/ Other Meter	Secondary	MOLGS ;MOLNS :MOLGSW	Summer/Winter	Customer Charge	72.26	79.28	79.28
13	3	Customer Charge/ Other Meter	Primary	MOLGP ;MOLNP	Summer/Winter	Customer Charge	237.71	260.80	260.80
14	4								
15	5	Facilities Charge - Blk 1	Secondary	MOLGS ;MOLNS :MOLGSW	Summer/Winter	Facilities Charge	2.211	2.426	2.426
16	6	Facilities Charge - Blk 1	Primary	MOLGP ;MOLNP	Summer/Winter	Facilities Charge	1.432	1.571	1.571
17	7								
18	8	Demand Charge - Blk 1/ Base	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	Billing Demand	0.875	0.960	0.960
19	9	Demand Charge - Blk 2/ Seasonal	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	Seasonal Billing Demand	0.875	0.960	0.960
20	10								
21	11	Demand Charge - Blk 1/ Base	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	Billing Demand	0.590	0.647	0.647
22	12	Demand Charge - Blk 2/ Seasonal	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	Seasonal Billing Demand	0.000	0.000	0.000
23	13								
24	14	Demand Charge - Blk 1/ Base	Primary	MOLGP ;MOLNP	Summer	Billing Demand	0.848	0.930	0.930
25	15	Demand Charge - Blk 2/ Seasonal	Primary	MOLGP ;MOLNP	Summer	Seasonal Billing Demand	0.848	0.930	0.930
26	16								
27	17	Demand Charge - Blk 1/ Base	Primary	MOLGP ;MOLNP	Winter	Billing Demand	0.572	0.628	0.628
28	18	Demand Charge - Blk 2/ Seasonal	Primary	MOLGP ;MOLNP	Winter	Seasonal Billing Demand	0.000	0.000	0.000
29	19								
30	20	Energy Charge - Blk 1/ On-Peak	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	First 180 Hours Use	0.08736	0.08736	0.09243
31	21	Energy Charge - Blk 2/ Off-Peak	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	Next 180 Hours Use	0.06610	0.06610	0.06994
32	22	Energy Charge - Blk 3/ Shoulder /S	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	Over 360 Hours Use	0.04625	0.04625	0.04894
33	23								
34	24	Energy Charge - Blk 1/ On-Peak	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	First 180 Hours Use	0.06655	0.06655	0.07042
35	25	Energy Charge - Blk 2/ Off-Peak	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	Next 180 Hours Use	0.06100	0.06100	0.06454
36	26	Energy Charge - Blk 3/ Shoulder /S	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	Over 360 Hours Use	0.04177	0.04177	0.04420
37	27								
38	28	Energy Charge - Blk 1/ On-Peak	Primary	MOLGP ;MOLNP	Summer	First 180 Hours Use	0.08471	0.08471	0.08963
39	29	Energy Charge - Blk 2/ Off-Peak	Primary	MOLGP ;MOLNP	Summer	Next 180 Hours Use	0.06410	0.06410	0.06782
40	30	Energy Charge - Blk 3/ Shoulder /S	Primary	MOLGP ;MOLNP	Summer	Over 360 Hours Use	0.04484	0.04484	0.04744
41	31								
42	32	Energy Charge - Blk 1/ On-Peak	Primary	MOLGP ;MOLNP	Winter	First 180 Hours Use	0.06414	0.06414	0.06787
43	33	Energy Charge - Blk 2/ Off-Peak	Primary	MOLGP ;MOLNP	Winter	Next 180 Hours Use	0.05878	0.05878	0.06219
44	34	Energy Charge - Blk 3/ Shoulder /S	Primary	MOLGP ;MOLNP	Winter	Over 360 Hours Use	0.04023	0.04023	0.04257
45	35								
46	36	Seasonal Energy Charge	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	First 180 Hours Use	0.08736	0.08736	0.09243
47	37	Seasonal Energy Charge 1	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	Next 180 Hours Use	0.06610	0.06610	0.06994
48	38	Seasonal Energy Charge 2	Secondary	MOLGS ;MOLNS :MOLGSW	Summer	Over 360 Hours Use	0.04625	0.04625	0.04894
49	39								
50	40	Seasonal Energy Charge	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	First 180 Hours Use	0.03654	0.03654	0.03866
51	41	Seasonal Energy Charge 1	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	Next 180 Hours Use	0.03654	0.03654	0.03866
52	42	Seasonal Energy Charge 2	Secondary	MOLGS ;MOLNS :MOLGSW	Winter	Over 360 Hours Use	0.03654	0.03654	0.03866
53	43								
54	44	Seasonal Energy Charge	Primary	MOLGP ;MOLNP	Summer	First 180 Hours Use	0.08471	0.08471	0.08963
55	45	Seasonal Energy Charge 1	Primary	MOLGP ;MOLNP	Summer	Next 180 Hours Use	0.06410	0.06410	0.06782
56	46	Seasonal Energy Charge 2	Primary	MOLGP ;MOLNP	Summer	Over 360 Hours Use	0.04484	0.04484	0.04744
57	47								
58	48	Seasonal Energy Charge	Primary	MOLGP ;MOLNP	Winter	First 180 Hours Use	0.03562	0.03562	0.03769
59	49	Seasonal Energy Charge 1	Primary	MOLGP ;MOLNP	Winter	Next 180 Hours Use	0.03562	0.03562	0.03769
60	50	Seasonal Energy Charge 2	Primary	MOLGP ;MOLNP	Winter	Over 360 Hours Use	0.03562	0.03562	0.03769
61	51								
62	40	Primary Discount	Secondary/	MOLGS ;MOLNS ;MOLGP ;MOLNP ;MOLGSW	Summer/Winter	Primary Discount	-1.00	-1.00	-1.00

	D	E	F	G	H	I
65	Secondary - Summer	Secondary	Summer	100.000%	1.301%	6.330%
66	Secondary Winter	Secondary	Winter	100.000%	1.583%	6.447%
67	Primary - Summer	Primary	Summer	100.000%	1.168%	6.514%
68	Primary - Winter	Primary	Winter	100.000%	1.514%	6.764%
69	Winter Price Below Summer (SUM-WIN)/SUM			15.112%	14.870%	15.014%
70	LGS Overall Change				1.462%	6.417%

	F	G	H	I
72	Revenue	$ 89,859,361.48	$ 91,173,173.78	$ 95,625,498.89
73	Change in Revenue			$5,766,137
75	Proposed change per Revenue Summary			$ 5,767,424
76				($1,287)
78	Net Metering Credit	$ (8,732.17)		
79	Parallel Generation Credit	$ (1,100.24)		
80	Customer Revenue Share	$ (14,240.43)		
81	Rollover Credit Available	$ (7,173.41)		
82	Reduced Commitment Surcharge	$ 170.84		
83	EDR Credit	$ (1,129,553.25)		
84	Ex FAC/Line Extension	$ 2,887.50		
85		$ 88,701,620.32		
88		Tie-out to Billed Revenue Total		
89		0.01		

Evergy - Missouri West
Small General Service

Case No.: ER-2022-0130
Status: Direct

4.30%

Charge	Voltage	Rate Code	Season	Tariff Language	Current Rates	Rates with Increase	Proposed Rates
						INPUT FOR MODEL	
				JURIS INCREASE (%)		5.38%	4.00%
Customer Charge/ Other Meter	Secondary/Primary	MOSDS /MOSND /MOSGP /MOSNS	Summer/Winter	Customer Charge	23.14	24.38	24.38
Customer Charge/ Other Meter	Secondary/Primary	MOSHS	Summer/Winter	Separately Metered Heat and/or Water Heating	9.43	9.94	9.94
Facilities Charge - Blk 1	Secondary	MOSDS /MOSND /MOSDSW	Summer/Winter	Facilities Charge	1.398	1.473	1.473
Facilities Charge - Blk 1	Primary	MOSGP	Summer/Winter	Facilities Charge	1.398	1.473	1.473
Demand Charge - Blk 1/ Base	Secondary	MOSDS /MOSND /MOSDSW	Summer	Billing Demand	1.227	1.293	1.293
Demand Charge - Blk 2/ Seasonal	Secondary	MOSDS /MOSND /MOSDSW	Summer	Seasonal Billing Demand	1.227	1.293	1.293
Demand Charge - Blk 1/ Base	Secondary	MOSDS /MOSND /MOSDSW	Winter	Billing Demand	1.199	1.263	1.263
Demand Charge - Blk 2/ Seasonal	Secondary	MOSDS /MOSND /MOSDSW	Winter	Seasonal Billing Demand	0.000	0.000	0.000
Demand Charge - Blk 1/ Base	Primary	MOSGP	Summer	Billing Demand	1.190	1.254	1.254
Demand Charge - Blk 2/ Seasonal	Primary	MOSGP	Summer	Seasonal Billing Demand	1.190	1.254	1.254
Demand Charge - Blk 1/ Base	Primary	MOSGP	Winter	Billing Demand	1.163	1.226	1.226
Demand Charge - Blk 2/ Seasonal	Primary	MOSGP	Winter	Seasonal Billing Demand	0.000	0.000	0.000
Energy Charge - Blk 1/ On-Peak	Secondary	MOSGS /MOSNS /MOSUS	Summer	Summer	0.13542	0.13542	0.14083
Energy Charge - Blk 1/ On-Peak	Secondary	MOSGS /MOSNS /MOSUS	Winter	Winter	0.08508	0.08508	0.08848
Energy Charge - Blk 1/ On-Peak	Secondary	MOSHS	Summer	Summer	0.13542	0.13542	0.14083
Energy Charge - Blk 1/ On-Peak	Secondary	MOSHS	Winter	Winter	0.06335	0.06335	0.06588
Energy Charge - Blk 1/ On-Peak	Secondary	MOSDS /MOSND /MOSDSW	Summer	First 180 Hours Use	0.09494	0.09494	0.09873
Energy Charge - Blk 2/ Off-Peak	Secondary	MOSDS /MOSND /MOSDSW	Summer	Over 180 Hours Use	0.07144	0.07144	0.07430
Energy Charge - Blk 1/ On-Peak	Secondary	MOSDS /MOSND /MOSDSW	Winter	First 180 Hours Use	0.06896	0.06896	0.07172
Energy Charge - Blk 2/ Off-Peak	Secondary	MOSDS /MOSND /MOSDSW	Winter	Over 180 Hours Use	0.06224	0.06224	0.06473
Energy Charge - Blk 1/ On-Peak	Primary	MOSGP	Summer	First 180 Hours Use	0.08907	0.08907	0.09263
Energy Charge - Blk 2/ Off-Peak	Primary	MOSGP	Summer	Over 180 Hours Use	0.06702	0.06702	0.06970
Energy Charge - Blk 1/ On-Peak	Primary	MOSGP	Winter	First 180 Hours Use	0.06773	0.06773	0.07044
Energy Charge - Blk 2/ Off-Peak	Primary	MOSGP	Winter	Over 180 Hours Use	0.06113	0.06113	0.06357
Seasonal Energy Charge	Secondary	MOSGS /MOSNS /MOSUS	Summer	Summer	0.13542	0.13542	0.14083
Seasonal Energy Charge	Secondary	MOSGS /MOSNS /MOSUS	Winter	Winter	0.04364	0.04364	0.04538
Seasonal Energy Charge	Secondary	MOSHS	Summer	Summer	0.13542	0.13542	0.14083
Seasonal Energy Charge	Secondary	MOSHS	Winter	Winter	0.04364	0.04364	0.04538
Seasonal Energy Charge	Secondary	MOSDS /MOSND /MOSDSW	Summer	First 180 Hours Use	0.09494	0.09494	0.09873
Seasonal Energy Charge - Blk 2	Secondary	MOSDS /MOSND /MOSDSW	Summer	Over 180 Hours Use	0.07144	0.07144	0.07430
Seasonal Energy Charge	Secondary	MOSDS /MOSND /MOSDSW	Winter	First 180 Hours Use	0.04364	0.04364	0.04538
Seasonal Energy Charge - Blk 2	Secondary	MOSDS /MOSND /MOSDSW	Winter	Over 180 Hours Use	0.04364	0.04364	0.04538
Seasonal Energy Charge	Primary	MOSGP	Summer	First 180 Hours Use	0.08907	0.08907	0.09263
Seasonal Energy Charge - Blk 2	Primary	MOSGP	Summer	Over 180 Hours Use	0.06702	0.06702	0.06970
Seasonal Energy Charge	Primary	MOSGP	Winter	First 180 Hours Use	0.04193	0.04193	0.04361
Seasonal Energy Charge - Blk 2	Primary	MOSGP	Winter	Over 180 Hours Use	0.04193	0.04193	0.04361
Primary Discount	Secondary/Primary	MOSDS /MOSND /MOSGP /MOSHS	Winter/Summer	PRIMARY DISCOUNT	-1.00	-1.00	-1.00

MOSGS ;MOSNS; MOS	Summer	100.000%	1.04%	4.26%
MOSGS ;MOSNS; MOS	Winter	100.000%	1.60%	4.40%
MOSHS	Summer	100.000%	0.00%	0.00%
MOSHS	Winter	100.000%	0.00%	0.00%
MOSDS ;MOSND ;MOS	Summer	100.000%	0.91%	4.23%
MOSDS ;MOSND ;MOS	Winter	100.000%	1.21%	4.31%
MOSGP	Summer	100.000%	1.07%	4.31%
MOSGP	Winter	100.000%	1.09%	4.34%
Winter Price Below Summer (SUM-WIN)/SUM		**22.792%**	**22.515%**	**22.723%**
SGS Overall Change			1.156%	4.292%

Revenue	$ 116,692,908	$ 118,041,385	$ 121,700,941
Change in Revenue			$ 5,008,032.71
Proposed change per Revenue Summary			$ 5,009,620.00
			($1,587)

Net Metering Credit	$ (46,221.39)
Parallel Generation Credit	$ (3,236.40)
Customer Revenue Share	$ (407.49)
Reduced Commitment Surcharge	$ 7.47
EDR Credit	$ (6,285.16)
Ex FAC/Line Extension	$ 216.00
	$ 116,636,981

	B	C	D	E	F	G	H	I
1				**Evergy - Missouri West**				
2				**Residential**				
3								
4				**Case No.**	**ER-2022-0130**			
5				**Status**	**Direct**			
6							10.84%	
7							*INPUT FOR MODEL*	
8				**JURIS INCREASE (%)**				**7.39%**
9	Charge	Usage	Rate Code	Season	Charge Values	**Current Rates**	**Rates with Increase**	**Proposed Rates**
10								
11	Customer Charge/ Other Meter	General Use, with Net Metering	MORG /MORN	Summer/Winter	General Use, with Net Metering	11.47	16.00	*16.00*
12	Customer Charge/ Other Meter	Space Heating	MORH /MORNH /MORHP	Summer/Winter	Space Heating - One Meter, with Net Meter	11.47	16.00	*16.00*
13	Customer Charge/ Other Meter	Other Use	MORO	Summer/Winter	Other Use	17.18	23.97	*23.97*
14	Customer Charge/ Other Meter	Time of Use	MORT	Summer/Winter	Residential	11.47	16.00	*16.00*
15								
16	Energy Charge - Blk 1/ On-Peak	General Use, with Net Metering	MORG /MORN	Summer	First 600 kWh	0.10938	0.10938	*0.11752*
17	Energy Charge - Blk 2/ Off-Peak	General Use, with Net Metering	MORG /MORN	Summer	Next 400 kWh	0.10938	0.10938	*0.11752*
18	Energy Charge - Blk 3/ Shoulder	General Use, with Net Metering	MORG /MORN	Summer	Over 1000 kWh	0.11927	0.11927	*0.12815*
19								
20	Energy Charge - Blk 1/ On-Peak	General Use, with Net Metering	MORG /MORN	Winter	First 600 kWh	0.09888	0.09888	*0.10623*
21	Energy Charge - Blk 2/ Off-Peak	General Use, with Net Metering	MORG /MORN	Winter	Next 400 kWh	0.07800	0.07800	*0.08380*
22	Energy Charge - Blk 3/ Shoulder /Super Off-Peak	General Use, with Net Metering	MORG /MORN	Winter	Over 1000 kWh	0.07800	0.07800	*0.08380*
23								
24	Energy Charge - Blk 1/ On-Peak	Space Heating - One Meter, with Net Metering, or Parallel Gen	MORH /MORNH /MORHP	Summer	First 600 kWh	0.11927	0.11927	*0.12815*
25	Energy Charge - Blk 2/ Off-Peak	Space Heating - One Meter, with Net Metering, or Parallel Gen	MORH /MORNH /MORHP	Summer	Next 400 kWh	0.11927	0.11927	*0.12815*
26	Energy Charge - Blk 3/ Shoulder /Super Off-Peak	Space Heating - One Meter, with Net Metering, or Parallel Gen	MORH /MORNH /MORHP	Summer	Over 1000 kWh	0.11927	0.11927	*0.12815*
27								
28	Energy Charge - Blk 1/ On-Peak	Space Heating - One Meter, with Net Metering, or Parallel Gen	MORH /MORNH /MORHP	Winter	First 600 kWh	0.09888	0.09888	*0.10623*
29	Energy Charge - Blk 2/ Off-Peak	Space Heating - One Meter, with Net Metering, or Parallel Gen	MORH /MORNH /MORHP	Winter	Next 400 kWh	0.06035	0.06035	*0.06484*
30	Energy Charge - Blk 3/ Shoulder /Super Off-Peak	Space Heating - One Meter, with Net Metering, or Parallel Gen	MORH /MORNH /MORHP	Winter	Over 1000 kWh	0.05005	0.05005	*0.05378*
31								
32	Energy Charge - Blk 1/ On-Peak	Other Use (all kWh)	MORO	Summer	SUMMER	0.14664	0.14664	*0.15755*
33	Energy Charge - Blk 1/ On-Peak	Other Use (all kWh)	MORO	Winter	WINTER	0.10996	0.10996	*0.11814*
34								
35	Energy Charge - Blk 1/ On-Peak	Residential - Time of Use	MORT	Summer	Peak	0.26577	0.26577	*0.31142*
36	Energy Charge - Blk 2/ Off-Peak	Residential - Time of Use	MORT	Summer	Off-Peak	0.08859	0.08859	*0.10381*
37	Energy Charge - Blk 3/ Shoulder /Super Off-Peak	Residential - Time of Use	MORT	Summer	Super-Off Peak	0.04429	0.04429	*0.05190*
38								
39	Energy Charge - Blk 1/ On-Peak	Residential - Time of Use	MORT	Winter	Peak	0.21629	0.21629	*0.15571*
40	Energy Charge - Blk 2/ Off-Peak	Residential - Time of Use	MORT	Winter	Off-Peak	0.08727	0.08727	*0.07786*
41	Energy Charge - Blk 3/ Shoulder /Super Off-Peak	Residential - Time of Use	MORT	Winter	Super-Off Peak	0.03667	0.03667	*0.05190*
42								
43								
44			General Use, with Net Metering		Summer	100.000%	3.368%	10.175%
45			General Use, with Net Metering		Winter	100.000%	5.841%	12.179%
46			Space Heating - One Meter, with Net Metering, or Parallel Gen		Summer	100.000%	2.874%	9.774%
47			Space Heating - One Meter, with Net Metering, or Parallel Gen		Winter	100.000%	4.284%	10.918%
48			Other Use (all kWh)		Summer	100.000%	#DIV/0!	#DIV/0!
49			Other Use (all kWh)		Winter	100.000%	#DIV/0!	#DIV/0!
50			Winter Price Below Summer (SUM-WIN)/SUM			**25.050%**	**23.620%**	**24.108%**
51			RES Overall Change				4.250%	10.841%
52								
53					Revenue	$ 376,086,292.10	$ 392,069,511.52	$ 416,859,656.06
54					Change in Revenue			$ 40,773,363.96
55								
56					Proposed change per Revenue Summary			$ 40,777,992.85
57								($4,629)
58								
59					Manual Bill			
60					Net Metering Credit	$ (115,036.41)		
61					Parallel Generation Credit	$ (66.92)		
62						$ 375,971,188.77		
63								

	B	C	D	E	F	G	H
1			**Evergy - Missouri West**				
2			**Lighting (Metered)**				
3							
4			**Case No.**	**ER-2022-0130**			
5			**Status**	**Direct**			
6							
7							
8						*INPUT FOR MODEL*	
9				**JURIS INCREASE (%)**		**0.00%**	**6.39%**
10	Charge	Rate Code	**Season**	Tariff Language	**Current Rates**	**Rates with Increase**	**Proposed Rates**
11	Customer Charge/ Other Meter	MO971	Summer/Winter	Service Charge (Frozen) - Rate Code (MO971):	7.20	7.20	*7.66*
12	Secondary Meter Base Installation	MO972 /MO973	Summer/Winter	Secondary Meter Base Installation - per meter (Frozen)	3.07	3.07	*3.27*
13			~~Summer/Winter~~	~~Meter Installation with Current Transformers - per meter (Frozen)~~	~~5.32~~	~~5.32~~	~~*5.66*~~
14	Customer Charge/ Other Meter	MO972	Summer/Winter	Other Meter - per meter (Frozen)	11.32	11.32	*12.04*
15	Customer Charge/ Other Meter	MOOLL	Summer/Winter	Customer Charge - Rate Code (MOOLL):	10.08	10.08	*10.72*
16							
17			**B: ENERGY CHARGE**				
18	Energy Charge - Blk 1/ On-Peak	MO971	Summer/Winter	Rate Code (MO971) (Frozen):	0.11880	0.11880	*0.12639*
19	Energy Charge - Blk 1/ On-Peak	MO972	Summer/Winter	Rate Code (MO972) (Frozen):	0.06139	0.06139	*0.06531*
20	Energy Charge - Blk 1/ On-Peak	MO973	Summer/Winter	Rate Code (MO973) (Frozen):	0.07373	0.07373	*0.07844*
21	Energy Charge - Blk 1/ On-Peak	MOOLL	Summer/Winter	Rate Code (MOOLL):	0.05639	0.05639	*0.06000*
22							
23			MO971	Summer	100.000%	0.00%	6.389%
24			MO971	Winter	100.000%	0.00%	6.389%
25			MO972	Summer	100.000%	0.00%	6.390%
26			MO972	Winter	100.000%	0.00%	6.389%
27			MO973	Summer	100.000%	0.00%	6.405%
28			MO973	Winter	100.000%	0.00%	6.403%
29			MOOLL	Summer	100.000%	0.00%	6.395%
30			MOOLL	Winter	100.000%	0.00%	6.397%
31			Winter Price Below Summer (SUM-WIN)/SUM		**9.587%**	**9.587%**	**9.588%**
32			Lighting Overall Change			0.000%	6.393%
33							
34				Revenue	$ 97,006.76	$ 97,006.76	$ 103,208.04
35				Change in Revenue			$ 6,201.28
36							
37				Proposed change per Revenue Summary			$ 6,201.68
38							$ (0.40)
39							
40				Ex FAC/ Line extension	$ 1,476.00		
41					$ 98,482.76	non-BD revenue	
42							

	B	D	E	G	J	L	N	O
1		**Evergy - Missouri West**						
2		Lighting (Unmetered)				**4.00%**	% for MV	
3						**1.92%**	% for all other non-LED	
4		**ER-2022-0130**		Juris Increase (%) =	6.39%	**0.00%**	% for permanent LED and traffic signals	
5		**Direct**				**22.52%**	% for transitional LED* - moving pricing toward	
6								
7	Rate		Tariff		Current Rate	Proposed Rate	%Δ	*MRU/CCB Item Type
8	Schedule	Rate Code	Sheet No.	Description	Monthly	Monthly		
9	L&P MSL	MOS22	42	Mercury Vapor Lamp - 400 watt (estimated 19,100 lumens)	$ 14.90	$ 15.50	4.027%	S085
10	L&P PAL	**Additional Facilities**						
11	L&P MSL	MOSJB	41	14' Decorative Pole Ug (1)	$ 12.23	$ 12.46	1.881%	S109
12	L&P MSL	MOSJB	41	Underground Circuit, in dirt	$ 0.05	$ 0.05	-7.253%	S113
13	L&P MSL	MOSJB	41	Special Contract Pole (1)	$ 21.56	$ 21.98	1.940%	S116
14								
15								
16	L&P SL	MOS16	43	Unmetered HPS 150W - at 63 per kWh energy on MO972	$ 3.85	$ 3.92	1.818%	S036
17	L&P SL	MOS25	43	HPS 150W Street Light	$ 14.00	$ 14.27	1.929%	S114
18	L&P SL	MOS25	43	HPS 150W Street Light	$ 17.34	$ 17.67	1.903%	S115
19	L&P SL	MOS26	43	Misc Street Light - 295W Incandescent	$ 26.96	$ 27.48	1.929%	S099
20								
21	L&P TR	MOS18	44	3-section-8" signal face (R,Y,G) (90 Watts) - Partial Operation	$ 4.05	$ 4.05	0.000%	S040
22	L&P TR	MOS18	44	3-section-12" signal face (R,Y,G) (2 @ 90 watts, 1 @ 135 watts) - Partial Operation	$ 4.70	$ 4.70	0.000%	S041
23	L&P TR	MOS18	44	3-section-signal face (R,Y,G) optically oprogrammed (3 @ 150 Watts) - Partial Operation	$ 6.70	$ 6.70	0.000%	S043
24	L&P TR	MOS18	44	2-section-signal face (Walk/Don't Walk) (2 @ 90 watts) - Partial Operation	$ 3.23	$ 3.23	0.000%	S044
25	L&P TR	MOS18	44	2-section-school signal (2 @ 90 watts) - Partial Operation	$ 0.29	$ 0.29	0.000%	S046
26	L&P TR	MOS18	44	1-section-school signal (1 @ 90 watts) - Partial Operation	$ 0.15	$ 0.15	0.000%	S047
27	L&P TR	MOS18	44	1-section-signal face (special function) (1 @ 90 watts) - Non-Continuous Operation but has sam	$ 1.62	$ 1.62	0.000%	S048
28	L&P TR	MOS20	44	3-section-12" signal face (R,Y,G) (2 @ 90 watts, 1 @ 135 watts) - Continuous Operation	$ 5.66	$ 5.66	0.000%	S056
29	L&P TR	MOS20	44	5-section-signal face (R,Y,G,Y arrow, G arrow) (4@ 90 watts, 1 @ 135 watts) - Continuous Ope	$ 7.36	$ 7.36	0.000%	S059
30	L&P TR	MOS20	44	3-section-8" signal face (R,Y,G) (90 Watts) - Continuous Operation	$ 4.86	$ 4.86	0.000%	S060
31	L&P TR	MOS20	44	1-section-signal face (special function) (1 @ 90 watts) - Continuous Operation	$ 1.62	$ 1.62	0.000%	S061
32	L&P TR	MOS20	44	1-section-signal face (flashing beacon) (1 @ 90 watts) - Continuous Operation	$ 2.43	$ 2.43	0.000%	S062
33	L&P TR	MOS20	44	Special Contract - (R,Y,G,Y arrow, G arrow) (4 @ 90 watts, 1 @ 135 watts), 99 kWh * kWh prici	$ 7.28	$ 7.28	0.000%	S063
34	L&P TR	MOS18	44	Special Contract - traffic signal, 34 kWh * kWh pricing	$ 2.50	$ 2.50	0.000%	S049
35	L&P TR	MOS18	44	Special Contract - traffic signal, 87 kWh * kWh pricing	$ 6.40	$ 6.40	0.000%	S050
36	L&P TR	MOS18	44	Special Contract - optically programmed (3 @ 150 watts), 95 kWh * kWh pricing	$ 6.99	$ 6.99	0.000%	S051
37	L&P TR	MOS28		CATV Power Supply	$ 68.00	$ 68.00	0.000%	S120
38								
39	L&P PAL	MOS30, MOS31	47	Private Area - Standard - MV - 175 W (7,650 lumens)	$ 11.08	$ 11.52	3.971%	S001
40	L&P PAL	MOS31	47	Private Area - Standard - MV - 400 W (19,100 lumens)	$ 22.41	$ 23.31	4.016%	S002
41	L&P PAL	MOS30, MOS31	47	Private Area - Standard - HPS - 150 W (14,400 lumens)	$ 14.00	$ 14.27	1.929%	S003
42	L&P PAL	MOS30, MOS31	47	Private Area - Roadway - HPS - 150 W (14,400 lumens)	$ 16.94	$ 17.27	1.948%	S004
43	L&P PAL	MOS31	47	Private Area - Roadway - HPS - 250 W (24,750 lumens)	$ 18.89	$ 19.25	1.906%	S005
44	L&P PAL	MOS30, MOS31	47	Private Area - Roadway - HPS - 400 W (45,000 lumens)	$ 21.63	$ 22.05	1.942%	S006
45	L&P PAL	MOS31	47	Special Contract - Private Area - HPS - 400 W (45,000 lumens)	$ 19.09	$ 19.46	1.938%	S024
46	L&P PAL	MOS32, MOS33	47	Directional Flood - Standard - MV - 400 W (19,100 lumens)	$ 25.26	$ 26.27	3.998%	S007
47	L&P PAL	MOS33	47	Directional Flood - Standard - MV - 1,000 W (47,500 lumens)	$ 50.12	$ 52.12	3.990%	S008
48	L&P PAL	MOS32, MOS33	47	Directional Flood - Standard - HPS - 150 W (14,400 lumens)	$ 14.00	$ 14.27	1.929%	S009
49	L&P PAL	MOS32, MOS33	47	Directional Flood - Standard - HPS - 400 W (45,000 lumens)	$ 25.44	$ 25.93	1.926%	S010
50	L&P PAL	MOS32, MOS33	47	Directional Flood - Standard - HPS - 1,000 W (126,000 lumens)	$ 54.31	$ 55.35	1.915%	S011
51	L&P PAL	MOS32, MOS33	47	Directional Flood - Standard - MH - 400 W (23,860 lumens)	$ 26.96	$ 27.48	1.929%	S012
52	L&P PAL	MOS32, MOS33	47	Directional Flood - Standard - MH - 1,000 W (82,400 lumens)	$ 50.12	$ 51.08	1.915%	S013
53	L&P PAL	MOS35	47	Special - Shoebox - MH - 1000 W (82,400 lumens)	$ 59.90	$ 61.05	1.920%	S015
54	L&P PAL	MOS35	47	Special - Shoebox - HPS - 400 W - (45,000 lumens)	$ 37.27	$ 37.99	1.932%	S017
55	L&P PAL	MOS35		Special Contract - PAL	$ 8.56	$ 8.72	1.869%	S021
56	L&P PAL							
57	L&P PAL	**Additional Facilities**						
58	L&P PAL	MOSJR, MOSJC	48	Wood - 35' - OH - 1 span	$ 3.93	$ 4.01	2.036%	S105
59	L&P PAL	MOSJR, MOSJC	48	Wood - 35' - UG - 100'	$ 9.55	$ 9.73	1.885%	S106
60	L&P PAL	MOSJC	48	Steel - 30' - UG - 1 span or 100'	$ 28.88	$ 29.43	1.904%	S107
61	L&P PAL	MOSJC	48	Decorative - 14' - UG - 100'	$ 46.70	$ 47.60	1.927%	S109
62	L&P PAL	MOSJC	48	Bronze (round) - 39' - UG - 1 span or 100'	$ 50.71	$ 51.68	1.913%	S110
63	L&P PAL	MOSJR, MOSJC	48	Additional UG Secondary - 50'	$ 0.02	$ 0.02	-15.966%	S113
64	L&P PAL	MOSJR, MOSJC		Transfer Charge/Special Facility	$ 1.00	$ 1.02	2.000%	S200
65								
66	MPS MSL	MON16	88	7700L, MV, open glassware, steel pole, UG	$ 16.76	$ 17.43	4.029%	M209
67	MPS MSL	MON20	88	12000L, HPS, open glassware, existing wood pole, UG	$ 12.61	$ 12.85	1.917%	M301
68	MPS MSL	MON36	89	8000L, SV, enclosed fixture, steel pole, UG	$ 20.85	$ 21.25	1.943%	M361
69	MPS MSL	MON36	89	13500L, SV, enclosed fixture, steel pole, UG	$ 21.45	$ 21.86	1.919%	M369

	B	D	E	G	J	L	N	O
7	Rate		Tariff		Current Rate	Proposed Rate	%Δ	*MRU/CCB Item Type
8	Schedule	Rate Code	Sheet No.	Description	Monthly	Monthly		
70	MPS MSL	MON30	89	13500L, SV, open fixture, existing wood, OH	$ 13.27	$ 13.53	1.934%	M324
71	MPS MSL	MON30	89	13500L, SV, open fixture, wood, OH	$ 13.69	$ 13.95	1.899%	M370
72	MPS MSL	MON36	89	25500L, SV, enclosed fixture, steel pole, UG	$ 23.47	$ 23.92	1.910%	M377
73	MPS MSL	MON36	89	50000L, SV, enclosed fixture, steel pole, OH	$ 22.97	$ 23.41	1.923%	M380
74	MPS MSL	MON36	89	Decorative Lighting	$ 1.00	$ 1.02	2.000%	MDCA
75	MPS MSL	MON66	89	8000L, HPS, Acorn, 14' Décor Pole, UG	$ 32.50	$ 33.13	1.925%	M384
76	MPS MSL	MON66	89	25500L, HPS, Acorn, 14' Décor Pole, UG	$ 33.40	$ 34.04	1.919%	M385
77	MPS MSL	MON90		Special Contract - Blinker Lights - Grandview	$ 13.42	$ 13.42	0.000%	M910
78	MPS MSL	MON90		Special Contract - Festoon Lighting	$ 0.64	$ 0.64	0.000%	M912
79	MPS MSL	MON90		Special Contract - Festoon Lighting	$ 0.82	$ 0.82	0.000%	M913
80	MPS MSL	MON90		Special Contract - Festoon Lighting	$ 0.87	$ 0.87	0.000%	M914
81	MPS MSL	MON90		Special Contract - Festoon Lighting	$ 0.66	$ 0.66	0.000%	M915
82	MPS MSL	MON90		Special Contract - Unmetered Traffic Signal	$ 17.06	$ 17.06	0.000%	M920
83	MPS MSL	MON91		Special Contract - 100 Watt Streetlight, concrete pole, UG - Liberty	$ 35.46	$ 36.14	1.920%	M929
84	MPS MSL	MON91		Special Contract - White Way Streetlight	$ 8.37	$ 8.53	1.920%	M930
85	MPS MSL	MON91		Special Contract - Multiple Enclosed Fixtures, WP, OH	$ 7.62	$ 7.77	1.920%	M931
86	MPS MSL	MON91		Special Contract - White Way - Clinton Streetlight	$ 6.85	$ 6.98	1.920%	M942
87	MPS MSL	MON91		Special Contract - 100 Watt Acorn, 14' pole - Longview Farms	$ 14.17	$ 14.44	1.920%	M956
88	MPS MSL	MON91		Special Contract - 250 Watt Decorative Acorn Metal Halide #1 - Sedalia	$ 33.40	$ 34.04	1.920%	M957
89	MPS MSL	MON91		Special Contract - 251 Watt Decorative Acorn Metal Halide #2 - Sedalia	$ 45.26	$ 46.13	1.920%	M958
90								
91	MPS PAL	MON26, MON27	91	7700L, MV, open glassware, WP, OH	$ 11.31	$ 11.76	4.002%	M500
92	MPS PAL	MON26, MON27	91	7700L, MV, open glassware, existing WP, OH	$ 10.89	$ 11.33	4.033%	M501
93	MPS PAL	MON28, MON29	91	7700L, MV, open glassware, SP, OH	$ 15.41	$ 16.02	3.987%	M502
94	MPS PAL	MON26, MON27	91	7700L, MV, streamlined fixture, WP, OH	$ 13.04	$ 13.56	4.008%	M503
95	MPS PAL	MON29	91	7700L, MV, streamlined fixture, SP, OH	$ 17.13	$ 17.81	3.990%	M504
96	MPS PAL	MON26, MON27	91	10500L, MV, enclosed fixture, WP, OH	$ 15.22	$ 15.83	4.030%	M505
97	MPS PAL	MON29	91	10500L, MV, enclosed fixture, SP, OH	$ 19.31	$ 20.08	4.010%	M506
98	MPS PAL	MON26, MON27	91	21000L, MV, enclosed fixture, WP, OH	$ 19.41	$ 20.19	4.023%	M507
99	MPS PAL	MON29	91	21000L, MV, enclosed fixture, SP, OH	$ 23.29	$ 24.22	3.997%	M508
100	MPS PAL	MON26, MON27	91	54000L, MV, enclosed fixture, WP, OH	$ 32.65	$ 33.95	3.995%	M509
101	MPS PAL	MON29	91	54000L, MV, enclosed fixture, SP, OH	$ 35.23	$ 36.64	4.010%	M510
102	MPS PAL	MON80, MON81	91	12000L, SV, open glassware, WP, OH	$ 13.89	$ 14.15	1.890%	M600
103	MPS PAL	MON80, MON81	91	12000L, SV, open glassware, existing WP, OH	$ 13.47	$ 13.73	1.924%	M601
104	MPS PAL	MON82, MON83	91	12000L, SV, open glassware, SP, OH	$ 17.98	$ 18.33	1.942%	M602
105	MPS PAL	MON80, MON81	91	12000L, SV, streamlined fixture, WP, OH	$ 15.61	$ 15.91	1.922%	M603
106	MPS PAL	MON82, MON83	91	12000L, SV, streamlined fixture, SP, OH	$ 19.70	$ 20.08	1.912%	M604
107	MPS PAL	MON82	91	Decorative Lighting	$ 1.00	$ 1.02	2.000%	MDCA
108	MPS PAL	MON81	91	36000L, SV, enclosed fixture, WP, OH	$ 21.82	$ 22.24	1.940%	M605
109	MPS PAL	MON48, MON49	92	5000L, SV, open glassware or enclosed fixture, WP, OH	$ 13.11	$ 13.36	1.926%	M643
110	MPS PAL	MON48, MON49	92	8000L, SV, open glassware or enclosed fixture, WP, OH	$ 13.70	$ 13.96	1.904%	M645
111	MPS PAL	MON48, MON49	92	8000L, SV, open glassware or enclosed fixture, existing WP, OH	$ 13.28	$ 13.54	1.939%	M646
112	MPS PAL	MON48, MON49	92	8000L, SV, open glassware or enclosed fixture, SP, OH	$ 17.79	$ 18.13	1.901%	M647
113	MPS PAL	MON48, MON49	92	13500L, SV, open glassware or enclosed fixture, WP, OH	$ 14.69	$ 14.97	1.918%	M648
114	MPS PAL	MON48, MON49	92	13500L, SV, open glassware or enclosed fixture, existing WP, OH	$ 14.27	$ 14.55	1.950%	M654
115	MPS PAL	MON48, MON49	92	13500L, SV, open glassware or enclosed fixture, SP, OH	$ 18.78	$ 19.14	1.917%	M649
116	MPS PAL	MON44, MON45	92	25500L, SV, enclosed fixture, WP, OH	$ 18.46	$ 18.81	1.919%	M650
117	MPS PAL	MON46, MON47	92	25500L, SV, enclosed fixture, SP, OH	$ 22.55	$ 22.98	1.910%	M651
118	MPS PAL	MON47	92	Decorative Lighting	$ 1.00	$ 1.02	2.000%	MDCA
119	MPS PAL	MON44, MON45	92	50000L, SV, enclosed fixture, WP, OH	$ 22.55	$ 22.98	1.918%	M652
120	MPS PAL	MON46, MON47	92	50000L, SV, enclosed fixture, SP, OH	$ 26.43	$ 26.93	1.901%	M653
121	MPS PAL	MON44, MON45	92	Directional Flood, 27500L, SV, enclosed fixture, existing WP, OH	$ 34.44	$ 35.10	1.919%	M675
122	MPS PAL	MON44, MON45	92	Directional Flood, 27500L, SV, enclosed fixture, WP, OH	$ 36.16	$ 36.86	1.927%	M676
123	MPS PAL	MON44, MON45	92	Directional Flood, 50000L, SV, enclosed fixture, existing WP, OH	$ 38.81	$ 39.56	1.926%	M677
124	MPS PAL	MON44, MON45	92	Directional Flood, 50000L, SV, enclosed fixture, WP, OH	$ 40.53	$ 41.31	1.914%	M678
125	MPS PAL	MON44, MON45	92	Directional Flood, 140000L, SV, enclosed fixture, existing WP, OH	$ 65.52	$ 66.78	1.918%	M679
126	MPS PAL	MON45	92	Directional Flood, 140000L, SV, enclosed fixture, WP, OH	$ 67.25	$ 68.54	1.921%	M680
127	MPS PAL	MON72, MON73	92	20500L, MH, enclosed fixture, existing WP, OH	$ 37.09	$ 37.81	1.932%	M681
128	MPS PAL	MON73	92	20500L, MH, enclosed fixture, WP, OH	$ 38.82	$ 39.56	1.915%	M682
129	MPS PAL	MON73	92	36000L, MH, enclosed fixture, existing WP, OH	$ 39.66	$ 40.42	1.908%	M684
130	MPS PAL	MON72, MON73	92	36000L, MH, enclosed fixture, WP, OH	$ 41.38	$ 42.18	1.923%	M685
131	MPS PAL	MON75	92	36000L, MH, enclosed fixture, SP, OH	$ 45.26	$ 46.13	1.917%	M686
132	MPS PAL	MON73	92	110000L, MH, enclosed fixture, existing WP, OH	$ 67.23	$ 68.52	1.924%	M687
133	MPS PAL	MON73	92	110000L, MH, enclosed fixture, WP, OH	$ 68.95	$ 70.27	1.913%	M688
134	MPS PAL	MON75	92	110000L, MH, enclosed fixture, SP, OH	$ 72.83	$ 74.22	1.913%	M689
135	MPS MSL/MPS PAL							
136	MPS MSL/MPS PAL	**Additional Facilities**						
137	MPS MSL/MPS PAL	MONWR, MONWC	90, 93	Wood pole and one span of OH wire - OH	$ 1.72	$ 1.76	2.177%	M800
138	MPS MSL/MPS PAL	MONSR, MONSC	90, 93	Break away bases for steel poles - OH & UG	$ 2.73	$ 3.35	22.859%	BKWY

	B	D	E	G	J	L	N	O
7	Rate		Tariff		Current Rate	Proposed Rate	%Δ	*MRU/CCB Item Type
8	Schedule	Rate Code	Sheet No.	Description	Monthly	Monthly		
139	MPS MSL/MPS PAL	MONWC	90, 93	Rock removal - UG	$ 0.19	$ 0.20	2.987%	M804
140	MPS MSL	MONWR	90	30 ft. requiring 35 f. WP	$ 1.68	$ 1.71	1.786%	M807
141	MPS MSL	MONWC	90	40 ft. requiring 45 ft. WP	$ 5.03	$ 5.13	1.988%	M811
142	MPS MSL	MONSC	90	40 ft. requiring 40 ft SP	$ 13.00	$ 13.25	1.923%	M812
143	MPS MSL/MPS PAL	MONSC	90, 93	Steel pole and one span of OH wire - OH	$ 5.60	$ 5.71	1.964%	M802
144	MPS PAL	MONWR, MONWC, MONSR, MONSC	93	Underground wiring for private lighting, WP	$ 0.05	$ 0.06	10.701%	M806
145	MPS PAL	MONWR, MONWC	93	Underground wiring for private lighting - per 100', WP	$ 5.47	$ 5.58	2.011%	UNPV
146	MPS PAL	MONWR, MONWC, MONSC	93	Underground wiring for private lighting under concrete per foot - UG, WP	$ 0.25	$ 0.25	1.338%	M805
147	MPS MSL/MPS PAL	MONWR, MONWC	Credit of 90a/93a	Credit - Wood pole and one span of OH wire - OH	$ (1.72)	$ (1.76)	2.177%	M954
148	MPS PAL	MONSC	Credit of 93b	Credit - Steel pole and one span of OH wire - OH	$ (5.60)	$ (5.71)	1.964%	M955
149								
150	MPS MSL/MPS PAL	MON84, MON85	95	Customer-Owned Non-Standard 100W	$ 2.26	$ 2.30	1.770%	M709
151	MPS MSL/MPS PAL	MON84, MON85	95	Customer-Owned Non-Standard 150W	$ 3.39	$ 3.46	2.065%	M710
152	MPS MSL/MPS PAL	MON85	95	Customer-Owned Non-Standard 175W	$ 3.95	$ 4.03	2.025%	M711
153	MPS MSL/MPS PAL	MON85	95	Customer-Owned Non-Standard 250W	$ 5.25	$ 5.35	1.905%	M712
154	MPS MSL/MPS PAL	MON85	95	Customer-Owned Non-Standard 360W	$ 7.39	$ 7.53	1.894%	M713
155	MPS MSL/MPS PAL	MON85	95	Customer-Owned Non-Standard 400W	$ 8.24	$ 8.40	1.942%	M714
156	MPS MSL/MPS PAL	MON85	95	Customer-Owned Non-Standard 1000W	$ 22.57	$ 23.00	1.905%	M715
157	MPS MSL/MPS PAL	MON85	95	Decorative lighting	$ 1.00	$ 1.02	2.000%	MDCA
158								
159	MSL LED	MOMLL	150	5000 Lumen LED (Class A) (Type V pattern)	$ 19.36	$ 19.36	0.000%	L0AAG
160	MSL LED	MOMLL	150	5000 Lumen LED (Class B) (Type II pattern)	$ 19.36	$ 19.36	0.000%	L0BAG
161	MSL LED	MOMLL	150	7500 Lumen LED (Class C) (Type III pattern)	$ 21.77	$ 21.77	0.000%	L0CAG
162	MSL LED	MOMLL	150	12500 Lumen LED (Class D) (Type III pattern)	$ 23.23	$ 23.23	0.000%	L0DAG
163	MSL LED	MOMLL	150	24500 Lumen LED (Class E) (Type III pattern)	$ 25.16	$ 25.16	0.000%	L0EAG
164	MSL LED	MOMLL	150	5000 Lumen LED (Class A) (Type V pattern)	$ 11.50	$ 14.09	22.522%	L0ABG
165	MSL LED	MOMLL	150	5000 Lumen LED (Class B) (Type II pattern)	$ 11.50	$ 14.09	22.522%	L0BBG
166	MSL LED	MOMLL	150	7500 Lumen LED (Class C) (Type III pattern)	$ 12.30	$ 15.43	25.447%	L0CBG
167	MSL LED	MOMLL	150	12500 Lumen LED (Class D) (Type III pattern)	$ 16.40	$ 18.65	13.720%	L0DBG
168	MSL LED	MOMLL	150	24500 Lumen LED (Class E) (Type III pattern)	$ 19.70	$ 21.50	9.137%	L0EBG
169	MSL LED	MOMLL	150	5000 Lumen LED (Class A) (Type II pattern)	$ 10.65	$ 10.65	0.000%	L0AEG
170	MSL LED	MOMLL	150	5000 Lumen LED (Class B) (Type II pattern)	$ 10.65	$ 10.65	0.000%	L0BEG
171	MSL LED	MOMLL	150	7500 Lumen LED (Class C) (Type III pattern)	$ 11.42	$ 11.42	0.000%	L0CEG
172	MSL LED	MOMLL	150	12500 Lumen LED (Class D) (Type III pattern)	$ 15.39	$ 15.39	0.000%	L0DEG
173	MSL LED	MOMLL	150	24500 Lumen LED (Class E) (Type III pattern)	$ 18.58	$ 18.58	0.000%	L0EEG
174	MSL LED	MOMLL	150.1	4300 Lumen LED (Class K) (Acorn Style)	$ 62.14	$ 62.14	0.000%	L0KDG
175	MSL LED	MOMLL	150.1	10000 Lumen LED (Class L) (Acorn Style)	$ 63.54	$ 63.54	0.000%	L0LDG
176	MSL LED	MOMLL		Decorative lighting	$ 1.00	$ 1.02	2.000%	MDCA
177	MSL LED							
178	MSL LED	**Optional Equipment**						
179	MSL LED	MOMLL	150.1	Metal pole instead of wood pole	$ 5.15	$ 5.15	0.000%	OMPLG
180	MSL LED	MOMLL	150.1	Underground Service extension, under sod	$ 4.84	$ 4.84	0.000%	OEUSG
181	MSL LED	MOMLL	150.1	Underground Service extension, under concrete	$ 23.40	$ 23.40	0.000%	OEUCG
182	MSL LED	MOMLL	150.1	Rock Removal	$ 19.36	$ 19.36	0.000%	OEACG
183	MSL LED	MOMLL	150.1	Breakaway Base	$ 3.35	$ 3.35	0.000%	OBABG
184	MSL LED	MOMLL	150.2	Special Mounting Heights - Between 31 and 41 ft. - Wood Pole	$ 2.06	$ 2.06	0.000%	SW31
185	MSL LED	MOMLL	150.2	Special Mounting Heights - Between 31 and 41 ft. - Steel Pole	$ 3.27	$ 3.27	0.000%	SM31
186	MSL LED	MOMLL	150.2	Special Mounting Heights - Greater than 41 ft. - Wood Pole	$ 4.35	$ 4.35	0.000%	SW41
187	MSL LED	MOMLL	150.2	Special Mounting Heights - Greater than 41 ft. - Steel Pole	$ 7.64	$ 7.64	0.000%	SM41
188								
189	MSL PL	MORPL, MOCPL	152	4500 Lumen LED (Type A-PAL)	$ 11.27	$ 11.27	0.000%	L45AP
190	MSL PL	MORPL, MOCPL	152	8000 Lumen LED (Type C-PAL)	$ 14.66	$ 14.66	0.000%	L80CP
191	MSL PL	MORPL, MOCPL	152	14000 Lumen LED (Type D-PAL)	$ 19.32	$ 19.32	0.000%	L14DP
192	MSL PL	MORPL, MOCPL	152	10000 Lumen LED (Type C-FL)	$ 14.66	$ 14.66	0.000%	L10CF
193	MSL PL	MORPL, MOCPL	152	23000 Lumen LED (Type E-FL)	$ 26.63	$ 26.63	0.000%	L23EF
194	MSL PL	MORPL, MOCPL	152	45000 Lumen LED (Type F-FL)	$ 56.86	$ 56.86	0.000%	L45FF
195	MSL PL							
196	MSL PL	**Additional Charges**						
197	MSL PL	MORPL, MOCPL	152	Each 30-foot metal pole installed	$ 5.01	$ 5.01	0.000%	SP30
198	MSL PL	MORPL, MOCPL	152	Each 35-foot metal pole installed	$ 5.47	$ 5.47	0.000%	SP35
199	MSL PL	MORPL, MOCPL	152	Each 30-foot wood pole installed	$ 6.71	$ 6.71	0.000%	WP30
200	MSL PL	MORPL, MOCPL	152	Each 35-foot wood pole installed	$ 6.90	$ 6.90	0.000%	WP35
201	MSL PL	MORPL, MOCPL	152	Each overhead span of circuit installed	$ 3.99	$ 3.99	0.000%	SPAN
202	MSL PL	MORPL, MOCPL	152	Breakaway Base	$ 3.35	$ 3.35	0.000%	BKWY
203	MSL PL	MORPL, MOCPL	152	Underground Lighting Unit	$ 3.57	$ 3.57	0.000%	U300
204								
205								

	B	C	D	E	F	G	H	I
1				**Evergy - Missouri West**				
2				**Thermal Energy Storage Pilot Program**				
3								
4				**Case No.**	**ER-2022-0130**			
5				**Status:**	**Direct**			
6							6.39%	
7				*INPUT FOR MODEL*				
8				**JURIS INCREASE (%)**			**7.99%**	**5.81%**
9	Charge	Voltage	Rate Code	**Season**	Tariff Values	**Current Rates**	**Rates with Increase**	**Proposed Rates**
10	Customer Charge/ Other Meter	Secondary/Primary	MO650 /MO660	Summer/Winter	Customer Charge	194.44	209.97	*209.97*
11								
12	Demand Charge - Blk 1/ Base	Secondary/Primary	MO650	Summer	Summer	9.903	10.694	*10.694*
13	Demand Charge - Blk 1/ Base	Secondary/Primary	MO650	Winter	Winter	7.250	7.829	*7.829*
14								
15	Demand Charge - Blk 1/ Base	Primary	MO660	Summer	Summer	8.260	8.920	*8.920*
16	Demand Charge - Blk 1/ Base	Primary	MO660	Winter	Winter	5.306	5.730	*5.730*
17								
18	Energy Charge - Blk 1/ On-Peak	Secondary	MO650	Summer	Peak	0.07882	0.07882	*0.08340*
19	Energy Charge - Blk 3/ Shoulder /S	Secondary	MO650	Summer	Shoulder	0.04422	0.04422	*0.04679*
20	Energy Charge - Blk 2/ Off-Peak	Secondary	MO650	Summer	Off-Peak	0.03965	0.03965	*0.04196*
21								
22	Energy Charge - Blk 1/ On-Peak	Secondary	MO650	Winter	Peak	0.04422	0.04422	*0.04679*
23	Energy Charge - Blk 2/ Off-Peak	Secondary	MO650	Winter	Off-Peak	0.03964	0.03964	*0.04195*
24								
25	Energy Charge - Blk 1/ On-Peak	Primary	MO660	Summer	Peak	0.07882	0.07882	*0.08340*
26	Energy Charge - Blk 3/ Shoulder /S	Primary	MO660	Summer	Shoulder	0.04422	0.04422	*0.04679*
27	Energy Charge - Blk 2/ Off-Peak	Primary	MO660	Summer	Off-Peak	0.03965	0.03965	*0.04196*
28								
29	Energy Charge - Blk 1/ On-Peak	Primary	MO660	Winter	Peak	0.04422	0.04422	*0.04679*
30	Energy Charge - Blk 2/ Off-Peak	Primary	MO660	Winter	Off-Peak	0.03964	0.03964	*0.04195*
31								
32								
33				MO650	Summer		2.018%	6.364%
34				MO650	Winter		2.144%	6.401%
35				MO660	Summer		0.000%	0.000%
36				MO660	Winter		0.000%	0.000%
37				Winter Price Below Summer (SUM-WIN)/SUM		15.46%	15.35%	15.43%
38				Thermal Energy Storage Overall Change			2.080%	6.382%
39								
40					Revenue	$ 460,184.06	$ 469,753.59	$489,552.78
41					Change in Revenue			$ 29,368.72
42								
43					Proposed change per Revenue Summary			$ 29,420.00

Evergy - Missouri West
Clean Charge Network

Case No. **ER-2022-0130**
Status **Direct**

					INPUT FOR MODEL		
		JURIS INCREASE (%)			**10.50%**	**0.00%**	
Charge	Rate Code	Season	Tariff Language	**Current Rates**	**Rates with Increase**	**Proposed Rates**	% Change
Energy Charge - Blk 1/ On-Peak	CCN	Summer	Energy Level 2 Charge	0.20000	0.22100	*0.22100*	10.50%
Energy Charge - Blk 2/ Off-Peak	CCN	Summer	Energy Level 3 Charge	0.25000	0.27625	*0.27625*	10.50%
Energy Charge - Blk 1/ On-Peak	CCN	Winter	Energy Level 2 Charge	0.20000	0.22100	*0.22100*	10.50%
Energy Charge - Blk 2/ Off-Peak	CCN	Winter	Energy Level 3 Charge	0.25000	0.27625	*0.27625*	10.50%

CCN	Summer	100.000%	10.50%	10.500%
CCN	Winter	100.000%	10.50%	10.500%
Winter Price Below Summer (SUM-WIN)/SUM		**2.43%**	**2.43%**	**2.43%**
CCN Overall Change			10.500%	10.500%

Revenue	$ 34,278.85	$ 37,878.13	$ 37,878.13
Change in Revenue			$3,599
Proposed change per Revenue Summary			$ 3,611.00
			($12)
	$ 34,278.85		

Tie-out to Billed Revenue Total

977

% Because Riders and Surcharges are included in pricing above, straight Revenue calculations from these prices include those extra charges, and thus do not match Billed Revenue total

The SSR rates are calculated from the class rates. Therefore, the SSR must be included in filed cases that involve a change in applicable class rates.
Explanation of calculation methology - reference case ER-2018-0145/0146, B. J. Meyer surrebuttal testimony

MO West SSR Summary								
SGS Secondary Voltage	SGS Primary Voltage	LGS Secondary Voltage	LGS Primary Voltage	LPS Secondary Voltage	LPS Primary Voltage	LPS Substation Voltage	LPS Transmission Voltage	
Standby Fixed Charges								
$110.00	$110.00	$130.00	$130.00	$430.00	$430.00	$430.00	$430.00	**Administrative Charge**
								Facilities Charge per month per kW of Contracted Standby Capacity
$0.162	$0.157	$0.120	$0.116	$1.433	$1.391	$1.361	$1.351	Summer
$0.158	$0.153	$0.081	$0.078	$0.746	$0.724	$0.709	$0.704	Winter
$0.162	$0.157	$0.120	$0.116	$1.433	$1.391	$1.361	$1.351	**Generation and Transmission Access Charge per month per kW of Contracted Standby Capacity**
Daily Standby Demand Rate - Summer								
$0.163	$0.161	$0.210	$0.151	$0.802	$0.756	$0.544	$0.540	Back-Up
$0.081	$0.080	$0.105	$0.076	$0.401	$0.378	$0.272	$0.270	Maintenance
Daily Standby Demand Rate - Winter								
$0.161	$0.159	$0.191	$0.134	$0.481	$0.445	$0.240	$0.238	Back-Up
$0.081	$0.080	$0.096	$0.067	$0.241	$0.222	$0.120	$0.119	Maintenance
Back-Up Energy Charges - Summer								
$0.09873	$0.09263	$0.09243	$0.08963	$0.05634	$0.05461	$0.05310	$0.05415	kWh in excess of Supplemental Contract Capacity
Back-Up Energy Charges - Winter								
$0.07172	$0.07044	$0.07042	$0.06787	$0.05259	$0.05101	$0.05018	$0.04891	kWh in excess of Supplemental Contract Capacity

SCHEDULE MEM-6
CONTAINS CONFIDENTIAL
INFORMATION
NOT AVAILABLE TO THE PUBLIC.

ORIGINALS FILED UNDER SEAL.