Exhibit No. 229

MoPSC Staff – Exhibit 229
Sarah L.K. Lange
Direct Testimony
File Nos. ER-2022-0129 & ER-2022-0130

Exhibit No.:	
Issue(s):	*Class Cost of Service, Rate Design, Time of Use*
Witness:	*Sarah L.K. Lange*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Direct Testimony*
Case Nos.:	*ER-2022-0129 and ER-2022-0130*
Date Testimony Prepared:	*June 22, 2022*

MISSOURI PUBLIC SERVICE COMMISSION

INDUSTRIAL ANALYSIS DIVISION

TARIFF/RATE DESIGN DEPARTMENT

DIRECT TESTIMONY

OF

SARAH L.K. LANGE

Evergy Metro, Inc., d/b/a Evergy Missouri Metro
Case No. ER-2022-0129

Evergy Missouri West, Inc., d/b/a Evergy Missouri West
Case No. ER-2022-0130

Jefferson City, Missouri
June 2022

TABLE OF CONTENTS OF

DIRECT TESTIMONY OF

SARAH L.K. LANGE

Evergy Metro, Inc., d/b/a Evergy Missouri Metro
Case No. ER-2022-0129

Evergy Missouri West, Inc., d/b/a Evergy Missouri West
Case No. ER-2022-0130

DIRECT TESTIMONY

OF

SARAH L.K. LANGE

Evergy Metro, Inc. d/b/a Evergy Missouri Metro
Case No. ER-2022-0129

Evergy Missouri West, Inc. d/b/a Evergy Missouri West
Case No. ER-2022-0130

Q. Please state your name and business address.

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

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

A. I am employed by the Missouri Public Service Commission ("Commission") as an Economist for the Tariff/Rate Design Department, in the Industry Analysis Division.

Q. Please describe your educational and work background.

A. Please see Schedule SLKL-d1.

<u>EXECUTIVE SUMMARY</u>

Q. What is the purpose of your direct testimony?

A. In its Report and Order in these cases, the Commission is likely to order new gross revenue requirements, net of other revenues, for Evergy Metro ("EMM") and Evergy West ("EMW"). The purpose of my direct testimony is to provide the Staff's recommended method of designing the rate schedules and rates for EMM and EMW to file to comply with the Commission Report and Order, and to recommend additional changes to the rate books of each utility and to the data retention practices of each utility.

Q. What rate schedules do you recommend the Commission order be promulgated in these cases?

A. For both utilities, I recommend the current residential rate schedule be modified to a low-differential time-based rate structure.[1] I further recommend elimination of distinctions within rate schedules and rate codes related to end-use or appliance types. I also recommend promulgation of an optional rate schedule with real time price variation, open to customers who have been well-educated on the risks of the energy market. For all non-lighting rate schedules excluding Real Time Pricing, and tariffs such as those made available to Nucor and certain data center customers, Staff recommends a summer off-peak discount for the "Super Off-Peak" period of -$0.01, from midnight to 6:00 am, and an on-peak premium of $0.01, from 4:00 pm until 8:00 pm. For the non-summer months, in conjunction with Staff's recommended rate schedule changes, Staff recommends the Super Off-Peak discount be held constant at $0.01, but that the on-peak premium be moderated to $0.025.

Q. What is your recommendation for applying any ordered increase in these cases, separately for EMM and EMW?

A. As described more fully here-in, a summary of Staff's Class Cost of Service Study results and recommended class-level revenue requirement increases are provided below, at Staff's direct-recommended revenue requirements:

EMM	Residential	SGS	MGS	LGS	LPS	Lighting	Other
Starting Indexed Return	59%	469%	408%	379%	-39%	-2055%	-1860%
Total Recommended Increase	$ 12,982,785	$ 1,383,397	$ 2,407,786	$ 3,563,895	$ 7,193,696	$ 588,301	$ 6,145
Ending Indexed Return	84%	236%	212%	204%	81%	-793%	-702%

EMW	Residential	SGS	LGS	LPS	Lighting	Other
Starting Indexed Return	7%	346%	280%	157%	57%	-975%
Total Recommended Increase	$ 25,351,098	$ 5,681,409	$ 4,355,940	$ 5,551,206	$ 1,144,189	$ 46,683
Ending Indexed Return	54%	190%	166%	123%	65%	-332%

[1] An optional rate schedule that is not time-based is necessary for customers without AMI meters.

Q. Are these recommendations based on an independent Class Cost of Service ("CCOS") study?

A. Staff did not do a full CCOS study. Rather, Staff generally applied Evergy's classifiers and allocators to Staff's calculated gross cost of service and other revenues, although it did independently develop or refine certain allocators as defined here-in.

Q. Do you have additional recommendations relating to future CCOS studies?

A. Yes, I recommend the Commission order both EMM and EMW to adopt the following data retention provisions:

> 1. Prior to the next rate case, the Company will identify and provide the data required to determine: line transformer costs and expenses by rate code; primary distribution costs and expenses by voltage; secondary distribution costs and expenses by voltage; primary voltage service drop costs and expenses; line extension costs, expenses, and contributions by rate code and voltage; and meter costs by voltage and rate code. If the required data is not readily available, the Commission should order Evergy to file an EO docket explaining why it cannot provide the data, and its individual estimate of the cost to provide each set of data described, for the further consideration of the parties and the Commission.
>
> 2. For each rate code, provide the total number of customers served on that rate schedule on the first day of the month and the last day of the month;
>
> a. For each rate schedule on which customers may take service at various voltages, the number of customers served at each voltage on the first day of the month and the last day of the month (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);
>
> 3. For each rate code, the number of customers served on that rate schedule on the first day of the month and the last day of the month for which interval meter readings are obtained;
>
> a. For each rate code on which customers may take service at various voltages, the number of customers served at each voltage on the first day of the month and the last day of the month which interval meter readings are obtained (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);
>
> 4. For each rate code for which service is available at a single voltage, the sum of customers' interval meter readings, by interval;
>
> a. For each rate code on which customers may take service at various voltages, the sum of customers' interval meter readings, by interval and by

voltage (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);

5. If any internal adjustments to customer interval data are necessary for the company's billing system to bill the interval data referenced in parts 4. and 4.a., such adjustments should be applied to each interval recording prior to the customers' data being summed for each interval;

6. From time to time the Commission may designate certain customer subsets for more granular study. If such designations have been made, the information required under parts 1 – 5 should be provided or retained for those instances.

7. Individual customer interval data shall be retained for a minimum of fourteen months. If individual data is acquired by the company in intervals of less than one hour in duration, such data shall be retained in intervals of no less than one hour.

8. Evergy shall:

a. Retain individual hourly data for use in providing bill-comparison tools for customers to compare rate alternatives.

b. Retain coincident peak determinants for use in future rate proceedings.

c. Provide to Staff upon request:

1) the information described in part 1;

2) a minimum of 12 months of the data described in parts 2-5;

3) for rate codes with more than 100 customers, a sample of individual customer hourly data, and identified peak demands for those 100 customers in the form requested at that time (i.e. monthly 15 minute non-coincident, annual 1 hour coincident);

4) for rate codes with 100 or fewer customers, individual customer hourly data, and identified peak demands for those customers in the form requested at that time (i.e. monthly 15 minute non-coincident, annual 1 hour coincident).

d. For purposes of general rate proceedings, Evergy shall provide all data described above for a period of not less than 36 months, except that Staff does not request individual customer data for 36 months except as described in part 8.c.3.

9. Demand-related information, to develop the determinants for assessment of an on-peak demand charge to replace the current monthly billing demand charge, and for potential implementation for customers not currently subject to a demand charge.

10. Reactive Demand-related information, including but not limited to the retention and study of data related to the reactive demand requirements of each rate code, and sample customers within each rate code.

Q. What additional items do you recommend be reflected in the Commission's Report and Order, but will not be further discussed in this testimony?

A. A number of routine updates of are appropriate where required by the terms of the underlying tariff, or to otherwise incorporate the changes in ordered revenue requirements to retain internal consistency of related rate schedules or riders:

1. Update MEEIA margin rates.
2. Update Standby Service Rider rates consistent with changes made to underlying rate schedules.
3. Update Community Solar distribution service rates.
4. Update Clean Charge Network rates, and other miscellaneous rate schedules to coincide with the overall ordered percentage increase.

<u>GROSS COST OF SERVICE AND OTHER REVENUES</u>

Q. Why is an understanding of the gross cost of service and other revenues of both EMM and EMW necessary in a discussion of class cost of service?

A. For CCOS purposes, it is important to be mindful of the totality of costs allocated, as well as the totality of offsetting revenues allocated.

Q. What increase in net revenue requirement is recommended by Staff for EMM and EMW?

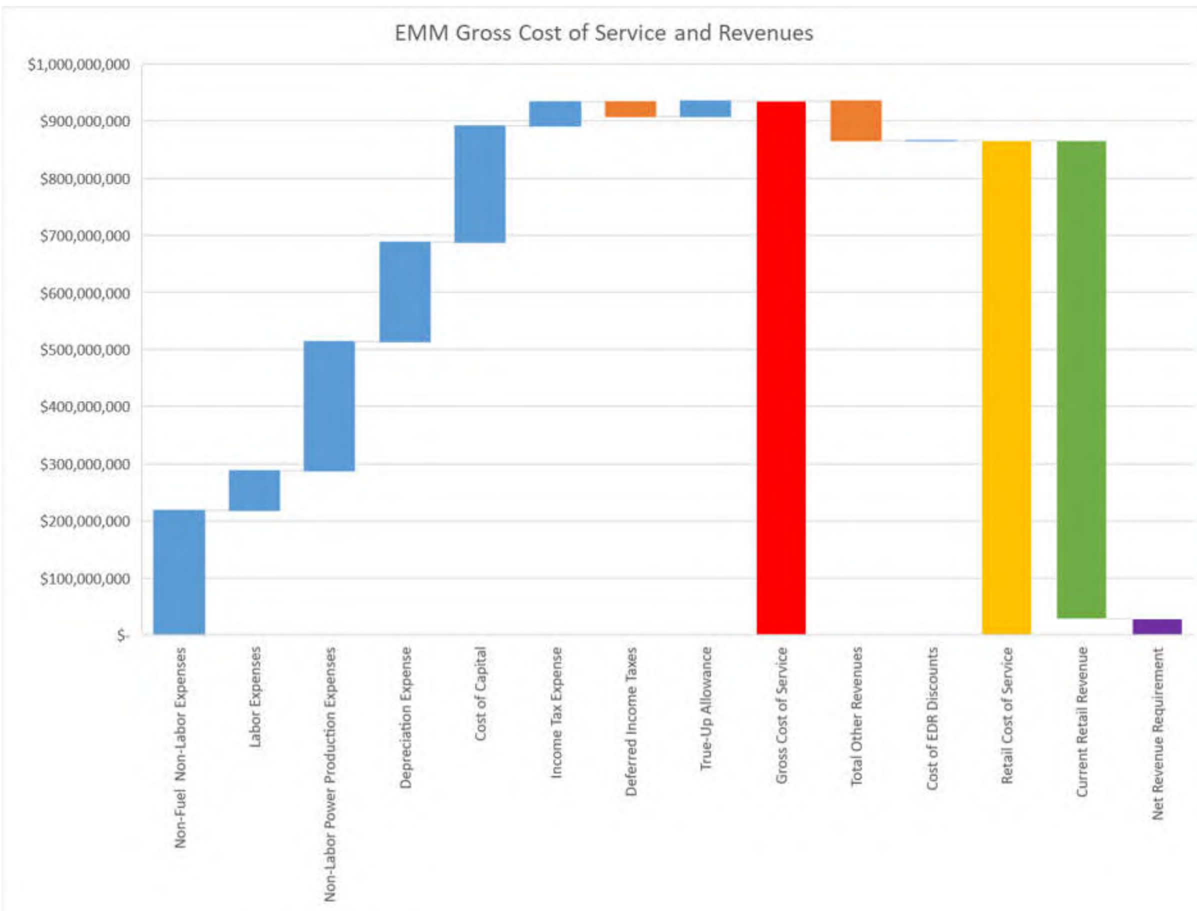
Q. The Staff's recommended increase for EMM is $33.9 million, inclusive of a $24.6 million true-up "plug" to reflect a general estimate of the expected revenue requirement impact of true-up. Currently, EMW's retail customers provide approximately $716 million in non-FAC non-MEEIA revenues, excluding Nucor revenues. The recommended $33.9 million increase is approximately 4.67% of the current non-Nucor retail revenues.[2]

Q. What are the gross costs of service of EMM and EMW?

A. Based on an analysis of the EMS run filed on June 8, 2022, the gross cost of service EMM is approximately $934,455,607, inclusive of the true-up plug. The gross cost of service of EMW is approximately $785,085,158.

Q. What comprises the gross cost of services, and what other revenues offset the gross cost of service to produce the retail cost of service?

A. Please observe the waterfall chart provided below for EMM:

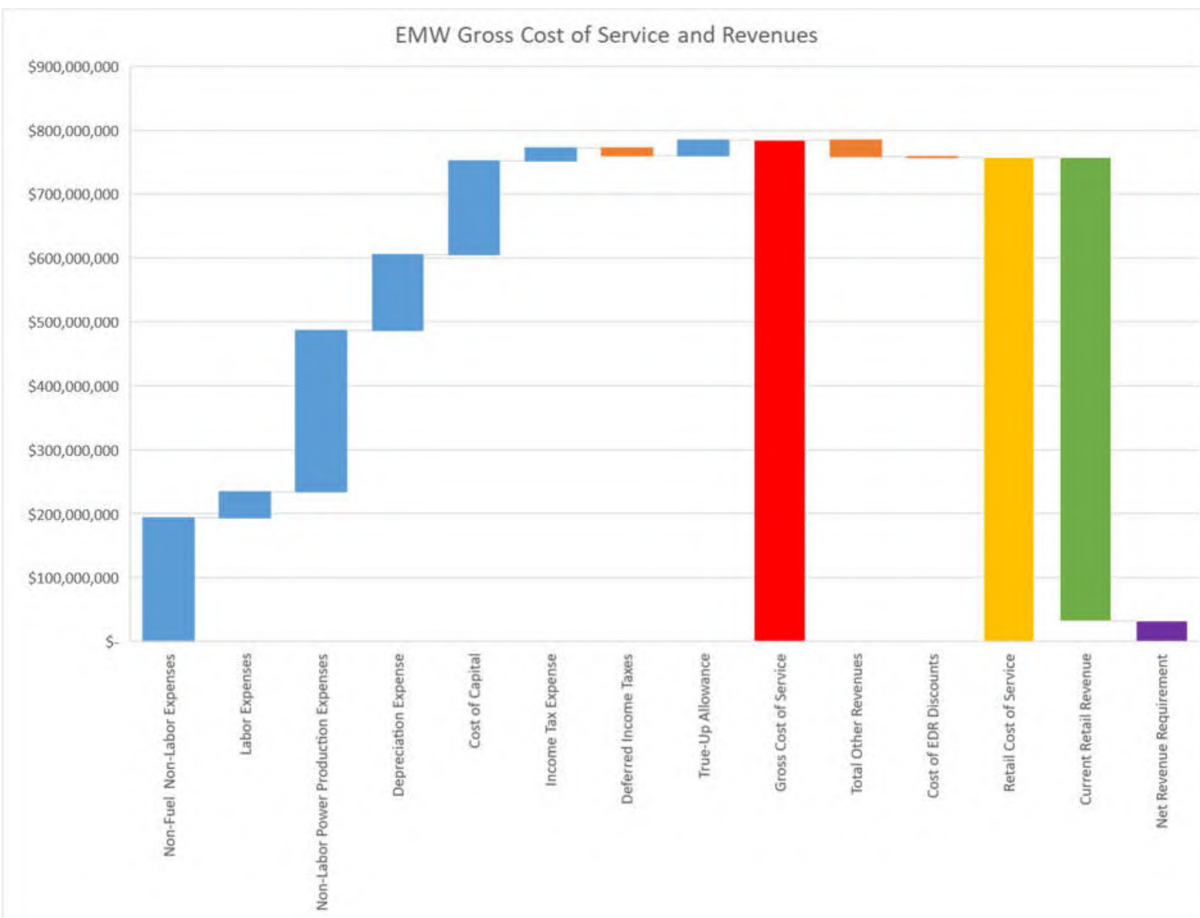


[2] EMW values provided here-in reflect Staff's revised accounting schedules submitted to EFIS on 6/15/2022.

As indicated, Non-Labor Power Production Expenses, Non-Fuel Non-Labor Expenses, Cost of Capital, and Depreciation Expense make up the majority of the gross cost of service. However, note that Other Revenues (primarily related to EMM's participation in the SPP integrated marketplace, and capacity sales) offset the gross cost of service by approximately 7%.

The gold column, third from the right, illustrates the total revenue to be allocated to the various rate schedules at the conclusion of this case based on Staff's direct filed COS and revenues. The final purple column illustrates the incremental revenue requirement to be allocated to the various classes at the conclusion of this case, net of the current revenues indicated by the green column.

These same amounts for EMW are summarized below:



RATE STRUCTURES AND RECOMMENDED TARIFF DESIGNS

Q. When you refer to rate structure and rate design, to what are your referring?

A. I will use “rate structure” to refer to the elements included on a given rate schedule, such as an energy block for usage from 0-600 kWh. I will use “rate design” to refer to the relative sizes of the charges for each rate element, such as a $0.15 per kWh charge for the first energy block and a $0.10 charge per kWh for the second energy block.

Q. What is a rate schedule, what is a class, and what is a rate code?

A. As used in this testimony, a rate schedule refers to the tariff sheet names under which customers receive service, for example Residential General Service and Residential Time of Use. A class refers to a group of rate schedules for which a utility has aggregated data, or for which have been consolidated by Staff for study purposes, for example, Residential, Small General Service, and Lighting. For EMM and EMW, some rate codes are essentially sub schedules within a rate schedule. For example, LPS customers billed at secondary, LPS customers billed at primary, and LPS customers billed at transmission would each be logged in the Evergy billing system under a different rate code. In addition, many of Evergy’s current rate codes are artifacts of prior rate schedules that are no longer associated with distinct effective rates. The tariff does define the applicability of rate codes among customers within a class where a single set of rates is applied to multiple rate codes. For example as shown below, EMM currently has 19 non-lighting rate options, but lists 48 rate codes in their tariff.

Class	Listed Rate Codes	Designation
Residential	1RO1A	Residential Other Use
	1RS1A, 1RSDA, 1RS1B	Residential General Use
	1RS2A, 1RS3A, 1RW7A, 1RH1A	Residential General Use and Space Heat- Two Meters
	1 RS6A, 1RFEB	Residential General Use and Space Heat - One Meter
	RTOU	Residential Time of Use Schedule
	RTOD, 1TE1A	Residential Time of Day Service (Frozen)
Small General Service	1SGSE, 1SGSH, 1SSSE, 1SUSE	Secondary Voltage
	1SGHE, 1SGHH, 1SSHE	Secondary Voltage Separetely Metered Space Heat (Frozen)
	1SGSF, 1SGSG, 1SSSF	Primary Voltage
Medium General Service	1MGSE, 1MGSH, 1MSSE	Secondary Voltage
	1MGHE, 1MGHH	Secondary Voltage Separetely Metered Space Heat (Frozen)
	1MGSF, 1MGSG	Primary Voltage
Large General Service	1LGSE, 1LGSH	Secondary Voltage
	1LGHE, 1LGHH, 1LSHE	Secondary Voltage Separetely Metered Space Heat (Frozen)
	1LGSF, 1LGSG	Primary Voltage
Large Power Service	1PGSE, 1PGSH	Secondary Voltage
	1PGSF, 1PGSG, 1POSF, 1POSG	Primary Voltage
	1PGSV, 1POSV	Substation Voltage
	1PGSZ, 1POSW, 1POSZ	Transmission Voltage

EMM also has a Large Power Service Off-Peak Rider, Schedule LPS-1, a Two-Part Time of Use (frozen) Schedule TPP, and a Thermal Storage Rider, that vary the bill calculation for participating customers under the above-described rate schedules.

Although it contains fewer seemingly duplicative rate codes, the EMW rate schedules include similar end use distinctions, and Staff's recommendations are in parallel with those for EMM.

Q. Why does Staff recommend changes in EMM and EMW rate schedules that will impact customer bills?

A. Staff recommends this case be taken as an opportunity to begin the modernization of the rate structures of EMM and EMW. Staff recommends that all non-lighting rate schedules be transitioned to simple time-based time of use ("ToU") rate structures in this case, with an eye towards eventual transition to more complex time-variant rate structures that better reflect cost causation. Staff further recommends elimination of end-use distinctions in customer rate schedules with regard to appliance configurations. Finally, Staff recommends better delineation of distinct customer groups within general customer classes to facilitate more accurate and meaningful data acquisition and retention.

Q. Why does Staff recommend changes in the rate schedules that will not impact customer bills?

A. Staff recommends elimination of duplicative rate codes because most are the legacy of prior territorial mergers and rate schedule consolidations that have become obsolete with the passage of time and prior rate consolidations. Staff further recommends use of the rate codes in conjunction with Staff's data retention recommendations to facilitate future studies. At this time, Staff recommends distinctive rate codes be defined within the tariff, and utilized in the billing and/or metering systems, as provided in the example below. Staff appreciates input from other parties to develop a reasonable number of manageable rate codes.

Q. What rate schedule consolidations and reconfigurations do you recommend?

A. I recommend elimination of end-use distinctions, elimination of multiple rate codes without a distinction in rate, and incorporation of a Real Time Price rate schedule available to customers of any size. Staff's recommended non-lighting rate schedules and exemplar code designations for EMM are provided below.

Class	Example Rate Schedule	Example Rate Code	Example Description
Residential	Default Residential	Res1	Residential Default ToU without Net Metering
		Res1NM	Residential Default ToU with Net Metering
	Optional Residential Non-Differentiated	Res2	Residential Opt-Out Rate Schedule without Net Metering
		Res2NM	Residential Opt-Out Rate Schedule with Net Metering
	Opt-In Time-Based	Res3	Residential Opt-In Time of Use without Net Metering
Small General Service	SGS Secondary	SGSS	Small General Service Secondary without Net Metering
		SGSSNM	Small General Service Secondary with Net Metering
	SGS Primary	SGSP	Small General Service Primary without Net Metering
		SGSPNM	Small General Service Primary with Net Metering
Medium General Service	MGS Secondary	MGSS	Medium General Service Secondary without Net Metering
		MGSSNM	Medium General Service Secondary with Net Metering
	MGS Primary	MGSP	Medium General Service Primary without Net Metering
		MGSPNM	Medium General Service Primary with Net Metering
Large General Service	LGS Secondary	LGSS	Large General Service Secondary without Net Metering
		LGSSNM	Large General Service Secondary with Net Metering
	LGS Primary	LGSP	Large General Service Primary without Net Metering
		LGSPNM	Large General Service Primary with Net Metering
Large Power Service	LPS Secondary	LPSS	Large Power Service Secondary without Net Metering
		LPSSNM	Large Power Service Secondary with Net Metering
	LPS Primary	LPSP	Large Power Service Primary without Net Metering
		LPSPNM	Large Power Service Primary with Net Metering
	LPS Transmission	LPST	Large Power Service Transmission without Net Metering
		LPSTNM	Large Power Service Transmission with Net Metering
	LPS Substation	LPSB	Large Power Service Substation without Net Metering
		LPSBNM	Large Power Service Substation with Net Metering
Real Time Price Service	RTP Secondary	RTPS	Real Time Price Service Secondary without Net Metering
	RTP Primary	RTPP	Real Time Price Service Primary without Net Metering
	RTP Transmission	RTPT	Real Time Price Service Transmission without Net Metering
	RTP Substation	RTPB	Real Time Price Service Substation without Net Metering

I recommend full elimination of the end use rate codes for the residential and small general service classes. I further recommend the creation of a net-metering rate code for all major rate schedules with identical rates and terms to that of the general rate code in every respect. It may be reasonable to further differentiate non-residential classes within the rate codes as “commercial” and “industrial” to facilitate compliance with FERC accounting requirements including consistency with data presented in the FERC Form 1.

While the detailed example above is illustrative of the EMM rate schedules, my recommendations for EMW are in parallel.

Q. Why eliminate the end use rated codes and schedules?

A. In the best case, when meters to facilitate time-based rates were cost-prohibitive, end use rate codes or rate schedules were a way to recognize that the times at which customers with certain end-uses used energy varied from the times at which customers without those end uses used energy. In today's world, end use rate codes are a clumsy instrument to use broad and currently-unsubstantiated assumptions in an attempt to support a rate disparity to align cost-causation with revenue recovery. This approach is unreasonable and unsupported by any cost study at today's point in time of widespread deployment of the AMI metering within the respective Evergy Missouri service territories. A much more reasonable way to align cost-causation related to time of consumption with revenue recovery is to use a time-variant rate element, namely, Staff's recommended default ToU rate structure.

Q. Why are various rate codes appropriate for data retention?

A. Ideally, a utility which has been equipped with Automated Meter Infrastructure ("AMI") should be capable of leveraging the meter data in conjunction with its billing system to generate reports of sales by hour to customers on a given rate code. It is my understanding that it may possible that this information could be gathered outside of the billing system under certain software configurations.

Q. Why make new rate codes for net metering customers if the rates and terms are identical in every respect?

A. In conjunction with Staff's data acquisition recommendations, creation of a separate rate code for net-metered customers will facilitate provision of hourly load data for these customers distinct from non-net metered customers. This data is necessary for the sole purpose of studying appropriate normalization techniques for potential application in future rate cases. These normalization techniques are likely to include a solar-generation factor in addition to the weather-normalization factor that is generally applied to weather-sensitive customers. This will facilitate more accurate estimate of billing determinants, revenues, and net system input in future rate cases. In this vein, Staff would not oppose retention of the all-electric rate codes if rates are set equal to the general service rates in all respects, so that hourly data is available, and so that any differences in weather normalization can be applied to distinct billing units.

Q. Would it be in the best interest of Evergy's customers as a whole to eliminate the opt-in ToU as presently designed?

A. Yes. While Staff will address the Evergy's ToU EM&V Report in greater detail in its Rebuttal testimony, in general the Evergy EM&V Report shows that the program allowed participants to avoid contributing to revenue, but did not avoid peak demands that relate to the generation, transmission, and distribution sizing requirements of the utility. Evergy's EM&V did not indicate the level of energy costs savings – if any – that were passed through the FAC, nor did it demonstrate that less energy was consumed by participating customers in the hour of monthly or annual system peaks. The Staff understands that certain policy considerations have underlain the Commission's interest in making these rate schedules available, therefore Staff takes no position as to whether these schedules should remain available on an opt-in basis at this time.

History of Evergy Commitments and Customer Education

Q. What commitments concerning customer education on time-based rates has Evergy made?

A. In the Nonunanimous Partial Stipulation and Agreement Concerning Rate Design Issues, filed September 25, 2018, in ER-2018-0145 (EMM) and ER-2018-0146 (EMW), EMM and EMW agreed, among other things that:

> c. The Company will develop a comprehensive customer research, education and marketing plan and identify the Company readiness and outreach capabilities and resources required to introduce the TOU rate plan to residential customers.
> i. By the end of Q4 2018, the Company will meet with Staff, OPC, DE and Renew MO (stakeholders) to review the customer research plan.
> ii. By the end of Q1 2019, the Company will launch the customer research plan.
> iii. The Company will evaluate leading practices on customer education and engagement on TOU deployment. During Q2 2019, the Company will develop a marketing and education plan and will meet with stakeholders to review.
> 1. The Company will develop a plan that may include various forms of tools, marketing, and customer education such as mailings, outbound calling, text messaging, website information, media outlets and outreach through various company partners including community action agencies, senior housing centers and others.
> 2. The plan will include marketing to specific end-uses that might benefit from the TOU rate plan, such as Electric Vehicle charging and space conditioning.
> 3. The Company will address the potential impact to the customer contact center and training that will ensue to properly address customer questions. The Company will provide all call center personnel with effective and sufficient training and education on their TOU offering. Company shall evaluate opportunities to educate new customers requesting service on the availability of a TOU as well as other educational opportunities when existing customers call the contact center for other matters, including TOU education through an Interactive Voice Recognition (“IVR”).
> 4. The plan will address how to approach vulnerable customer segments, such as low-income customers, elderly customers and customers with electricity-dependent medical needs.
> **5. Education on the merits of the TOU opt-in rate plan, both specific to the customers taking service thereunder as well as to customers at large, will continue throughout the offering of the TOU opt-in rate plan.**
> 6. The Company will work with stakeholders to operationalize the customer journey from first learning about the TOU rates, to enrolling/un-enrolling, receiving the first bill and managing their energy usage going forward
> iv. The Company will develop a process to solicit feedback from customers availing themselves of the TOU rate and those who do not avail themselves

of such rate to determine program success and opportunities for improvement. This is referred to as "Customer Feedback Mechanism". This process shall be developed with stakeholder input. The Company will keep customer documentation and records on all customer feedback to the degree possible regarding its post-implementation of TOU in a format that can be shared with stakeholders upon request.

1. End of Q4 2018, discuss with stakeholder options for Customer Feedback Mechanism.

2. End of Q2 2019, finalize draft of Customer Feedback Mechanism and share with stakeholders.

3. End of Q4 2019, finalize Customer Feedback Mechanism and plans for implementing the mechanism, and share with stakeholders.

v. The Company will develop, with stakeholder input, metrics to gauge changes in customer behavior. This is referred to as "Customer Behavior Metrics."

1. End of Q4 2018, discuss with stakeholders options for Customer Behavior Metrics.

2. End of Q2 2019, finalize draft of Customer Behavior Metrics and share with stakeholders.

3. End of Q4 2019, finalize Customer Behavior Metrics and share with stakeholders.

vi. Company will develop a business case for implementation of shadow billing feasibility, with the goal of implementing shadow billing for all residential customers.

1. End of Q4 2018, Company will review draft plan of shadow billing with stakeholders.

2. End of Q1 2019, Company will finalize business case for shadow billing and share with stakeholders to define next steps.

vii. **Education on the merits of the opt-in rates, both specific to the customers taking service thereunder as well as to customers at large, will continue from the dates addressed herein until the Company's next general rate cases**."

***

j. **KCP&L and GMO will submit a Residential TOU rate design in their next rate cases** based on lessons learned from the TOU service.

[Emphasis added.]

Q. With this process having been in place since the fall of 2018, should Evergy's customers at large be well-educated on both the general the economic underpinning and the potential bill impacts of rates that vary with the time of day at which energy is consumed?

A. That was the purpose of the customer education provisions of the 2018 stipulation, and since that time EMM has spent $1,386,936 and EMW has spent $1,692,041 on ToU program costs. EMM has spent $98,788 on customer education costs related to ToU and EMW has spent $24,000.

Q. Is your recommended ToU rate design for all classes built on the preferred parameters of EMM and EMW based on lessons learned as embodied in the Residential ToU rate design submitted by EMM and EMW in this case?

A. No. EMM and EMW did not submit a preferred default time-based rate design in this case. However, as described here-in, my design leverages the existing time periods, including the "wait 'til 8" campaign.

Time of Consumption as a Factor in Cost-Based Rate Design

Q. Why are time-based rate structures more reasonable than the existing rate structures of EMM and EMW?

A. Well-designed time-based rates can reflect economic responsibility for an individual customer's contribution to a number of factors that may run counter to the customer's class's characteristics. In general, times of high usage are also times of relatively higher energy cost, and conditions during those times may drive need for additional infrastructure.[3] In general, times of low usage are also times of relatively lower energy costs, and more capacity may be available on existing infrastructure during these conditions than is being utilized. When

[3] Factors to consider in designing complex ToU rates include physical characteristics of the utility system, system loads, and class loads as a surrogate for estimates of geographic dispersal of load, and economic factors such as the market price of energy or of market participation. This is not entirely straightforward, for example, integrated market prices may be driven by load or generation availability outside of the utility's footprint, and equipment like transformers need periods of reduced load – especially during times of hot weather – to cool off to avoid significant reduction in capacity for daytime operation.

designing ToU rates it is reasonable to assume that (a) aligning greater revenue responsibilities with times when much of the system's capacity is utilized and energy costs are higher can be used to (b) reduce revenue responsibilities with times when additional capacity is available and when energy costs are lower. In other words, the basic concept of ToU design is to price energy consumed during high-cost and/or high-utilization times higher than the energy consumed during low-cost and/or low-utilization times.

Q. Is Staff recommending transition of EMM and EMW rate schedules to designs comparable to Evergy's optional time-based rate structures in this case?

A. No. Consistent with the Ameren Missouri default ToU approach, in which a modest on-peak overlay was included in the default residential rate design,[4] and the Empire default ToU approach in which a modest off-peak discount overlay was included in the default residential rate design, [5] Staff recommends the EMM and EMW rate structures incorporate an on-peak overlay as a result of this rate case, to operate in conjunction with an off-peak discount overlay.

Q. What lessons learned from the deployment of Evergy's optional time-based rate structures can be applied to design of default time-based rates?

A. Several. These will be discussed in greater detail in Staff's rebuttal filing, but key takeaways relevant to the design of Staff's recommended default ToU rate structure are summarized below:

[4] For example, as approved in the Ameren Missouri rate case, ER-2019-0335, as customers receive AMI meters, they are transitioned to a rate schedule that includes an additional charge of half a cent during summer months and a quarter of a cent during non-summer months for energy consumed from 9:00 am to 9:00 pm.

[5] As approved in the Empire rate case, File No. ER-2021-0312, beginning in October of 2022, the default residential rate structure includes an "Off-Peak Discount Rider" that reduces the amount on the bill by $0.02 per kWh for energy consumed from 10:00 pm to 6:00 am.

1. Customers like lower bills, but also like to use energy when it is convenient for them.
2. Time of Use rate designs for self-selected customers did not reduce annual system peaks.
3. Customers who did not save money at the level they expected did not remain in the program.
4. Time of Use periods should be aligned with seasonal peak usage.
5. The design and education process within the utility itself was dominated by those with marketing backgrounds.
6. The high-differential opt-in design studied was revealed to lack support in cost-causation.

Q. How can these lessons be incorporated into design of default time-based rates?

A. The main take-away from the first three lessons learned is that the differential should be present, but not onerous. Customers may find it worthwhile to move laundry time from 6 pm to 9 pm, but may find it infeasible to avoid air-conditioning their home on a hot afternoon. This combined with the fourth lesson learned is that customers should not be financially incented to couple their usage peak with the seasonal usage peak of the system. The final lessons learned emphasize that time-based rates that are differentiated in excess of the relative differences in wholesale energy costs do not align cost-causation with revenue-responsibility any better than non-time-based rates.

Q. Why should the Commission order default ToU rate structures for all customers in this case, excluding the lighting, RTP, and special customer rate schedules?

A. We know that energy generally costs more in certain time periods. We know that utilities must build transmission and distribution facilities to meet the peak demands of their customers, and obtain generation capacity to meet their needs plus a margin. However, we also know that with very limited exceptions, energy costs for the customers of Evergy at wholesale range from about $-0.04/kWh to about $0.175 per kWh, with each of those extremes being an exceptional rarity.[6]

We also know that Evergy has indicated to its investors its intent to expend over $3 billion of capital into their distribution systems over the next 5 years.[7] We also know that if customers quit using energy today, the existing distribution and transmission systems would continue to exist, and are only avoidable over decades of time.

To summarize, there is a cost-based difference in a kWh consumed at 6:00 pm, and a kWh consumed at 2:00 am on a given day, but that difference is typically less than $0.05/kWh. Recognizing that difference is best accomplished through moderated time-based rates, rather than declining block rate schedules, inclining block rate schedules, or end use rates. However, because customers are accustomed to these rate elements, a sudden abandonment of all of them at once may result in unmanageable bills. A moderately-paced transition, beginning with elimination of end-use rates, movement towards leveling block declines, and imposition of time-based elements is a reasonable place to start in this case.

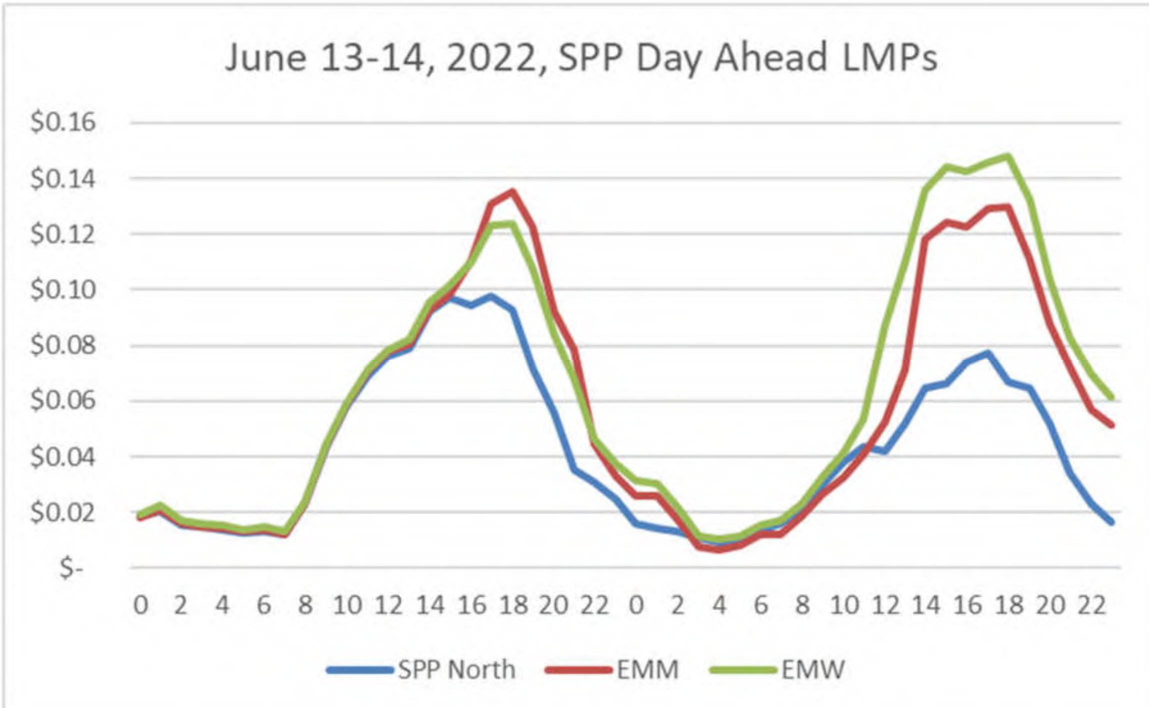
Q. Does your recommendation acknowledge extreme pricing events?

A. While extreme prices can and do occur, these tend to be related to isolated weather events such as Winter Storm Uri, the Polar Vortex of 2014, or unseasonable heat, such as a 100 degree day in June. Critical peak pricing or targeted DSM are better tools to address these extremes than are ToU rates, whether default or optional. For reference, the energy prices

[6] For example, the EMM load node LMP was between $0.000 and $0.06 in 91% of hours during the 12 months ending April 30, 2022, and between $0.001 and $0.05 in 83% of hours. The EMW load node LMP was between $0.000 and $0.06 in 89% of hours during the 12 months ending April 30, 2022, and between $0.001 and $0.05 in 80% of hours.

[7] See Investor Presentation, attached as SLKL-d2.

for June 13-14, 2022, which established a new record high daily minimum temperature and the most hours with a minimum temperature above 80 degrees, are provided below:



Even in this extreme event, the highest prices of the day were only about $0.12 higher than the lowest prices of the day.

Q. Given that the annual range of expected electric prices is a $0.049/kWh window, highly differentiated ToU was not demonstrated to impact annual peak demands, and EMM and EMW are not reducing distribution or generation revenue requirements based on potential load reductions, are more extremely-differentiated ToU rates cost justified?

A. No. Factors to consider to justify any differential beyond approximately $0.05 would be limited to:

1. Narrowly tailored seasonal diurnal differences in LMP[8],
2. Avoidable transmission expense,
3. Reductions in planned increases in distribution revenue requirement.

Q. Is there a cost-based rationale for the on peak premium and off-peak discount to be the same size year round, using the existing time periods?

A. For EMM and EMW, for the last several years, during the non-summer months, particularly during winter seasonal weather, there is not a difference between on-peak and other day-time hours to justify a significant price differential. Ideally based on the EMM and EMW load node LMPs, during winter seasonal weather, the price signal would actually be inverted, with morning periods and evening periods at a slight premium to the daytime periods. However, due to the potential bill shock of space heating customers, and to improve customer understandability, Staff recommends holding the hours of each charge period constant, and simply varying the charge amounts.

Q. What is the hour-weighted average cost of energy by time period in the summer and non-summer months, and what do they tell us about reasonable ToU design parameters if we remain grounded in cost-causation?

A. These results are provided in the tables below:

EMM results:

	Midnight to 6	Shoulders	4 pm - 8 pm
Summer:	$ 0.01282	$ 0.02673	$ 0.04359
Non-Summer:	$ 0.01299	$ 0.02650	$ 0.02922
	Off-Peak Discount	**On-Peak Premium**	**Maximum Range**
Summer:	$ (0.014)	$ 0.017	$ 0.031
Non-Summer:	$ (0.014)	$ 0.003	$ 0.016

[8] The Locational Marginal Price "LMP" is used here-in to refer to the wholesale cost of energy as obtained at transmission voltage through the SPP integrated marketplace.

EMW results:

	Midnight to 6		Shoulders		4 pm - 8 pm	
Summer:	$	0.01367	$	0.02689	$	0.04199
Non-Summer:	$	0.01474	$	0.02755	$	0.02995
	Off-Peak Discount		**On-Peak Premium**		**Maximum Range**	
Summer:	$	(0.013)	$	0.015	$	0.028
Non-Summer:	$	(0.013)	$	0.002	$	0.015

Q. Did you study the differentials between weekends and weekdays?

A. Yes. For neither EMM nor EMW was there a distinction to justify a difference:

EMM results:

	Midnight to 6		Shoulders		4 pm - 8 pm	
Weekend:	$	0.01309	$	0.02392	$	0.03184
Weekday:	$	0.01311	$	0.02798	$	0.03534
	Off-Peak Discount		**On-Peak Premium**		**Maximum Range**	
Weekend:	$	(0.011)	$	0.008	$	0.019
Weekday:	$	(0.015)	$	0.007	$	0.022

EMW results:

	Midnight to 6		Shoulders		4 pm - 8 pm	
Weekend:	$	0.01439	$	0.02445	$	0.03184
Weekday:	$	0.01436	$	0.02846	$	0.03507
	Off-Peak Discount		**On-Peak Premium**		**Maximum Range**	
Weekend:	$	(0.010)	$	0.007	$	0.017
Weekday:	$	(0.014)	$	0.007	$	0.021

Q. Did you exclude Storm Uri from these analysis?

A. Yes.

Q. At this time, is it reasonable to build on the existing advertising and educational campaigns associated with the existing optional ToU rates?

A. Yes. While the time periods used in the Evergy optional ToU design have not been demonstrated to be the most optimized to current market conditions,[9] at this point they are not unreasonable starting points. To build on the "Wait 'til 8!" campaign, I recommend year-round "On-Peak" hours of 4:00 – 8:00 pm, and "Super Off-Peak" hours of midnight until 6:00 am. However, I do not recommend exclusion of weekends and holidays from the on-peak period based on historical pricing and usage data which indicates that peaks can occur on holidays, and that weekends are not necessarily lower cost.

Real Time Pricing Schedule

Q. What elements should be included in a well-designed Real Time Pricing rate schedule?

A. An outline of applicable tariff contents is described below:

1. A one-on-one consultation should precede enrollment of any customer on a schedule, which should educate the customer on the potential variability of prices experienced at market, drawing on actual prices experienced during extreme weather events such as Winter Storm Uri. The completion of this consultation with triennial refreshers should be included in the eligibility requirements.
2. A limitation that the schedule is not available for resale, standby, breakdown, auxiliary or supplemental service; that it is not available to customers participating in demand response programs or other riders that provide incentives or disincentives related to changes in demand; or in conjunction with community solar, the wind participation tariff, or similar programs.
3. A customer charge based on the size of the meter installed, generally consistent with those established for customers operating at a similar level of demand in the otherwise applicable rate schedules, for illustration only, an example is provided below:

[9] EMM generally experiences high energy prices in fall shoulder month mornings. This is pervasive across the years studied, but is anomalous to expectations. This is likely due to the use of the fall shoulder period for generator outages, and the tendency of gas units in and around the Evergy service territory to lack firm gas transportation outside of the peak summer months.

0-24 kW: $50
25-199 kW: $75
200-999 kW: $100
1,000 -5,000 kW: $1,000
5,000 kW or above: $5,000

4. In addition to the customer charge, a monthly administrative fee that is reasonably related to the level of additional cost expected to administer this rate schedule, not to exceed $250 per month per customer.
5. A facilities charge generally consistent with those established for customers operating at a similar level of demand in the otherwise applicable rate schedules.
6. A demand charge applicable to a customer's peak demand in a given month:
    a. For summer months the period noon – 10 pm,
    b. For non-summer months the period be 6 am – 10 pm.
7. The demand charge shall be specified in the rate schedule, but shall be set to approximate the capacity value specified in the contract in place between EMM and EMW for capacity.
8. A charge per kWh of varying amounts, by applicable voltage, generally established by subtracting the FAC base factor from the energy revenue associated with each level of voltage during the development of compliance tariffs in these cases. For illustration only, an example is provided below:
    a. Secondary: $0.05
    b. Primary: $0.04
    c. Transmission: $0.03
    d. Substation: $0.029
9. The product of the respective EMM/EMW hourly average DA LMP for load, as published the day after, and the customer's average hourly load, adjusted to transmission voltage, for each hour, times 1.02, if the applicable LMP is positive for that hour. In the event that the applicable LMP is negative, the bill component shall be the product of the respective LMP and the customer's average hourly load, adjusted to transmission voltage, for each hour, times 0.98.
10. A Reactive Demand Adjustment charge consistent with similarly situated customers.
11. A requirement that a customer cannot re-enroll for a minimum of 12 months following disenrollment and a requirement that customers remain enrolled for a minimum of 12 months. However, if within 6 months of initial enrollment a customer decides to disenroll, they may do so but they will be required to pay a rebill of what their bill would have been on the otherwise applicable rate schedule.
12. Statements indicating the applicability of the Fuel Adjustment, MEEIA, RESRAM, and similar riders, and taxes.

Q. Would Staff be opposed to reasonable limitations on the number of customers allowed to participate, or to maximum and/or minimum demands of customers allowed to participate?

A. No, Staff welcomes productive input from the parties.

Q. Are the valuations of the rates described above based on actual cost of service amounts?

A. No. These valuations are purely intended to be indicative of the order of magnitude of expected for indicated rate elements, ie, hundreds of dollars versus cents, actual valuation would need to be calculated to tie to the revenues, net of FAC base, expected from a similarly-situated customer operating at class-average load factor.

CCOS STUDIES AND INTERCLASS REVENUE RESPONSIBILTY RECOMMENDATIONS

Role of CCOS Studies in Rate Cases & Overview of Staff Study Development

Q. What is the purpose of a CCOS study in the rate case process in Missouri?

A. A robust CCOS is a reasonable guide to designing the rates of each customer class, both in the sense of establishing the magnitude of a given rate element within a class, and the relative revenue to recover from each class. However, a CCOS is limited by the precision of the information studied. In this case, Staff's CCOS studies are not as robust as would be ideal due to lack of information about the use of the distribution system, lack of information about distribution expenses, lack of detail of energy consumption by rate schedule, and reliance on antiquated production allocation methods - the latter of which was done to minimize disparities among parties in this case to identify the impact of revenue requirement level and composition and in the absence of detailed energy consumption by rate schedule. For example, without hourly load information for space heating customers versus general use customers, one cannot assess the reasonableness of the revenues provided by each.

Q. Could you provide an analogy for the precision of CCOS Studies?

A. Yes. Imagine sitting at your desktop computer seeking directions on Google Maps for a cross country drive, from Seattle, Washington, to Miami, Florida. Google Maps will readily calculate a route via I-90 at 3,294 miles and 49 hours, and a route via I-70 at 3,359 miles and 50 hours. I can request a route that detours into San Francisco, California, and Chicago, Illinois, that Google Maps calculates to be precisely 4,317 miles in length, with 65 hours' duration. It is reasonable to assume that more often than not, my detour route will take longer than either of the initial routes, but it is not reasonable to assume exactly where the car will be on any route 33 hours and 21 minutes after my departure, nor would Google Maps attempt to account for whether I may decide to detour to the Grand Canyon for a week on the offered I-70 route. In other words, I can use the tools in Google Maps to develop an answer on route duration down to the hour, or route length down to the mile, but while we can rely on those results to determine that detouring through San Francisco and Chicago adds time and miles, we cannot rely on those results to assume exact arrival time or to know the exact location of a the car at a given point in the trip. While during the trip I could use my phone's GPS to "true-up" any route or time deviations, we do not get that opportunity in a rate case. A CCOS Study is one and done at direct, based on the information and revenue requirement available at that time.

Similarly, CCOS study results may be useful for observing that the Small General Service class (as an example) is providing a much higher rate of return as studied than the Large Power Service class, but I have never seen a CCOS so robust based on data so accurate that

I would find it reasonable to attempt to precisely match class revenues to the resulting class revenue requirement.

Q. What is Staff's general approach to the precision of CCOS results?

A. In general, Staff will not recommend any class receive a reduction in a general rate proceeding with a positive net revenue requirement; and Staff will not recommend adjustment to study results unless those results indicate one or more classes' percent change to bring class rate revenue to the studied cost of service exceeds 5% in one direction AND another class or classes' indicated change exceeds 5% in the opposite direction.

Q. Is that general approach further tempered in this case?

A. Yes. In these cases I was able to determine early on that EMM and EMW were unable to provide the data necessary to do a robust study of the proper classification, assignment, and allocation of the distribution system. I was also able to determine early on that rate design will be a time-consumptive issue in these cases, as will various optional tariff programs requested by EMM and EMW, such as subscription pricing and prepaid utility service. I was also disappointed to learn that hourly electrical consumption by rate code was not accessible by EMM and EMW aggregated by hour at the rate code level. Given these known limitations on the reasonableness of the results of any CCOS studies I could do in these cases, and given the level of controversy that has surrounded the allocation of production capacity costs, production operation and maintenances expenses, and fuel and purchased power costs, I made the decision to essentially treat these areas as though the SPP integrated marketplace does not exist, for purposes of conducting the CCOS studies in this case.

Consistent with the allocation of expenses for generation in this manner, I had no reasonable choice but to allocate the revenues from energy sales on class energy requirements, in order to ensure that one class wasn't paying for the fuel necessary to generate the energy sold into the market. This, obviously, requires tempering reliance on the results of these studies with knowledge that the SPP integrated marketplace does, in fact, exist. Based on this reality, and based on the relationship I have observed in other CCOS studies between the costs allocated under an Average & Excess approach versus any study approach acknowledging the existence of the SPP integrated marketplace, I would recommend that results that indicate undercontribution from non-lighting classes with relatively low load factors, and results that indicate overcontribution from non-lighting classes with relatively high load factors be viewed with more than usual skepticism. Further, this approach underallocates revenues from non-retail energy sales to classes with relatively high capacity determinants and relatively lower class energy consumption, while overallocating revenues from non-retail energy sales to classes with relatively low capacity determinants and relatively higher class energy consumption.

Much like I know more than Google Maps knows about my intention to detour the I-70 trip to the Grand Canyon for a week, I know going in that the study methods I will employ in these cases are going to skew revenue requirement to classes who are less energy-intensive, and will skew non-retail revenues to classes who are more energy-intensive. However, for these cases, the more apt comparison would be a trip to Ethiopia, via assorted modes of transportation, more so than a cross-country drive. Specifically, the manner in which Nucor costs and revenues are incorporated into the revenue requirement due to the design Schedule SIL and the implementation of record keeping by EMW, as discussed in the direct cost of service testimony of J Luebbert, significant additional effort would be been required to achieve results that still would lack the level of precision to which Staff has developed prior CCOS Studies.

Q. Are the imprecisions you discuss above related only to the portions of the revenue requirement comprised of production capacity costs, production operation and maintenances expenses, fuel and purchased power costs, and distributions costs and expenses?

A. No. Because currently all CCOS approaches rely heavily on what Staff calls "internal allocators" and the Company calls "secondary allocators" any imprecision introduced in the allocation of these costs is carried on first to the associated expense accounts, and then grossed up to additional revenue requirement components.

Q. What is an example of an internal allocator?

A. The most direct example of an internal allocator is "Net Plant." Within the Staff's CCOS excel macro, any item for with the Net Plant allocator is selected will be allocated to the classes proportionate to how net plant has been allocated with non-internal allocators. In its clearest application, this allocator can be used to allocate income tax expense to the classes, as income tax is incurred by the company on its return on equity, which is derived from its net rate base. However, it is not uncommon for this allocator (or another internal allocator "Gross Production, Transmission, Distribution Plant") to be used for accounts such as administrative and general expenses, or other, difficult to functionalize expenses or costs.[10]

Q. Could you provide an example of how an imprecision in an initial allocation will grow?

[10] Functionalization is the description of a portion of revenue requirement by its function, classically, Generation, Transmission, Distribution, and Customer, though various levels of detail of these categories exist. Functionalization is distinct, though related to, classification. Classification is the description of a portion of revenue requirement by its underlying causation, typically Demand, Energy, and Customer.

A. Yes. As illustrated below, if an account that is considered in an internal allocator is allocated imprecisely, that skew will be carried forward to accounts allocated with the internal allocator.

Proper Allocation Example	Allocator	Class A %	Class B %	Total $	Class A $	Class B $
Generation	Generation Allocator	50%	50%	$ 1,000	$ 500	$ 500
Transmission	Transmission Allocator	40%	60%	$ 1,000	$ 400	$ 600
Distribution	Distribution Allocaotr	60%	40%	$ 1,000	$ 600	$ 400
General Plant	Internal - Reallocate of GTD Plant	50%	50%	$ 1,000	$ 500	$ 500
Administrative Expense	Internal - Reallocate on Gross Plant	50%	50%	$ 1,000	$ 500	$ 500
	Total Revenue Requirement:			$ 5,000	$ 2,500	$ 2,500

Skewed Allocation Example	Allocator	Class A %	Class B %	Total $	Class A $	Class B $
Generation	Generation Allocator	55%	45%	$ 1,000	$ 550	$ 450
Transmission	Transmission Allocator	45%	55%	$ 1,000	$ 450	$ 550
Distribution	Distribution Allocaotr	65%	35%	$ 1,000	$ 650	$ 350
General Plant	Internal - Reallocate of GTD Plant	55%	45%	$ 1,000	$ 550	$ 450
Administrative Expense	Internal - Reallocate on Gross Plant	55%	45%	$ 1,000	$ 550	$ 450
	Total Revenue Requirement:			$ 5,000	$ 2,750	$ 2,250

In this example, while only $150 was initially misallocated, that misallocation carried forward with multiple rounds of internal allocators, to result in a large total misallocation.

	Class A $	Class B $
Direct Misallocation:	$ 150	$ (150)
Indirect Misallocation:	$ 100	$ (100)
Total Misallocation:	$ 250	$ (250)

Q. What is the underlying causation of newer components of revenue requirement, such as Plant in Service Accounting deferrals, or generation deployed to meet environmental goals or achieve profits in the SPP integrated marketplace?

A. These revenue requirement components do not appear to have been a consideration in the 1992 NARUC Cost Allocation Manual. As a kWh of energy is the basic unit of the service an electric utility provides, these costs and expenses are best allocated on the basis of energy sales.

Q. Which allocators did you prepare based on Staff's direct filed revenue requirement?

A. I prepared class revenue allocators to coincide with the revenues developed in Staff's direct case. I also relied on the billing determinants that underlie Staff's direct case to develop allocators related to customer numbers and sales of energy to the classes.

Q. For which allocators do you rely on company allocators?

A. I relied on the EMM and EMW allocators for customer deposits, meter investment and expense, uncollectible accounts, and customer services and information. I also rely on the Company's classification and allocation of substantial components of the distribution system. I also relied on the Companies' class-level demand estimates. Use of these values, even if they are suboptimal, minimizes inconsistencies in study results among the parties. I have been unable to obtain the information necessary to either independently calculate these classifiers and allocators, which would also be necessary to the accuracy of the Companies' valuation.

Q. What information did you request that the company was unable to provide?

A. Relevant data requests and responses from the EMM case are provided below:[11]

> Question: 0211
> For each voltage and phase combination at which the company operates transmission or distribution equipment, please identify the typical or representative retirement units and quantities associated with providing 1 span of overhead (and the equivalent distance of underground) infrastructure including devices. For each combination, by overhead and underground, please indicate the number of pole miles, and the typical number of conductors. If multiple conductor numbers are in common use, please identify the number of pole miles associated with each number of conductors. Sarah Lange (sarah.lange@psc.mo.gov)

[11] Substantially identical questions and responses were made and received in the EMW case. I did not seek to independently verify the Companies' allocations of customer deposits.

RESPONSE:
The Company does not retain information in a form that would facilitate a response to this question.
Information provided by: Brad Lutz

Question: 0212
Please identify, by retirement unit and account, the transmission or distribution plant associated with providing service to isolated customers. Please identify, by rate schedule and voltage and phase at which service is taken, the retirement unit and account associated with transmission or distribution plant associated with providing service to isolated customers. For example, if a customer is served at 34kV but is adjacent to a 69kV, please identify the transformation equipment, conductor, switchgear, etc, used to facilitate service to that customer; or the line transformer and conductor combination used as a service drop for a given size of secondary customer. Please specify plant that may be shared to a limited extent by adjacent customers, such as line transformers. Sarah Lange (sarah.lange@psc.mo.gov)
RESPONSE:
The Company does not retain information in a form that would facilitate a response to this question.
Information provided by: Brad Lutz

Question: 0214
A. Please identify each voltage and phase combination at which service is provided to customers, and identify the number of customers taking service on each, by rate schedule. B. For each voltage and phase combination at which service is provided to customers, identify (1) the typical or representative retirement units and quantities associated with providing 1 span of overhead (and the equivalent distance of underground) infrastructure including devices, and (2) the typical or representative meter(s) and related installations, by retirement unit or more specific information if available. (3) if these items vary with usage characteristics of customers, Company shall provide items 1 & 2 for a minimum of high, medium, and low infrastructure customers. Sarah Lange (sarah.lange@psc.mo.gov)
RESPONSE:
The Company does not retain information in a form that would facilitate a response to this question.
Information provided by: Brad Lutz

Question: 0215
A. Please identify each voltage and phase combination at which customers are billed, and identify the number of customers billed on each, by rate schedule. For each rate schedule, please identify the number of customers served and billed at each combination of voltages and phases at which the

company provides service and bills customers, at the beginning and 15th of each calendar month, for the period 1/1/2018-12/31/2022. B. For each rate schedule voltage and phase service and billing combination identified above on which fewer than 100 customers are served, please provide individual hourly load data for each customer for the period 1/1/2018-12/31/2022. C. For each rate schedule voltage and phase service and billing combination identified above on which more than 100 customers are served, please provide individual hourly load data for each of 100 randomly sampled customers for the period 1/1/2018-12/31/2022. D. For each rate schedule voltage and phase service and billing combination, please provide the sum of all customers' hourly loads for each hour for the period 1/1/2018-12/31/2022. Sarah Lange (sarah.lange@psc.mo.gov)
RESPONSE:
The Company does not retain information in a form that would facilitate a response to this question.
Information provided by: Brad Lutz

Question: 0216
Please identify the number of employees or contractors and level of payroll associated with providing customer service to customers, by rate schedule. Sarah Lange (sarah.lange@psc.mo.gov)
RESPONSE:
The Company does not retain information in a form that would facilitate a response to this question.
Information provided by: Brad Lutz

Question: 0217
Please identify the number of employees or contractors and level of payroll associated with repairing, maintaining, or installing the distribution or transmission equipment used to provide service to isolated customers, by rate schedule. Sarah Lange (sarah.lange@psc.mo.gov)
RESPONSE:
The Company does not retain information in a form that would facilitate a response to this question.
Information provided by: Brad Lutz

Question: 0248
Please refer to the Company's "Allocators Workpapers 202106 – Direct Filing" at Tab "Cust3_Acct 369" and explain why LGS, LPS, and Lighting customers were excluded from this allocator calculation. Explain where equipment analogous to the equipment recorded in account 369 is booked for each of these customer classes served at secondary, and served at any other applicable voltage level. Clarify if the average cost of a service is the same for all customers, regardless of the voltage or amperage of the customer served. DR requested by Sarah Lange (sarah.lange@psc.mo.gov).

RESPONSE:
Customer classes allocated a portion of Account 369 are known to typically experience service drops. This assumption is consistent with our examination standards and historical methods. No ready source for alternative allocation is available.
Account 369's equipment is booked for each of the customer classes served at secondary. The allocation calculation does not incorporate a breakdown of Account 369 equipment, but rather utilizes secondary customer counts to allocate the broader Account 369.
Actual costs will vary by customer. Allocation used is consistent with historical and standard expectation for this unit of plant.
Information provided by: Brandon Lombardino, Regulatory Analyst II, Regulatory Affairs

Q. What improvements to the CCOS Studies would have been possible with the information sought above?

A. This information would have facilitate more reasonable classification and allocation of the distribution system, as well as enabled more reasonable allocation of the costs, expenses, and revenues associated with EMW and EMM's generation of energy, participation in the SPP integrated energy market, and acquisition of wholesale energy to serve customers, at a rate code level. Given the significant growth of distribution, transmission, and non-dispatchable generation anticipated over the next five years, it is necessary at this time to review these costs and expenses and the allocation there-of in greater detail than may have been acceptable in the past. Given the growth of rate base and expenses associated with services that have not been historically subject to regulation (such as electric vehicle charging services and optional rate structures and designs) the level of data needed to review the proper assignment or allocation of costs associated with these elements will only increase.

Q. Please describe your "Co Lines & Poles Composite" allocator.

A. In the absence of the detailed information necessary to reasonably classify and allocate the revenue requirement associated with accounts 364 – Poles, Towers, & Fixtures, 365 – Overhead Conductors & Devices, 366- Underground Conduit, and 367 – Underground Conductors & Devices, I created one allocator that I understand to be consistent with the EMM and EMW classification and allocation of the revenue requirement associated with these distribution system components.

Q. How did you calculate the production capacity allocator used in this case?

A. As discussed above, due to data limitations and to reduce the number of contested issues in this case to enable focus on rate design in the absence of robust data, I used an Average and Excess allocator. However, I used an A&E 4CP allocator consistent with the 1992 NARUC Cost Allocation Manual, which differs from the A&E 4NCP allocator developed by the Company.[12] I also weighted the resulting allocator by the ratio of non-dispatchable low/no fuel cost generation to dispatchable generation, and with those costs allocated to the classes on the basis of class energy consumption.

Q. How did you allocate fuel, purchased power, and revenues from non-retail energy sales?

A. Given the acceptance discussed above of a regulatory fiction that the SPP integrated marketplace does not exist, all of these items are allocated on the basis of class energy requirements.

Q. How did you allocate transmission costs, expenses, and revenues?

A. All transmission-related items are allocated on the basis of the classes' 12 coincident peaks.

[12] "CP" is the acronym for "Coincident Peak," and refers to a given class's load in the hour in a given month (or year) when the system has the highest energy usage. NCP is the acronym for "Non-Coincident Peak," and refers to a given class's load in the hour it is the highest in a given month (or year).

Q. Please describe your "composite secondary" allocator?

A. Unlike many other utilities, EMM has Large Primary customers who are technically served at secondary voltages. The Composite Secondary allocator is weighted by number of customers in each class served at secondary voltage and the energy usage of those customers as a means of providing perspective to the relative size of the facilities necessary to serve each customer.

EMM Study Results and Recommended Revenue Responsibility Shifts

Q. Please provide a summary of your CCOS Study results for EMM.

A. The summary table is provided below:

	Residential	SGS	MGS	LGS	LPS	Lighting	Other	Total
	$ 301,915,606	$ 51,209,568	$ 91,946,691	$ 139,796,157	$ 102,699,036	$ 16,826,622	$ 1,028,806	$ 705,422,486
Offsetting Revenue	$ 4,891,968	$ 5,578,617	$ 9,639,682	$ 13,606,332	$ 16,461,754	$ 19,332,164	$ 3,322	$ 69,513,839
Current Rate Revenue	$ 328,695,098	$ 70,950,862	$ 123,489,122	$ 182,782,977	$ 120,906,602	$ 9,887,749	$ 103,282	$ 836,815,692
Revenue Available for RoR	$ 21,887,524	$ 14,162,677	$ 21,902,749	$ 29,380,487	$ 1,745,812	$ (26,271,037)	$ (928,846)	$ 61,879,367
	$ 1,381,122,168	$ 219,654,227	$ 381,032,310	$ 537,430,434	$ 365,429,530	$ 107,831,077	$ 4,374,777	$ 2,996,874,523
Current RoR with New Income Tax Requirement	1.58%	6.45%	5.75%	5.47%	0.48%	-24.36%	-21.23%	
Return on Rate Base at System Average Return	$ 93,501,971	$ 14,870,591	$ 25,795,887	$ 36,384,040	$ 24,739,579	$ 7,300,164	$ 296,172	$ 202,888,405
Difference from System-Average RoR $	$ (71,614,446)	$ (707,914)	$ (3,893,138)	$ (7,003,553)	$ (22,993,767)	$ (33,571,201)	$ (1,225,019)	$ (141,009,038)
Difference from System-Average RoR %	-22%	-1%	-3%	-4%	-19%	-340%	-1186%	-17%
Estimated Net Class Cost of Service	$ 390,525,609	$ 60,501,542	$ 108,102,897	$ 162,573,865	$ 110,976,861	$ 4,794,622	$ 1,321,656	$ 838,797,052
Additional Rev Req for True-Up Estimate	$ 12,172,376	$ 1,885,786	$ 3,369,482	$ 5,067,300	$ 3,459,062	$ 149,445	$ 41,195	$ 26,144,645
Total Estimated CCoS at System-Average RoR	$ 402,697,985	$ 62,387,328	$ 111,472,379	$ 167,641,165	$ 114,435,923	$ 4,944,067	$ 1,362,851	$ 864,941,697
Total CCoS minus Current Rate Revenue	$ 74,002,887	$ (8,563,534)	$ (12,016,743)	$ (15,141,812)	$ (6,470,679)	$ (4,943,682)	$ 1,259,569	$ 28,126,005
Current RoR with New Income Tax Requirement and True-Up Estimate	0.70%	5.59%	4.86%	4.52%	-0.47%	-24.50%	-22.17%	1.19%

Q. Does any studied class fail to meet the expenses allocated to that class and provide some contribution to the rate of return?

A. The LPS, Lighting, and the "Other" class to which EV equipment and other customer-specific costs have been allocated fails to meet allocated expenses. In the case of LPS, the class meets its allocated expenses prior to inclusion of the plug for true-up, but provides a negative return on investment after the true-up allowance is incorporated. All other studied classes provide some contribution to rate of return, though the amounts vary significantly.

Q. Based on your knowledge of the study methods and experience, how do you recommend the Commission order any increase in this case be applied to the class revenue requirements?

A. For purposes of aligning class revenue requirements with cost causation, I recommend that if an increase is ordered in this case in excess of approximately $20 million, the first $20 million be applied as a 1% increase to SGS, MGS, and LGS, a 3% increase to the residential class, and a 5% increase to LPS, the lighting class, and to the miscellaneous rate schedules associated with the "Other" class.

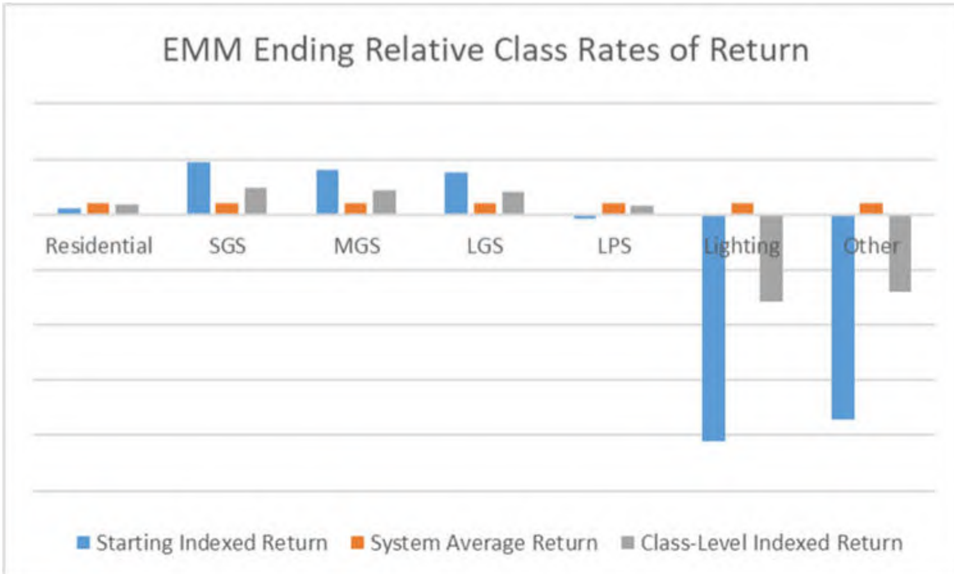
	Residential	SGS	MGS	LGS	LPS	Lighting	Other	Total
Potential Increase Level 1	3.0%	1.0%	1.0%	1.0%	5.0%	5.0%	5.0%	2.4%
Increase to Current Revenue	$ 9,860,853	$ 709,509	$ 1,234,891	$ 1,827,830	$ 6,045,330	$ 494,387	$ 5,164	$ 20,177,964
Difference from System-Average RoR $	$ 64,142,034	$ (9,273,043)	$ (13,251,634)	$ (16,969,642)	$ (12,516,009)	$ (5,438,070)	$ 1,254,405	$ 7,948,041
Revenue Available for RoR	$ 31,748,377	$ 14,872,186	$ 23,137,641	$ 31,208,317	$ 7,791,142	$ (25,776,650)	$ (923,682)	$ 82,057,331
Increase Level 1 RoR	2.30%	6.77%	6.07%	5.81%	2.13%	-23.90%	-21.11%	2.74%

Any additional increases should be applied as an equal percentage increase to the current rate revenues of each class:

	Residential	SGS	MGS	LGS	LPS	Lighting	Other	Total
Potential Increase Level 2	0.95%	0.95%	0.95%	0.95%	0.95%	0.95%	0.95%	0.95%
Increase to Current Revenue	$ 3,121,933	$ 673,888	$ 1,172,895	$ 1,736,065	$ 1,148,366	$ 93,913	$ 981	$ 7,948,041
Difference from System-Average RoR $	$ 61,020,102	$ (9,946,931)	$ (14,424,529)	$ (18,705,707)	$ (13,664,375)	$ (5,531,983)	$ 1,253,424	$ -
Revenue Available for RoR	$ 34,870,310	$ 15,546,074	$ 24,310,535	$ 32,944,382	$ 8,939,508	$ (25,682,736)	$ (922,701)	$ 90,005,372
Increase Level 2 RoR	2.52%	7.08%	6.38%	6.13%	2.45%	-23.82%	-21.09%	3.00%

Q. Why does the total rate of return shown in the final step equal only 3%?

A. Because the true-up revenue-requirement allowance is essentially treated as an expense in this calculation, even though it includes rate base estimates, it effectively "cancels out" the revenue amount available for rate of return on a system average basis. To better illustrate the ending class-level rates of return after incorporating these shifts, please refer to the graph below:



Q. For any increase below $20 million, how should the revenue requirement be allocated?

A. Any increase less than $20 million should be applied as an equal percentage adjustment to the class revenue requirements of the Residential, LPS, Lighting, and "Other" classes. Any overall reduction in revenue requirement should be allocated to the SGS, MGS, and LGS classes, although it would likely be appropriate to perform a new study if the case enters the posture of an overall revenue decrease.

EMW Study Results and Recommended Revenue Responsibility Shifts

Q. Please provide a summary of your CCOS Study results for EMW.

A. The summary table is provided below:

	Residential	SGS	LGS	LPS	Lighting	Other
	$ 343,779,295	$ 88,005,827	$ 71,075,221	$ 99,069,550	$ 11,368,376	$ 1,108,757
Offsetting Revenue	$ 15,110,900	$ 4,108,653	$ 3,359,913	$ 4,211,318	$ 288,638	$ 20,682
Current Rate Revenue	$ 374,907,431	$ 119,308,161	$ 91,473,636	$ 116,573,918	$ 13,058,599	$ 532,797
Revenue Available for RoR	$ 16,017,237	$ 27,193,682	$ 17,038,502	$ 13,293,050	$ 1,401,585	$ (596,643)
	$ 1,319,143,530	$ 300,258,175	$ 223,425,325	$ 265,109,229	$ 67,796,447	$ 2,871,579
Current RoR with New Income Tax Requirement	1.21%	9.06%	7.63%	5.01%	2.07%	-20.78%
Return on Rate Base at System Average Return	$ 88,448,574	$ 20,132,311	$ 14,980,668	$ 17,775,574	$ 4,545,752	$ 192,539
Difference from System-Average RoR $	$ (72,431,337)	$ 7,061,371	$ 2,057,834	$ (4,482,524)	$ (3,144,166)	$ (789,182)
Difference from System-Average RoR %	-19%	6%	2%	-4%	-24%	-148%
Estimated Net Class Cost of Service	$ 417,116,969	$ 104,029,485	$ 82,695,976	$ 112,633,806	$ 15,625,490	$ 1,280,614
Additional Rev Req for True-Up Estimate	$ 13,992,995	$ 3,489,870	$ 2,774,196	$ 3,778,519	$ 524,187	$ 42,961
Total Estimated CCoS at System-Average RoR	$ 431,109,964	$ 107,519,355	$ 85,470,172	$ 116,412,325	$ 16,149,677	$ 1,323,575
Total CCoS minus Current Rate Revenue	$ 56,202,533	$ (11,788,806)	$ (6,003,464)	$ (161,593)	$ 3,091,078	$ 790,778
Current RoR with New Income Tax Requirement and True-Up Estimate	0.15%	7.89%	6.38%	3.59%	1.29%	-22.27%

Note, the "Other" class for EMW includes Thermal Rate Code 650. Due to the manner in which the revenue requirement information was made available, in general, this study includes Nucor costs, but does not include Nucor revenues. For this reason, non-Nucor customers are overallocated capacity costs and transmission costs within the study. The same concerns described above related to the regulatory fiction of self-generation and the lack of distribution and expense information necessary for a reasonable study are also present with this EMW study.

Q. Does any studied class fail to meet the expenses allocated to that class and provide some contribution to the rate of return?

A. The "Other" class to which EV equipment and other customer-specific costs have been allocated fails to meet allocated expenses. All other studied classes provide some contribution to rate of return, though the amounts vary significantly.

Q. Based on your knowledge of the study methods and experience, how do you recommend the Commission order any increase in this case be applied to the class revenue requirements?

A. For purposes of aligning class revenue requirements with cost causation, I recommend that if an increase is ordered in this case in excess of approximately $15 million, the first $15 million be applied as a 1% increase to SGS, LGS, and LPS a 3% increase to the residential class, and a 5% increase to the lighting class and to the miscellaneous rate schedules associated with the "Other" class.

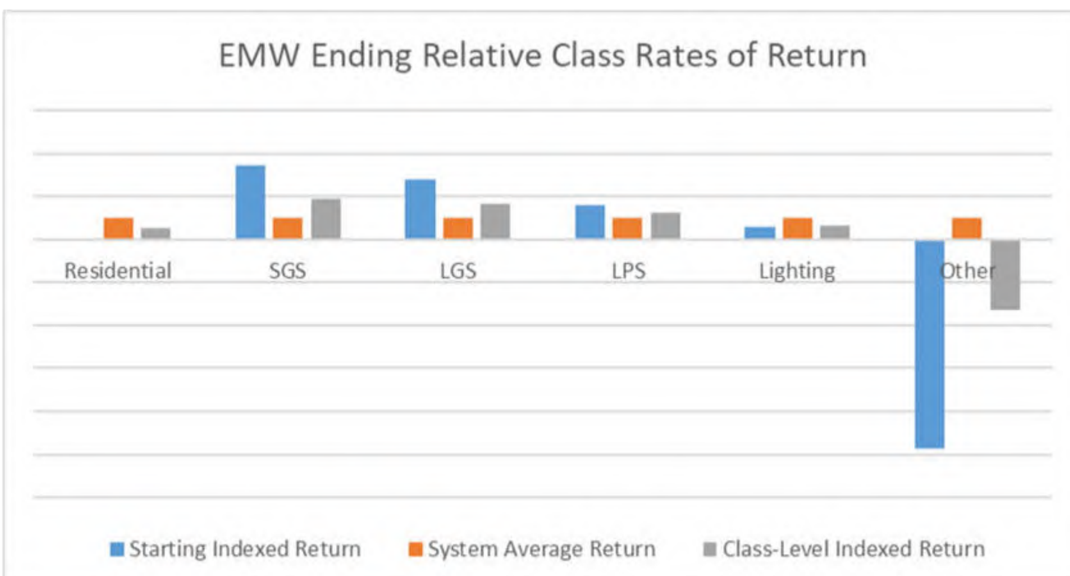
	Residential	SGS	LGS	LPS	Lighting	Other
Potential Increase Level 1	3.0%	1.0%	1.0%	1.0%	5.0%	5.0%
Increase to Current Revenue	$ 11,247,223	$ 1,193,082	$ 914,736	$ 1,165,739	$ 652,930	$ 26,640
Difference from System-Average RoR $	$ 44,955,310	$ (12,981,888)	$ (6,918,200)	$ (1,327,333)	$ 2,438,148	$ 764,138
Revenue Available for RoR	$ 27,264,460	$ 28,386,763	$ 17,953,238	$ 14,458,789	$ 2,054,515	$ (570,003)
Increase Level 1 RoR	2.07%	9.45%	8.04%	5.45%	3.03%	-19.85%

Any additional increases should be applied as an equal percentage increase to the current rate revenues of each class:

	Residential	SGS	LGS	LPS	Lighting	Other
Potential Increase Level 2	3.76%	3.76%	3.76%	3.76%	3.76%	3.76%
Increase to Current Revenue	$ 14,103,875	$ 4,488,328	$ 3,441,203	$ 4,385,466	$ 491,260	$ 20,044
Difference from System-Average RoR $	$ 30,851,435	$ (17,470,215)	$ (10,359,403)	$ (5,712,799)	$ 1,946,889	$ 744,095
Revenue Available for RoR	$ 41,368,335	$ 32,875,091	$ 21,394,442	$ 18,844,256	$ 2,545,775	$ (549,959)
Increase Level 2 RoR	3.14%	10.95%	9.58%	7.11%	3.76%	-19.15%

Q. What are the ending class-level rates of return after incorporating these shifts?

A. The results for EMW are provided below:



Q. For any increase below $15 million, how should the revenue requirement be allocated?

A. Any increase less than $15 million should be applied as an equal percentage adjustment to the class revenue requirements of the Residential, Lighting, and "Other" classes. Any overall reduction in revenue requirement should be allocated to the SGS and LGS classes, although it would likely be appropriate to perform a new study if the case enters the posture of an overall revenue decrease.

INTRACLASS RATE DESIGN RECOMMENDATIONS

Residential Rate Design

Residential ToU Design

Q. What ToU design does Staff recommend?

A. While final design will depend on the overall revenue requirement ordered in this case and the degree of recommended consolidation of end-use rates ordered in this case, at this time, Staff recommends a summer off-peak discount for the "Super Off-Peak" period of -$0.01, and an on-peak premium of $0.01. For the non-summer months, in conjunction with Staff's recommended rate schedule changes, Staff recommends the "Super Off-Peak" discount be held constant at $0.01, but that the on-peak premium be moderated to $0.025. This customer friendly approach will mitigate the impact of ToU rates to customers with energy-intensive HVAC units. This approach will simplify the customer experience and relies on the education process Evergy agreed to begin in its last rate cases, ER-2018-0145 and 0146. This recommendation is made in conjunction with the rate schedule consolidations and reconfigurations recommended by Staff.[13]

Q. Could you walk through the relevant ToU design process for EMM?

[13] Staff adopted the time period names used for the current opt-in ToU rates, but would support renaming to more meaningful names, such as "Off-peak" for the overnight hours currently denominated "Super Off-Peak," and "Shoulder," for the current "Off-Peak," hours during the morning and late evening.

A. Yes. Once I had determined that it was not unreasonable to rely on the existing Evergy ToU periods, with the exception of incorporating weekend and holiday peak periods, I needed to estimate determinants for each of the overlay periods. To do this I started with the EMM sales at meter provided by Evergy in Response to Data Request No. 0240 in ER-2022-0129. This data source was represented to include the summed value of EMM residential sales from AMI meters for the period of January 1, 2019, through December 31, 2021. For February 2021, I substituted in the hourly sales for February of 2020. The percent of metered usage falling into each time period, by season, are provided by season and time period below:

	Super-off	Off-peak	Peak
Summer	18%	59%	23%
Non-Summer	21%	59%	19%

I then applied the percentages derived from the study of hourly sales data to the normalized and annualized residential billing determinants, by season, that were used in Staff's direct COS filing. Those results are provided below:

	Total kWh	Super-off	Off-peak	Peak
Summer Residential kWh	992,540,793	177,484,292	584,018,082	231,038,418
Non-Summer Residential kWh	1,569,860,362	334,076,778	933,873,094	301,910,490

Finally, using the overlay rates I developed using the analysis discussed above, I calculated the revenue impact of applying those rates to these determinants, provided below:

	Overlay Rate	Super-off	Off-peak	Peak
Summer peak	$ 0.01000			$ 2,310,384
Summer Super Off-Peak	$ (0.01000)	$ (1,774,843)		
Non-Summer Peak	$ 0.00250			$ 754,776
Non-Summer Super Off-Peak	$ (0.01000)	$ (3,340,768)		
		$ (5,115,611)	$ -	$ 3,065,160

Using the results of this analysis, I determined that the annual net impact of the ToU design on overall Residential revenues was less than 1%. This level of impact did not seem unreasonable, so I proceeded to analyze the range of possible individual customer impacts by month.

Those same values for EMW are provided below:

	Super-off	Off-peak	Peak
Summer	17%	59%	24%
Non-Summer	22%	59%	19%

	Total kWh	Super-off	Off-peak	Peak
Summer Residential kWh	1,290,198,630	215,313,045	764,914,638	309,970,947
Non-Summer Residential kWh	2,241,486,821	482,432,446	1,330,298,464	428,755,912

	Overlay Rate	Super-off	Off-peak	Peak
Summer peak	$ 0.01000			$ 3,099,709
Summer Super Off-Peak	$ (0.01000)	$ (2,153,130)		
Non-Summer Peak	$ 0.00250			$ 1,071,890
Non-Summer Super Off-Peak	$ (0.01000)	$ (4,824,324)		
		$ (6,977,455)	$ -	$ 4,171,599

Residential Customer Impacts Due to ToU Implementation

Q. Have you reviewed the range of customer impacts associated with your recommended ToU design?

A. Yes. Because the ToU is applied as overlays to the existing summer-incline and non-summer decline rate designs, the range of bill impacts is a product of the kWh and the size of the overlay. It is very unlikely that any customer will use all of their energy for a month in a single overlay period.

To review customer impacts I created four customer load profiles, with varying levels of average usage per month for each profile, by season. They are summarized below:

	Low Usage Annual	High Usage Annual	Small Space Heat	Large Space Heat
Summer	750	2,500	750	2,500
0-600	600	600	600	600
600-1000	150	400	150	400
1000+	-	1,500	-	1,500
Shoulder	500	1,000	500	2,000
0-600	500	600	500	600
600-1000	-	400	-	400
1000+	-	-	-	1,000
Peak Winter	750	2,500	1,500	4,000
0-600	600	600	600	600
600-1000	150	400	400	400
1000+	-	1,500	500	3,000

The table provided below illustrates the absolute maximum impacts a customer at each level of indicated usage could experience in a given summer month, non-summer shoulder month, and non-summer winter month, if all of that customers usage coincided with a single overlay period. These results are applicable to both EMM and EMW. The annual impact of 4 of each of those months is also provided:

	Low Usage Annual	High Usage Annual	Small Space Heat	Large Space Heat
ToU Summer Range Upper	$ 7.50	$ 25.00	$ 7.50	$ 25.00
ToU Summer Range Lower	$ (7.50)	$ (25.00)	$ (7.50)	$ (25.00)
ToU Shoulder Range Upper	$ 1.25	$ 2.50	$ 1.25	$ 5.00
ToU Shoulder Range Lower	$ (5.00)	$ (10.00)	$ (5.00)	$ (20.00)
ToU Winter Range Upper	$ 1.88	$ 6.25	$ 3.75	$ 10.00
ToU Winter Range Lower	$ (7.50)	$ (25.00)	$ (15.00)	$ (40.00)
ToU Annual Range Upper	$ 42.50	$ 135.00	$ 50.00	$ 160.00
ToU Annual Range Lower	$ (80.00)	$ (240.00)	$ (110.00)	$ (340.00)

Q. Could you summarize your takeaways from these results?

A. Yes. If a customer who uses around 1,000 kWh a month uses a lot of their energy over night, they can expect to see their monthly bills go down by about $10 each month. If a customer who uses around 1,000 kWh a month uses a lot of their energy in the afternoon and early evening, they can expect to see their bills go up by about $10 each month. If a customer is able to change when they use energy, they can save about $20 per month. But, under Staff's plan, no customer will have a ToU-related bill increase of more than one cent per kWh in the summer, or one cent for each 4 kWh the rest of the year, and even that increase will only apply if that customer uses all of their energy between 4 pm and 8 pm.

Implementation of Residential Rate Increase

Q. What customer charge do you recommend for EMM and EMW?

A. The EMW CCOS is not sufficiently reliable for development of specific rate elements. However, the directly-allocated costs and closely related expenses for EMW indicate a customer charge cost-causation of approximately $10. Because this amount is not inclusive of any related indirectly-allocated costs or expenses, I targeted retention of the existing customer charges. However, because I recommend consolidating customer charges across rate codes, I reviewed various levels of customer charges for EMM and EMW that would minimize the change in revenue recovered from customer charges. Ultimately, I recommend $11.55 as a reasonable residential customer charge for both EMM and EMW for all residential customers.

Q. Have you designed rates for residential customers that implement your recommended rate code consolidations and incorporate the revenue impact of your recommended default ToU rate design?

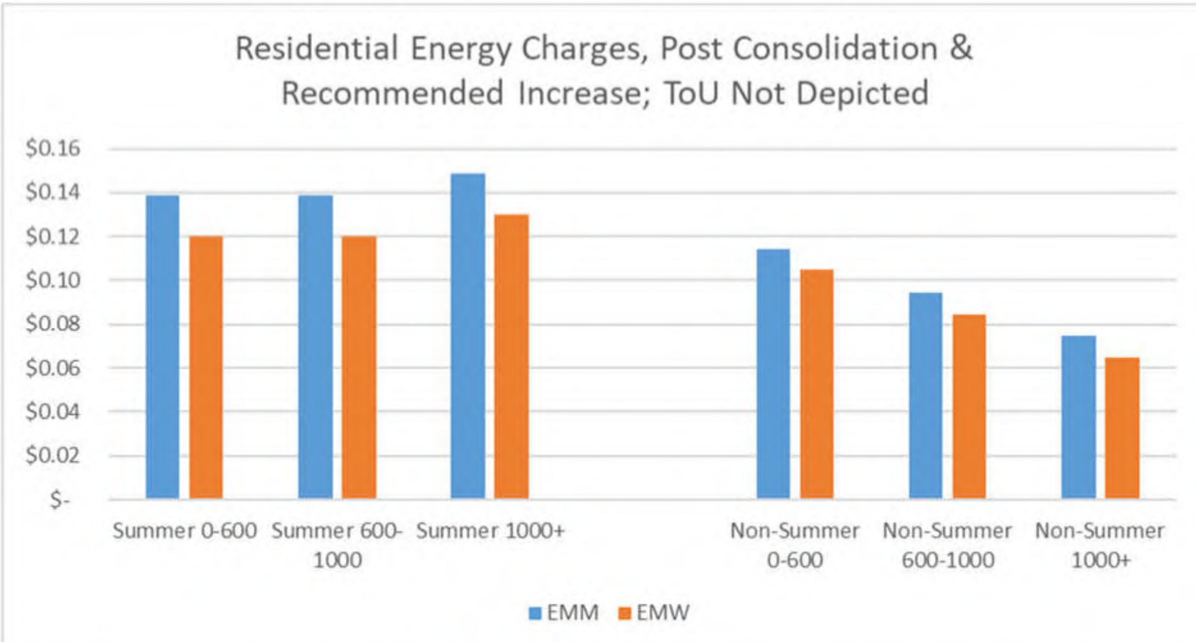
A. Yes. These calculations for each utility and resulting rates are summarized below. Note, in these calculations I assume the net-meter carryforward credit amount is held constant, and that the optional ToU rate schedules are adjusted by a percent equal to the adjustment to the energy charge revenue of the EMM and EMW residential classes, respectively.

	Determinants	Revenues	ToU & Customer Charge Change Implentation	Subtotals Subject to Adjustment	Implement Net Increase By Season	Charge Type Revenue Requirement	Rate
EMM			$ 11.55				
Customer Charge	3,109,223	$ 35,935,687	$ (24,161)			$ 35,911,526	$ 11.55
Other Charges		$ 3,016,387		$ 3,016,387	$ 134,456	$ 3,150,843	Equal % Increase
Net Metering Etc		$ (35,383)				$ (35,383)	No Change
Summer				$ 133,808,844	$ 5,964,555.70	$ 139,773,399	
0-600	532,711,216	$ 69,367,091					$ 0.1384
601-1000	221,473,685	$ 30,077,674					$ 0.1384
1000+	238,241,978	$ 34,899,620					$ 0.1484
Net ToU			$ 535,541			$ 535,541	+/-1 cent
Non-Summer				$ 154,972,613	$ 6,907,934.90	$ 161,880,548	
0-600	996,417,654	$ 110,961,553					$ 0.1144
601-1000	260,408,028	$ 21,237,934					$ 0.0944
1000+	312,888,764	$ 20,187,133					$ 0.0744
Net ToU			$ (2,585,992)			$ (2,585,992)	+.25/-1 cent
		$ 325,647,697	$ (2,074,611)	$ 291,797,843	$ 13,006,947	$ 338,630,483	
					$ -	$ 0	

	Determinants	Revenues	ToU & Customer Charge Change Implentation	Seasonal Revenue Requirement	Implement Net Increase By Season	Charge Type Revenue Requirement	Rate
EMW			$ 11.55				
Customer Charge	3,491,465	$ 40,334,365	$ (7,941)			$ 40,326,423	$ 11.55
Other Charges		$ 3,574,748		$ 3,574,748	$ 268,519	$ 3,843,267	Equal % Increase
Net Metering Etc		$ (115,861)				$ (115,861)	No Change
Summer				$ 147,643,485	$ 11,090,318	$ 158,733,803	
0-600	616,831,841	$ 70,025,278					$ 0.1201
601-1000	293,102,961	$ 33,210,719					$ 0.1201
1000+	380,263,828	$ 45,354,067					$ 0.1301
Net ToU			$ 946,579			$ 946,579	+/-1 cent
Non-Summer				$ 186,276,551	$ 13,992,261	$ 200,268,811	
0-600	1,168,200,735	$ 115,641,732					$ 0.1048
601-1000	419,647,794	$ 28,776,830					$ 0.0848
1000+	653,638,293	$ 38,105,554					$ 0.0648
Net ToU			$ (3,752,435)			$ (3,752,435)	+.25/-1 cent
		$ 374,907,431	$ (2,813,797)	$ 337,494,784	$ 25,351,098	$ 400,250,588	

Q. Could you illustrate the resulting energy rate elements, by utility, block, and season?

A. Yes, please see below:



Note, a mild incline of 1 cent for usage in excess of 1,000 kWh per month is retained in summer billing months, consistent with recent Commission guidance, and a decline is retained for non-summer months, to mitigate customer impacts.

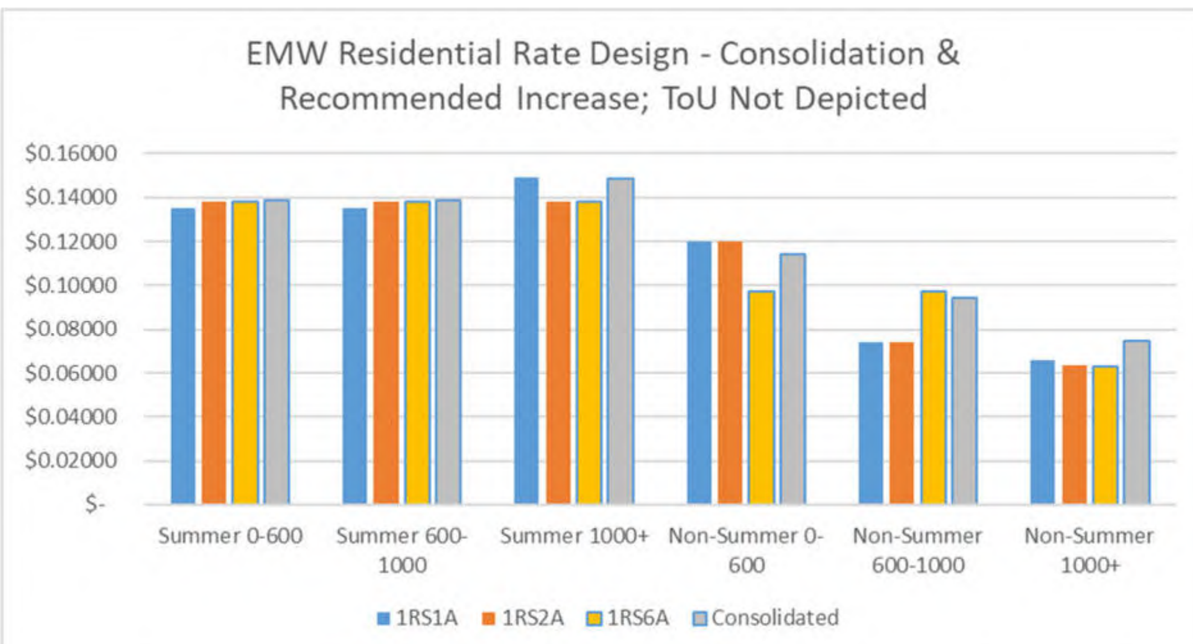
Customer Impacts

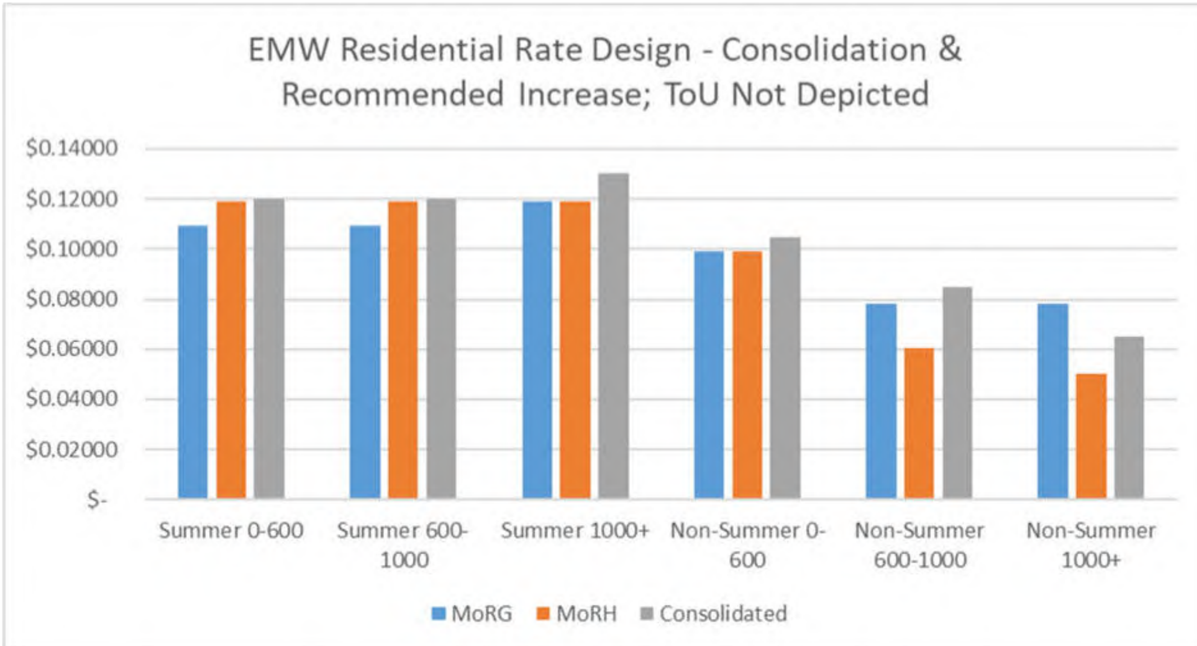
Q. For each utility, could you provide a summary of the residential rate consolidations you recommend above?

A. Yes, implementing the respective residential revenue requirement increases, I recommend an initial consolidation of the EMM and EMW residential rate schedules as provided below, respectively:

EMM	1RS1A	1RS2A	1RS6A	Consolidated
Summer 0-600	$ 0.13511	$ 0.13806	$ 0.13806	$ 0.13844
Summer 600-1000	$ 0.13511	$ 0.13806	$ 0.13806	$ 0.13844
Summer 1000+	$ 0.14916	$ 0.13806	$ 0.13806	$ 0.14844
Non-Summer 0-600	$ 0.12013	$ 0.12013	$ 0.09703	$ 0.11442
Non-Summer 600-1000	$ 0.07396	$ 0.07396	$ 0.09703	$ 0.09442
Non-Summer 1000+	$ 0.06561	$ 0.06353	$ 0.06300	$ 0.07442

EMW	MoRG	MoRH	Consolidated
Summer 0-600	$ 0.10938	$ 0.11927	$ 0.12008
Summer 600-1000	$ 0.10938	$ 0.11927	$ 0.12008
Summer 1000+	$ 0.11927	$ 0.11927	$ 0.13008
Non-Summer 0-600	$ 0.09888	$ 0.09888	$ 0.10476
Non-Summer 600-1000	$ 0.07800	$ 0.06035	$ 0.08476
Non-Summer 1000+	$ 0.07800	$ 0.05005	$ 0.06476





I also recommend eliminating the frozen time of use rate code TE1A, the Residential Other rate code RO1A, and the Separately Metered Space Heating rate code 1RS2A. Those rate codes do not rely on the same rate structure as those listed above, so direct comparison is difficult. The overall composition of the EMM rate codes by number and percent of customers are illustrated below:

Rate Code	Evergy Workpaper Approximate Customers	Percent
1RO1A	172	0.07%
1RS1A	185,598	72.78%
1RS2A	9,619	3.77%
1RS6A	57,441	22.53%
1RTOU	2,141	0.84%
1TE1A	26	0.01%

Q. Have you reviewed the customer impacts of consolidation and Staff's recommended residential revenue increases?

A. Yes.

Provided below are bill calculations for each residential load profile for the existing residential rate schedules at the current revenue requirement and the Consolidated schedule, at the new revenue requirement. Note, the consolidated results do not incorporate the ToU overlays, as these will vary significantly by customer.

				Low Usage Annual	High Usage Annual	Small Space Heat	Large Space Heat
EMM	**Current Rate Schedule**	**1RS1A**	**Annual Total:**	$ 978.28	$ 2,642.36	$ 1,183.46	$ 3,298.46
1RS1A-Summer	Summer		Summer month total:	$ 405.33	$ 1,435.40	$ 405.33	$ 1,435.40
	0-600	$ 0.13511		$ 324.26	$ 324.26	$ 324.26	$ 324.26
	600-1000	$ 0.13511		$ 81.07	$ 216.18	$ 81.07	$ 216.18
	1000+	$ 0.14916		$ -	$ 894.96	$ -	$ 894.96
1RS1A-Non-Summer	Non-Summer		Non-Summer month total:	$ 572.95	$ 1,206.96	$ 778.13	$ 1,863.06
	0-600	$ 0.12013		$ 528.57	$ 576.62	$ 528.57	$ 576.62
	600-1000	$ 0.07396		$ 44.38	$ 236.67	$ 118.34	$ 236.67
	1000+	$ 0.06561		$ -	$ 393.66	$ 131.22	$ 1,049.76
	Current Rate Schedule	**1RS2A**	**Annual Total:**	$ 987.13	$ 2,575.08	$ 1,188.15	$ 3,210.38
1RS2A-Summer	Summer		Summer month total:	$ 414.18	$ 1,380.60	$ 414.18	$ 1,380.60
	0-600	$ 0.13806		$ 331.34	$ 331.34	$ 331.34	$ 331.34
	600-1000	$ 0.13806		$ 82.84	$ 220.90	$ 82.84	$ 220.90
	1000+	$ 0.13806		$ -	$ 828.36	$ -	$ 828.36
1RS2A-Non-Summer	Non-Summer		Non-Summer month total:	$ 572.95	$ 1,194.48	$ 773.97	$ 1,829.78
	0-600	$ 0.12013		$ 528.57	$ 576.62	$ 528.57	$ 576.62
	600-1000	$ 0.07396		$ 44.38	$ 236.67	$ 118.34	$ 236.67
	1000+	$ 0.06353		$ -	$ 381.18	$ 127.06	$ 1,016.48
	Current Rate Schedule	**1RS6A**	**Annual Total:**	$ 899.33	$ 2,534.84	$ 1,122.36	$ 3,164.84
1RS6A-Summer	Summer		Summer month total:	$ 414.18	$ 1,380.60	$ 414.18	$ 1,380.60
	0-600	$ 0.13806		$ 331.34	$ 331.34	$ 331.34	$ 331.34
	600-1000	$ 0.13806		$ 82.84	$ 220.90	$ 82.84	$ 220.90
	1000+	$ 0.13806		$ -	$ 828.36	$ -	$ 828.36
1RS6A-Non-Summer	Non-Summer		Non-Summer month total:	$ 485.15	$ 1,154.24	$ 708.18	$ 1,784.24
	0-600	$ 0.09703		$ 426.93	$ 465.74	$ 426.93	$ 465.74
	600-1000	$ 0.09703		$ 58.22	$ 310.50	$ 155.25	$ 310.50
	1000+	$ 0.06300		$ -	$ 378.00	$ 126.00	$ 1,008.00
	Rate Schedule	**Consolidated**	**Annual Total:**	$ 975.41	$ 2,742.25	$ 1,218.67	$ 3,486.44
Consolidated-Summer	Summer		Summer month total:	$ 415.32	$ 1,444.39	$ 415.32	$ 1,444.39
	0-600	$ 0.13844		$ 332.25	$ 332.25	$ 332.25	$ 332.25
	600-1000	$ 0.13844		$ 83.06	$ 221.50	$ 83.06	$ 221.50
	1000+	$ 0.14844		$ -	$ 890.64	$ -	$ 890.64
Consolidated-Non-Summer	Non-Summer		Non-Summer month total:	$ 560.09	$ 1,297.86	$ 803.35	$ 2,042.04
	0-600	$ 0.11442		$ 503.44	$ 549.21	$ 503.44	$ 549.21
	600-1000	$ 0.09442		$ 56.65	$ 302.14	$ 151.07	$ 302.14
	1000+	$ 0.07442		$ -	$ 446.51	$ 148.84	$ 1,190.69

The total bill change during summer months, the total bill change during non-summer months, and the total annual bill change to be expected from moving each Customer profile from each existing rate schedule to the consolidated rate schedule with the revenue requirement increase are provided below:

	Low Usage Annual		High Usage Annual		Small Space Heat		Large Space Heat	
Annual Total:	$	978.28	$	2,642.36	$	1,183.46	$	3,298.46
Summer month total:	$	405.33	$	1,435.40	$	405.33	$	1,435.40
	$	324.26	$	324.26	$	324.26	$	324.26
	$	81.07	$	216.18	$	81.07	$	216.18
	$	-	$	894.96	$	-	$	894.96
Non-Summer month total:	$	572.95	$	1,206.96	$	778.13	$	1,863.06
1RS1A-Summer	$	405	$	1,435	$	405	$	1,435
1RS1A-Non-Summer	$	573	$	1,207	$	778	$	1,863
1RS1A-Total	$	978	$	2,642	$	1,183	$	3,298
1RS2A-Summer	$	414	$	1,381	$	414	$	1,381
1RS2A-Non-Summer	$	573	$	1,194	$	774	$	1,830
1RS2A-Total	$	987	$	2,575	$	1,188	$	3,210
1RS6A-Summer	$	414	$	1,381	$	414	$	1,381
1RS6A-Non-Summer	$	485	$	1,154	$	708	$	1,784
1RS6A-Total	$	899	$	2,535	$	1,122	$	3,165
Consolidated-Summer	$	415	$	1,444	$	415	$	1,444
Consolidated-Non-Summer	$	560	$	1,298	$	803	$	2,042
Consolidated-Total	$	975	$	2,742	$	1,219	$	3,486
1RS1A-Summer	$	10	$	9	$	10	$	9
1RS1A-Non-Summer	$	(13)	$	91	$	25	$	179
1RS1A-Total	$	3	$	(100)	$	(35)	$	(188)
1RS2A-Summer	$	1	$	64	$	1	$	64
1RS2A-Non-Summer	$	(13)	$	103	$	29	$	212
1RS2A-Total	$	12	$	(167)	$	(31)	$	(276)
1RS6A-Summer	$	1	$	64	$	1	$	64
1RS6A-Non-Summer	$	75	$	144	$	95	$	258
1RS6A-Total	$	(76)	$	(207)	$	(96)	$	(322)

Q. What residential rates should be available to customers who opt-out of the default residential time-based rate schedule?

A Because the overall net impact of the time-based design is a less than 1% decrease to the residential revenue of each utility, it is reasonable to simply use the rates described above, without the time-based overlays, for those customers who do opt out of the default residential rate design.

Q. Direct comparisons of the bill impact for customers on the frozen time of use rate code TE1A, the Residential Other rate code RO1A, and the Separately Metered Space Heating rate code 1RS2A are more difficult as those rate codes do not rely on the same rate structure as those listed above. However, customers currently on TE1A and 1RS2A will see reduced bills due to reductions in customer charges, and RO1A customers will have reduced energy charges.

Q. Could you provide an overview of the EMW residential consolidation?

A. Yes, the current residential rate options, prior to any increase, and the post-increase consolidated rates are summarized below:

EMW	MoRG	MoRH	Consolidated
Summer 0-600	$ 0.10938	$ 0.11927	$ 0.12008
Summer 600-1000	$ 0.10938	$ 0.11927	$ 0.12008
Summer 1000+	$ 0.11927	$ 0.11927	$ 0.13008
Non-Summer 0-600	$ 0.09888	$ 0.09888	$ 0.10476
Non-Summer 600-1000	$ 0.07800	$ 0.06035	$ 0.08476
Non-Summer 1000+	$ 0.07800	$ 0.05005	$ 0.06476

Q. Could you provide the customer impacts expected for EMW?

A. Yes. Please see below:

				Low Usage Annual	High Usage Annual	Small Space Heat	Large Space Heat
EMW	**Current Rate Schedule**	**MoRG**	**Annual Total:**	$ 810.01	$ 2,345.36	$ 1,044.01	$ 3,125.36
MoRG-Summer	Summer		Summer month total:	$ 328.14	$ 1,153.14	$ 328.14	$ 1,153.14
	0-600	$ 0.10938		$ 262.51	$ 262.51	$ 262.51	$ 262.51
	600-1000	$ 0.10938		$ 65.63	$ 175.01	$ 65.63	$ 175.01
	1000+	$ 0.11927		$ -	$ 715.62	$ -	$ 715.62
MoRG-Non-Summer	Non-Summer		Non-Summer month total:	$ 481.87	$ 1,192.22	$ 715.87	$ 1,972.22
	0-600	$ 0.09888		$ 435.07	$ 474.62	$ 435.07	$ 474.62
	600-1000	$ 0.07800		$ 46.80	$ 249.60	$ 124.80	$ 249.60
	1000+	$ 0.07800		$ -	$ 468.00	$ 156.00	$ 1,248.00
	Current Rate Schedule	**MoRH**	**Annual Total:**	$ 829.09	$ 2,160.74	$ 989.54	$ 2,661.24
MoRH-Summer	Summer		Summer month total:	$ 357.81	$ 1,192.70	$ 357.81	$ 1,192.70
	0-600	$ 0.11927		$ 286.25	$ 286.25	$ 286.25	$ 286.25
	600-1000	$ 0.11927		$ 71.56	$ 190.83	$ 71.56	$ 190.83
	1000+	$ 0.11927		$ -	$ 715.62	$ -	$ 715.62
MoRH-Non-Summer	Non-Summer		Non-Summer month total:	$ 471.28	$ 968.04	$ 631.73	$ 1,468.54
	0-600	$ 0.09888		$ 435.07	$ 474.62	$ 435.07	$ 474.62
	600-1000	$ 0.06035		$ 36.21	$ 193.12	$ 96.56	$ 193.12
	1000+	$ 0.05005		$ -	$ 300.30	$ 100.10	$ 800.80
	Rate Schedule	**Consolidated**	**Annual Total:**	$ 872.03	$ 2,423.40	$ 1,086.29	$ 3,070.96
Consolidated-Summer	Summer		Summer month total:	$ 360.25	$ 1,260.83	$ 360.25	$ 1,260.83
	0-600	$ 0.12008		$ 288.20	$ 288.20	$ 288.20	$ 288.20
	600-1000	$ 0.12008		$ 72.05	$ 192.13	$ 72.05	$ 192.13
	1000+	$ 0.13008		$ -	$ 780.50	$ -	$ 780.50
Consolidated-Non-Summer	Non-Summer		Non-Summer month total:	$ 511.78	$ 1,162.57	$ 726.04	$ 1,810.12
	0-600	$ 0.10476		$ 460.92	$ 502.82	$ 460.92	$ 502.82
	600-1000	$ 0.08476		$ 50.85	$ 271.22	$ 135.61	$ 271.22
	1000+	$ 0.06476		$ -	$ 388.53	$ 129.51	$ 1,036.08
			MoRG-Summer	$ 328	$ 1,153	$ 328	$ 1,153
			MoRG-Non-Summer	$ 482	$ 1,192	$ 716	$ 1,972
			MoRG-Total	$ 810	$ 2,345	$ 1,044	$ 3,125
			MoRH-Summer	$ 358	$ 1,193	$ 358	$ 1,193
			MoRH-Non-Summer	$ 471	$ 968	$ 632	$ 1,469
			MoRH-Total	$ 829	$ 2,161	$ 990	$ 2,661
			Consolidated-Summer	$ 360	$ 1,261	$ 360	$ 1,261
			Consolidated-Non-Summer	$ 512	$ 1,163	$ 726	$ 1,810
			Consolidated-Total	$ 872	$ 2,423	$ 1,086	$ 3,071
			MoRG-Summer	$ 32	$ 108	$ 32	$ 108
			MoRG-Non-Summer	$ 30	$ (30)	$ 10	$ (162)
			MoRG-Total	$ (62)	$ (78)	$ (42)	$ 54
			MoRH-Summer	$ 2	$ 68	$ 2	$ 68
			MoRH-Non-Summer	$ 40	$ 195	$ 94	$ 342
			MoRH-Total	$ (43)	$ (263)	$ (97)	$ (410)

Compatibility of Recommended Default Rate Design with Net Metering

Q. What is the statutory guidance on billing net metered customers?

A. Relevant provisions of Section 386.890 are excerpted below:

> 2.(5) "Net metering", using metering equipment sufficient to measure the difference between the electrical energy supplied to a customer-generator by a retail electric supplier and the electrical energy supplied by the customer-generator to the retail electric supplier over the applicable billing period;

***

3. (2) Offer to the customer-generator a tariff or contract that is identical in electrical energy rates, rate structure, and monthly charges to the contract or tariff that the customer would be assigned if the customer were not an eligible customer-generator but shall not charge the customer-generator any additional standby, capacity, interconnection, or other fee or charge that would not otherwise be charged if the customer were not an eligible customer-generator; and

***

5. Consistent with the provisions in this section, the net electrical energy measurement shall be calculated in the following manner:

(1) **For a customer-generator, a retail electric supplier shall measure the net electrical energy produced or consumed during the billing period in accordance with normal metering practices for customers in the same rate class,** either by employing a single, bidirectional meter that measures the amount of electrical energy produced and consumed, or by employing multiple meters that separately measure the customer-generator's consumption and production of electricity;

(2) **If the electricity supplied by the supplier exceeds the electricity generated by the customer-generator during a billing period, the customer-generator shall be billed for the net electricity supplied by the supplier in accordance with normal practices for customers in the same rate class;**

(3) **If the electricity generated by the customer-generator exceeds the electricity supplied by the supplier during a billing period**, the customer-generator shall be billed for the appropriate customer charges for that billing period in accordance with subsection 3 of this section **and shall be credited an amount at least equal to the avoided fuel cost of the excess kilowatt-hours generated during the billing period**, with this credit applied to the following billing period;

(4) Any credits granted by this subsection shall expire without any compensation at the earlier of either twelve months after their issuance or when the customer-generator disconnects service or terminates the net metering relationship with the supplier;

Q. Could you provide an example of a rate calculation for a net metered customer under the Staff's recommended default residential design?

A. Yes. The first step is to determine "If the electricity supplied by the supplier exceeds the electricity generated by the customer-generator during a billing period" or "If the electricity generated by the customer-generator exceeds the electricity supplied by the supplier during a billing period." The billing period is approximately 30 days, without distinction for time of consumption or generation.

Q. What is the next step if the electricity supplied by the supplier exceeded the electricity generated by the customer-generator during the billing period?

A. If the electricity supplied by the supplier exceeded the electricity generated by the customer-generator during the billing period, the next step is to calculate the bill for the net electricity supplied by the supplier in accordance with normal practices for customers in the same rate class. We will first calculate a customer charge:[14]

	Rate		Determinant	Charge	
Customer Charge:	$	12.00	1	$	12.00
First 1,000 kWh/month:	$	0.10			
1,001+ kWh/month:	$	0.11			
Additional Charge/On-Peak kWh:	$	0.01			
Additional Charge/Off-Peak kWh:	$	(0.01)			

We will then calculate the non-time contingent charges. We will assume for this example that the customer had a monthly net consumption of 400 kWh, which will all fall in the first block.

	Rate		Determinant	Charge	
Customer Charge:	$	12.00	1	$	12.00
First 1,000 kWh/month:	$	0.10	400	$	40.00
1,001+ kWh/month:	$	0.11	0	$	-
Additional Charge/On-Peak kWh:	$	0.01			
Additional Charge/Off-Peak kWh:	$	(0.01)			

For customers in the recommended residential default rate class, additional charges will be applicable to usage between 4:00 pm and 8:00 pm, and additional charges will be

[14] Depicted rate schedule is simplified for ease of illustration and not intended to reflect Staff's recommended rate design in this case.

applicable to usage between 12:00 am and 6:00 am. So, to determine the charges applicable in accordance with normal practices, we will then look to the net consumption that is subject to each rate element:

	Total	During On-Peak Times	During Shoulder Times	During Off-Peak Times
Net Grid to Customer Energy:	600	100		500
Net Customer to Grid Energy:	(200)		(200)	
	400	100	(200)	500

We will then calculate the charges for those elements, which provides us with our total bill, excluding FAC, RESRAM, MEEIA, and applicable taxes:

	Rate	Determinant	Charge
Customer Charge:	$ 12.00	1	$ 12.00
First 1,000 kWh/month:	$ 0.10	400	$ 40.00
1,001+ kWh/month:	$ 0.11	0	$ -
Additional Charge/On-Peak kWh:	$ 0.01	100	$ 1.00
Additional Charge/Off-Peak kWh:	$ (0.01)	500	$ (5.00)
			$ 48.00

Q. Could you provide a different example with usage in different periods?

A. Yes.

	Total	During On-Peak Times	During Shoulder Times	During Off-Peak Times
Net Grid to Customer Energy:	1,250		500	750
Net Customer to Grid Energy:	(50)	(50)		
	1,200	(50)	500	750

	Rate		Determinant	Charge	
Customer Charge:	$	12.00	1	$	12.00
First 1,000 kWh/month:	$	0.10	1,000	$	100.00
1,001+ kWh/month:	$	0.11	200	$	22.00
Additional Charge/On-Peak kWh:	$	0.01	(50)	$	(0.50)
Additional Charge/Off-Peak kWh:	$	(0.01)	750	$	(7.50)
				$	126.00

Q. What is the next step if it is determined that the electricity generated by the customer-generator exceeded the electricity supplied by the supplier during a billing period?

A. If the electricity generated by the customer-generator exceeds the electricity supplied by the supplier during a billing period, the customer-generator shall be billed for the appropriate customer charges for that billing period in accordance with subsection 3 of this section and shall be credited an amount at least equal to the avoided fuel cost of the excess kilowatt-hours generated during the billing period, with this credit applied to the following billing period.

Q. Could you provide an example?

A. Yes. For this example, consider a customer with the following usage and supply characteristics:

	Total	During On-Peak Times	During Shoulder Times	During Off-Peak Times
Net Grid to Customer Energy:	150			150
Net Customer to Grid Energy:	(300)	(200)	(100)	
	(150)	(200)	(100)	150

Note, the net total is a negative value, and this is the only information we will therefore carry forward to the next step:

	Rate		Determinant	Charge	
Customer Charge:	$	12.00	1	$	12.00
First 1,000 kWh/month:	$	0.10			
1,001+ kWh/month:	$	0.11			
Additional Charge/On-Peak kWh:	$	0.01			
Additional Charge/Off-Peak kWh:	$	(0.01)			
				$	12.00
Credit to be applied in future billing period:	$	0.022	(150)	$	(3.30)

Q. Could you provide examples which may be indicative of a customer engaging in price arbitrage through the use of a battery?

A. Yes, in this first example, the net consumption is negative, so our analysis ends with the customer charge and the calculation of the carry-forward credit:

	Total	During On-Peak Times	During Shoulder Times	During Off-Peak Times
Net Grid to Customer Energy:	999			999
Net Customer to Grid Energy:	(1,000)	(1,000)		
	(1)	(1,000)	-	999

	Rate		Determinant	Charge	
Customer Charge:	$	12.00	1	$	12.00
First 1,000 kWh/month:	$	0.10			
1,001+ kWh/month:	$	0.11			
Additional Charge/On-Peak kWh:	$	0.01			
Additional Charge/Off-Peak kWh:	$	(0.01)			
				$	12.00
Credit to be applied in future billing period:	$	0.022	(1)	$	(0.02)

Our next example the net consumption is positive, so we repeat the steps of the bill analysis described above:

	Total	During On-Peak Times	During Shoulder Times	During Off-Peak Times
Net Grid to Customer Energy:	1,000			1,000
Net Customer to Grid Energy:	(999)	(999)		
	1	(999)	-	1,000

	Rate	Determinant	Charge
Customer Charge:	$ 12.00	1	$ 12.00
First 1,000 kWh/month:	$ 0.10	1	$ 0.10
1,001+ kWh/month:	$ 0.11	-	$ -
Additional Charge/On-Peak kWh:	$ 0.01	(999)	$ (9.99)
Additional Charge/Off-Peak kWh:	$ (0.01)	1,000	$ (10.00)
			$ (7.89)

Q. Is it possible that customers could arbitrage energy consumption and storage to result in a negative bill?

A. Yes.

Q. Is there a risk of serious harm to other rate payers or the utility from arbitrage under Staff's recommended rate designs?

A. No, there is not. If problems materialize in the future, legislative or initiative action may be sought by various stakeholders.

Q. If a customer engaging or seeking to engage in arbitrage requests upgraded distribution or metering equipment to facilitate that arbitrage, what are Staff's expectations?

A. Staff would expect such a customer to bear the cost of the upgrades under the facility extension agreement, as the utility would not expect commensurate marginal revenues with the additional facilities. Failure to ensure that customer's seeking additional distribution and metering equipment to facilitate an overall bill reduction would be imprudent on the part of EMM and EMW.

Residential Customer Information Improvements

Q. Has Evergy made Staff aware of specific customer interfaces now available?

A. Yes. Evergy's direct testimony has provided information concerning mobile applications to alert customers to daily consumption levels, the product of current consumption and the applicable energy rate, and other customer-friendly measures. This section will include quotes from their testimony on prepayment and/or subscription.

Q. Does Staff recommend Evergy implement these programs?

A. Staff recommends Evergy solicit bids for wide-scale deployment of these interfaces, and provide information in its rebuttal for the Commission to make that decision.

Q. Would Staff recommend these programs be mandatory for customers or opt-in?

A. Opt in.

Non-Residential Rate Consolidations and Rate Designs

Q. How should end-use rates within the non-residential non-lighting classes be eliminated?

A. Any remaining end-use distinctions within the EMM and EMW rate schedules should be eliminated, with the relevant determinants transitioned to the generally-applicable rate code. This process will not be revenue neutral, and the resulting revenue increase will need to be netted from the applicable revenue requirement increase for each class.

Q. How should the time-of-use elements be incorporated into each class?

A. The process described above for the residential class should be repeated for each class, to determine the revenue impact of the time-based overlays. This process will not be revenue neutral, and the applicable revenue requirement increase for each class will need to be adjusted for the resulting revenue change.

Q. After the revenue-neutral consolidation within each class, and the incorporation of the time-based rate elements, how should any revenue requirement increase ordered in this case be implemented for the non-Residential, non-Lighting classes?

A. Each rate element should be adjusted by an equal percentage to achieve the revenues targeted for that class.

Q. How should the lighting class rates be adjusted in this case?

A. At this time, Staff does not object to an equal percentage adjustment to each lighting class rate element.

Q. What changes should be implemented to the EV rate schedules?

A. The EV rates should be increased consistent with the underlying non-residential rate schedule. Further, the EV bus rate schedule should be updated to change the demand determinant to Facilities demand from Billing demand.

Q. What additional rate schedule changes are appropriate in this case?

A. For compliance tariff purposes, all rate schedules including Cogeneration, and Community Solar should be updated, consistent with the related rate schedules. The MEEIA TD amounts also require updating.

DATA RETENTION

Q. In this case, were EMM and EMW able to provide hourly load data by the subgroups within the residential class, namely, Residential Space Heating, Residential General Use, and Residential Optional Time of Use?

A. No.

Q. Is it necessary that EMM and EMW provide additional data in the future in order for Staff to provide more accurate CCOS studies and rate designs that more accurately reflect cost causation?

A. Yes. It is necessary that EMM and EMW can supply accurate information about the quantity and costs of meters, services, and components of the primary distribution system that serve individual customers, by the rate schedule on which those customers are served. It is also necessary to identify the portions of plant related to non-core service such as solar & EV. Further, an improved understanding of the expenses incurred in association with these facilities and items of plant is appropriate to reasonably verify whether in today's reality of automation it is reasonable to exclusively allocate expenses on the basis of related plant account allocation.

Q. How should Evergy be prepared to provide load data and example customer usage to Staff?

A. Evergy should be able to provide hourly load by rate code, and to provide a sample of 100 customer individual hourly loads for any rate code with more than 100 customers, and be prepared to provide hourly load data for each customer on a rate code with less than 100 customers. This information, if provided by rate code, would necessarily include the voltage-identification information necessary to sum hourly loads. Similarly, Evergy should be able to identify the number of customers served on each rate code each month.

Q. What specific data should the Commission order be retained?

A. Staff recommends inclusion of the following in the Commission's Report and Orders in each of these cases:

> 1. Prior to the next rate case, the Company will identify and provide the data required to determine: line transformer costs and expenses by rate code; primary distribution costs and expenses by voltage; secondary distribution costs and expenses by voltage; primary voltage service drop costs and expenses; line

extension costs, expenses, and contributions by rate code and voltage; and meter costs by voltage and rate code. If the required data is not readily available, the Commission should order Evergy to file an EO docket explaining why it cannot provide the data, and its individual estimate of the cost to provide each set of data described, for the further consideration of the parties and the Commission..

2. For each rate code, provide the total number of customers served on that rate schedule on the first day of the month and the last day of the month;

a. For each rate schedule on which customers may take service at various voltages, the number of customers served at each voltage on the first day of the month and the last day of the month (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);

3. For each rate code, the number of customers served on that rate schedule on the first day of the month and the last day of the month for which interval meter readings are obtained;

a. For each rate code on which customers may take service at various voltages, the number of customers served at each voltage on the first day of the month and the last day of the month which interval meter readings are obtained (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);

4. For each rate code for which service is available at a single voltage, the sum of customers' interval meter readings, by interval;

a. For each rate code on which customers may take service at various voltages, the sum of customers' interval meter readings, by interval and by voltage (this is only applicable if rate codes are not used to delineate the voltage at which customers are served);

5. If any internal adjustments to customer interval data are necessary for the company's billing system to bill the interval data referenced in parts 4. and 4.a., such adjustments should be applied to each interval recording prior to the customers' data being summed for each interval;

6. From time to time the Commission may designate certain customer subsets for more granular study. If such designations have been made, the information required under parts 1 – 5 should be provided or retained for those instances.

7. Individual customer interval data shall be retained for a minimum of fourteen months. If individual data is acquired by the Company in intervals of less than one hour in duration, such data shall be retained in intervals of no less than one hour.

8. Evergy shall:

a. Retain individual hourly data for use in providing bill-comparison tools for customers to compare rate alternatives.

b. Retain coincident peak determinants for use in future rate proceedings.

c. Provide to Staff upon request:

1) the information described in part 1;

2) a minimum of 12 months of the data described in parts 2-5;

3) for rate codes with more than 100 customers, a sample of individual customer hourly data, and identified peak demands for those 100 customers in the form requested at that time (i.e. monthly 15 minute non-coincident, annual 1 hour coincident);

4) for rate codes with 100 or fewer customers, individual customer hourly data, and identified peak demands for those customers in the form requested at that time (i.e. monthly 15 minute non-coincident, annual 1 hour coincident).

d. For purposes of general rate proceedings, Evergy shall provide all data described above for a period of not less than 36 months, except that Staff does not request individual customer data for 36 months except as described in part 8.c.3.

Q. Are there further recommendations for data retention?

A. Yes. First, Staff recommends that EMM and EMW be ordered to develop the determinants for assessment of an on-peak demand charge to replace the current monthly billing demand charge, and for potential implementation for customers not currently subject to a demand charge. At this time, Staff recommends that in summer months the period be noon – 10 pm, and during non-summer months the period be 6 am – 10 pm, but Staff welcomes the input of other parties to refine this time periods. Staff does not recommend that weekends and holidays be excluded.

Second, Staff recommends the EMM and EMW begin to retain and study data related to the reactive demand requirements of each rate code, and sample customers within each rate code. While in recent history reactive demand has not been a determinant in CCOS studies or a rate element for many customers, emerging system conditions associated with changes in regional generation fleets may occasion further study of reactive demand requirements.

<u>CONCLUSION</u>

Q. Does this conclude your direct testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Evergy Metro, Inc. d/b/a Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service	)	Case No. ER-2022-0129
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 SARAH L.K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Sarah L.K. Lange
SARAH L.K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 21st day of June 2022.

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

D. Suzie Mankin
Notary Public

Sarah L.K. Lange

I received my J.D. from the University of Missouri, Columbia, in 2007, and am licensed to practice law in the State of Missouri. I received my B.S. in Historic Preservation from Southeast Missouri State University, and took courses in architecture and literature at Drury University. Since beginning my employment with the MoPSC I have taken courses in economics through Columbia College and courses in energy transmission through Bismarck State College, and have attended various trainings and seminars, indicated below.

I began my employment with the Commission in May 2006 as an intern in what was then known as the General Counsel's Office. I was hired as a Legal Counsel in September 2007, and was promoted to Associate Counsel in 2009, and Senior Counsel in 2011. During that time my duties consisted of leading major rate case litigation and settlement, and presenting Staff's position to the Commission, and providing legal advice and assistance primarily in the areas of depreciation, cost of service, class cost of service, rate design, tariff issues, resource planning, accounting authority orders, construction audits, rulemakings and workshops, fuel adjustment clauses, document management and retention, and customer complaints.

In July 2013 I was hired as a Regulatory Economist III in what is now known as the Tariff / Rate Design Department. In this position my duties include providing analysis and recommendations in the areas of RTO and ISO transmission, rate design, class cost of service, tariff compliance and design, and regulatory adjustment mechanisms and tariff design. I also continue to provide legal advice and assistance regarding generating station and environmental control construction audits and electric utility regulatory depreciation. I have also participated before the Commission under the name Sarah L. Kliethermes.

Presentations

Midwest Energy Policy Series – Impact of ToU Rates on Energy Efficiency (August 14, 2020)

Billing Determinants Lunch and Learn (March 27, 2019)

Support for Low Income and Income Eligible Customers, Cost-Reflective Tariff Training, in cooperation with U.S.A.I.D. and NARUC, Addis Ababa, Ethiopia (February 23-26, 2016)

Fundamentals of Ratemaking at the MoPSC (October 8, 2014)

Ratemaking Basics (Sept. 14, 2012)

Participant in Missouri's Comprehensive Statewide Energy Plan working group on Energy Pricing and Rate Setting Processes.

Relevant Trainings and Seminars

Regional Training on Integrated Distribution System Planning for Midwest/MISO Region (October 13-15, 2020)

"Fundamentals of Utility Law" Scott Hempling lecture series (January – April, 2019)

Today's U.S. Electric Power Industry, the Smart Grid, ISO Markets & Wholesale Power Transactions (July 29-30, 2014)

MISO Markets & Settlements training for OMS and ERSC Commissioners & Staff (January 27–28, 2014)

Validating Settlement Charges in New SPP Integrated Marketplace (July 22, 2013)

PSC Transmission Training (May 14 – 16, 2013)

Grid School (March 4–7, 2013)

Specialized Technical Training - Electric Transmission (April 18–19, 2012)

The New Energy Markets: Technologies, Differentials and Dependencies (June 16, 2011)

Mid-American Regulatory Conference Annual Meeting (June 5–8, 2011)

Renewable Energy Finance Forum (Sept. 29–Oct 3, 2010)

Utility Basics (Oct. 14–19, 2007)

Testimony and Staff Memoranda

Company	Case No.
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Convenience and Necessity Under Section 393.170 RSMo Relating to Transmission Investments in Southeast Missouri	EA-2022-0099
The Empire District Electric Company d/b/a Liberty In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	ER-2021-0312
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	ER-2021-0240
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for a Certificate of Public Convenience and Necessity to Construct, Install, Own, Operate, Maintain, and Otherwise Control and Manage a 138 kV Transmission Line and associated facilities in Perry and Cape Girardeau Counties, Missouri	EA-2021-0087
Evergy Affiliates In the Matter of the Application of Evergy Metro, Inc. d/b/a Evergy Missouri Metro and Evergy Missouri West, Inc. d/b/a Evergy Missouri West for Approval of a Transportation Electrification Portfolio	ET-2021-0151
Spire Missouri, Inc. In the Matter of Spire Missouri Inc.'s d/b/a Spire Request for Authority to Implement a General Rate Increase for Natural Gas Service Provided in the Company's Missouri Service Areas	GR-2021-0108

Company	**Case No.**
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren for Approval of its Surge Protection Program	ET-2021-0082
Union Electric Company d/b/a Ameren Missouri In the Matter of the Request of Union Electric Company d/b/a Ameren Missouri to Implement the Delivery Charge Adjustment for the 1st Accumulation Period beginning September 1, 2019 and ending August 31, 2020	GT-2021-0055
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs Approval of a Transportation Electrification Portfolio for Electric Customers in its Missouri Service Area	ET-2020-0390
The Empire District Electric Company In the Matter of The Empire District Electric Company's Tariffs to Increase Its Revenues for Electric Service	ER-2019-0374
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Decrease Its Revenues for Electric Service	ER-2019-0335
KCP&L Greater Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company Request for Authority to Implement Rate Adjustments Required by 4 CSR 240-20.090(8) And the Company's Approved Fuel and Purchased Power Cost Recovery Mechanism	ER-2019-0413
Union Electric Company d/b/a Ameren Missouri In the Matter of of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Natural Gas Service	GR-2019-0077
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri Revised Tariff Sheets	ET-2019-0149
The Empire District Electric Company In the Matter of The Empire District Electric Company's Revised Economic Development Rider Tariff Sheets	ET-2019-0029

Company	**Case No.**
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040
The Empire District Electric Company In the Matter of a Proceeding Under Section 393.137 (SB 564) to Adjust the Electric Rates of The Empire District Electric Company	ER-2018-0366
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Construct a Wind Generation Facility	EA-2018-0202
Kansas City Power & Light Company KCP&L Greater Missouri Operations Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2018-0145 ER-2018-0146
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of Efficient Electrification Program	ET-2018-0132
Union Electric Company d/b/a Ameren Missouri In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for Approval of 2017 Green Tariff	ET-2018-0063
Laclede Gas Company Laclede Gas Company d/b/a Missouri Gas Energy In the Matter of Laclede Gas Company's Request to Increase Its Revenue for Gas Service, In the Matter of Laclede Gas Company d/b/a Missouri Gas Energy's Request to Increase Its Revenue for Gas Service.	GR-2017-0215 GR-2017-0216
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0316
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2017-0167

Company	Case No.
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Annual RESRAM Tariff Filing	ET-2017-0097
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2016-0358
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Demand Side Investment Rider Rate Adjustment And True-Up Required by 4 CSR 240-3.163(8)	ER-2016-0325
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	ER-2016-0285
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri for Permission and Approval and a Certificate of Public Convenience and Necessity Authorizing it to Offer a Pilot Subscriber Solar Program and File Associated Tariff	EA-2016-0207
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2016-0179
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0156
Empire District Electric Company In the Matter of The Empire District Electric Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2016-0023

Company	Case No.
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line from Palmyra, Missouri to the Iowa Border and an Associated Substation Near Kirksville, Missouri	EA-2015-0146
Ameren Transmission Company of Illinois In the Matter of the Application of Ameren Transmission Company of Illinois for Other Relief or, in the Alternative, a Certificate of Public Convenience and Necessity Authorizing it to Construct, Install, Own, Operate, Maintain and Otherwise Control and Manage a 345,000-volt Electric Transmission Line in Marion County, Missouri and an Associated Switching Station Near Palmyra, Missouri	EA-2015-0145
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA	EO-2015-0055
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	ER-2014-0370
Empire District Electric Company In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	ER-2014-0351
Union Electric Company d/b/a Ameren Missouri City of O'Fallon, Missouri, and City of Ballwin, Missouri, Complainants v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0316
Union Electric Company d/b/a Ameren Missouri In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	ER-2014-0258

Company	**Case No.**
Evergy Metro, Inc. dba Evergy Missouri Metro Evergy Missouri West, Inc. dba Evergy Missouri West In the Matter of Evergy Metro, Inc. dba Evergy Missouri Metro's Request for Authority to Implement a General Rate Increase for Electric Service. In the Matter of Evergy Missouri West, Inc. dba Evergy Missouri West's Request for Authority to Implement a General Rate Increase for Electric Service.	ER-2022-0129 ER-2022-0130
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Energy Transition Costs Related to the Asbury Plant	EO-2022-0193
The Empire District Electric Company d/b/a Liberty In the Matter of the Petition of The Empire District Electric Company d/b/a Liberty to Obtain a Financing Order that Authorizes the Issuance of Securitized Utility Tariff Bonds for Qualified Extraordinary Costs	EO-2022-0040
Union Electric Company d/b/a Ameren Missouri Noranda Aluminum, Inc., et al., Complainants, v. Union Electric Company d/b/a Ameren Missouri, Respondent	EC-2014-0224
Grain Belt Express Clean Line, LLC In the Matter of the Application of Grain Belt Express Clean Line LLC for a Certificate of Convenience and Necessity Authorizing It to Construct, Own, Operate, Control, Manage, and Maintain a High Voltage, Direct Current Transmission Line and an Associated Converter Station Providing an Interconnection on the Maywood - Montgomery 345 kV Transmission Line	EA-2014-0207
KCP&L Great Missouri Operations Company In the Matter of KCP&L Greater Missouri Operations Company's Application for Authority to Establish a Renewable Energy Standard Rate Adjustment Mechanism	EO-2014-0151
Kansas City Power & Light Company In the Matter of Kansas City Power & Light Company's Filing for Approval of Demand-Side Programs and for Authority to Establish A Demand-Side Programs Investment Mechanism	EO-2014-0095
Veolia Energy Kansas City, Inc. In the Matter of Veolia Energy Kansas City, Inc. for Authority to File Tariffs to Increase Rates	HR-2014-0066

Fourth Quarter 2021 Earnings Call

February 25, 2022

Important Information

Forward Looking Statements

Statements made in this document that are not based on historical facts are forward-looking, may involve risks and uncertainties, and are intended to be as of the date when made. Forward-looking statements include, but are not limited to, statements relating to Evergy's strategic plan, including, without limitation, those related to earnings per share, dividend, operating and maintenance expense and capital investment goals; the outcome of legislative efforts and regulatory and legal proceedings; future energy demand; future power prices; plans with respect to existing and potential future generation resources; the availability and cost of generation resources and energy storage; target emissions reductions; and other matters relating to expected financial performance or affecting future operations. Forward-looking statements are often accompanied by forward-looking words such as "anticipates," "believes," "expects," "estimates," "forecasts," "should," "could," "may," "seeks," "intends," "proposed," "projects," "planned," "target," "outlook," "remain confident," "goal," "will" or other words of similar meaning. Forward-looking statements involve risks, uncertainties and other factors that could cause actual results to differ materially from the forward-looking information.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, Evergy, Inc., Evergy Kansas Central, Inc. and Evergy Metro, Inc. (collectively, the Evergy Companies) are providing a number of risks, uncertainties and other factors that could cause actual results to differ from the forward-looking information. These risks, uncertainties and other factors include, but are not limited to: economic and weather conditions and any impact on sales, prices and costs; changes in business strategy or operations; the impact of federal, state and local political, legislative, judicial and regulatory actions or developments, including deregulation, re-regulation, securitization and restructuring of the electric utility industry; decisions of regulators regarding, among other things, customer rates and the prudency of operational decisions such as capital expenditures and asset retirements; changes in applicable laws, regulations, rules, principles or practices, or the interpretations thereof, governing tax, accounting and environmental matters, including air and water quality and waste management and disposal; the impact of climate change, including increased frequency and severity of significant weather events and the extent to which counterparties are willing to do business with, finance the operations of or purchase energy from the Evergy Companies due to the fact that the Evergy Companies operate coal-fired generation; prices and availability of electricity in wholesale markets; market perception of the energy industry and the Evergy Companies; the impact of the Coronavirus (COVID-19) pandemic on, among other things, sales, results of operations, financial condition, liquidity and cash flows, and also on operational issues, such as supply chain issues and the availability and ability of the Evergy Companies' employees and suppliers to perform the functions that are necessary to operate the Evergy Companies; changes in the energy trading markets in which the Evergy Companies participate, including retroactive repricing of transactions by regional transmission organizations (RTO) and independent system operators; financial market conditions and performance, including changes in interest rates and credit spreads and in availability and cost of capital and the effects on derivatives and hedges, nuclear decommissioning trust and pension plan assets and costs; impairments of long-lived assets or goodwill; credit ratings; inflation rates; the transition to a replacement for the London Interbank Offered Rate (LIBOR) benchmark interest rate; effectiveness of risk management policies and procedures and the ability of counterparties to satisfy their contractual commitments; impact of physical and cybersecurity breaches, criminal activity, terrorist attacks and other disruptions to the Evergy Companies' facilities or information technology infrastructure or the facilities and infrastructure of third-party service providers on which the Evergy Companies rely; ability to carry out marketing and sales plans; cost, availability, quality and timely provision of equipment, supplies, labor and fuel; ability to achieve generation goals and the occurrence and duration of planned and unplanned generation outages; delays and cost increases of generation, transmission, distribution or other projects; the Evergy Companies' ability to manage their transmission and distribution development plans and transmission joint ventures; the inherent risks associated with the ownership and operation of a nuclear facility, including environmental, health, safety, regulatory and financial risks; workforce risks, including those related to the Evergy Companies' ability to attract and retain qualified personnel, maintain satisfactory relationships with their labor unions and manage costs of, or changes in, retirement, health care and other benefits; disruption, costs and uncertainties caused by or related to the actions of individuals or entities, such as activist shareholders or special interest groups, that seek to influence Evergy's strategic plan, financial results or operations; the possibility that strategic initiatives, including mergers, acquisitions and divestitures, and long-term financial plans, may not create the value that they are expected to achieve in a timely manner or at all; difficulties in maintaining relationships with customers, employees, regulators or suppliers; and other risks and uncertainties.

This list of factors is not all-inclusive because it is not possible to predict all factors. You should also carefully consider the information contained in our other filings with the Securities and Exchange Commission (SEC). Additional risks and uncertainties are discussed in the Annual Report on Form 10-K for the year ended December 31, 2021 filed by the Evergy Companies with the SEC, and from time to time in current reports on Form 8-K and quarterly reports on Form 10-Q filed by the Evergy Companies with the SEC. Each forward-looking statement speaks only as of the date of the particular statement. The Evergy Companies undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Financial Measures

Evergy uses adjusted EPS and adjusted O&M which are non-GAAP financial measures. A reconciliation of the non-GAAP measures to the most directly comparable GAAP measures are included in the appendix.

Agenda

David Campbell, President & CEO

- 2021 accomplishments
- Affordability, reliability, and sustainability
- Regulatory and legislative update
- Evergy value proposition

Kirk Andrews, EVP & CFO

- 2021 financial results
- Retail sales trends
- 2022 guidance
- 2022 objectives

Business Update

David Campbell

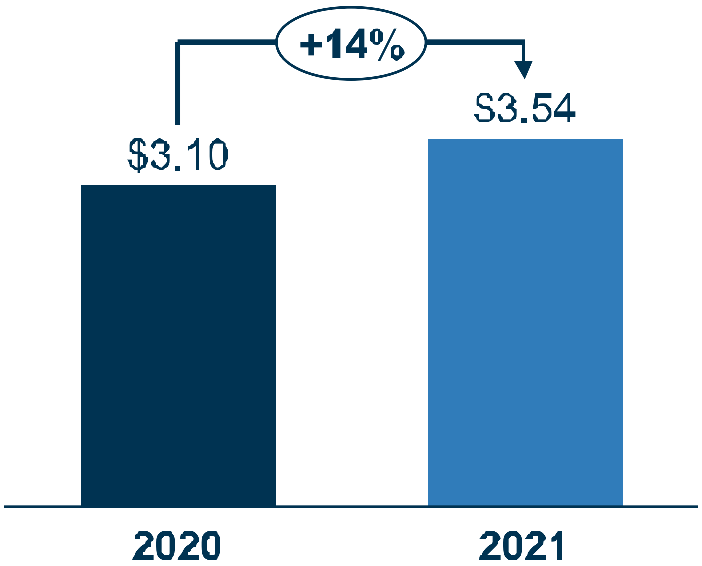
President & CEO

2021 Accomplishments

2021 EPS

- GAAP: $3.83
- Adjusted[1]: $3.54

Adjusted EPS[1]



- Delivered adjusted EPS of $3.54 vs initial guidance range of $3.20–$3.40 per share
- Invested $2.05 billion in electric infrastructure projects for the benefit of Kansas and Missouri customers
- Enhanced affordability and regional rate competitiveness by delivering an overall 4.2% reduction in rates from 2017 to 2021
- Reduced total adjusted operating and maintenance expenses by 18% since 2018
- Lowered total CO_2 emissions by 46% relative to 2005 levels and introduced net zero CO_2 emissions target by 2045[2]
- Securitization legislation enacted in Kansas and Missouri

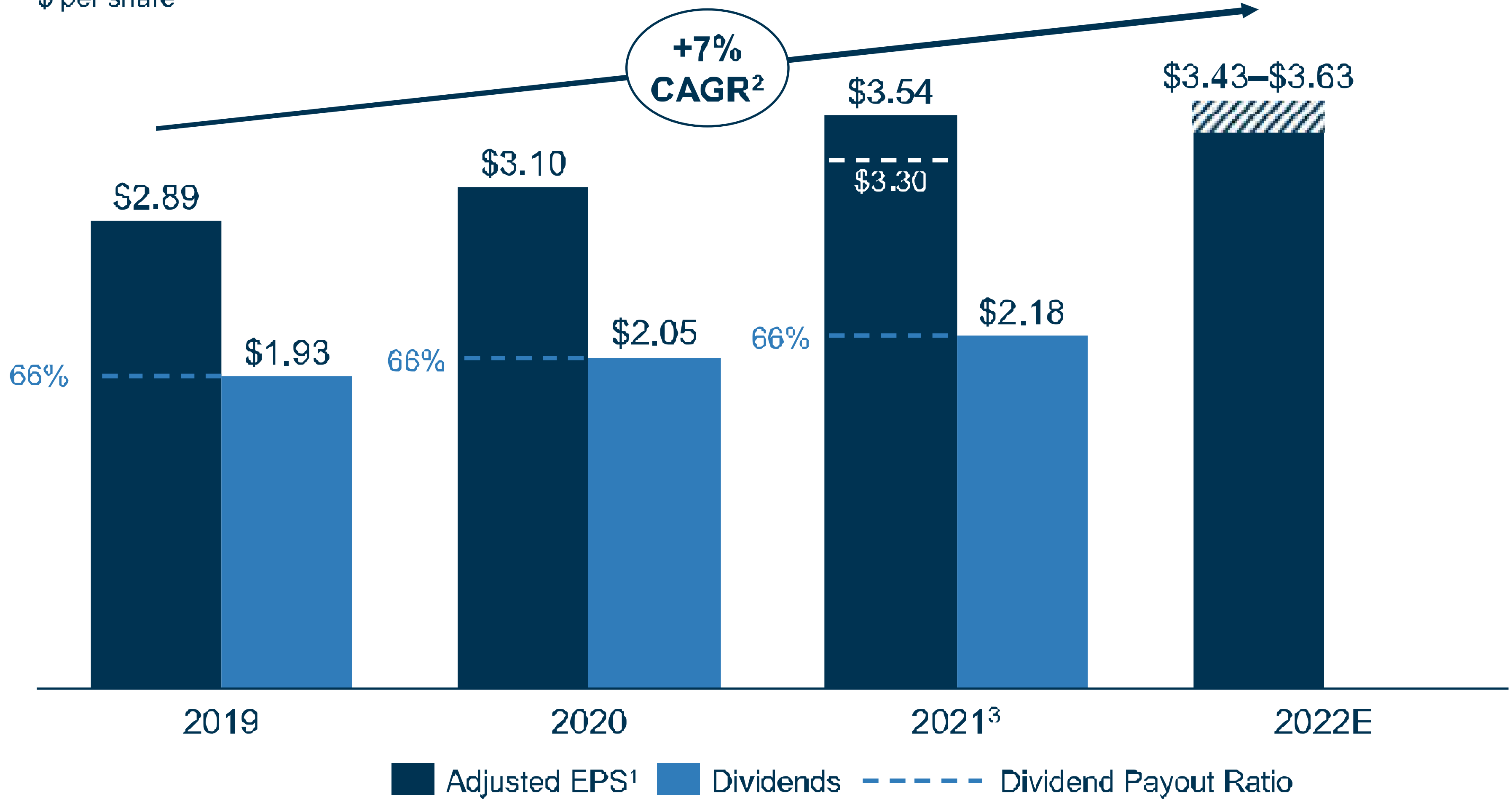
Strong execution builds momentum into 2022 and beyond

[1]Adjusted EPS is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP information. [2]The trajectory and timing of reaching Evergy's net-zero carbon emissions goal are dependent on enabling technology developments and supportive energy policies and regulations.

Consistent Execution

Dividend and Adjusted EPS[1] Growth

$ per share



Consistent execution of strong earnings and dividend growth

[1]Adjusted EPS is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP information. [2]CAGR calculated using $3.53 mid-point of 2022 adjusted EPS guidance. [3]2021 dividend payout ratio is calculated using the $3.30 mid-point of original 2021 adjusted EPS guidance range

Advancing Sustainability

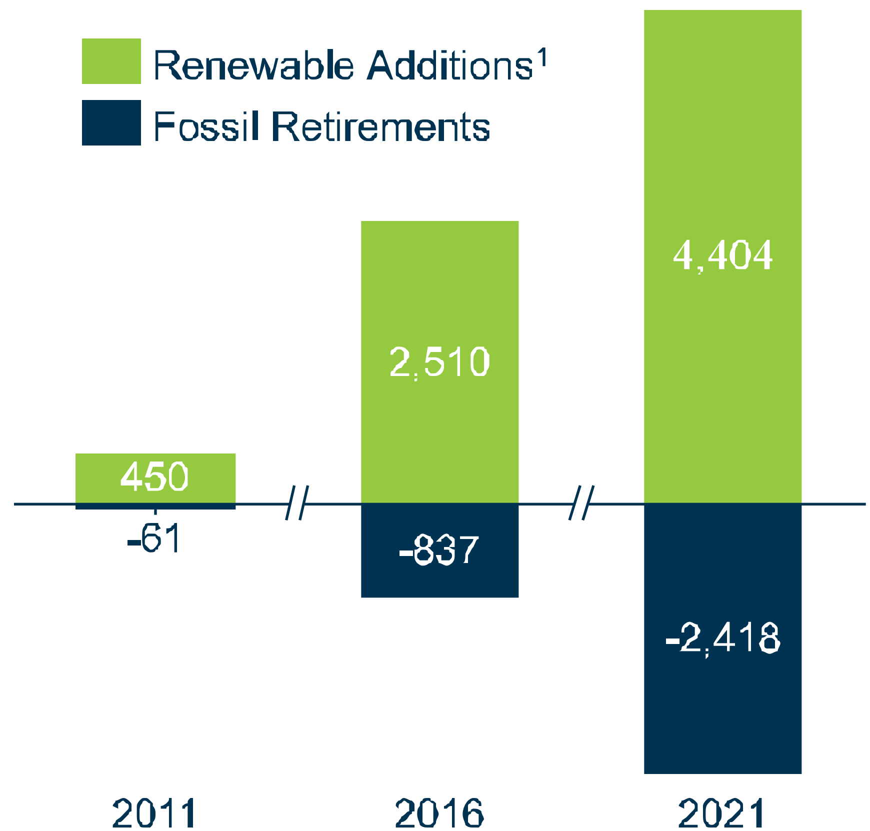
Achieved Emissions Reductions
Since 2005

46%
CO_2 emissions

98%
SO_2 emissions

88%
NO_X emissions

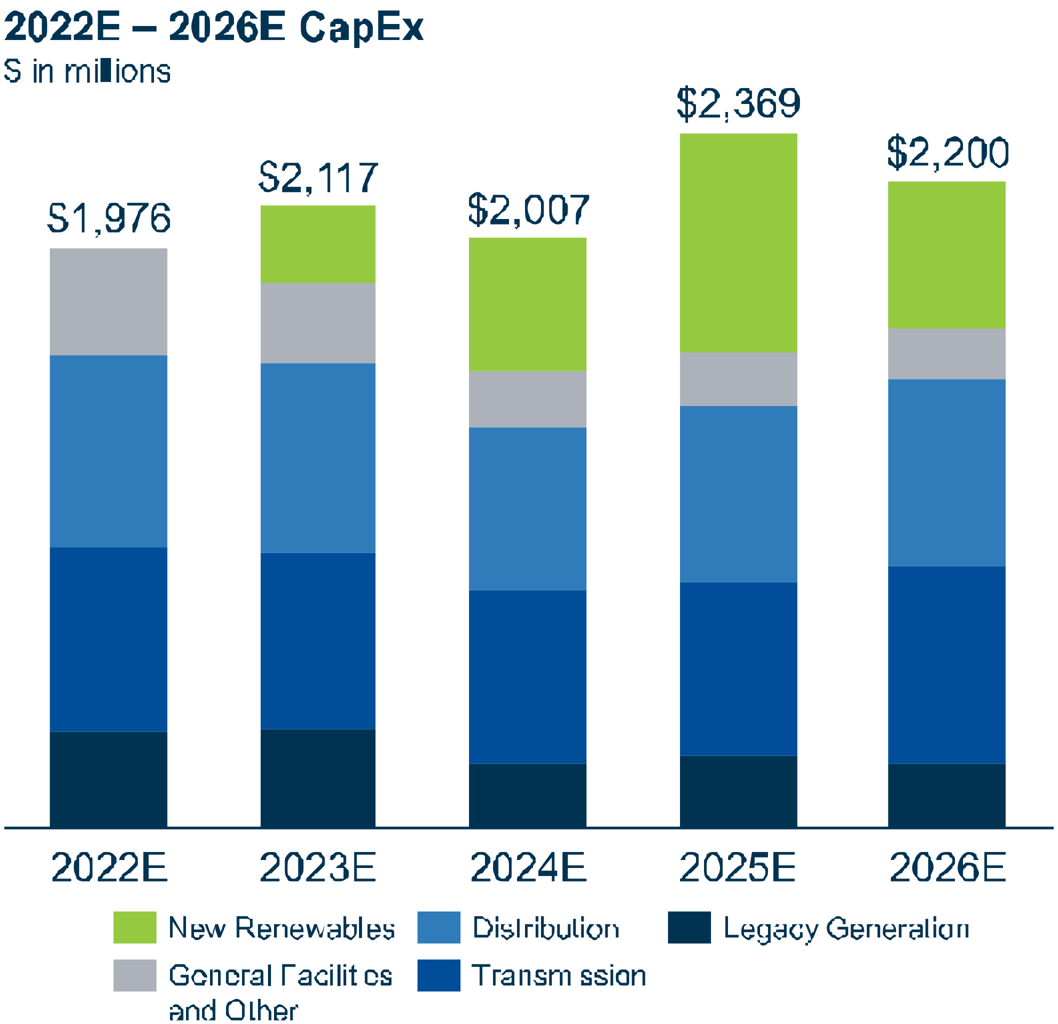
Cumulative Retirements / Additions (MW)
Since 2005



Track record of significant emissions reductions and renewables additions

[1]Renewables include both owned and power purchase agreements.

Investing In Reliability & Fleet Transition

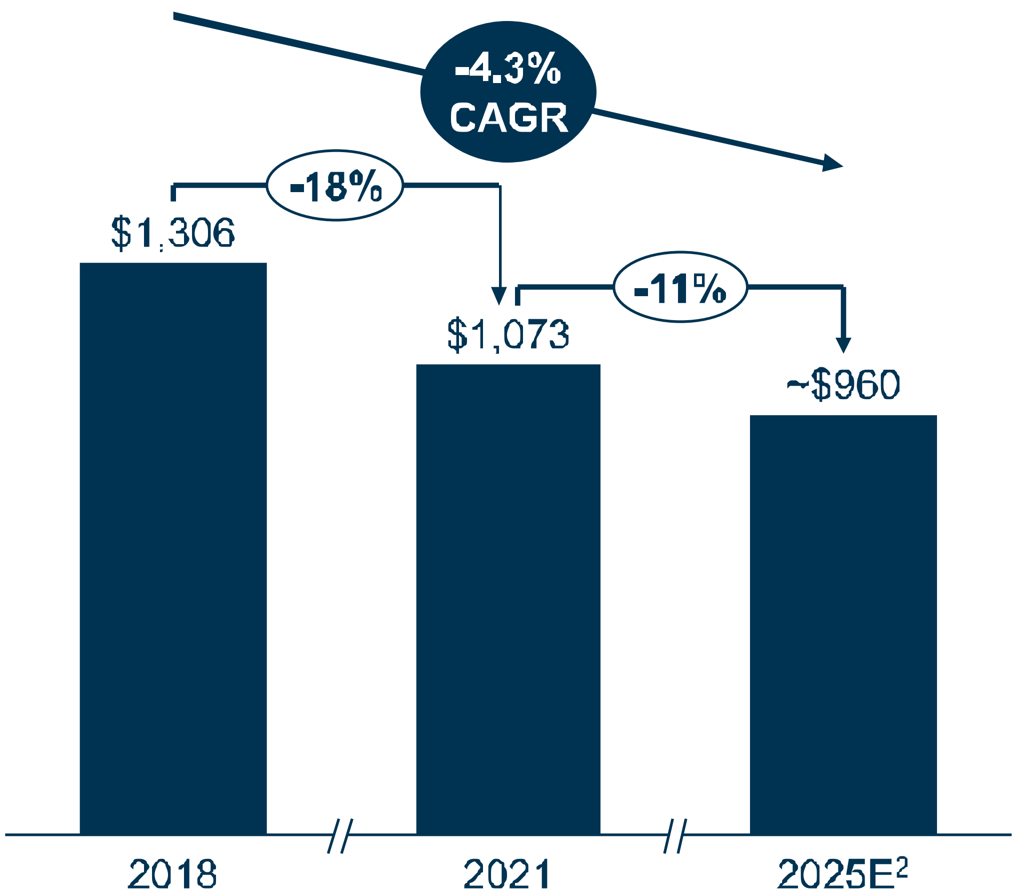


- Investing to modernize the grid, enhance resiliency and security, and increase reliability
- Adopting smart grid technologies and enhancing automation and customer service tools and options
- Transitioning to a lower-cost, lower-emissions energy portfolio
- Enabling operating efficiencies that reduce costs to customers
- 2021–25E capex plan is in-line (up ~$100M) relative to 9/21/21 Investor Day; 2022E–26E capex plan is $235M higher vs 2021–25E

Investing in reliability, resiliency, security and a lower-cost, lower-emissions portfolio

Driving Efficiencies To Enhance Affordability

Adjusted O&M[1]
$ in millions



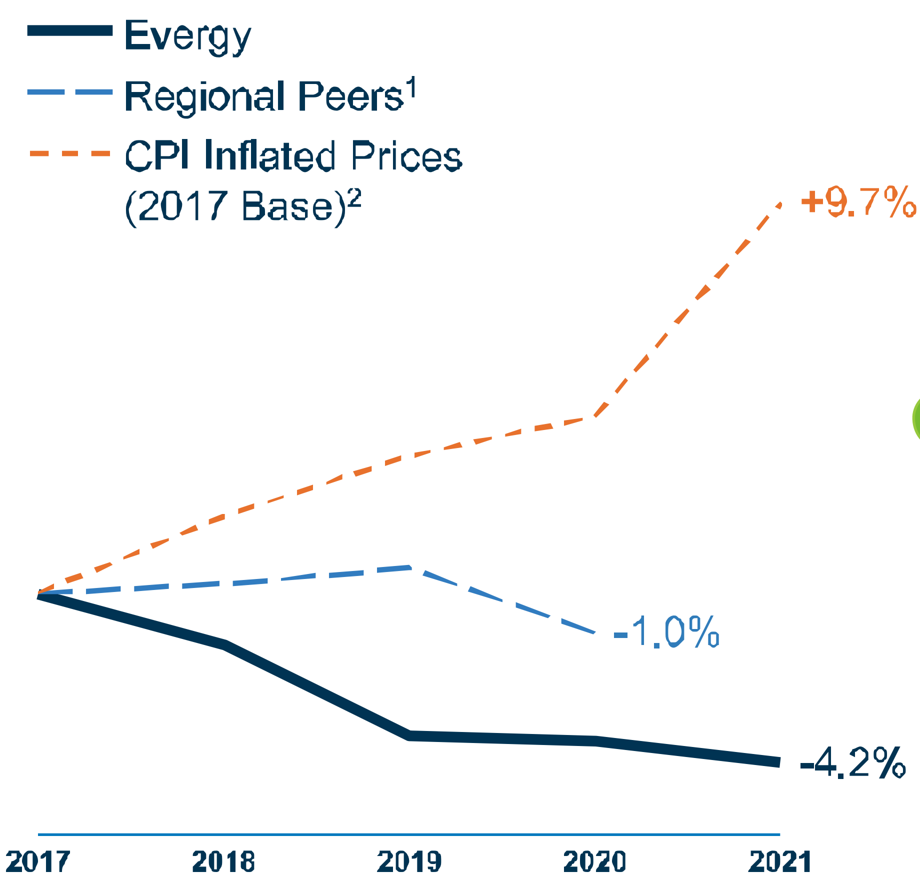
- 2018 merger enabled significant efficiency gains
- Comprehensive program across the business to instill an operational excellence culture
- Investments enable increased use of data analytics, automation, and predictive maintenance
- Enhanced generation flexibility and seasonal operations

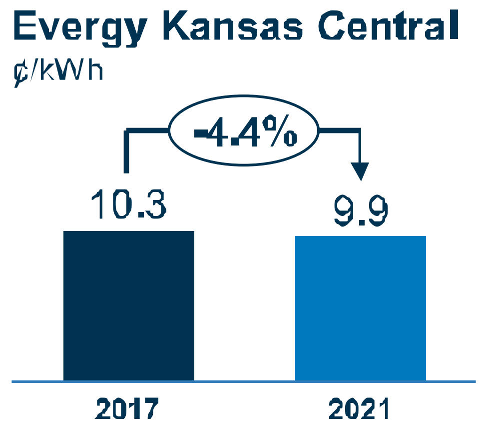
Driving efficiencies and leveraging investments to reduce costs to serve customers

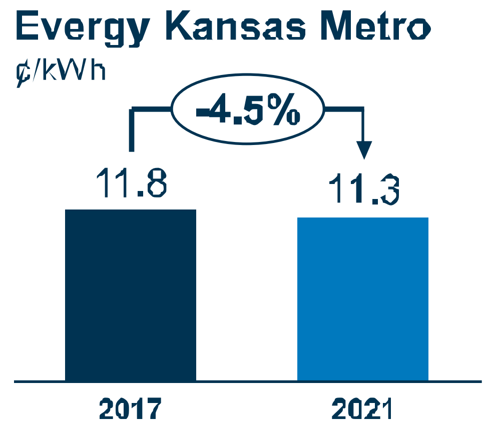
[1]Adjusted O&M is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP information. [2]2025E adjusted O&M (non-GAAP) guidance of $957M to $967M

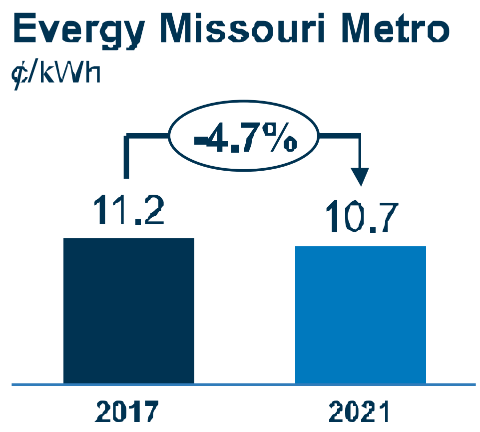
Improving Affordability & Rate Competitiveness

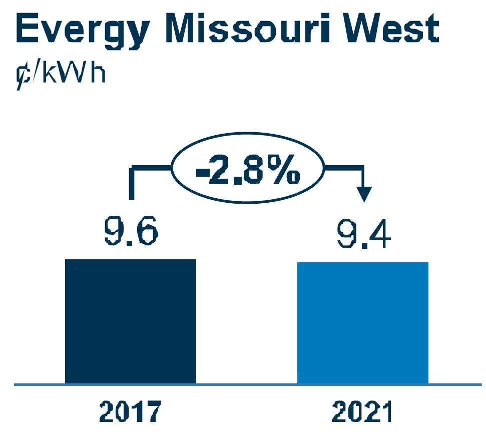
Change in rates











Favorable rate trajectory compared to both regional peers and inflation

[1]Regional peer data is sourced from EIA and is comprised of revenues and sales for all sectors based for the following states: Iowa, Kansas, Missouri, Nebraska, North Dakota, South Dakota, Arkansas, Oklahoma, Texas, and Colorado. [2]Source: US Bureau of Labor Statistics for historic CPI.

Missouri Rate Reviews

Missouri Metro

Revenue Increase since 2018[1]	$43.9M
Percent Increase since 2018[1]	5.20%
Rate Base	$3,154M
ROE	10.00%
Common Equity Ratio	51.19%
Case Number	ER-2022-0129

Missouri West

Revenue Increase since 2018[2]	$27.7M
Percent Increase since 2018[2]	3.85%
Rate Base	$2,485M
ROE	10.00%
Common Equity Ratio	51.81%
Case Number	ER-2022-0130

Estimated Timeline
(Procedural schedule has not been finalized)

2022			
Q1	Q2	Q3	Q4
Rate Requests Filed: January 7th	Intervenor testimony: late Q2	Potential hearings: late Q3	Rates effective: December 6th

Rate requests well below inflation due to ~$110M of annual savings since merger

[1]Excludes 95% of net fuel costs, or $3.8 million, unlike other elements of base rates, fuel costs will be subject to adjustment (up or down) through a fuel recovery mechanism every six months based on incurred costs. Total requested increase including net fuel is $47.6 million or 5.65%. [2]Excludes 95% of net fuel costs, or $32.1 million, unlike other elements of base rates, fuel costs will be subject to adjustment (up or down) through a fuel recovery mechanism every six months based on incurred costs. Total requested increase including net fuel is $59.8 million or 8.31%.

Regulatory & Legislation Updates

Kansas

- **Predetermination of Lawrence Coal Retirement and Kansas Solar Addition:** recently withdrew docket and plan to refile later this year
- **Winter Storm Uri AAO requests:** KCC Staff recommended approval of Kansas Metro returning benefits and Kansas Central recovering costs
- **Integrated Resource Plan**: plan to file annual update by July 1, 2022

Missouri

- **Winter Storm Uri AAO requests:** Awaiting MPSC approval to return benefits to Missouri Metro customers and to defer and securitize cost recovery for Missouri West customers
- **Integrated Resource Plan:** received MPSC approval for 3-month filing extension; plan to file annual update by July 1, 2022
- **Proposed Legislation | PISA | SB 756 / HB 1734:** would modify PISA rate cap from current all-in 3.0% CAGR to a 2.5% average annual cap on PISA deferrals; expand economic development incentives; and remove sunset date on the legislation

Pursuing constructive regulatory outcomes and enhanced regulatory frameworks to support infrastructure investment and economic development

Evergy Value Proposition

- All-electric regulated utility driving continuous improvement and performance management culture
- Reduced carbon emissions by nearly half since 2005; well-positioned to transition generation portfolio cost-effectively
- Geographically advantaged to participate in clean energy infrastructure buildout
- Targeting 6-8% annualized adjusted EPS[1] growth 2021-25. No additional equity; strong balance sheet

[1]Adjusted EPS is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP numbers.

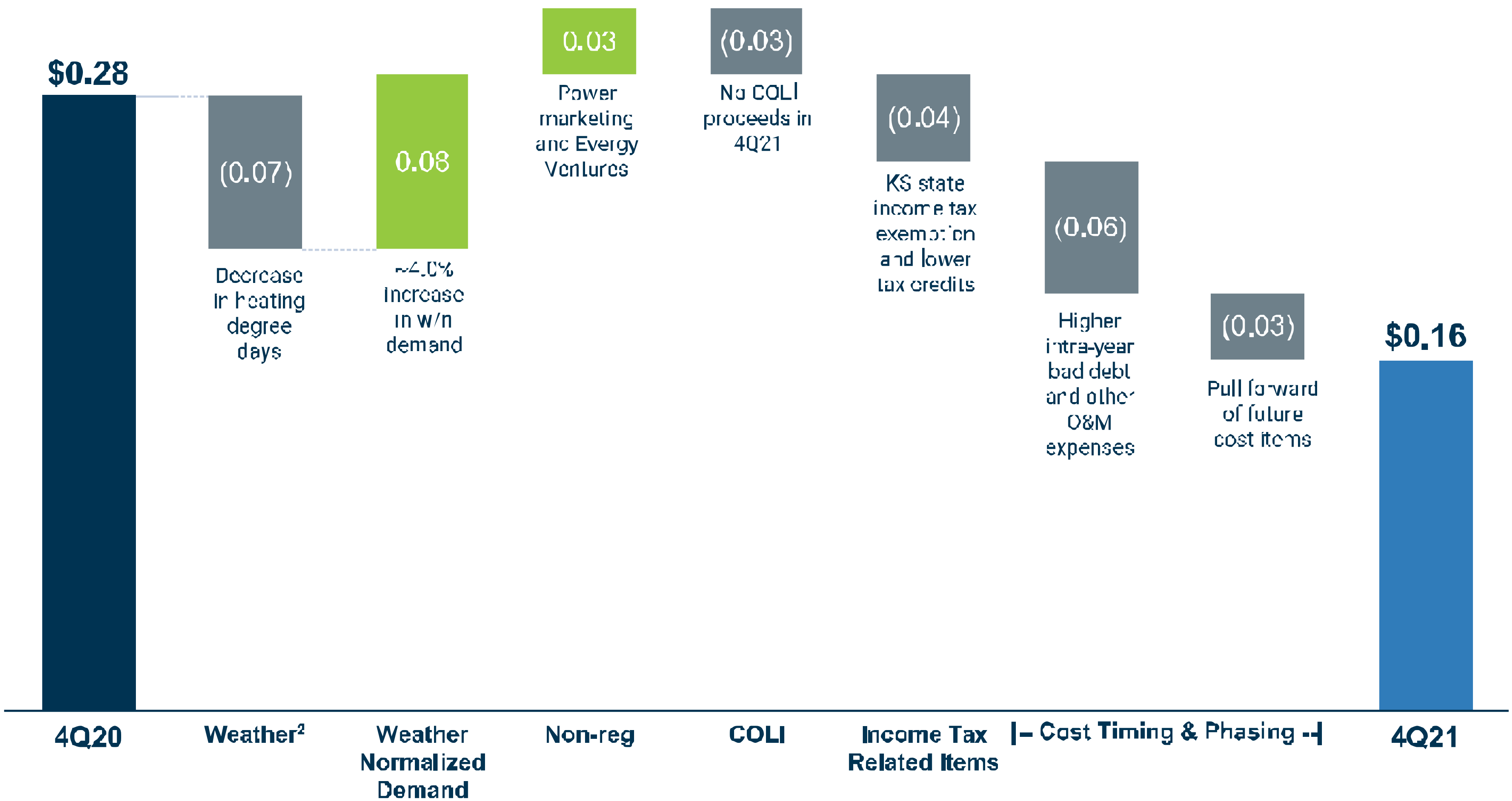
Financial Update

Kirk Andrews

Executive Vice President & CFO

Fourth Quarter 2021 Adjusted EPS[1]

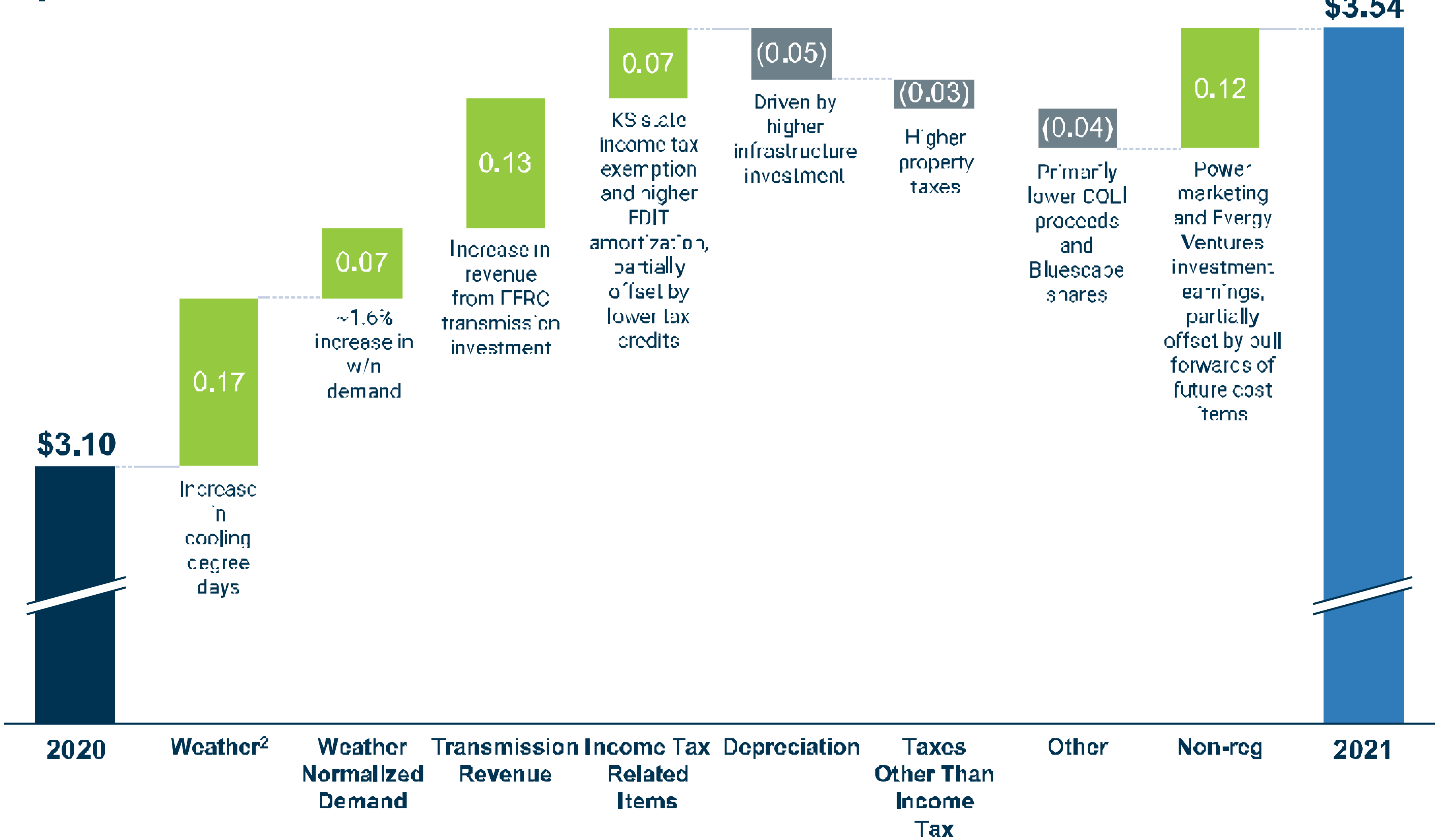
Adjusted EPS[1] Drivers



[1]Adjusted EPS is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP information. [2]Weather compared to normal was an estimated $0.10 unfavorable

Full Year 2021 Adjusted EPS[1]

Adjusted EPS[1] Drivers

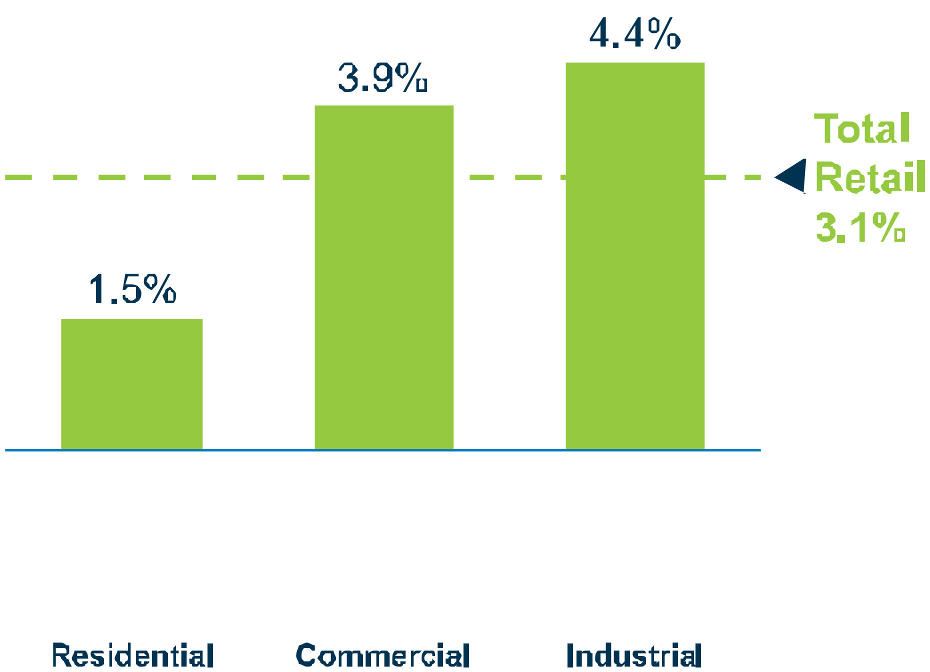


[1]Adjusted EPS is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP information. [2]Weather compared to normal was an estimated $0.08 favorable.

Retail Sales Trends

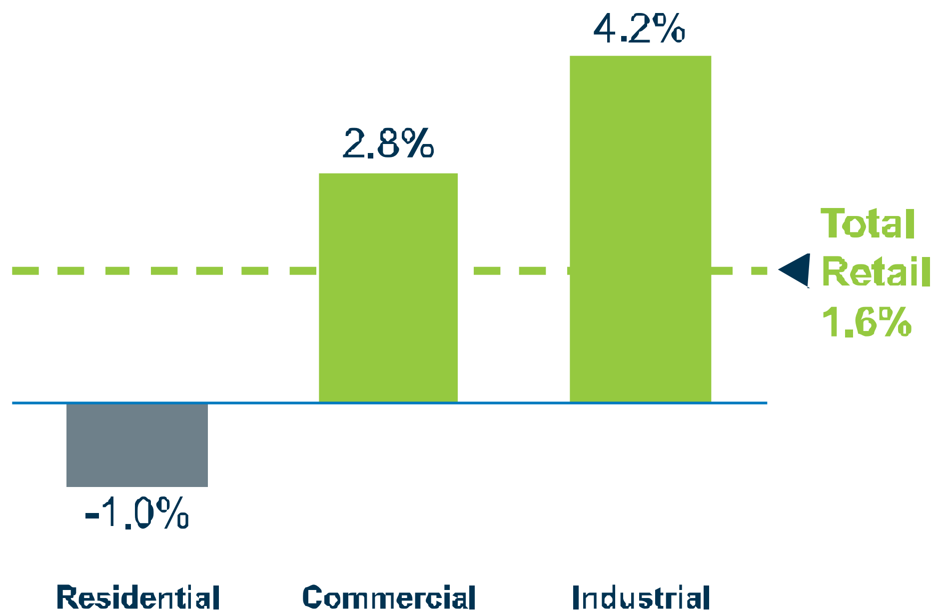
2021 Retail Sales Growth

Compared to prior year[1]



Weather-Normalized 2021 Retail Sales Growth

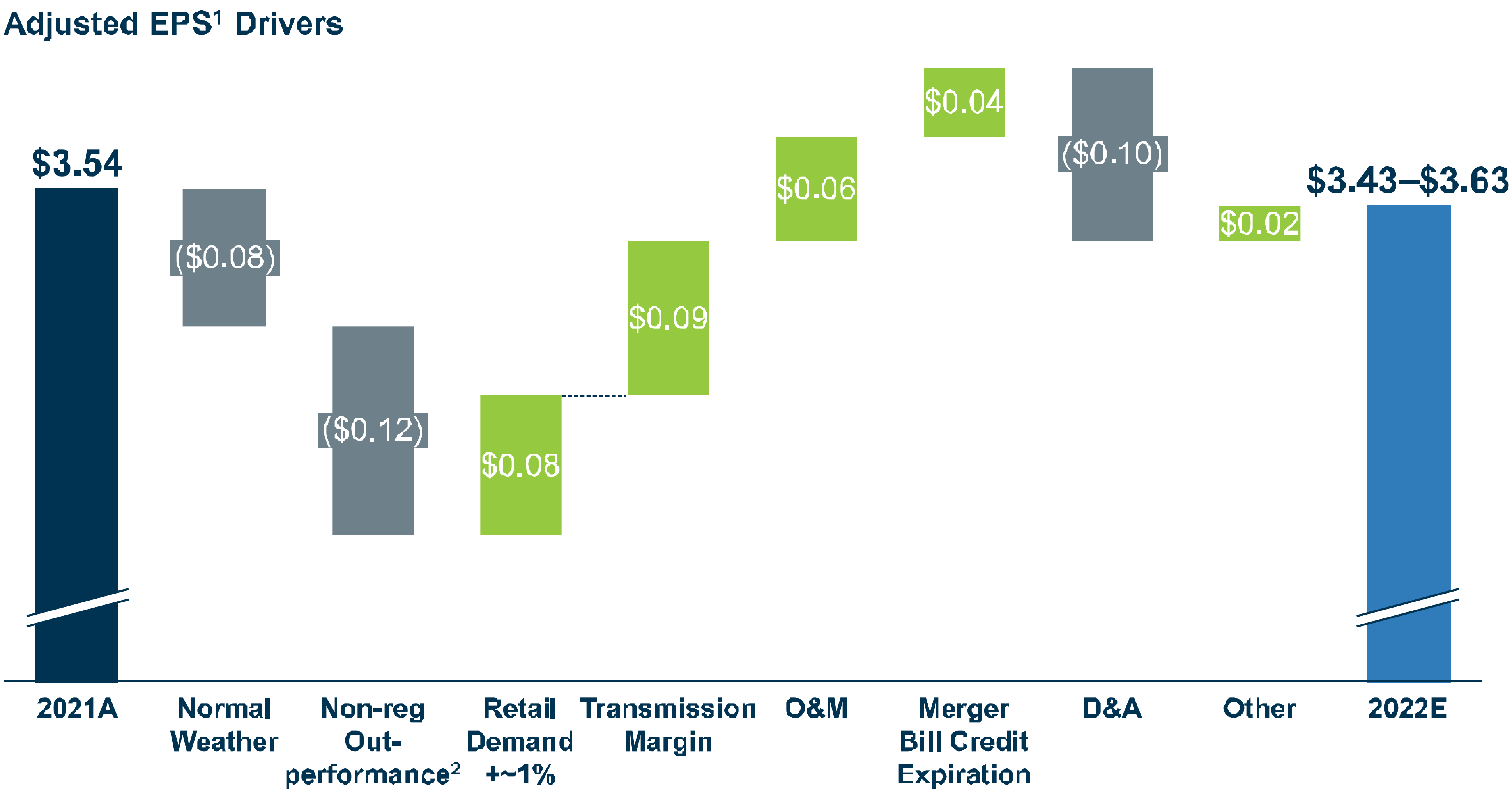
Compared to prior year[1,2]



Resilient local economy provided strong sales growth in 2021

[1]Percentages are approximations. [2]Weather-normalization uses a 30-year normal weather model

2021A To 2022E Adjusted EPS[1] Walk-forward

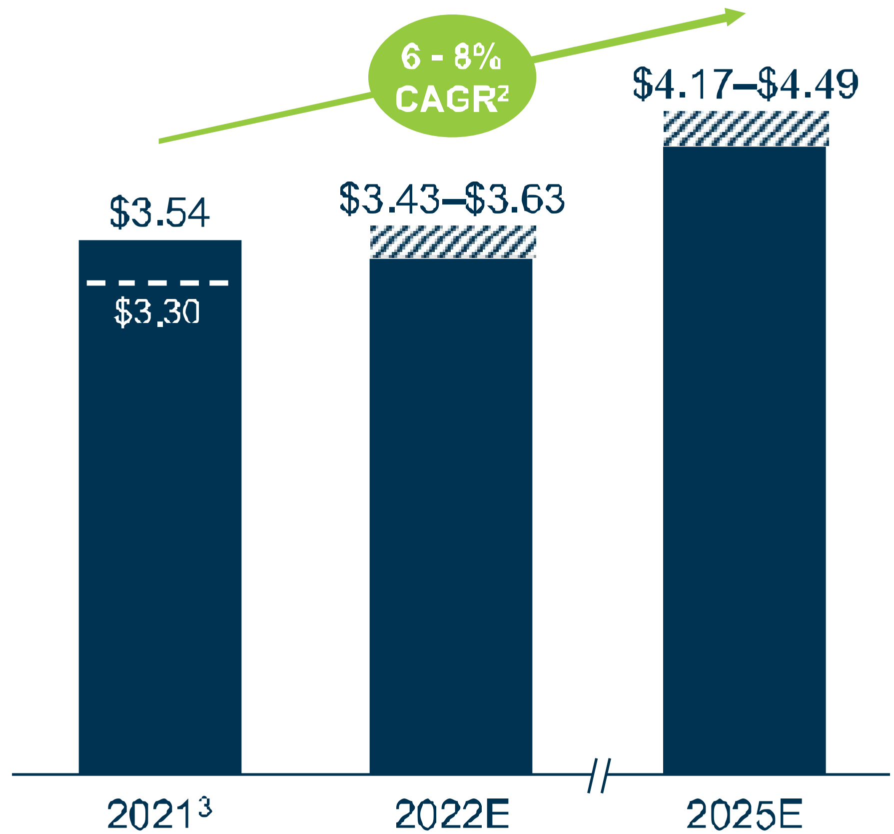


[1]Adjusted EPS is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP information. [2]Includes 2021 power marketing margins and Evergy Ventures investment earnings above plan run-rate, partially offset by pull forwards of cost items from future years. Note: expected 2022 effective income tax rate range is 8.5–10.5%.

Maintaining Execution & Building Momentum

- Focusing on building a track record of consistent execution
- Reaffirming adjusted EPS guidance[1]
  - 2022 target: \$3.43–\$3.63
  - 2021[2] to 2025E annualized growth target of 6% to 8%
- Planning \$10.7B of infrastructure investment 2022E–26E
- Targeting annualized rate base growth of 5% to 6% 2021–26E
- Targeting dividend growth in line with long-term earnings growth
- Focusing on financial and operational execution, enhancing reliability and customer service, and generation fleet transition

Targeted Adjusted EPS Growth[1]



Well positioned to deliver on our strong EPS and dividend growth targets

[1]Adjusted EPS is a non-GAAP financial measure. See appendix for reconciliation to most comparable GAAP information. [2]CAGR is calculated using \$3.30 mid-point of original 2021 adjusted EPS guidance and \$3.53 mid-point of 2022 adjusted EPS guidance. [3]\$3.30 in 2021 represents mid-point of original 2021 adjusted EPS guidance range.

2022 Objectives

- Meet or exceed financial targets
- Reach constructive outcomes in Missouri rate reviews
- Execute Build Transfer Agreement for Kansas solar project
- Execute Build Transfer Agreements for 800MW of 2024-2025 wind projects and at least one PPA buy-in

Q&A

Appendix

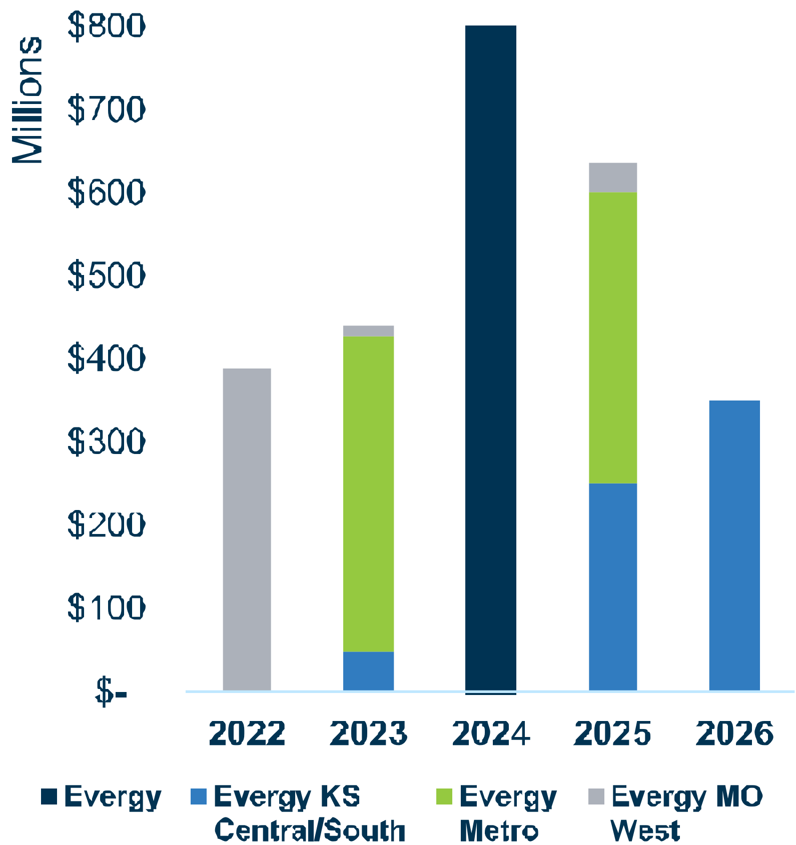
Five-Year Capital Investment Plan

$ in millions	2022E	2023E	2024E	2025E	2026E	Total
Generation	331	337	223	250	216	**1,357**
Transmission	626	600	591	592	679	**3,088**
Distribution	655	652	549	595	632	**3,083**
General Facilities and Other[1]	364	270	194	182	173	**1,183**
Subtotal Base CapEx	**1,976**	**1,859**	**1,557**	**1,619**	**1,700**	**8,711**
New Renewables	-	258	450	750	500	**1,958**
Total	**1,976**	**2,117**	**2,007**	**2,369**	**2,200**	**10,669**

[1]Includes information technology, safety and operations planning, customer operations, and other.

Debt Maturities & Credit Ratings

Long-Term Debt Maturities



Strong Credit Ratings	Moody's	S&P Global
Evergy, Inc.		
Outlook	Stable	Negative
Senior Unsecured Debt	Baa2	BBB+
Commercial Paper	P-2	A-2
Evergy Kansas Central		
Outlook	Stable	Negative
Senior Secured Debt	A2	A
Commercial Paper (KS-Central only)	P-2	A-2
Evergy Kansas South		
Outlook	Stable	Negative
Senior Secured Debt	A2	A
Short Term Rating	P-2	A-2
Evergy Metro		
Outlook	Stable	Negative
Senior Secured Debt	A2	A+
Commercial Paper	P-2	A-1
Evergy Missouri West		
Outlook	Stable	Negative
Senior Unsecured Debt	Baa2	A-
Commercial Paper	P-2	-

GAAP to Non-GAAP EPS Reconciliation[1]

Adjusted EPS[1]				
	2019A	Original 2021E	2022E	2025E
GAAP EPS – Guidance	**$2.79**	**$3.14 - $3.34**	**$3.43 - $3.63**	**$4.17 - $4.49**
Executive transition expense, pre-tax	-	0.03	-	-
Severance costs, pre-tax	0.08	-	-	-
Rebranding, pre-tax	0.05	-	-	-
Advisor expense, pre-tax	-	0.05	-	-
Income tax benefit	(0.03)	(0.02)	-	-
Adjusted EPS (non-GAAP)	**2.89**	**$3.20 - $3.40**	**$3.43 - $3.63**	**$4.17 - $4.49**

[1] Adjusted earnings per share guidance (non-GAAP) and adjusted O&M (non-GAAP) are financial measures that are not calculated in accordance with GAAP and may not be comparable to other companies' presentations of similarly-named measures or more useful than the GAAP information.

GAAP to Non-GAAP O&M Reconciliation[1]

2018 Adjusted O&M ($ in millions)	
2018 GAAP O&M	**$1,116**
Great Plains Energy O&M prior to the merger	318
Non-recurring merger-related costs	(101)
Pro Forma O&M	**$1,333**
Severance expense	$(24)
Deferral of merger transition costs	28
Inventory write-off from retiring generating units	(31)
2018 Adjusted O&M (non-GAAP)	**$1,306**

Adjusted O&M ($ in millions)	2021A	2025E
GAAP O&M	**$1,108**	**$957 - $967**
Non-regulated energy marketing costs related to February 2021 winter weather event	(8)	-
Executive transition expense	(11)	-
Severance expense	(3)	-
Advisor expense	(12)	-
COVID-19 Vaccine Incentive	(1)	-
Adjusted O&M (non-GAAP)	**$1,073**	**$957 - $967**

[1] Adjusted O&M (non-GAAP) is a financial measure that is not calculated in accordance with GAAP and may not be comparable to other companies' presentations of similarly-named measures or more useful than the GAAP information.

GAAP to Non-GAAP EPS Reconciliation

Three Months Ended December 31		Earnings (Loss)		Earnings (Loss) per Diluted Share		Earnings (Loss)		Earnings (Loss) per Diluted Share
	2021				2020			
	(millions, except per share amounts)							
Net income attributable to Evergy, Inc.	$	53.4	$	0.23	$	51.0	$	0.22
Non-GAAP reconciling items:								
Non-regulated energy marketing costs related to February 2021 winter weather event, pre-tax[b]		2.0		0.01		—		—
Executive transition costs, pre-tax[c]		0.2		—		—		—
Severance costs, pre-tax[d]		—		—		11.0		0.05
Advisor expenses, pre-tax[e]		3.2		0.01		6.2		0.03
COVID-19 vaccine incentive, pre-tax[f]		1.2		0.01		—		—
Restricted equity investment gains, pre-tax[g]		(27.7)		(0.12)		—		—
Income tax expense (benefit)[h]		4.5		0.02		(4.4)		(0.02)
Adjusted earnings (non-GAAP)	$	37.3	$	0.16	$	63.8	$	0.28

(a) Reflects non-regulated energy marketing margins related to the February 2021 winter weather event and are included in operating revenues on the consolidated statements of comprehensive income.
(b) Reflects non-regulated energy marketing incentive compensation costs related to the February 2021 winter weather event and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(c) Reflects costs associated with executive transition including inducement bonuses, severance agreements and other transition expenses of which $10.5 million is included in operating and maintenance expense and $0.3 million is included in other expense in 2021 on the consolidated statements of comprehensive income.
(d) Reflects severance costs incurred associated with certain voluntary severance programs at the Evergy Companies and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(e) Reflects advisor expenses incurred associated with strategic planning and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(f) Reflects incentive compensation costs incurred associated with employees becoming fully vaccinated against COVID-19 and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(g) Reflects gains related to equity investments which are subject to a restriction on sale and are included in investment earnings on the consolidated statements of comprehensive income.
(h) Reflects an income tax effect calculated at a statutory rate of approximately 22% in 2021 and 26% in 2020, with the exception of certain non-deductible items.
(i) Reflects the revaluation of Evergy Kansas Central's, Evergy Metro's and Evergy Missouri West's deferred income tax assets and liabilities from the Kansas corporate income tax rate change and are included in income tax expense on the consolidated statements of comprehensive income.

GAAP to Non-GAAP EPS Reconciliation

Year Ended December 31	Earnings (Loss) 2021	Earnings (Loss) per Diluted Share 2021	Earnings (Loss) 2020	Earnings (Loss) per Diluted Share 2020
	(millions, except per share amounts)			
Net income attributable to Evergy, Inc.	$ 879.7	$ 3.83	$ 618.3	$ 2.72
Non-GAAP reconciling items:				
Non-regulated energy marketing margin related to February 2021 winter weather event, pre-tax[(a)]	(94.5)	(0.41)	—	—
Non-regulated energy marketing costs related to February 2021 winter weather event, pre-tax[(b)]	7.9	0.03	—	—
Executive transition costs, pre-tax[(c)]	10.8	0.05	—	—
Severance costs, pre-tax[(d)]	2.8	0.01	66.3	0.29
Advisor expenses, pre-tax[(e)]	11.6	0.05	32.3	0.14
COVID-19 vaccine incentive, pre-tax[(f)]	1.2	0.01	—	—
Restricted equity investment gains, pre-tax[(g)]	(27.7)	(0.12)	—	—
Income tax expense (benefit)[(h)]	20.8	0.09	(25.2)	(0.11)
Kansas corporate income tax change[(i)]	—	—	13.8	0.06
Adjusted earnings (non-GAAP)	$ 812.6	$ 3.54	$ 705.5	$ 3.10

(a) Reflects non-regulated energy marketing margins related to the February 2021 winter weather event and are included in operating revenues on the consolidated statements of comprehensive income.
(b) Reflects non-regulated energy marketing incentive compensation costs related to the February 2021 winter weather event and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(c) Reflects costs associated with executive transition including inducement bonuses, severance agreements and other transition expenses of which $10.5 million is included in operating and maintenance expense and $0.3 million is included in other expense in 2021 on the consolidated statements of comprehensive income.
(d) Reflects severance costs incurred associated with certain voluntary severance programs at the Evergy Companies and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(e) Reflects advisor expenses incurred associated with strategic planning and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(f) Reflects incentive compensation costs incurred associated with employees becoming fully vaccinated against COVID-19 and are included in operating and maintenance expense on the consolidated statements of comprehensive income.
(g) Reflects gains related to equity investments which are subject to a restriction on sale and are included in investment earnings on the consolidated statements of comprehensive income.
(h) Reflects an income tax effect calculated at a statutory rate of approximately 22% in 2021 and 26% in 2020, with the exception of certain non-deductible items.
(i) Reflects the revaluation of Evergy Kansas Central's, Evergy Metro's and Evergy Missouri West's deferred income tax assets and liabilities from the Kansas corporate income tax rate change and are included in income tax expense on the consolidated statements of comprehensive income.