Exhibit No. 203

Office of the Public Counsel – Exhibit 203
Lena M. Mantle
Surrebuttal Testimony
File No. EO-2020-0262
January 13, 2021

Exhibit No.:	________________
Issue(s)	FAC Imprudence
Witness/Type of Exhibit:	Mantle/Surrebuttal
Sponsoring Party:	Public Counsel
Case No.:	EO-2020-0262

SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE

Submitted on Behalf of the Office of the Public Counsel

EVERGY METRO, INC. D/B/A EVERGY MISSOURI METRO AND EVERGY WEST, INC D/B/A EVERGY MISSOURI WEST

CASE NO. EO-2020-0262
(CONSOLIDATED WITH CASE NO EO-2020-0263)

January 13, 2021

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of the Ninth Prudence	)	
Review of Costs Subject to the	)	
Commission-Approved Fuel Adjustment	)	Case No. EO-2020-0262
Clause of Evergy Missouri West, Inc d/b/a	)	
Evergy Missouri West	)	

VERIFICATION OF LENA M. MANTLE

Lena M. Mantle, under penalty of perjury, states:

1. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony in the above-captioned case.

2. My answer to each question in the attached surrebuttal testimony is true and correct to the best of my knowledge, information, and belief.

*/s/Lena M. Mantle*_______
Lena M. Mantle
Senior Analyst
Office of the Public Counsel

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SURREBUTTAL TESTIMONY

OF

LENA M. MANTLE, P.E.

EVERGY METRO, INC. d/b/a EVERGY MISSOURI METRO
and
EVERGY WEST, INC. d/b/a EVERGY MISSOURI WEST

CASE NO. EO-2020-0262 (Consolidated with Case No. EO-2020-0263)

<u>Introduction</u>

Q. What is your name and business address?

A. My name is Lena M. Mantle and my business address is P.O. Box 2230, Jefferson City, Missouri 65102.

Q. Are you the same Lena M. Mantle that filed direct testimony in this case?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. In this testimony I:

1. Explain why the implementation of demand-side resources - including demand response ("DR") programs - should be reviewed in the fuel adjustment clause ("FAC") prudence process;
2. Provide a response to Evergy's[1] attempts to excuse its imprudence for failing to fully implement its demand-side resources (including the claim that any forgone energy savings is insignificant); and
3. Explain why it is appropriate to tie resource planning to an FAC prudence review and respond to Evergy's reply to this issue.

Q. What are your recommendations in your surrebuttal testimony?

A. My recommendations remain the same as they were in my direct testimony. The Commission should find Evergy imprudent for not optimizing its demand response

[1] In this testimony, "Evergy" refers to Evergy Metro, Inc. and Evergy West, Inc. collectively.

programs and for presenting a present value revenue requirement ("PVRR") in its preferred resource plan to the Commission and its customers that it knew was impossible to achieve.

Q. What are the imprudence amounts you are recommending for these issues?

A. The imprudence amounts OPC is recommending are in the following table.

Imprudence Amounts

	Evergy Metro	Evergy West
Capacity Sales	$ 5,220,000	
Energy Sales	$ 160,174	$ 169,360
Schedule 11 Fees	$ 161,123	$ 270,175
Total	$ 5,541,297	$ 439,535

The recommended imprudence amounts for capacity sales have not changed from my direct testimony. The energy sales imprudence amounts have changed. For this testimony, I looked at the data available to me and updated the energy imprudence amounts. In my direct testimony, I used an amount for energy sales calculated by Staff in the Missouri Energy Efficiency Investment Act ("MEEIA") case EO-2020-0227 adjusted for the difference between the FAC and MEEIA prudence review time periods.

The SPP Schedule 11 fees are the amounts provided in the rebuttal testimony of Evergy witness John R. Carlson.[2]

As an alternate resolution to the capacity sales issue, I recommend the Commission order Evergy to, in its triennial resource plan filing that Evergy will be making in April 2021, include for each of its modeled scenarios, a run with no capacity sales other than its current contracts.

The other issues in my direct testimony were resolved when Evergy agreed to return the costs associated with the retirements of the Montrose and Sibley plants

[2] Page 22.

that it had included as FAC costs during the prudence review period in a non-unanimous partial stipulation and agreement filed on December 18, 2020, in this case. These costs will be returned to the customers if the Commission approves the stipulation and agreement and issues an order approving it.

Evergy Did Not Utilize Its Demand Response Programs to Minimize FAC Costs

Q. Staff witness Brad Fortson recommends in his rebuttal testimony that Demand Response program imprudence issues only be dealt with in Evergy's current MEEIA prudence review filing and not in this proceeding because of the Commission's *Order Denying Motion to Limit Scope* in that case.[3] Do you agree with Mr. Fortson?

A. No. Mr. Fortson provides the following quote from that Commission order[4] to support his position.

> The Commission finds that Staff has raised allegations of imprudence by Evergy that are relevant to the Commission's determination of whether Evergy has operated its MEEIA programs in a prudent manner. Whether the alleged imprudent acts are costs subject to the DSIM is a question of fact in addition to a question of law. Ultimately, after hearing the evidence, the Commission will find that Evergy has, or has not been prudent. But it must first hear that evidence. Evergy's request to limit the scope of the review is not well founded and will be denied

While I believe this is a legal issue and neither Mr. Fortson nor I are attorneys, my opinion of this order is that it does not exclude the review of DR programs from other cases. It merely states that the Commission would not exclude a review of the DR programs from the MEEIA prudence case.

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[3] Page 4.
[4] Case EO-2020-0227, *Order Denying Motion to Limit Scope,* pages 3 – 4.

Q. Contrary to Mr. Fortson's interpretation of the Commission order, are there issues with Evergy's utilization of its demand response programs that need to be addressed in the context of the FAC specifically?

A. Yes. As I explained in my direct testimony, the utilization of Evergy's demand response programs can have a direct impact on the FAC. It is therefore reasonable and necessary that an FAC prudence review should include a review of the utilization of the available demand response programs.

Q. Would you please elaborate on why FAC prudence reviews should include a review of the utilization of available demand response programs?

A. Certainly. The resource planning process results in the identification of resources, both demand-side and supply-side resources, that minimize present value revenue requirements. Both types of resources affect the costs included in the FAC. Therefore, just as Staff reviews whether or not a generation plant was utilized in a manner that minimized fuel and purchased power costs included in the FAC, so also should it review whether or not DR programs were utilized in a manner that minimized fuel and purchased power costs included in the FAC. Knowingly not managing a resource in a manner that would reduce FAC costs is imprudent.

Q. Would you briefly explain what a demand-response program is?

A. The Southwest Power Pool ("SPP"), like most regional transmission organizations, requires its load-serving members to have enough resources to meet expected peak demand of their load plus a margin. The first resources that comes to mind are generation resources – coal, natural gas, nuclear, and renewables. Generating resources are supply-side resources because they supply the electricity to meet the customers' needs.

Demand-side resources are on the other side of the meter - the customer's side of the meter. Typically, demand-side resources provide incentives to the customers to change how they use electricity, *i.e.* their demands on the utility system. Demand response programs target customers' usage at specific times. These types of programs not only have value because they enable the utility to reduce the load at system peak (thus reducing the need for supply-side resources), but can also be used to reduce the energy purchased at times of high market prices thereby reducing the need for and total cost of energy. It is this second use, the reduction of energy purchased at times of high market prices, that influences the costs that are recovered through Evergy's FACs.

Q. In his rebuttal testimony, Mr. Fortson asserts that the MEEIA prudence review is the proper proceeding for the issues surrounding the DR programs to be addressed.[5] Why is this assertion incorrect?

A. The DR programs should be used to reduce the cost of energy Evergy purchases at times of high market prices and thereby reduce the costs recovered through its FAC.

Q. Would you explain the relationship between the DR programs and the FAC?

A. Evergy pays the SPP for the energy consumed by its customers in each hour of the year regardless of the amount of energy its generation is producing. The SPP load cost for each hour is the number of megawatts ("MW") demanded by its customers in a given hour multiplied by the market price for the Evergy load node in that hour. When Evergy calls a DR event, the result is that its customers require a lower amount of energy in that hour. Since the load is lower, the SPP cost to Evergy for that hour is also lower.

This hourly payment to SPP for the customers' load is included in the FAC as a cost. A utility with a DR program that does not utilize the program to reduce energy costs is acting imprudently. This remains true regardless of the prudency surrounding the original rationale for the introduction of the program.

In addition to the customers having to pay higher energy costs because Evergy did not effectively manage its DR programs, customers also end up paying

[5] Page 5.

more in certain SPP costs since some of these costs are based on the demands of the utility in the previous year. One cost in particular, the SPP Schedule 11[6] costs, are partially included in the FAC. Minimizing load through calling DR program events reduces the utility's SPP Schedule 11 costs. Calling additional events would therefore have also reduced these SPP costs that are passed through Evergy's FACs.

Q. Would you briefly summarize Evergy's DR programs?

A. Evergy has two different DR programs. For the residential and small commercial customers, Evergy offers free thermostats as an incentive for Evergy to have the ability to reduce the customer's air conditioning load each day from June 1 through September 30 for up to 4 consecutive hours. Although the tariff sheets do not provide a limit for the number of days curtailment events can be called, Evergy witness Brian A. File states in his rebuttal testimony this thermostat program was designed for a maximum of 15 events per curtailment season (every June 1 through September 30).

Evergy's other DR program is offered to large customers who have the ability to curtail at least 25 kilowatt ("kW"). The curtailment season is June 1 through September 1. Evergy can only curtail ten times during that season but the length of the curtailment can be up to eight hours. Evergy provides all of the participants a financial incentive for participating and, based on certain criteria, some of the participants also receive payment for successful performance. This program also includes a penalty to participating customers when the curtailment amount contracted by the customer is not achieved when an event is called.

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[6] SPP Schedule 11 charges recover costs associated with the new transmission system investment in the SPP footprint.

Q. Could you please summarize, again, why you are recommending the Commission find Evergy imprudent for failing to fully utilize its DR programs in the FAC and not just in the MEEIA?

A. A reasonable person, in addition to assuring the MEEIA program design had been achieved, would have utilized these DR programs as much as reasonably possible to minimize the energy costs and SPP Schedule 11 fees recovered through the FAC. Evergy had the ability, according to Mr. File, to call 30 events for the residential and commercial participants and 20 for the large customer participants, yet it only called five events in the two summers at issue in this FAC prudence review period.[7] By not calling additional events to reduce energy and SPP Schedule 11 costs, Evergy acted imprudently.

Q. Mr. File reiterates over and over again that Evergy met the design purpose for the DR programs. Does that show that the DR programs are prudent?

A. Not with respect to the minimization of FAC costs. The FAC prudence cases look at the actions (or inactions) of a utility to minimize FAC costs by efficiently utilizing all of its resources. While the design purpose of the DR programs from a MEEIA perspective might be considered simply as a means to reduce peak, another purpose of the programs should be to reduce energy costs. In fact, Evergy's tariff sheets describing these programs specifically cites both of these reasons as a basis for when a curtailment event could called:

> Curtailments may be requested for operational or economic reasons. Operational curtailments may occur when any physical operating parameter(s) approaches a constraint on the generation, transmission or distribution systems or to maintain KCP&L's capacity margin requirement. **Economic reasons may include any occasion when the marginal cost to produce or procure energy or the price to sell the energy in the wholesale market is greater than a customer's retail price.** (emphasis added)

[7] Sur-surrebuttal testimony of Brian A. File, Case EO-2020-0227, pg. 14.

Evergy seemed to forget the second reason to curtail once it achieved the first.

The first objective of reducing the system peak was necessary to show the programs were cost effective as modeled in its MEEIA requests so that the costs of the programs, plus a throughput disincentive and performance incentive, could be recovered from Evergy's customers. However, that does not excuse or otherwise explain why Evergy chose not to call any events for the second reason outlined in the tariff sheets, which is what the OPC now argues was imprudent.

Evergy is only able to keep 5% of the benefits achieved when the programs are curtailed for economic reasons as defined in the tariff sheets. The other 95% of any reductions in FAC costs are flowed through to the customers. This is why DR programs should also be reviewed in the FAC prudence cases. What OPC is asking is that the Commission hold Evergy to its second reason provided in the tariff sheets and find Evergy imprudent in this FAC case for not calling as many DR program events as was economically reasonable.

Q. Do you have any other evidence Evergy was aware of this potential benefit of reducing energy costs through these programs during the FAC prudence review period?

A. Yes. Evergy offers to its large customers that participate in its DR program the opportunity to receive market settlement fees from SPP through its Market Based Demand Response Program.[8] This is not a MEEIA program and the customers cannot receive benefits through this program for events called to meet the MEEIA design of the DR program. This program allows the participating customers to reduce their bills through targeted event calls when market prices are high.

This program, implemented during the FAC prudence period of this case, shows that Evergy knew that it could use events called through its DR programs to

[8] The tariff sheets implementing this program became effective during this FAC prudence period on December 6, 2018.

reduce energy costs. The difference is that the savings for this program are available only to a small group of large customers.

Q. Mr. File testifies that it is his opinion that Evergy acted reasonably given the allegations of imprudence in this case because 'the Commission explicitly found that the "Amended MEEIA Plan meets the requirements of MEEIA and the Commission's rules and is just and reasonable." The "reasonableness" conclusion of the Commission was specifically based on a finding that the design of the MEEIA Cycle 2 programs were cost-effective and "expected to provide benefits to all customers."'.[9] Does this finding of the Commission signify Evergy acted prudently?

A. No.

Q. Would you explain?

A. While Mr. File provides the case-number that this Commission quote was from in a footnote, he did not provide the name of the order or when the order was issued. In my review of the orders in the case referenced by Mr. File, EO-2015-0240, I found this quote in the Commission's *Report and Order* that was effective on March 12, 2016 – more than two years before the beginning of the FAC prudence period that is the subject of this case.

Commission findings approving the *design* of the DR programs in March 2016 is not an indication that Evergy prudently *implemented* the programs in 2018 and 2019 in a manner that minimized costs.

[9] Page 14.

Q. According to Mr. File, there will be a negative impact to peak load reduction efforts by calling an increased number of events.[10] Do you agree with Mr. File?

A. No. The three data points provided by Mr. File do not conclusively demonstrate that calling more events results in more customers opting out. A definitive trend cannot be simply determined with three data points. There could be many things that impact the number of customers opting out. In Evergy's MEEIA Cycle 2 2016-2018 filing in EO-2015-0250, Evergy[11] stated in its description of the residential and commercial DR programs "For each participant, the Company will combine pre-cooling, temperature setbacks, and cycling to achieve the maximum load reduction possible while still maintaining an outstanding customer experience." The negative impacts could have arisen because the participants did not like how cold their homes got prior to the event. It could have been the number of free riders, people that just wanted the thermostat, was a greater percentage of total participants in 2016. It is unlikely that it was as simple as the number of events that Evergy called.

Q. Mr. File testifies that calling more events would erode the trust between Evergy and its customers because of the inconvenience to customers of having their air conditioning adjusted regularly.[12] Would you respond to Mr. File's testimony on this impact to customers?

A. The participants in these programs have been given a free-to-them thermostat.[13] If the program requirements have been communicated correctly to them, then they should expect a bit of inconvenience in exchange for receiving that thermostat. Moreover, if the inconvenience really were too great, then the participants

[10] Page 9.
[11] Then known as Kansas City Power & Light Company.
[12] Pages 8-9.
[13] The participants and non-participants are paying for these thermostats, along with a throughput disincentive adder, through the MEEIA charge on their bill.

(assuming Evergy has effectively communicated all aspects of the program) know that the inconvenience can be overcome during the event by walking over to their thermostat and changing it. As such, any inconvenience will be of the customer's own choosing.

Contrary to what Mr. File argues, it is actually Evergy that is eroding the trust of the participants when it tells them there could be ten or more events in a summer and yet only calls two. After several years with only a limited number of events called, customers begin to believe that this is normal. If Evergy in subsequent years decides to call even just four or five events in one year, customers will get frustrated because they had come to trust that they would only be inconvenienced two times a year despite what they were told when they accepted a thermostat from Evergy.

Finally, Evergy is eroding the trust that non-participants place in it to act as a prudent utility by charging them for a resource that it chooses to not efficiently utilize.

Q. Mr. File testifies that you asserted that calling more events would be at zero or very minimal incremental cost. Is there an incremental cost when DR events are called?

A. First of all, I did not make this assertion in my direct testimony. That being said, Mr. File makes a good point. There can be a small cost impact on the MEEIA budget when an event is called regardless of the reason the event was called.

Q. When is there a small impact?

A. For some of the participants in the large customer DR program, there is a small incremental cost to calling an event. However, when an event is called, whether for operational or economic reasons, there are no variable costs for the other participants in the large customer DR program or for the residential and commercial participants. Evergy pays most participants the same whether no events are called or fifteen events are called. This is part of the program design to ensure that the MW of response from the customers is available for capacity credit with SPP. This is similar to the fixed costs of supply-side generation.

Despite there not being any cost for Evergy to call an event for the residential and commercial participants, a cost to Evergy's customers occurs when Evergy does not maximize the benefits that it can achieve with its DR programs. Using my recommended imprudence amounts, Evergy's customers unnecessarily paid $313,056 during the prudence period for energy because Evergy chose not to utilize its DR programs more.

Q. What was the impact on Evergy for not calling any events when using your estimate of the cost of energy that should have been saved?

A. Given that Evergy would have recovered 5% of any reduction of FAC costs and using my recommended imprudence amounts for this prudence period, Evergy lost only $16,477 during the prudence period by choosing not to utilize its DR programs more.

Q. Mr. File testifies that any benefits derived from reduction in SPP fees and market pricing opportunities is minimal compared to the value of the long-term reduction of system annual peaks.[14] Later in his testimony, he testifies to the benefits as being insignificant.[15] How do you respond to this?

A. Evergy's definition of minimal varies greatly by witness. Evergy witness Lisa A. Starkebaum provided testimony in this case to show how the Montrose retirement costs that Evergy agreed to return to the customer should be reduced from $44,832 to $28,269.[16] This correction resulted in Evergy retaining approximately $9,000. To Evergy witness Ms. Starkebaum, $9,000 is not minimal.

[14] Page 6.
[15] Page 10.
[16] Pages 10-11.

Evergy witness Mr. File has a different understanding of minimal. I estimate that well over $780,000 of energy and SPP Schedule 11 costs could have been saved if Evergy had called a limited number of events in the summers of 2018 and 2019. Of this amount, I have calculated that almost $500,000 passed through Evergy's FAC. Mr. File considers this amount, which would be returned to Missouri customers, minimal.

It seems that if it is the customers' money, $500,000 is minimal but no amount is too small if it is Evergy's money. In my opinion, $500,000 is not minimal.

Q. Mr. File, on page 9 of his testimony, states that OPC suggested 20 events be called or even that events be called every day. Did you suggest this?

A. While the tariff sheets do allow events to be called every day in the summer months, I did not suggest 20 events or daily events be called in this case. If I had, the imprudence amount requested would have been much greater.

Q. Then Mr. File discusses the impact of calling 20 to 50 events in a summer.[17] Have you suggested that 20 to 50 events should be called in a summer?

A. Not in this case.

Q. How many events did you suggest?

A. As Mr. File provides on page 4 of his rebuttal testimony, I did not suggest a preferred number of events. He states that it is his understanding that my testimony was just that more events should be called.

Even more confusing, after stating that OPC suggested 20 events and then providing testimony regarding the impact of having 20 to 50 events or events every

[17] Page 9.

day in the summer, Mr. File, on page 14 of his testimony, states that OPC never suggested the DR programs were designed to call a high frequency of events.

Q. What is your position on how many events should be called?

A. Given the design of the DR programs as described by Mr. File of 15 events for the residential and commercial[18] and 10 for the large customer, I suggest that 14 and 9 events should have been called for residential and commercial customers and large customers respectively for economic reasons during the summers of 2018 through 2019. This is because one event would be for operational reasons – the other reason stated in the tariff sheets for the calling of events.

OPC's position in this case is that every resource, demand- or supply-side, should be used to minimize FAC costs. To do anything less is imprudent; increasing costs for Evergy's customers and increases their bills unnecessarily.

Q. Mr. File discusses how difficult it would be to maximize the energy savings since the hours of peak prices are not known.[19] You say that Evergy was imprudent for not utilizing the DR programs to minimize costs in the FAC. Would a reasonable person always be able to predict the hours with the highest prices so they could get the absolute minimum costs in the FAC?

A. No. It would be unreasonable to expect anyone to be able to time events so accurately they achieve the absolute minimization of energy costs. However, given the potential gain, a reasonable person would at least call all the available events and try to maximize savings. If an event is not called, then there is no gain. If an event is called energy is saved and cost is reduced regardless of whether or not it ends up being a peak pricing period. Evergy had the ability to call 30 events for the two years for the residential and commercial DR program. It called five. For

[18] The tariff sheets for the residential and commercial DR program only restricts the number of events to one a day through the curtailment period of June 1 through September 30.
[19] Page 7.

the large customer DR program it could have called 20. It called five. That shows that it was not even attempting to utilize this resource cost effectively.

Q. What would a reasonable person do to increase their odds of maximizing energy savings and reducing monthly peaks?

A. A reasonable person would look at the pattern of when the highest market prices occur for each of the utilities and, recognizing the limitations of the programs, would set some parameters. For example, system peaks typically occur late July or early August when the weather is the hottest. Therefore, a reasonable person would not call all events before then. Prior to the summer curtailment season, a reasonable person would evaluate the historical hourly prices to determine a minimum price under which no events would be called. However, this reasonable person would be watching the prices in the summer to see if that minimum needs to be changed. Because a little savings is better than none at all, if there were still a number of events available after mid-September, a reasonable person would maximize the events in the time that remained to obtain some savings.

Q. In his rebuttal testimony, Evergy witness John R. Carlson provides an example of where calling an event would have resulted in an increase in energy cost.[20] How do you respond to this testimony?

A. The negative benefits included in Mr. Carlson's example occur for two reasons. First, the real time locational marginal price ("RT LMP") included in his example is much higher than the day ahead locational marginal price ("DA LMP"). Mr. Carlson did not provide information on how often there is this extreme difference in the DA LMP and RT LMP. These types of differences between the day ahead and real time market creates problems in the energy market and, in a mature market like SPP, should be rare.

[20] Page 19.

The second reason that there is a negative benefit is because whoever bid the load into the market did not have a realistic understanding of the reductions achievable through the DR programs or how to best achieve benefits. Below is a table where instead of bidding in the 57.41 MW of DR, 45.93 MW were bid into the market. In this case the result is very different.

Example 1			
Requested Reduction			57.41
Actual Reduction			45.93
HE	DA LMP ($/MWh)	RT LMP ($/MWh)	Benefit
15	58.41	1125.22	$ (9,564.21)
16	72.99	118.07	$ 2,834.91
17	65.44	25.34	$ 3,466.01
	Total Benefit/(Cost)		$ (3,263.29)

Example 2			
Requested Reduction			45.93
Actual Reduction			57.41
HE	DA LMP ($/MWh)	RT LMP ($/MWh)	Benefit
15	58.41	1125.22	$15,600.30
16	72.99	118.07	$ 4,707.87
17	65.44	25.34	$ 3,296.56
	Total Benefit/(Cost)		$ 23,604.73

Example 1 was provided in Mr. Carlson's testimony. In his example, Evergy made a bid in the market expecting a 57.41 MW reduction in load but only achieved 45.93 MW. Using the formulas in Mr. Carlson testimony, Evergy would have achieved savings for the requested reduction in the day ahead market but would have paid a penalty because the actual reduction was less than the requested reduction. Because of the large difference in hour 15 between the day ahead and real time price, there would be a negative benefit, i.e. calling an event for the full estimated amount in this hour would have cost the customer, for this hour, $9,564.

In example 2, the same formulas were applied but the requested and actual reductions were inverted such that the actual reduction was greater than the requested reduction resulting in a benefit in that hour of $15,600. The decision maker in the second example had a better understanding of the market.

Q. Should Mr. Carlson's example of an hour when the RT LMP was much greater than the DA LMP cause concern?

A. Only if it happens frequently. Mr. Carlson provides no testimony that indicates this is a common occurrence.

Q. Mr. Carlson characterizes what OPC has recommended similar to placing bets on the day ahead market saying that customers may not see a benefit and may instead see a cost.[21] Do you see this as a risk for the customers?

A. Only if the decision to call events was made without information on the market and DR programs. However, Evergy has taken bigger risks – ones that have resulted in hundreds of millions of increased costs in its customers' bills – with much less concern. Mr. Carlson's concern seems insincere knowing that Evergy lost almost *$140 million* in 2018 and 2019 in wind purchase power agreements that it entered into because Evergy was betting these purchased power agreements would provide "economic benefits" to its customers based on market prices. In contrast, Mr. Carlson seems to be reluctant to take a risk that could possibly increase costs by $3,320 while forgoing the potential for benefits of well over $600,000.

Q. Mr. File discusses how Staff used hindsight to determine the monthly peaks in calculating the imprudence amounts.[22] In this testimony, you have included an even larger imprudence amount than Staff's estimate. Is the amount that OPC is requesting be returned to the customers in this surrebuttal testimony based on perfect information fully maximizing the energy savings?

A. No, it is significantly below the maximized energy savings.

[21] Page 20.
[22] Page 12.

Q. How is the amount you are recommending being returned to customers different from what a maximized benefit based on hindsight would be?

A. To maximize the savings, ten eight-hour large customer DR events would have to be called (80 hours of reduction) that include the highest cost hours of the summer. For the residential and commercial DR program, 15 four-hour events would be called (60 hours).

Hourly market prices for the summers of 2018 through 2019 are necessary to determine the maximum amount Evergy could have reduced energy cost if it had optimally chosen events in the summers of 2018 and 2019. I did not have this information available to calculate the maximum savings. I did have available to me, from Evergy's response to Staff data request 41, five hours in each summer month with the highest market prices for a total of 20 hours of market prices for each summer. The imprudence amount I am requesting is the hourly market prices multiplied by the amount of DR MW available[23] in these 20 hours.

Q. How do you know that this is not the maximized energy savings cost?

A. Evergy's large customer DR program allows for 80 hours of called events and the residential and commercial DR program allows for 60 hours of events. This number was calculated using only 20 hours which is 25% of the event hours available for the large customer DR program and 33% of the available residential and commercial event hours. An estimate of the total maximized savings would be much larger.

Q. How is the imprudence amount you recommend in this case different from what you recommended in your direct testimony?

A. In my direct testimony, I used the amount estimated by Staff in the MEEIA prudence case EO-2020-0227 adjusted for the difference in the MEEIA prudence

[23] As found in the Evaluation, Measurement, and Valuation (EMV) MEEIA Databooks provided by Evergy.

periods and the FAC prudence periods. Staff's estimates did not include all 20 of the hours provided to it.

Q. Is there anything else in Mr. File's rebuttal testimony that you would like to respond?

A. Yes. In addition to asserting that I had provided testimony regarding incremental costs and testimony accusing me of wanting 20 to 50 events to be called, there were at least two mischaracterizations of my testimony that I would like to address. First of all, Mr. File testified that OPC's assertion of imprudence in this FAC prudence case was an attack on the Commission's findings that the design of the MEEIA Cycle 2 programs were reasonable.[24] There is nothing in my direct or surrebuttal testimony regarding the Commission's findings of reasonableness of the programs.

The reasonableness of the design of the MEEIA Cycle 2 programs is irrelevant to this case. This case is about whether or not a reasonable person would have utilized the DR programs as they exist to lower costs. Evergy has been unwilling to maximize the benefits to the customers from these programs the Commission found reasonable. While the benefits that are the subject of this testimony may not be the only design reason for the programs, a reasonable person would not ignore these benefits that come at a very low additional cost.

Q. What is the other mischaracterization that Mr. File made?

A. Mr. File testifies that OPC is trying to re-litigate the application or methodology for determining avoided cost in the MEEIA cycle 2.[25]

[24] Page 14.
[25] Page 11.

Q. Is OPC trying to re-litigate anything in this FAC prudence case?

A. No. OPC's recommendations of imprudence in this case have nothing to do with the avoided capacity cost. There would be no credit for changes in avoided cost in Evergy's FAC. This is not the proper case to re-litigate the avoided cost.

Q. Do you have an opinion as to why Mr. File included all of these in his rebuttal testimony in this case?

A. In preparing this testimony, I reviewed Mr. File's sur-surrebuttal in the MEEIA prudence review case, EO-2020-0227. It is my opinion that Mr. File cut and pasted from his sur-surrebuttal testimony in the MEEIA into his testimony in this case without a careful review of the testimony he was responding to.

Q. Why is this important?

A. The purpose of this case is completely different from the purpose of the MEEIA case. The purpose of this case, as I stated earlier, is to review the prudence of decisions made that influence the costs included in the FAC. It is not to determine whether or not the design of a MEEIA program was prudent or whether a MEEIA program met the targets set out in its design.

Q. Is there anything else in Mr. Carlson's rebuttal testimony that you would like to respond to?

A. Yes. Mr. Carlson testifies that Evergy should not be expected to use the DR programs to reduce the SPP Schedule 11 fees because SPP Schedule 11 fees are based on an average of the monthly peaks of the previous year and it would be difficult to use the DR programs to reduce all four monthly peaks in the summer. This position is confusing given the testimony provided by Evergy witness Mr. File in the surrebuttal report filed in case EO-2019-0132. In that report, Mr. File provided testimony that Evergy's DR programs could be used to reduce monthly peaks resulting in reduced SPP Schedule 11 fees.[26] Mr. File did not mention that Evergy should not be expected to take advantage of this benefit of DR programs because it would be difficult to do. In fact, in his testimony he stated:

> While forecasting peaks (because it is weather driven) is not an exact science, a focus on timely system reporting for loads for the month can improve the potential for better accuracy of reducing the monthly peak."

The Commission relied on this testimony in its Amended Report and Order in that case.

Q. Is there only a reduction in fees if all four summer month peaks are reduced?

A. No. Because the SPP Schedule 11 fee is dependent upon the average of the *twelve* monthly peaks, each monthly peak that is reduced subsequently reduces the SPP Schedule 11 fees. Evergy has managed to reduce one peak while only utilizing a few of the DR events available to it. A reduction in two or more monthly peaks would reduce the SPP Schedule 11 fees even further.

Q. Finally, what is your experience with reviewing DR programs of electric utilities?

A. In my time on the Staff, I had extensive experience reviewing the design, implementation, and impact of DR programs. Not long after I came to work at the Commission in 1983, one of my job requirements was to review the demand response programs[27] of the electric utilities in the state of Missouri.[28] I continued my review of DR programs in the preparation and development of the Commission's Chapter 22 Electric Utility Resource Planning rules in the 1990s and

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[26] Page 23.
[27] At that time, DR programs were referred to as load management programs.
[28] One of the first programs I reviewed was a Kansas City Power & Light Company program. In the late 1970's KCPL installed devices on customers' air conditioners so that it could reduce these customers' loads if it needed capacity. While the technology was different in the 1970s, the goal of this early program was the same as Evergy's current DR programs.

the revision of the rules in the early 2000s. I was responsible for Staff's review of many of the utility's filings to meet the Demand-Side Resource Analysis rule in Chapter 22.

Evergy Acted Imprudently When It Included Capacity Sales in Its Resource Planning Process

Q. Staff witness Fortson, in his rebuttal testimony, recommends that Evergy resource plan assumptions be reviewed and addressed in Evergy's resource planning process.[29] Is there a process for "addressing" such an issue in the resource planning process?

A. No, there is not. Because there is nothing specific in Chapter 22 regarding the inclusion or exclusion of capacity sales, Evergy cannot be found deficient in its resource planning process for including the sale of excess capacity in its resource planning process. Since Chapter 22 is about the resource planning process and not the implementation of a plan, there is no mechanism set by the rule for finding of imprudence regarding the implementation of Evergy's resource plan. This is left for other cases such as this FAC prudence case.

Q. Evergy witness Carlson provides testimony regarding Evergy's efforts to enter into capacity sales contracts. Why should the Commission find Evergy imprudent in this FAC prudence case for capacity sales that both you and Evergy agree did not exist?

A. The existence of a FAC allows Evergy to include assumptions in its resource planning process that impact customers' bills but have little to no negative impact on Evergy. One of these assumptions that Evergy has included in its resource planning is the sale of excess capacity. When these sales are included in the

[29] Page 5.

modeling, the resulting amount of “excess capacity” is lower therefore making the addition of more capacity look more reasonable.

Q. Evergy witness Kayla Messamore provides schedules to her rebuttal testimony showing that removing short-term capacity sales would not have changed the choice of the preferred resource plan.[30] Does this change your position?

A. No. The inclusion of capacity sales in every plan modeled was a deliberate choice by Evergy. It is not an assumption based on reality and did not change with the resources included in the plan. Ms. Messamore merely shows that taking the exact same capacity sales out of each of the plans modeled does not change the rankings of the plan. The Commissions should know that the models do not optimize the resources to find the best fit. The models merely calculate the expected present value revenue requirement (“PVRR”) given the assumptions input by the modeler.

The FAC enables a utility to make assumptions in its resource planning process that places 95% of the risk on the customers. In the absence of its FAC, there would be an incentive for Evergy to enter into short-term capacity contracts between rate cases because the revenues from these contracts would increase Evergy’s earnings as the revenue was not included when rates were initially set. Putting short-term sales when there was no expectation of being able to enter into an actual contract in a resource planning model without a FAC would estimate a financial situation for Evergy that could not be achieved. Because this could impact financial ratings of the utility if it was found to consistently earn below what was shown in its resource plans, a reasonable person would not include these sales in its resource planning modeling absent an FAC.

Because Evergy has a FAC, there seems to be no concern from Evergy with assumptions that impact the customers’ financials. Commission oversight is the only mechanism to reduce the risk on the customers of imprudent assumptions

[30] Page 3.

being included in Evergy's resource planning modeling. It is the Commission's role to make sure that only costs of prudent decisions that adequately balance the interests of the customers and the utility be recovered from customers.

Conclusion

Q. Would you summarize this testimony?

A. Evergy did not fully utilize the DR program resources available to it. This resulted in a minimal amount of forgone benefit to Evergy and a much larger forgone benefit to its customers. Evergy should be held accountable for the imprudence of its failure to utilize these DR programs by having the benefits that could have been achieved imputed to it. The Company's attempted justification that "it would be difficult" to fully utilize its DR programs should be unacceptable to the Commission. It is difficult to build power plants, it is difficult to participate in SPP, and it is difficult to bill customers, yet Evergy has still managed to accomplish all of these. Evergy could easily have reduced the costs imposed by customers through the FAC by calling more demand response program events, it simply chose not to.

Evergy also knowingly included inputs in its resource planning process that would not occur. These inputs resulted in the models showing a lower PVRR than could be achieved by the customers while not changing the financials of the utility.

Both the inaction and actions of Evergy were influenced by the FAC. It knew that it would only retain 5% of the benefits from fully utilizing the DR programs. It also knew that it would have only retained 5% of any revenue from capacity sales so including them in the resource planning process mostly impacted the forecast of the customer bill, not Evergy's earnings.

I believe the legislature realized that an FAC would change the incentives for the utilities because it requires a prudence review at least every 18 months. It also requires the return of imprudently incurred costs to the customers. Because the customers have no say in these decisions yet assume all of the risks, the customers rely on the Commission for protection from inefficient decisions of the utility.

The Commission should find that Evergy was imprudent in not fully utilizing its DR programs to minimize energy costs within the parameters of the fully implemented programs and return to the customers a measure of what should have been saved.

The Commission should further find that Evergy was imprudent in its resource planning process when it included assumptions that it knew were false resulting in estimates of customer bills that could not be achieved and order Evergy to return to its customers a measure of what would have been earned had Evergy's inputs been true. At a minimum, the Commission should order Evergy to not include capacity sales in future resource planning analysis unless Evergy has a contract in hand. The resource planning process becomes a costly, time-consuming sham if there are no consequences to Evergy for using assumptions in the process that it knows are unrealistic.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Exhibit:
Witness: Various
Type of Exhibit: Surrebuttal Report
Sponsoring Party: Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company
Case No. EO-2019-0132 / 0133
Date Testimony Prepared: September 16, 2019

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: EO-2019-0132 / 0133

SURREBUTTAL REPORT

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY and
KCP&L GREATER MISSOURI OPERATIONS COMPANY

Kansas City, Missouri
September 2019

TABLE OF CONTENTS

I. INTRODUCTION

In 2009, the Missouri General Assembly enacted the Missouri Energy Efficiency Investment Act ("MEEIA"). While many states have mandatory energy efficiency targets that regulated utilities must meet, MEEIA is voluntary. Instead, utilities are motivated to participate in MEEIA because the statute authorizes a cost-recovery structure that allows utilities to value efficiency equal to investments in traditional resources. The MEEIA statute provides:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs.
>
> In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
>
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
>
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.

20 CSR 4240-20.092 through 20 CSR 4240-20.094 provide detailed rules for the Commission, Commission Staff ("Staff") and utilities to adhere in the development, implementation, and regulation of demand side management ("DSM") programs. Additionally, Chapter 22, Electric Utility Resource Planning (specifically 20 CSR 4240-22.050) also provides rules for DSM programs to adhere. Chapter 22 specifies the principles by which potential demand-side resource options shall be developed and analyzed for cost effectiveness, with the goal of achieving all cost-effective demand-side savings.

Kansas City Power & Light Company ("KCP&L") and KCP&L Greater Missouri Operations ("GMO"), (collectively the "Company"), believe that Staff has taken a contrary position to previous interpretations of MEEIA statutory language, Commission rules and prior Commission orders, which presents a significant departure from the successful past of MEEIA programs in the state.

In addition to Company witness Charles Caisley's testimony, the Report herein is the Company's surrebuttal and addresses Staff, Office of Public Counsel ("OPC"), Division of Energy ("DE"), National Housing Trust ("NHT"), Renew Missouri, and National Resources Defense Council ("NRDC") findings and recommendations submitted as rebuttal. The Company refutes many of the recommendations made by parties and recommend that the Commission approve the Company's application as filed with minor adjustments that are described herein.

Company Expert/Witness: *Darrin R. Ives*

II. STAFF AND OPC ANALYSIS

A. Customer Perspective and Utilization of Customer Feedback

In this section, the Company will contest Staff witness Tammy Huber's statement that "KCPL/GMO has not demonstrated that proposed demand-side programs are beneficial to all of its customers or even preferred by its customers."[1] To the contrary, the Company has provided significant evidence in its direct filing with respect to both customer experience and its customer sentiments towards demand-side management programs through research and third-party evaluations.

[1] Staff Report, p. 5, Lines 18-19.

i. Supporting evidence that KCP&L customers prefer, benefit and are satisfied with DSM programs

The Company has over a 10-year history in developing, implementing and providing successful DSM programs to its customers. The Company began offering DSM programs to its customers following approval of 12 programs as part of its Comprehensive Energy Plan ("CEP")[2] in 2005. The Company invested nearly $93.5 million and achieved 159 MW in capacity reduction and over 268 GWh energy savings during the CEP. It was during this time that the MEEIA was pursued by the electric utilities. Following the legislative approval of MEEIA in 2009 and the rule development, the Company filed and the Commission approved a 36-month portfolio in GMO in 2012 and then an 18-month portfolio in KCP&L-MO ("Cycle 1"). Customers responded very favorably to the portfolio of programs and the Company successfully executed programs with demonstrated savings and capacity reduction. During Cycle 1, the Company invested $107 million and achieved 122 MW in capacity reduction and over 403 GWh energy savings. It was also during this Cycle 1 that the Company developed the first demand response programs in the state and offered an energy efficiency portfolio that met diverse customer needs. The Company exceeded its MEEIA Cycle 1 goals by 152 percent.[3]

It was evident from the Company's Cycle 1 success that customers wanted energy efficiency to help them save energy and money. The Company filed a second, successive portfolio ("Cycle 2") in both GMO and KCP&L-MO territories and the Commission approved a 36-month Cycle 2 portfolio in 2016. Cycle 2 has demonstrated continued

[2] Stipulation and Agreement in Case No. EO-2005-0329 (0329 S&A).
[3] Total based on ex ante annual energy savings achieved to filed totals for KCP&L and GMO.

success with customers to date, as well as developing innovative programs that are leading in the industry. The Company has received national recognition for its implementation of DSM programs including:

- Peak Load Management Alliance (PLMA) 2016 – Thought Leadership Award;
- Smart Thermostats: The Killer DER, Tendril Networks, Melanson, 2017;
- DistribuTECH 2018 Project of the Year for Demand Response/Energy Efficiency;
- PMLA Thought Leaders Award - KCP&L Thermostat Program & Marketing;
- SEPA's Change Agents of the Year - KCP&L Thermostat Program & Marketing;
- Public Relations Society of America PRIZIM Award - KCP&L Nest Promotion Email Campaign; and
- IBAC Regional Connect17 Conference – Silver Quills - Marketing and Advertising - KCP&L Rebate Hunter

During the 36-month period, the Company invested $93 million with its customers and achieved 158 MW in capacity reduction and 386 GWh in energy savings.

With each successive portfolio filing, the Company has evolved and enhanced its programs such that all customers may save money and energy. Programs are designed so that all customers can participate in some manner – whether they are low income, single family homeowners, multifamily dwellers, elderly or small to large businesses.

It is evident from the continued participation in the Company's programs that these programs are wanted and preferred by customers. Staff witness Huber provides testimony that the Company "has not demonstrated that proposed demand-side programs are beneficial to all of its customers or even preferred by its customers."[4] She addresses the important elements of measuring customer experience, such as fast feedback surveys,

[4] Staff Report p. 5.

customer journey maps, and other aspects of the Evaluation, Measurement, and Verification ("EM&V") process as a means to further understand customer experience. This is something the Company has been doing and are already part of the ongoing process evaluation of an EM&V, which the Company, Staff, Staff's auditor and stakeholders collaborate extensively. The annual EM&V is a key element in understanding how to improve and offer our programs – both from a process and impact evaluation perspective. The Company has completed an EM&V annually for the past six years and recommendations from the EM&V process have been implemented by the Company and continue to enhance its offerings to customers.

The process evaluation of the EM&V is meant to provide feedback to the utility to improve upon the customer experience. Additionally, the process evaluation documents program design and operations to provide the Company with actionable recommendations to improve its program processes. It includes recommendations about program design, program targeting, improving customer and trade ally satisfaction, reducing barriers to participation, and alternative promotion strategies[5]. Staff does not conclude that the Company is not executing on any of the elements of customer experience. Staff's testimony is simply statements of elements of an EM&V and reiterates work that the Company is already doing to improve the overall customer experience.

Within the process evaluation, the Company has utilized journey mapping research to better align program design with customer experience marketing. Journey mapping each program allows the Company to better understand where customers and trade allies like to

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[5] Navigant Report Summary, KCPL and GMO EM&V 2018, Program Year.

be engaged, when and how often they like to be communicated with and how each program meets those needs. Leveraging measure data analytics with the right marketing message at the right point along the journey not only lowers the program and portfolios cost of acquisition benefiting all customers, but creates a participating customer who has a propensity to either: (a) repeat the program journey again, (b) continue the journey with another program or service, (c) inform other customers or a combination of the three.

Creating a simplified journey in tune with customer needs, which the Company has demonstrated and continues to refine, results in a sales force multiplier effect that generates a broader base of customer participants at a reduced cost to serve.

Staff did not offer any such documentation in their testimony that customers do not prefer the Company's DSM portfolio of programs, or that the programs are not beneficial to customers. On the other hand, the Company provided a 164-page document as Appendix 8.8 titled "Customer Research" in its filing. This customer research was used as a foundational element in preparation of the Company's Cycle 3 portfolio. This of course was not the only means of feedback from customers or others. In the Company's due diligence to provide a program portfolio that was wanted by its customers, input was sought from several groups[6], including business customers, online residential panel, trade ally businesses, multi-family interest groups, program design consultants, program implementers, environmental focused stakeholders, income-eligible focused stakeholders, Company leadership, and the DSM Advisory Group (which Staff and OPC are key

[6] Company's direct filing, p. 29.

stakeholders). Offering any product to customers is an ever-evolving process and products are not developed in a vacuum.

Staff has also not provided evidence that the Company is not reaching all customers in its outreach, education and marketing capabilities. In fact, they imply the opposite. Ms. Huber recommends that we ***continue*** to educate customers of ***all*** income levels [emphasis added]. She does not point out in her testimony that the Company is missing any segment or type of customer in its education and marketing.

A common theme throughout Staff's comments is captured on page 12 of their testimony, "Utilities should increase customer awareness of existing energy efficiency programs. Increasing customer awareness and helping customers feel like they have more control over their utility bills would help to increase customer satisfaction."[7]

Home Energy Reports ("HER") and the Home Energy Analyzer (online portal for residential customers) accomplish Staff's objectives. Both programs were approved by the Commission in Cycle 1 and Cycle 2 and the Company has partnered with Oracle/OPower for the delivery of the programs. In the last publicly available evaluation (for the 2017 program year), Navigant[8] conducted its own process evaluation and reviewed the results of Oracle's customer engagement survey (Customer Engagement Tracker ("CET")). Navigant confirmed that "most customers (81%) read the report and 27% report taking an energy-saving action." Of "CET respondents who recall the reports, 72% like the reports and 61% talk to other people about the reports." Ultimately, Navigant found that HERs

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[7] Staff Report.
[8] Navigant is the Company's independent evaluator.

increase customer satisfaction and "KCP&L should continue providing reports and encouraging customers to log into the Online Energy Analyzer to help customers understand how to manage their energy use" and "reports have a positive impact on customer satisfaction."[9] Staff or Staff's Auditor did not contest these conclusions by Navigant.

The positive impact of DSM programs on customer satisfaction is further supported by the Company's most recent CET as seen in the **Exhibit A**. The survey was conducted by Oracle and was completed in January 2019, after the Company's November 2018 filing.

Company Expert/Witness: Brian File

ii. Absence of DSM programs

If the Commission were to reject the Company's DSM programs as Staff and OPC recommend, customers, the region, and the state would suffer. Customers would no longer have the programs that are offered today to save on energy and reduce their bill. Programs are offered in such a manner to provide all customers an opportunity to participate.

For example, as discussed in the previous section, residential customers have the ability to understand how they can reduce energy in their home through the Company's online energy portal, Home Energy Analyzer. To date, the Company has had over 164,000 customers interact with its online energy portal. As technology has improved, customers continue to engage with our online energy portal in new ways. The Company improved upon its portal in June 2019, which drove an approximately 20,000 additional customers to the online portal. Additionally, over 225,000 Missouri customers receive a HER that

[9] GMO Evaluation, Measurement, and Verification Report – FINAL. Navigant Consulting, Inc. December 21, 2018.

further guides them in using energy and how they measure against their neighbor. The HER program has repeatedly shown that customers save 1 to 2 percent annually. Additionally, the Company's programmable thermostat program provides not only energy savings to those customers who have it on their wall, but it also is a key piece in the portfolio's demand response strategy. The Company currently has over 35,000 thermostats across its jurisdictions in Missouri – the majority of which are smart thermostats. The Company also implemented a Distributed Energy Management System ("DERMS") platform and used it for the first time this summer to better communicate with customers in demand response events. The DERMs will also poise the Company for the future for other progressive uses. The Company's MEEIA business programs have touched over 6,000 customers. For example, the Company has collaborated with the City of Kansas City, Missouri and has lowered usage in city buildings by 4 percent.

Having no DSM programs or a significantly lower level of DSM programs would also likely result in the elimination or lowering of non-energy benefits. The Company discussed the value of economic development and environmental benefits that are expected to result from its direct filing, as well as those benefits that have resulted from prior implementation of DSM programs[10]. Additionally, the Company has proposed to continue its partnership with Spire on the delivery of its Income Eligible Multi-Family and its Heating, Cooling and Weatherization programs. It would be logical to expect that there would be negative effects to customers if this joint delivery did not continue as it would

[10] Company Direct Filing, MEEIA Cycle 3 2019–2022 Filing Report, Section 2.2.2, Economic Impact.

impact Spire's ability to implement programs that result in the elimination or significant reduction of non-electric consumption.

Company Expert/Witness: *Brian File*

B. Avoided Costs

In this section, the Company supports its filed avoided costs based on Missouri law and rule definitions. Specifically, this section will outline how viewing avoided costs over the long term avoids a "Cycle of Denial" for DSM. The Company also highlights the support provided in its most recent Integrated Resource Plan ("IRP") demonstrating that DSM is the best investment for minimizing revenue requirement. Lastly, the Company will address Staff's assessment of alternate values of capacity through market based Request for Proposal ("RFP") responses as well as Southwest Power Pool ("SPP") fees as cost avoidance.

i. MEEIA does not require that capacity additions must be avoided

Staff errs in applying the requirements of 20 CSR 4240-20.092 (1)(C) to assert that "[c]ontrary to the rule requirement, KCPL/GMO is not substituting demand-side programs for existing and new supply-side resources to meet its current capacity needs."[11] The MEEIA statute[12] has no requirement to defer capacity. For the same reasons, Staff's Deficiency 2 and Concern B[13] in the 2018 triennial IRP are based on an incorrect interpretation of the MEEIA statute.

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[11] Staff Report, p. 19 lns 1-2.
[12] 393.1075.4 RSMo. 2014.
[13] 2018 Triennial IRP cases EO-2018-0268 and EO-2018-0269.

However, the Company's DSM programs are substituting for **existing** supply-side resources. The substitution for an existing supply-side resource occurs instantaneously and simultaneously when a demand-side measure is implemented. Every kWh of energy saved though a demand-side measure is offsetting (i.e. "substituting") a kWh that would have otherwise been generated by a supply-side resource. The MEEIA statute does **not** require that a supply-side resource be retired or removed from service.

Company Expert/Witness: Tim Nelson

ii. Company's selection of the avoided cost of a CT is appropriate

In the Application section 5.1, the Company points out that a combustion turbine is used as the avoided capacity cost to best represent the MEEIA policy directive and IRP rules to value demand-side and supply-side investments equally. The Company views the terms from the statute "traditional supply side resource investments" to mean those that are putting "steel in the ground" such as a Combustion Turbine ("CT"). The value chosen for the MEEIA Cycle 3 application is the estimated levelized cost of a CT in the Company's footprint.

As another supporting point to using the levelized cost of a CT, note that even the Southwest Power Pool ("SPP") uses the avoided cost of a CT for the value of capacity. The SPP penalty for being short capacity is based on a multiple (125%, 150% or 200% depending on the actual SPP reserve margin) of the Cost of New Entry ("CONE"), which represents the levelized cost of a new combustion turbine.

Staff asserts that CONE is not an appropriate method to value avoided cost unless the Company has a shortfall in capacity[14]. But in doing so, Staff falls into the Cycle of Denial as described in the next section.

Company Expert/Witness: Tim Nelson

iii. Investing in DSM for the long-term avoids "Cycle of Denial"

Staff asserts that the avoided cost should be zero for all years except for 2032.

> Therefore, KCPL/GMO should have assumed an avoided capacity cost equal to zero dollars in years 2019 through 2031, the estimated market cost of capacity to serve the capacity deficit in 2032, and zero dollars from that point on for the MEEIA Cycle 3 program evaluation.[15]

Staff's avoided capacity cost assumption vastly understates the value of the Company's proposed DSM programs and makes multiple errors in this single statement.

The avoided cost of capacity is normally represented by a price in dollars per kW-year ($/kW-yr) which is a levelized fixed charge cost of capacity for one unit of capacity (one kW) for a single year over the life of the resource. Using one single year's price is not equivalent to a supply-side resource because the supply-side resource does not have a one-year life.

Staff's position that the Company should have assumed a single year's value for avoided capacity cost violates MEEIA (Section 393.1075.3), which requires valuing demand-side investments equal to supply-side investments. The Company cannot build a supply-side resource such as a CT, operate it for one year, and then unbuild the CT and get

[14] Staff Report p. 20.
[15] Staff Report p. 20 ln 20 – p. 21 ln 3.

a refund. A single year's value of avoided capacity cost is not equivalent to investing in supply-side infrastructure because physical infrastructure cannot be used in that way.

Additionally, Staff did not apply their flawed logic in a consistent manner. Staff says that the avoided capacity cost should return to zero in 2033[16] because the Company might build a CT in 2033 ignoring the fact that this supply-side resource does not currently exist. So now Staff is imputing non-existent supply-side resources into the determination as to whether or not the Company will need demand-side resources.

With this argument Staff falls into the trap dubbed the "Cycle of Denial"[17] by Tim Woolf of Synapse. The Cycle of Denial illustrates how Staff's way of thinking will prevent DSM programs from ever happening.

The Cycle of Denial works like this: 1) the Company is not currently short capacity and will not need new capacity for several years, therefore DSM programs are not needed; 2) sometime in the future a capacity need will arise; 3) at this point it is too late to implement new demand-side programs in time to meet the capacity need; 4) thus a new supply-side resource is constructed to meet the capacity need; 5) after the supply-side resource is constructed there is no longer a capacity need and demand-side programs are again not needed.

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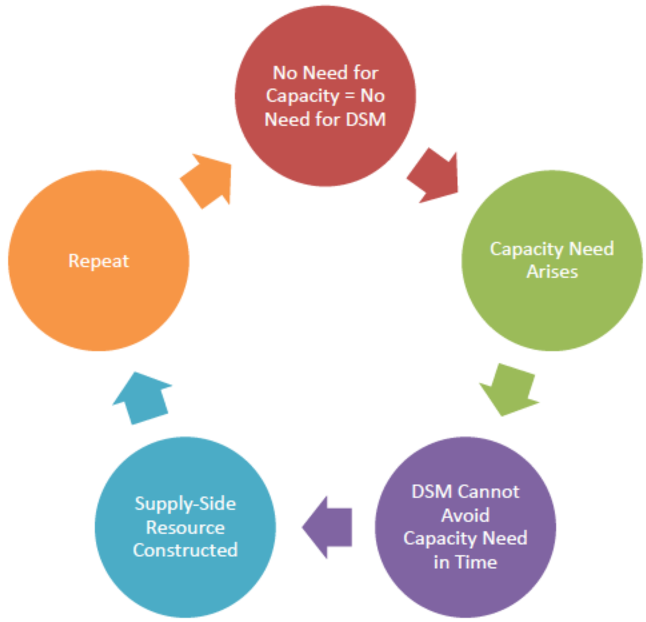
[16] Staff Report, pp. 20-21.

[17] https://aceee.org/sites/default/files/pdf/conferences/eer/2015/Tim_Woolf_Session4B_EER15_9.22.15.pdf

Figure 1 Cycle of Denial



Company Expert/Witness: *Tim Nelson*

iv. IRP shows that DSM is lowest cost to customers and is independent of the avoided capacity cost used in screening

While Staff expresses concern over the Company's use of the levelized cost of a CT for avoided capacity costs, it is important to remember that the primary test of DSM cost-effectiveness is based on the impact on long-term revenue requirements. 20 CSR 4240-22.010 states in part:

> (2) The fundamental objective of the resource planning process at electric utilities shall be to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The fundamental objective requires that the utility shall—
>
> (A) Consider and analyze demand-side resources, renewable energy, and supply-side resources on an equivalent basis, subject to compliance with all legal mandates that may affect the selection of utility electric energy resources, in the resource planning process;

> (B) **Use minimization of the present worth of long-run utility costs as the primary selection criterion** in choosing the preferred resource plan, subject to the constraints in subsection (2)(C); and [Emphasis added]

As part of the 2018 IRP integrated analysis, the Company evaluated several alternative resource plans ("ARPs") that varied the amount of DSM to be implemented. ARPs included the maximum achievable potential ("MAP"), realistic achievable potential ("RAP"), reduced RAP levels, and no additional DSM beyond completing Cycle 2. Results demonstrated that plans at the reduced RAP level, which is consistent with the Company's Cycle 3 filing, resulted in the lowest 20-year net present value of revenue requirements ("NPVRR"). The following table shows the reduction in NPVRR at various DSM levels. Consistent with prior IRP evaluations, in most cases DSM programs reduce long-term revenue requirements.

Figure 2 – IRP NPVRR Savings[18]

Utility	DSM Level	NPVRR Savings (Cost) Compared to no DSM ($ million)
KCP&L	RAP -	$55
KCP&L	Modified RAP	$52
KCP&L	RAP	$37
KCP&L	MAP	($64)
GMO	RAP-	$103
GMO	RAP	$84
GMO	MAP	$3

Note that the NPVRR calculations are based on the total projected costs to serve retail customers and are not impacted by the avoided capacity costs used in the screening process of the DSM potential study. For a given set of DSM programs, the NPVRR results

[18] Calculated from 2018 IRP scenarios.

would be the same whether the avoided capacity cost assumption was $0 or the levelized cost of a combustion turbine.

If the Commission feels that an additional approach to evaluating DSM potential study inputs into the IRP process, the Company understands that Ameren will undertake a new process to analyze alternative resource plans in the future as evidenced in the recent Stipulation and Agreement in Case EO-2018-0211[19]. The Company is amenable to further discussions on how to approach a "dynamically optimized portfolio" for future proceedings.

Company Expert/Witness: Burton Crawford

v. Potential revenues through capacity sales

The Company acknowledges that on a total Company basis, it is currently long capacity. In fact, it should also be noted that the Company's current capacity position is similar to what it has been for the previous two cycles in that the KCP&L/GMO system is long capacity. The Company's programs in these previous cycles were supported by Staff and approved by the Commission. Even though Staff now takes a different position from what it has supported in the past, Staff recognizes there are still ways to identify benefits to customers through other means such as capacity markets or bilateral contracts. While Staff "recognizes that when a utility is long capacity, there are ways to derive potential revenues through bilateral contracts"[20], they recommend a $0 avoided capacity cost value. A $0 value for avoided capacity cost is not appropriate even if the Company is currently

[19] Section 7 Integrated Resource Plan (p. 5).
[20] Staff Report, p. 26, lns. 4-5.

long capacity. If DSM programs are to be viewed on an equivalent basis as generation, a long-term perspective is warranted. At a minimum, the avoided cost value should reflect the market for capacity. Per the IRP rules concerning DSM evaluation in 20 CSR 4240-22.050(5)(A)1 which reads in part:

> 1. The utility avoided demand cost shall include the capacity cost of generation, transmission, and distribution facilities adjusted to reflect reliability reserve margins and capacity losses on the transmission and distribution system **or the corresponding market-based equivalent of those costs**. [Emphasis added]

The rule allows that either the cost of generation or a market-based approach can be used to determine the avoided capacity cost. Staff points out that Ameren Missouri is a member of MISO which has a transparent capacity market unlike SPP.[21] But in fact, Ameren is using a market-based approach[22] to calculate their avoided capacity cost - not the MISO market capacity clearing price. Ameren uses the MIDAS model to estimate the avoided capacity prices.[23] Therefore, the presence or absence of a traded capacity market (i.e. MISO) does not make one utility (in MISO) different from another utility (in SPP) if both are using a market-based approach to calculate avoided capacity costs. One way that the Company could view a market-based approach is bilateral contracts as identified by Staff[24] and discussed further below.

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[21] Staff Report, p. 26.

[22] EO-2018-0211 – Surrebuttal Testimony of Matt Michels, pg. 5, "Q. How long has Ameren Missouri been using a market-based approach to estimate its avoided capacity costs? A. Since no later than 2010 for its 2011 IRP filing…."

[23] EO-2018-0211 – Surrebuttal Testimony of Matt Michels, pg. 5, "To estimate the price of the capacity that is purchased, **the Company uses Ventyx's MIDAS model** to simulate the addition retirement, and dispatch of resources in the market and **determine market clearing prices for both energy and capacity** for a number of scenarios defined by a range of values for key driver variables." [Emphasis added]

[24] Staff Report, p. 26.

In late 2017 GMO issued a Request for Proposal ("RFP") for generating capacity. The responses to this RFP provide an indication of near-term capacity values in the area. It is important to understand that capacity market values vary based on factors such as the capacity contract term (i.e., length of time) and any associated energy pricing. In general, the longer the contract term and the lower any associated energy pricing, the higher the capacity price.

Given the Company's intended long-term commitment to DSM programs, when looking at a market-based approach to valuing capacity, it is appropriate to look at longer-term offers. GMO received seven offers to supply capacity with terms ranging from 4 to 10 years. The average monthly capacity cost over the contract terms varied from **[redacted]**/kW-month to **[redacted]**/kW-month with an overall average of **[redacted]**/kW-month (equal to **[redacted]**/kW-year). Note these supply offers, with a maximum term of 10 years, are short by comparison to physical generation assets that can have lives of 30+ years.

While the Company used the value of a CT in its initial filing, if the Commission preferred the market-based approach to determining avoided capacity cost values, using the **[redacted]** value to screen the Company's proposed MEEIA programs would still result in all but one of the programs being cost effective[25]. Note this does not include any provisions for avoided transmission and distribution costs.

[25] While the Company's calculation shows that Business Thermostat program is not cost effective at the alternative avoided capacity cost level, we would be willing to make program modifications to address the cost effectiveness (including but not limited to installation method changes, device types and volume requirements).

While the Company would not want to sell all excess capacity down to the minimum needed to meet its SPP reserve margin, obligations as uncertainty in load forecasts and generation availability drive the necessity to keep some level of capacity in reserve. In other words, it is necessary to maintain a “cushion” to prevent an unintended drop below the margin requirement. Over time as the Company’s DSM portfolio grows, there would be increased opportunities to sell capacity should the Company have excess available for sale.

Company Expert/Witness: *Burton Crawford*

vi. Calculation of net benefits

Staff took issue with the Company’s discounting method for calculating net benefits[26]. Staff disagreed with the Company’s discounting the benefits and costs to each individual program year. Staff argued that the benefits and costs should be discounted to the first program year of Cycle 3. The Company maintains that the individual program year makes more sense for a couple of reasons.

First, the budgets and targets are developed for each program year in nominal dollars and not discounted to the first year. Programs are also tracked in program year dollars not first year dollars. Second, it makes little sense to discount the net benefits of a measure to a year prior to the installation of that measure. Furthermore, the Company’s discounting method is consistent to the method used in MEEIA Cycle 2. Finally, as this section in Staff’s report was titled “Overall Portfolio Cost Effectiveness”, it must be pointed out that when calculating the cost effectiveness ratios, **it does not matter what**

[26] Staff Report, p. 31.

year the dollars are discounted to, as long as ALL benefits and costs are discounted to the SAME year.

Unfortunately, in recalculating Staff's version of Cycle 3 net benefits[27], Staff did not follow its own guidance to discount all benefits and costs to 2019 dollars. In fact, Staff made multiple errors in discounting the Earnings Opportunity ("EO") costs in Staff's Estimate of Cycle 3 Net Benefits.

First, Staff incorrectly assumed that the EO dollars would be recovered in the program year. But EO dollars are not actually recovered until much later, after EM&V net benefits are confirmed. For example, EO earned for program year 2019 would not be recovered until 2021.

In Staff's second error, Staff discounted the EO to the wrong year. Rather than 2019, Staff discounted the EO to 2018.

Third, the Company's avoided energy benefits calculation varied slightly from Staff's. Staff's avoided energy benefits calculation for GMO and KCP&L did not include all years of benefits. Plus, for KCP&L, the Company was also not able to reconcile some other variances in the avoided energy benefits calculation.

Finally, Staff's calculation of GMO program costs used the KCP&L weighted average cost of capital ("WACC") instead of GMO's WACC. This resulted in only a minor difference of $554.

[27] Staff Report, p. 32 second table.

While the Company maintains that discounting net benefits to the program year is appropriate, below is a restated table showing the net benefits based on the Company's application for Cycle 3, discounted to 2019, and including the EO Costs.

Figure 3

Company MEEIA Cycle 3 Application Net Benefits
(All Dollars Discounted to 2019)

		KCP&L	GMO	KCP&L/GMO
a	Energy Benefits	$ 50,025,561	$ 47,391,939	$ 97,417,500
b	Capacity Benefits	$ 59,893,989	$ 74,457,378	$134,351,367
c = a + b	Total Benefits	$109,919,550	$121,849,317	$231,768,868
d	Program Costs	$ 39,759,797	$ 47,808,936	$ 87,568,733
e	EO Costs	$ 6,443,213	$ 8,225,221	$ 14,668,435
f = d + e	Total Costs	$ 46,203,010	$ 56,034,157	$102,237,168
g = c - f	Net Benefits	$ 63,716,540	$ 65,815,160	$129,531,700

Revised: Avoided Capacity Cost = Original filing value of **[redacted]**

If the Commission preferred the market-based approach described by Company witness Crawford to determining avoided capacity prices, from Section II.B.v. that utilizes an avoided capacity value of **[redacted]**, the net benefits would be $66,850,519. The results of this calculation are shown in the table below (also discounted to 2019). This market-based value would result in the Company's proposed programs still passing except for one.[28]

[28] See FN 24.

Figure 4

	Company MEEIA Cycle 3 Application Net Benefits (All Dollars Discounted to 2019)			
		KCP&L	GMO	KCP&L/GMO
a	Energy Benefits	$50,025,561	$47,391,939	$ 97,417,500
b	Capacity Benefits	$31,702,982	$39,967,205	$ 71,670,187
c = a + b	Total Benefits	$81,728,543	$87,359,144	$169,087,687
d	Program Costs	$39,759,797	$47,808,936	$ 87,568,733
e	EO Costs	$ 6,443,213	$ 8,225,221	$ 14,668,435
f = d + e	Total Costs	$46,203,010	$56,034,157	$102,237,168
g = c - f	Net Benefits	$35,525,533	$31,324,986	$ 66,850,519
Revised:	*Avoided Capacity Cost = GMO RFP bids of **[redacted]** no inflation for first 8 years*			

Company Expert/Witness: *Tim Nelson*

vii. Additional DSM value from SPP fee avoidance

Staff witness Luebbert introduces SPP member costs as a source of potential cost avoidance. The Company agrees that SPP member fees for Schedule 11, Schedule 12 and SPP administrative fees, Schedule 1-A, could be reduced through reductions in energy and demand. In simplified terms, the SPP transmission fees, Schedule 11, are allocated among applicable utilities on a load-ratio-share basis, which is calculated using average monthly MW peaks. Similarly, Schedule 1-A is determined and impacted by monthly MW demand. Schedule 12 fees are based on energy usage. Therefore, by reducing the average monthly MW demand and energy, the Company could reduce the amount of SPP transmission and administrative fees.

Company Expert/Witness: *Burton Crawford*

The Company's Cycle 3 proposal has two potential ways to minimize the monthly peaks, thereby reducing the SPP fees as discussed above. First, the energy efficiency measures in the Company's proposal already include demand reductions that will drive the

SPP savings. Second, the demand response programs could be altered slightly to call events monthly to capture additional monthly peak reduction value.

First, with the Cycle 3 proposal, reducing the monthly MW demand will occur by the investment in energy efficiency measures that reduce demand during utility peak times (generally 4-6 PM during weekdays). Examples of these measures include residential and commercial heating, ventilating and air conditioning ("HVAC"), "always on" lighting, commercial and industrial refrigeration among others. This demand reduction is calculated by measure and used as the demand targets for the Cycle 3 proposal for a total of 185 MW[29] for the combined Company.

Additionally, the monthly MW demand could be reduced by demand response programs in the June through September curtailment season. The Company has the ability to alter its approach to event calling such that an objective is to minimize monthly peaks. While forecasting peaks (because it is weather driven) is not an exact science, a focus on timely system reporting for loads for the month can improve the potential for better accuracy of reducing the monthly peak. The program rules and expectations with customers would need to be set up differently such that expectations of calls and event impact will be different than in previous program cycles. In prior program cycles, customers would expect hot or sustained hot weather leading up to a demand response event. This may or may not be true in the case of events in June or September based on an attempt to hit the monthly peak. These changes to the approach and customer expectations would be new and include

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[29] Company Application, pp. 16-17.

some effort on the part of the utility and customers but are reasonable to help gain value from this cost avoidance.

As for the quantification of the value, Staff witness Luebbert created Schedule JLR-1 to calculate a dollar amount per year that SPP fees from Schedule 11 and Schedule 12 and Schedule 1-A. While the basic structure of the calculation appears to be valid, the inputs to demand reduction only used the value of the energy efficiency as discussed above for energy efficiency measures (i.e. excluding demand response). The values average $10.32/kW per year over the 2019-2027 timeframe. The addition of savings from the demand response reductions would only increase the savings of SPP member fees.

Company Expert/Witness: *Brian File*

C. Provide Benefits to All Customers (Section 393.1075.4)

The Company's MEEIA Application[30] and information below show that its proposed Cycle 3 programs are beneficial to all customers in a class in which the programs are proposed, regardless of whether the programs are utilized by all customers. This support is in line with the correct interpretation of the statute that all customers in a class must benefit as opposed to Staff's assertion that every individual customer must benefit. The Company presents that the programs are beneficial to all customers in a class in which they are proposed as demonstrated by Figures 4.4 and 4.5 in the Company's Application. Staff's position that the programs are not beneficial tie back to the wrong assumption of avoided cost as discussed at length in Section II.B. This section will highlight how EM&V has continually shown net energy benefits to customers, Cycle 3 programs are designed with all customers in mind and the IRP shows there is a reduction in the NPVRR. In

[30] Company's Direct Filing, Section 2.2, p. 24.

addition, this section will highlight some additional context for topics brought by Staff on energy price benefits, environmental benefits and reduction in SPP fees. Lastly, the Company will comment on the rate design implications of MEEIA now and in the future.

i. EM&V shows savings and benefits to customers

Savings and benefits of MEEIA Cycle 1 and Cycle 2 have been evaluated and verified by a third party and an independent auditor detailing benefits associated with the investment in demand-side programs. Staff contends that "MEEIA Cycle 3 … depends on highly variable and very uncertain purported benefits in later years to justify the programs and those associated costs."[31] The Company has six plus years starting with Cycle 1 in 2013 of demonstrating energy and demand savings. In fact, annual reports from 2013-2018 that are reviewed by all MEEIA stakeholder parties and ultimately approved by the Commission have documented over 1,000 GWH of annual energy savings and 400 MW of demand reduction over the period[32]. While the energy and demand savings achieved have varied year to year, the trend shows a steady reduction annually. So not only are savings and benefits certain as reviewed and approved by multiple independent parties, they also have been steady reduction over the period of six years of MEEIA implementation.

Company Expert/Witness: Brian File

[31] Staff Report, p. 23 lns. 9-11.
[32] Company Application – Figure 2.1 p. 23.

ii. The Company's application is designed for any customer to participate

A demand-side management portfolio is meant to provide options and opportunities for a myriad of customer types and customer classes. With OPC Witness Dr. Marke's recommendation to focus only on demand measures, there will be a gap in offerings that help customers enjoy and participate in programs that can benefit them. In effect, the OPC program recommendation focuses efforts and investments on only a few customer types and eligible measures. This approach is counter to the intent of MEEIA to provide program offerings for **all** MEEIA eligible customers. All customers should have the opportunity to participate, while it is still ultimately the customer's choice to take advantage of those opportunities. The Company must also take the approach to remove as many barriers as possible to participate (partnering with financing institutions[33], having easy rebate processes, communicating through a variety of channels as a few examples). Considering that the Company has and continues to carve out specific amounts of dollars for programs that are targeted to income-eligible customers ($10 million proposed over six years in its Cycle 3 application), the Company is trying to ensure that the most vulnerable can participate and benefit.

Company Expert/Witness: Brian File

iii. MEEIA programs reduce NPVRR in the IRP

Customers as a whole benefit from the Company's Cycle 3 programs. This is achieved because the MEEIA programs will avoid costs as demonstrated by the reduction in long-term revenue requirements whether or not supply-side resources are avoided as

[33] Discussed further in Section II F vii – PAYS – financing.

discussed in Section II.B.iv. The IRP evaluates what the best long-term solution is for customers via the objective to lower NPVRR. The IRP analysis has consistently shown that demand-side management investments lower the net present value of revenue requirements.

Figures 6 and 7[34] of Dr. Marke's testimony do not include the fact that Cycle 3 programs are projected to reduce NPVRR. This should be included in his Figure 7, "Phase 3". This point is true regardless of the need for constructing other supply-side resources as evidenced by the figures showing reduced revenue requirements in the Company's direct filing, Section 8.11.

Company Expert/Witness: Burton Crawford

iv. Energy price benefits flow through the FAC to all customers

Staff claims that there are no DSM program benefits for non-participants. The Company disagrees. Since the Company participates in the SPP markets, all energy used to serve its retail customers is purchased through the SPP energy market. Energy market purchase prices are generally positively correlated with the load in the SPP market. In other words, as the demand for energy increases, so do the energy market prices. Conversely, as demand for energy falls, so do energy market prices.

For example, some types of plants have higher marginal costs than others, such as peaker plants. Energy efficiency, by displacing the energy from power plants with the highest marginal costs, reduces purchased power costs and saves customers money.

[34] Witness Marke rebuttal, p. 20.

Therefore, as DSM programs reduce energy needs, energy market prices are reduced. This in turn reduces the cost of purchased power. Since purchased power costs are one component of the Company's fuel adjustment clause ("FAC"), reductions in purchased power flow back to all retail customers through the FAC. All customers benefit from such a reduction whether they participate in the Company's DSM programs or not.

Company Expert/Witness: *Burton Crawford*

v. Environmental benefits

One of the many benefits of energy efficiency is the environmental benefits. That benefit is available to all those that live in the region whether or not they created the energy reduction. While the avoided costs associated with the environmental benefits are harder to quantify, the Company used a publicly available Environmental Protection Agency ("EPA") tool to estimate the emissions reductions. The energy reduction achieved from the Cycle 3 programs will cause generating units in the region to run less and emit fewer pollutants. The Emissions and Generation Resource Integrated Database[35] provides a calculation tool to estimate emissions for a specific region. The energy savings (343,716 MWh) from the Cycle 3 programs will lead to an estimated annual reduction of 502 Million lbs. of CO_2, 303 Thousand lbs. of NO_x and 324 Thousand lbs. of SO_2.

Company Expert/Witness: *Brian File*

[35] https://www.epa.gov/energy/emissions-generation-resource-integrated-database-egrid

vi. Reduction in SPP fees

The reduction in the SPP-related fees discussed in the avoided cost Section II.B.vii is an additional benefit to all customers as part of MEEIA implementation and generally reflected in base rates.

Company Expert/Witness: Burton Crawford

vii. Rate design implications of DSM programs

While the 2018 IRP analysis clearly shows reductions in long-term revenue requirements, Staff expresses concerns that DSM programs increase average customer rates. Note that energy savings from DSM programs will increase average rates even if the DSM programs have no cost (i.e., free to both the customer and the Company). This is a function of the current retail rate structure. Since the average avoided energy cost from DSM programs is less than the retail customer's energy charge, on average, every kWh of avoided energy results in under-recovery of fixed costs. It is the recovery of these fixed costs that drive the increase in average rates. This seeming anomaly is not caused by the MEEIA program but is due to the current retail rate structure. However, as evidenced by the lower revenue requirement, average customer bills would go down even though average rates went up.

This DSM program impact on average rates is nothing new. Like the Company's proposed Cycle 3 programs, prior MEEIA cycles had a similar effect on average rates. Note that as proposed, the Company's Cycle 3 programs will not have a material impact on average rates as the impact of DSM programs from prior cycles is already included. If the measuring stick is now to be based primarily on average rate impacts (as compared to revenue requirements), utility DSM programs in Missouri will not pass this additional litmus test of rate impacts until retail rates are significantly restructured.

Company Expert/Witness:Darrin R. Ives

D. Demand-Side Programs

In this section, the Company will respond to the testimony from Staff and other parties on specific demand-side programs and associated attributes. The Company will address cost effectiveness of programs, and then the Company will outline how the use of AMI infrastructure will benefit programs and the evaluation of them during Cycle 3. Lastly, the Company will discuss concerns raised by Staff with our Technical Resource Manual ("TRM"). There are additional program responses in Section F.

i. Cost-effectiveness of programs

a. Total Resource Cost ("TRC") results

The Company agrees that 20 CSR 4240-20.094(4)(C) requires that the utility provide a "demonstration of cost-effectiveness for each demand-side program and for the total of all demand-side programs". It requires that the utility include "the total resource cost (TRC) test" (20.094(4)(C)(1)) and that "the commission shall consider the TRC test a preferred cost-effectiveness test" (4240-20.094(4)(I)).

Staff provides significant testimony on Pages 40-42 of its Report regarding cost effectiveness of programs and presents its calculation of the TRC test using their recommended avoided capacity cost of zero. As discussed above, the Company in no way supports Staff's recommendation of an avoided capacity cost of zero.

When using the Company's avoided cost, the Company's proposed portfolio as filed is TRC cost effective as a whole. It is also cost effective at a program level not including income-eligible programs with one exception (HER in KCP&L). That exception is explained in Section II.F.iii.a. As also discussed in Section II.B.v., this portfolio passes when using the alternate market-based avoided cost approach.

Company Expert/Witness: Brian File

b. Program modifications throughout the Cycle

Staff argues that recovery of program costs, throughput disincentive, and earnings opportunity should only be allowed for cost effective programs[36]. Their strict interpretation would disallow all cost recovery for programs that may miss cost effectiveness by a small margin (e.g. a cost-effectiveness ratio of 0.99). The Company does not dispute that programs should be cost-effective; however, the statute does not specify over what period of time cost effectiveness must be measured and in fact the rules contemplate that programs may need to be tweaked to improve its cost effectiveness. The rule states, "[n]othing herein requires utilities to end any demand-side program which is subject to a cost-effectiveness test deemed not cost-effective immediately."[37]

As explained below, the rule explicitly gives the utility an opportunity to "fix" a demand-side program to improve its cost-effectiveness. The rule states that it is a goal of MEEIA's to "achiev[e] all cost-effective demand-side savings"[38], which can be done in concert with a utility's ability to modify its programs.

> (B) **If the TRC calculated for a demand-side program not targeted to low-income customers or a general education campaign is not cost effective, the electric utility shall identify the causes why and present possible demand-side program modifications that could make the demand-side program cost-effective. If analysis of these modified**

[36] Staff Report, p. 43 lns. 15-18.
[37] 20 CSR 4240-20.094(6)(B).
[38] Section 393.1075.4 RsMo 2014.

> **demand-side program designs suggests that none would be cost effective, the demand-side program may be discontinued.** In this case, the utility shall describe how it intends to end the demand-side program and how it intends to achieve the energy and demand savings initially estimated for the discontinued demand-side program. **Nothing herein requires utilities to end any demand-side program which is subject to a cost-effectiveness test deemed not cost-effective immediately.** Utilities proposal for any discontinuation of a demand-side program should consider, but not be limited to: the potential impact on the market for energy efficiency services in its territory; the potential impact to vendors and the utilities relationship with vendors; the potential disruption to the market and to customer outreach efforts from immediate starting and stopping of demand-side programs; and whether the long term prospects indicate that continued pursuit of a demand-side program will result in a long-term cost-effective benefit to ratepayers.[39] [Emphasis added]

Under Staff's extreme position, 100 percent of ALL costs would be disallowed even if the program had a TRC ratio of 0.99. A TRC of 0.99 means that the program has $0.99 of benefits for every $1.00 of costs. But Staff's overly strict interpretation is inconsistent with the rule's provision for the utility to make modifications to the program throughout the cycle. The Company would suffer significant harm for reasonably and prudently operating a program that was approved based on a cost-effective design which ultimately proved not to be cost effective as a result any number of factors which may not have been within the Company's control, even if such shortfall were minimal.

Even if all programs were ultimately verified as cost effective, current accounting rules would prevent the Company from recognizing part or all the revenues associated with program cost and throughput disincentive recoveries which are subject to refund until the EM&V report verifying cost effectiveness was complete and approved by the Commission almost a year after such costs were incurred. This would cause a negative impact on

[39] 20 CSR 4240-20.094(6)(B).

Company earnings and value. Staff's hindsight analysis would result in an unacceptable business risk for the Company to undertake.

Company Expert/Witness: Brian File

c. Participant contribution to cost-effectiveness of program

If a program falls below TRC cost effectiveness, there is an additional consideration that Staff ignores. Staff has failed to acknowledge or account for the provision in the statute that allows for non-cost-effective programs if the **participant** is paying for the portion of costs above the level of cost-effectiveness.

> Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose.[40]

Company Expert/Witness: Tim Nelson

d. Inputs on cost effectiveness test for demand response

Staff Witness Luebbert states that incentives as a pass-through cost are inappropriate when there is little, if any, investment necessary to participate in DR programs.[41] The assertion that there is little to no investment for customers to participate in Commercial and Industrial focused DR is incorrect. While the customer costs incurred for BDR are harder to quantify than a capital cost for an energy efficiency measure

[40] Section 393.1075.4 RsMo 2014.
[41] Staff Report, p. 70, l. 2-8.

purchase because they vary widely customer to customer, there are certainly significant customer investments incurred to participate in the BDR program.

The California 2016 Demand Response Protocols[42] specifically describe that participant costs for demand response include the value of service lost and transaction costs in addition to capital costs. Participant costs such as employee time invested in facility evaluations and enrollment, lost product revenue during shut-down, reduced employee productivity, reduced employee comfort, additional wages for altered employee work hours, self-generation fuel cost, etc. are examples of these categories. As a local example, a specific large DRI customer recently reported that participating in a recent event required two hours pre-event preparation to execute their facility shutdown plan as well as preparing to send home 150 employees for the rest of the day. So, when a typical event is scheduled to start early/mid-afternoon, this customer essentially invests half of their business day in order to participate.

Additionally, Mr. Luebbert states that the Company could offer any amount of payment for participation in demand response programs and the program would be TRC cost effective so along as the benefits exceeded administrative costs. He then states that this is not the case for any other program. This is incorrect. First, all programs use the same formulae for cost-effectiveness testing. There is not a different TRC test or different Utility Cost Test ("UCT") test for demand response from other programs. Second, all DSM programs have finite approved budgets that they must operate within. Indicating that "any amount of payment" could be paid is a ridiculous notion. Third, Mr. Luebbert is correct

[42] https://www.cpuc.ca.gov/general.aspx?id=7023

that a DR program would be cost effective so long as benefits exceed administrative costs, which is essentially the definition of the benefit cost ratio being greater or equal to 1. However, every program is considered cost effective if benefits exceed costs, not just DR programs.

Company Expert/Witness: Brian File

e. Use of UCT test

It remains that the MEEIA statute identifies the TRC[43] as the preferred cost effectiveness test for DSM programs, regardless of the kind of program, and does not require that the UCT be used to approve programs. With the avoided costs as filed, the DR programs are designed that the UCT is greater than 1. Additionally, the BDR pay for performance incentive structure provides additional protection to other retail customers by ensuring the participant would not be paid incentives without delivering their demand reduction. While this pay for performance structure was not explicitly detailed in the application, the tariff as filed allows for this program structure.

Staff contends that the UCT should be used for the primary cost-effectiveness test for demand response programs and is consistent with the evaluation methodology proposed by Ameren.[44] Staff makes several observations of the differences between the costs included in the TRC test and the UCT test, but these differences are true for all programs and are not a reason to treat demand response programs differently. Staff's assertion that a

[43] Section 393.1075.4 RSMo. 2014.
[44] Staff Report, p. 70 lns. 20-23.

UCT less than 1.0 conflicts with the Section 39.1075.4 is wrong. This section explicitly says "[t]he commission shall consider the total resource cost test a preferred cost-effectiveness test."[45] It does NOT say, the TRC is preferred **except** when the UCT is lower. There is no rule or statutory requirement that the UCT be above 1.0. The MEEIA rules merely state that the UCT should be **calculated**—"the utility shall also include calculations for the utility cost test,"—but provides no other direction on value or use of the UCT. Upon review of Ameren's workpapers Appendix A, the UCT and TRC are the same value in the Residential Demand Response (RDR) program and the same value in the Business Demand Response (BDR) Program. The results of both tests are presented in the report, but Ameren did not state that it was using the UCT as the preferred test instead of the TRC. In fact, all programs, including energy efficiency programs, are presented this way, not just Demand Response. A review of budget information shows that there are no incentive costs listed for BDR; all costs are delivery and administrative. In that scenario, the UCT and TRC will always be the same.

Company Expert/Witness: *Brian File*

ii. AMI infrastructure

a. AMI will support Cycle 3 programs and evaluation

Advanced metering infrastructure ("AMI") allows the evaluator to efficiently provide the Company with more time-specific and customer-specific demand and energy impacts. AMI data provides a more granular measurement of the magnitude of energy and demand impacts – specifically with respect to *when* these impacts occur. This allows the

[45] Section 393.1075.4 RSMo. 2014.

Company to implement operational improvements to achieve load reductions that coincide with a specific time period (i.e. during the system peak period) in a more cost-effective manner. Further, the data represents actual energy usage that can be provided for *every* customer without having to conduct costly on-site data collection activities. This enables the evaluator to assess the impacts and performance of individual customers within a program providing the Company with the insights necessary to engage with specific customers to improve their performance or to implement program changes that address sub-optimal outcomes.

The Company has worked throughout Cycle 2 in standardizing AMI data management and transfer protocols and will continue to improve upon these processes throughout Cycle 3 to facilitate the use of AMI data in EM&V. When appropriate, the evaluator will calculate program energy and demand impacts through a regression analysis of AMI data.

The Company offers multiple programs that would benefit from billing analyses utilizing AMI data in Cycle 3, including but not limited to:

- Commercial and Industrial Demand Response
- Residential and Small Business Demand Response
- Business Smart Thermostat Program
- Residential Smart Thermostat Program
- Home Energy Report
- Business Custom Incentive

When evaluating demand response programs, the use of econometric matching methods to create control groups using quasi-experimental design, along with the availability of hourly (or sub-hourly) AMI data, has resulted in more robust billing analyses at a lower cost compared to other EM&V methods. Additionally, this approach directly calculates net savings, which eliminates the need for additional data collection associated with free ridership and spillover. The evaluator should consider using billing analysis to calculate savings of the demand response programs, using both AMI and monthly billing data.

Additionally, the evaluation of large commercial and industrial (C&I) projects using standard evaluation practices involves visiting a *sample* of customer locations, installing metering equipment, and retrieval of equipment. Leveraging AMI data to calculate impacts reduces the need for these costly activities and allows the evaluator to include *every* customer's data, therefore making the programs more robust and cost effective. The evaluator should consider evaluating large C&I projects using available AMI data.

The Company recommends exploring the use of calculating savings using AMI data for the programs with the largest savings (effect size) first and recognize that billing analysis is not appropriate for some programs, particularly those for which there may be insufficient data for the pre- and/or post-installation timeframe, where there is a great deal of heterogeneity among customers, or where the participants can't be specifically identified.

b. AMI usage across the behavioral energy management platform

The Company has made significant investments in smart meters and in its behavioral EE programs. More than any other program in the Company's residential MEEIA portfolio, the behavioral program is poised to take advantage of AMI data to engage and benefit residential customers of every income level and in rural and urban geographies. While delivering the benefits of behavioral energy efficiency does not require a smart meter, the availability of AMI data unlocks additional benefits and smarter insights to deliver dynamic and personalized insights to customers.

The Company's behavioral energy efficiency program makes extensive use of AMI data across the entire platform, which is used today to power its Home Energy Reports and Analyzer energy management web tools. Within the home energy reports (print and email), AMI data will be used extensively in the usage graphs, usage and cost analyses based on HVAC appliance disaggregation, and other marketing modules. Web insights, including the data browser (with energy usage and cost by bill, day, and hourly breakdowns), bill projections, energy savings day crediting, rate analysis, green button data, and home energy use disaggregation will all rely on AMI data.

As the Company's behavior program evolves, additional features that utilize AMI data will be offered. These include weekly AMI reports, high usage and high bill alerts, and behavioral demand response.

Company Expert/Witness: *Brian File*

iii. Staff TRM concerns

After review of the Company's Technical Resource Manual ("TRM"), Staff criticized the level of detail regarding the source of the data[46]. While the Company's proposed TRM contained at least the same level of detail as the MEEIA Cycle 2 TRM, Staff expressed a need for additional information. The original source of the TRM was the 2017 Potential Study. The primary updates to the TRM since then have been based on EM&V results. Staff has been involved in both the potential study and the EM&V process.

[46] Staff Report, p. 45.

The MEEIA Cycle 3 TRM includes measures from MEEIA Cycle 2 plus new measures added based on the planning process. Subsequent updates and additions to the TRM are more completely documented as to source of data.

The Company would agree with Staff to make the additional changes suggested and are already in the process of working on this.

Company Expert/Witness: Tim Nelson

E. <u>DSIM Charge</u>

The Staff Report makes a number of recommendations and conditions regarding the DSIM Charge. These matters are addressed as follows: Earnings Opportunity and recovery timing; allocation of BDR costs, NTG factors used, tariff sheet retention, Cycle 1 cost treatment, margin rates, long lead projects, reconciliation procedures and rate case annualization.

i. Earnings opportunity

The earnings opportunity is one component of the three parts (program costs, throughput disincentive, earnings opportunity) of the recovery mechanism of demand-side management programs enabled by MEEIA. Valuing investment in traditional supply side resources comparable with demand-side resources has been deemed important by lawmakers. A continued careful consideration of each component is needed to provide utilities with the structure to offer demand-side programs. The Staff specifically recommended that the earnings opportunity should be zero, which clearly leaves out 1/3 of the components of the mechanism and would preclude the Company from investing in MEEIA. The Company will rebut Staff's position on EO and benchmarks used in the Application as well as present additional reasons why the proposed value is supported, reasonable and valid.

a. EO proposed aligns with statute

The Company has proposed an earnings opportunity that is in line with the MEEIA statute. It will be based on a verified, retrospective EM&V as evidenced by the application EM&V plan.[47] In this way, the Commission is ensured the EO is "associated with cost-effective, measurable and verifiable efficiency savings."[48]

Second, Staff makes many statements about level and method of calculating the earnings opportunity that contradict provisions in the statute.

> …KCPL/GMO is requesting an earnings opportunity that greatly exceeds its most recently approved return on investment.[49]

> If such investments are actually avoided, then the projected return on investment ("ROI"), based upon an ROI that the Commission deems appropriate, that KCPL or GMO would have received from such investments in infrastructure upgrades but for the MEEIA programs may be appropriate.[50]

Staff's recommendation is not supported by the MEEIA statute. The statute says that the earnings opportunity is to be "associated with cost-effective measurable and verifiable efficiency savings" and does not include language about the EO being based on "deferred" or "avoided" supply-side resources. In other words, this means the utility can earn on achieving efficiency savings.

> (3) Provide timely **earnings opportunities associated with** cost-effective **measurable and verifiable efficiency savings**.[51] [Emphasis added]

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[47] Company Application – Section 8.4 – EM&V Plan.
[48] 393.1075.3 (3) RS Mo.
[49] Staff Report, p. 22 lns. 23-24.
[50] Staff Report, p. 86 lns. 19-22.
[51] Section 393.1075.3(3) RSMo. 2014.

While the Commission has provided guidance on "deferred" or "avoided" resources as a way to value the EO[52], the statute is silent on how to explicitly value EO. The Company will provide a number of options to demonstrate a reasonableness for earnings opportunity in Section II.E.i.c. below.

Staff claims that the Company should not be allowed to receive an EO if at any time a program is not deemed 100% cost effective. This would not meet MEEIA's stated policy[53] of ensuring that utility financial incentives are aligned with helping customers use energy more efficiently and is inconsistent with how the EO has been applied in past MEEIA cycles.

b. No double recovery

Staff also suggests that that the Company's proposal could allow for double-recovery of earnings opportunity.

> Approving KCPL's and GMO's EO could allow a **double-recovery** because there is expected to be no postponement of supply-side resources and no lost earnings opportunity as a result of MEEIA Cycle 3 programs, as proposed.[54] [Emphasis added]

This is not the case. Under MEEIA, the **opportunity** for the additional earnings is only possible by achieving cost-effective demand-side savings. This earnings opportunity does not exist without the new demand-side savings, so there is no double-recovery. In fact, an earnings opportunity was approved by the Commission under similar capacity need

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[52] Case EO-2015-055 Report and Order, pp. 11-13.
[53] Section 393.1075.3 RsMo 2014 – "3. **It shall be the policy of the state** to value demand-side investments equal to traditional investments in supply and delivery infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. **In support of this policy, the commission shall**:
(2) **Ensure that utility financial incentives are aligned with helping customers use energy more efficiently** and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; [Emphasis added]
[54] Staff Report, p. 84 lns. 34-36.

circumstances in Cycles 1 and 2. Customers will continue to benefit from permanent demand reduction created by measures in those cycles. Those benefits will be in place whether the Company substitutes, avoids or defers generation.

c. Earnings opportunity is at a reasonable level

As provided in the Company's direct filing, Section 8.11 "Earnings Opportunity Valuation", there are multiple ways to calculate acceptable earnings opportunities. The level of earnings that the Company is requesting is consistent with prior Commission-approved earnings opportunity levels for both the Company and Ameren. Staff Witness Eaves disagrees with Company's evaluation of EO with the three benchmarks used to test reasonableness.

While the Company does not believe that it is necessary to demonstrate deferred generation build to justify earnings opportunity, there are scenarios where the Company would lose earnings as a result of implementing these MEEIA programs.[55] Therefore a zero earnings opportunity is inappropriate.

Second, Staff also surmises Percentage of Net Benefits is not a valid way to show an EO because the Staff calculated net benefits is less than zero. This issue clearly goes back to Staff's assumption of avoided costs as addressed in Section II.B. The table on page 6 in Appendix 8.11 in the Company application is still valid as a reasonable range of percentage of Net Benefits as discussed. In addition, the Company has one more EO benchmark for reasonableness that is common among other utilities across the US - earnings as a percentage of program spend. The EO that the Company is requesting is in

[55] See table in Company Application Appendix 8.11, p.7.

line with this metric as well and consistent with prior Commission orders for both the Company and Ameren. Ameren's recently approved EO at target of $30M equates to 15% as a percent of program budget. This is consistent with the Company's approved Cycle 2 EO target of 14.7% for KCP&L and 19.7% for GMO as a percent of Cycle 2 program budget, as well as the Company's Cycle 3 EO target request of 18% for KCP&L and 19.2% for GMO as a percent of program budget. It should be noted that the Company's EO matrix is an additional metric based component to ensure that customers are receiving savings before shareholders earn.

Lastly, Staff concludes "It doesn't make economic sense for customers to pay $96.1 million for program costs in the near term with the hope of receiving $2 million in savings over 20 years."[56] First, the statement is misleading in that the customers actually receive $98.1 million of benefits over the 20 years for their investment compared to the cost of $96.1 million. Second, in consecutive cycles the Company has achieved more cost-effective savings ($/kWh) than the approved plan. For example, in Cycle 2 through program year 2, the Company spent 77% of approved budget to achieve 91% of kWh savings in KCP&L. This incremental gain results in additional benefits that goes above and beyond the "hope" that Staff refers to. It is proven repeatedly that the Company delivers on and exceeds its expectations for savings benefits for dollars spent.

Company Expert/Witness: Darrin Ives

[56] Staff Report, p. 86 lns. 11-13.

ii. Timing of earnings opportunity recovery

On page 34, lines 11-13, of his testimony, OPC Witness Dr. Marke recommends that the Company's earnings opportunity be awarded at the end of the three-year EM&V verification of performance against targets rather than on an annual basis as proposed by the Company.

The Company continues to believe that an annual award of earnings opportunity based on the cumulative annual achievement of EO targets using annual EM&V results is an appropriate means of awarding and recovering the allowed earnings opportunity as proposed by the Company. It spreads the cost more evenly across the program years and avoids some of the variability for customers in DSIM recoveries resulting from recovering the three-year EO award over a shorter period after the completion of the cycle. The annual award of EO based achievement of targets is consistent with the Commission's recently approved Ameren Cycle 3 recovery mechanism.

Company Expert/Witness: Mark Foltz

iii. Allocation of Business Demand Response ("BDR") costs

On page 91, lines 3-10, of Staff's Report, Staff recommends that the Company:

> allocates the costs from Business Demand Response to each rate class based upon participation similar to the methodology proposed for other programs;
>
> The costs from Business Demand Response related to MEEIA participants will be allocated to each non-residential rate class based upon participation, except for Business Demand Response costs associated with opt-out customer participation which should be allocated to all non-lighting classes based on kWh sales, if opt-outs are allowed to participate in Business Demand Response;

While the Company continues to believe that the programs proposed in Cycle 3 (including the BDR program) benefit all customers, the Company is willing to work with Staff to reflect Staff's recommendation on the allocation of costs from the BDR program in the final tariffs as indicated.

Company Expert/Witness: *Mark Foltz*

iv. Use of 0.85 Net to Gross (NTG) factor for TD recovery

On page 91, lines 21-24, of Staff's Report, Staff recommends that the Company:

> uses a NTG factor of 0.85 in calculating the MEEIA Cycle 3 TD, which provides a reasonably accurate NTG factor and still provides the ability to adjust for an EM&V result lower than 0.85. If the Commission approves KCPL/GMO's proposed NTG, then Staff recommends that the EO be able to be adjusted below zero;

The Company believes that the use of separate Net-to-Gross ("NTG") factors for each program is reasonably supported based on EM&V results for the first two program years of MEEIA Cycle 2 and preliminary results for the third program year would result in a greater level of attribution by customer classes. Additionally, as the EO is adjusted for the difference between the deemed savings and the net evaluated savings the final impact is the same. Nevertheless, the Company is prepared to work with Staff to modify tariffs to incorporate Staff's recommended use of the 0.85 NTG factor.

Company Expert/Witness: *Mark Foltz*

v. Retain Cycle 2 tariff sheets for GMO similar to KCP&L

On page 91, lines 19-20, of Staff's Report, Staff recommends that tariff sheets be modified to:

> retains the MEEIA Cycle 2 tariff sheets in the tariff books for both utilities until they are no longer necessary;

The Company commits to work with Staff to modify the Cycle 2 tariff sheets for both utilities until they are no longer necessary.

Company Expert/Witness: *Mark Foltz*

vi. Remaining Cycle 1 costs

On page 90, lines 13-18, of Staff's Report, Staff recommends that tariff sheets be modified to:

> include provisions such that any remaining reconciliations related to recovery and true-up of MEEIA Cycle 1 Program Cost Reconciliation, Throughput Disincentive Reconciliation and Performance Incentive Reconciliation will be incorporated into the initial period MEEIA Cycle 3 PC, TD and EO to fully reconcile MEEIA Cycle 1 so that additional calculations related to MEEIA Cycle 1 do not have to continue;

The Company commits to work with Staff to modify the tariff sheets for KCP&L and GMO to incorporate any remaining balances from Cycle 1 as recommended by Staff.

Company Expert/Witness: *Mark Foltz*

vii. Margin rates

On page 91, lines 25-26, of Staff's Report, Staff recommends that the Company:

> uses the same margin rates that took effect on December 6, 2018, for the initial MEEIA Cycle 3 period, subject to update in future general rate cases;

The Company commits to work with Staff to modify the final tariffs to ensure that the same margin rates that took effect December 6, 2018 are used for the initial Cycle 3 period, subject to update in future general rate cases.

Company Expert/Witness: *Mark Foltz*

viii. Cycle 2 long-lead projects

On page 92, lines 1-3, of Staff's Report, Staff recommends that the Company:

> clearly states within the DSIM riders that long-lead projects associated with MEEIA Cycle 2 are addressed pursuant to the Stipulations and Agreements filed in Case Nos. EO-2015-0240 and EO-2015-0241;

The Company commits to work with Staff to modify the tariffs to ensure that long-lead projects associated with MEEIA Cycle 2 will be addressed pursuant to the Stipulations and Agreements filed in Case Nos. EO-2015-0240 and EO-2015-0241.

Company Expert/Witness: Mark Foltz

ix. Reconciliation definitions

On page 92, lines 4-7, of Staff's Report, Staff recommends that the Company:

> corrects the definitions regarding Program Costs Reconciliation ("PCR"), Throughput Disincentive Reconciliation ("TDR"), Earnings Opportunity Reconciliation ("EOR") and Ordered Adjustment Reconciliation ("OAR") so that the costs to be reconciled are like costs;

This was clearly the Company's intent. The Company commits to work with Staff to clarify the definitions of such reconciliations to ensure that each cost component is reconciled with like costs from the same cycle (Cycle 2 or Cycle 3).

Company Expert/Witness: Mark Foltz

x. Rate case annualization – hourly load shapes

On page 92, lines 11-12, of Staff's Report, Staff recommends that the Company:

> provides the hourly load shapes of energy efficient savings measures for any future KCPL and GMO general rate cases;

Neither the Company, nor any other utility that we are aware of, currently collects load research data at the end-use level. Specific end-use load research typically requires the utility to install additional equipment within the premises of the customer and develop a new infrastructure for collecting this data. The cost of this research is generally cost prohibitive. To obtain detail hourly load shapes applicable to the end-uses of energy efficiency savings measures, end-use load shape data must be acquired from secondary sources. The Company has had preliminary discussions with the current consultant selected to perform its upcoming DSM potential study regarding the delivery of hourly load shape data for energy efficiency saving measures. Preliminary cost estimates provided a range from $55,000-$170,000 depending on the level of detail shapes required by program or measure.

The Company believes that the inclusion of the proposed kWh and kW annualization adjustments in its general rate cases is essential to determining updated Net System Input ("NSI") and Class Cost of Service ("CCOS") analysis. Accordingly, the Company is willing to commit to work with its current DSM potential study consultant, or other sources, to obtain hourly saving load shape data for use in its future general rate cases.

Company Expert/Witness: Tim Nelson

F. Response to Stakeholder Recommendations

Staff and stakeholders presented a myriad of ideas and suggestions to the Cycle 3 proposal throughout testimony. The Company developed common themes to respond to these suggestions and present the Company's position. The themes include: Demand Response programs, Business EE Programs, Home Energy Report, Income-Eligible programs, Research and Pilot, PAYS, tariff requests, cycle length, default MEEIA levels, syncing IRP/Potential Study and jurisdiction consolidation. Failure to address a particular issue raised by the parties does not mean that the Company accepts that position.

i. Demand response programs[57]

a. Demand response benefit streams

The benefits of Demand Response programs were challenged by Staff in the rebuttal testimony[58]. Essentially, their argument funnels back to avoided cost. The Company has highlighted in Section II.B. above the ways to value avoided capacity cost which solve the issue with how the Demand Response programs are evaluated. By choosing the proper level of avoided cost and what has proven to provide benefits in the IRP, the Demand Response programs pass as proposed. In addition, as Staff suggests, there are more benefits associated with SPP fee reduction that are addressed in Section II.B.vii. that have not been included in the Company's original proposal and could potentially be incorporated into the demand response event calling process discussed below.

Business Demand Response measure and program life

In the Company's MEEIA 3 Business Demand Response program, customers can participate in a variety of ways that might or might not include technology or physical devices to facilitate the load reduction. In other words, there is generally no required equipment or hardware investment to participate although some customers do utilize technology. This participation flexibility is necessary, but creates a difficulty in assigning a typical value measure life to any specific equipment. Therefore, due to the Company providing an annual incentive payment to the customer for participating, the 1-year measure life has been historically relied on. In terms of the cycle, the total cycle benefits

[57] Staff Report p. 91 lns 13-15
[58] Staff Rebuttal, pp. 65-67

for the Business Demand Response program are calculated as cumulative of single year benefits for the three-year period, consistent with the term of the MEEIA cycle. In other jurisdictions through the US and one in Missouri, utilities sometimes evaluate the program over 10 years to better represent the long-term nature of how the programs are generally run. For example, as of today NV Energy (Nevada) and CPS Energy (Texas) have run their respective business demand response portfolios well past 10 years. For calculation of cost effectiveness, other utilities, including Ameren Missouri, look at benefits and costs over 10 years of a program life.

Due to uncertainty of program changes and continuity across MEEIA cycle, the Company seeks to minimize risk in the Business Demand Response program (or formerly Demand Response Incentive) by not pursuing customer agreements across MEEIA cycles. Therefore, the Company's demand response capacity resets to zero at the beginning of each approved MEEIA cycle. Significant effort to engage, re-sign, and seek new capacity reduction with customers is required each cycle period. For example, in Cycle 2 when the Commission approved the extension period, all Demand Response Incentive customer contracts expired consistent with the expected termination of Cycle 2, or March 31, 2019. Due to the extension (or even if Cycle 3 was approved) the Company had to re-recruit and re-sign all customers in efforts to achieve the capacity reduction target for the extension period. Subsequently, all Cycle 2 extension contracts signed after Marcy 31, 2019 will now expire December 31, 2019 and necessary Cycle 3 customer education and recruitment will start again with the new BDR Program design.

While the customer may have technology or devices to continue to enable them to participate past the end of their program contract, the Company takes the conservative view in such that we will need to evaluate contracts with customers each year in order to have them participate at appropriate levels, thus the 1-year life. This fact also drives the proposed savings targets with EO associated to recognize the effort and results each year of each cycle for retaining and/or re-filling the customer participation in the program.

<u>Residential/Small Business Thermostat measure and program life</u>

Conversely, the Residential Demand Response program measure life of 10-years is based on the estimated average service life of the hardware that is used to participate in the program. The measure life for thermostat was approved by the Commission, Staff and Staff Auditor in Cycles 1 and 2 as part of the Technical Resource Manual. The Company provides a smart thermostat to the customer to participate and its measure life is 10-years. While currently the Company continues to pay a portion of customers (those with a Nest) annually for participation, there are others that are not paid for ongoing participation but receive free service to their device as long as they are in the program. The benefits for the Residential Demand Response program are calculated as those associated with each newly installed device over the expected useful life of the measure, or 10 years. The Company does not include benefits related to thermostat devices that were installed in prior cycles.

Staff believes that since the customer "owns" the thermostat after three years of participation, the Company stops seeing benefits from that product. However, by giving customers an energy saving device, they will experience energy savings from the time of install until the time they uninstall it. Even if customers aren't actively participating in the program, they are still experiencing the same energy savings from the thermostat itself. While the customer may own the thermostat after three years of participation, there is no un-enrollment that takes place. These thermostats are still contributing to DR by being enrolled in the program as far back as our pre-MEEIA implementation of one-way thermostat devices. The Company has seen this exemplified through these "legacy" thermostats that are still installed and are being called for demand response events. This fact also addresses Staff's comment about customers not wanting to participate if they are not being incentivized to do so. Participant expectation setting is key to how and when they will respond with these legacy assets that aren't being incentivized anymore but are still a part of the demand response resource pool.

Company Expert/Witness: Brian File

b. BDR Cycle to Cycle demand reduction

Staff recommends that the Commission only allow the Company an opportunity to earn on Cycle 3 demand response that ***exceeds*** the incremental peak demand savings achieved in Cycle 2.[59] The Company objects to this recommendation. Staff bases their recommendation on the false premise that the Business Demand Response (BDR) demand savings achieved in Cycle 3 are not incremental savings and that these savings are just a continuation of Cycle 2 savings.[60] This is incorrect. Without Cycle 3 there are no BDR demand savings. All Cycle 3 BDR demand savings are therefore incremental savings.

In addition, the BDR program, while designed with similar purpose and target participant audience to Cycle 2 Demand Response Incentive (DRI) program, will not have any carry over contracts from one cycle to another. Each new participant will require education, marketing, technical evaluation and enrollment for the BDR program. The BDR

[59] Staff Report, p. 89.
[60] Staff Report, p. 68, lns. 12-14.

program will be evaluated on actual kW goal achievement based on this baseline of “0” scenario and the Company should be allowed earnings opportunity commensurate with the evaluated BDR program impact independent of any past similar program performance.

Company Expert/Witness: Brian File

c. Redesign BDR customer incentive payments[61]

Staff expresses concern over the program design of customer participation incentives in Business Demand Response. The Company’s proposed Cycle 3 BDR program employs a very different incentive payment structure for Business Demand Response than the Cycle 2 DRI program. The Company filed these changes in response to EM&V results and with the desire to strengthen the cost effectiveness of the program. As noted in Staff Witness Leubbert’s extensive comments on the DRI payment structure[62], DRI participant incentive payments were heavily weighted on customer enrollment rather than on actual customer event performance and that “Staff is unaware of KCPL or GMO removing any customer from the program for failing to perform at the contracted level”[63].

While the customer enrollment weighting made sense for historical program goals of participation, the Company acknowledges that a different structure is necessary for stronger customer performance. The proposed BDR incentive payment structure has been designed such that customers will be rewarded for the average reduction they achieve across the demand response season rather than on a promised reduction amount in their contract. In other words, customers will be paid commiserate with their actual event

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[61] Staff Report, p. 90 lns. 26-28.
[62] Staff Report pp. 65-68.
[63] Staff Report, p. 67 lns. 25-26.

performance, rather than a large upfront payment for enrolling to participate. This pay for performance model better aligns the actual demand reduction a customer achieves and encourages the customer to fulfill their contract and maximize their incentive payment. Additionally, the Company objects to Staff's assertion that they are unaware of the Company removing any customer for failing to perform at contract levels. The company discussed during the November 2018 DSMAG meeting the operational measures executed during the 2018 DRI season to manage customer performance vs. contract levels. Specifically, in the summer of 2018 the Company removed or reduced contract values for 6 customers for a loss of over 4.5 MW in GMO potential goal attainment because these participants were not able to perform at contract level. This reduction resulted in program savings of nearly $150,000. Subsequently, every 2018 contract was re-evaluated prior to offering any new contracts for the 2019 DRI season. This last evaluation resulted in 23 past participants (6.3 MW) not being offered 2019 contracts and net reductions of another 2.7 MW for the remaining returning participants. This 2019 contract evaluation resulted in a reduction in the DRI program budget of nearly $300,000 in upfront payments and created a further barrier to the programs 2019 enrollment goals.

Company Expert/Witness: Brian File

d. Demand response event calls

Staff and OPC raise concern with respect to how the Company calls demand response events. The Company has had an established weekly internal cross functional team meeting during Cycle 2 to determine whether or not it is needed or appropriate to call a demand response event. It has been determined that the most impactful variables in predicting the need for a demand response event may include jurisdictional load forecasts for each day of the week, forecasted market energy market pricing, short and long-term weather forecasts, anticipated wind generation resources, local generation status, known SPP conditions, etc. As of September 15, 2019, the Company has called five demand response events for thermostats for the 2019 season, which meets the requirement of the Stipulation & Agreement for Cycle 2 Extension.

Dr. Marke also requests that the Company guarantee that demand response events will be called beyond "test runs" and also that they be called when there are economic benefits possible from the event call[64]. Dr. Marke has not acknowledged that the Company currently calls demand response events with the intent of best utilization of demand response as a resource, and not just for "test runs". The existing Cycle 2 DRI tariff and the proposed Cycle 3 BDR tariff both list a minimum of one event call per season. The Company also uses the weekly meetings and updates of changing conditions through the remainder of the week to strategically call events with the most beneficial impact to forecasted seasonal peaks and with the least negative impact on customer experience. The Company strongly believes effectively managing customer relationships is essential for DR as a viable long-term resource and thoughtful evaluation of this forecasted peaks versus customer experience balance is key.

The Company also already considers the economic benefit to the Company and the benefit of the overall SPP system when determining to call an event or not. In Cycle 2, the DRI tariff had a requirement of a 4-hour minimum notification window to customers, which was designed to be more customer-friendly. This has been a major barrier for

[64] Witness Marke Rebuttal, p. 25.

economic calls to be of any significant benefit. This minimum notification window has been reduced to 1-hour in Cycle 3 for increased economic and operational flexibility. Additionally, the Cycle 3 BDR design provides intentional focus on introducing and encouraging automated demand response (ADR) that even further enhances controllability, response time and confidence in customer response. As discussed in Section II.A.ii, the Company launched its DERMS platform and plans to mature the platform during MEEIA 3 for further demand response utilization. DERMS has allowed the Company to track, forecast, evaluate and model customer's demand response loads using the Company's AMI data. AMI alone merely provides data in a more granular timeframe that is an input into DERMS whereas the DERMS makes the AMI data actionable.

Company Expert/Witness: Brian File

e. Opt-out customers

Staff recommends[65] that if the Commission approves the BDR program, only those customers who have not opted out of MEEIA programs should be eligible to receive the incentives pursuant to Section 393.1075.10 RSMo. Staff believes that opt-out customers can utilize the Company's Curtailable Demand Rider as it is a curtailable or interruptible tariff outside of MEEIA.

Staff's recommendation is not consistent with its position in Cycles 1 or 2. Staff witness John Rogers recommends in his MEEIA Cycle 1 testimony that GMO allow customers who opt-out of participating in the Company's DSM programs to participate in

[65] Staff Report, p. 72.

interruptible or curtailable rate schedules or tariffs offered by GMO, including GMO's Energy Optimizer and MPower programs.[66] Under the settlement agreement in the GMO MEEIA Cycle 1 case (EO-2012-0009) customers who opt-out of the demand-side programs were permitted to participate in the Energy Optimizer or MPower programs, which were GMO curtailable or interruptible MEEIA programs. There are 7 opt-out customers currently participating in these programs or in the successor demand response programs (Demand Response Incentive (Cycle 2)). As a result, opt-out customers currently make up a significant portion of kW demand enrolled (over 35%) and have exhibited strong participation in the Company's demand response programs, in some cases more than 30 percent better than contracted. Now Staff is backtracking from its position in the last two MEEIA cycles and requiring that these opt-out customers not be allowed to participate in MEEIA programs.

The Company believes that since opt-out customers have been allowed to participate in demand response MEEIA programs in past MEEIA cycles, they should be allowed to continue to participate in Cycle 3 as well. Staff interpreted MPower as a curtailable or interruptible program in GMO Cycle 1 and 2 and the proposed Business Demand Response program in Cycle 3 is fundamentally the same program concept. Therefore, the Company believes the program is an interruptible or curtailable rate or tariff and should allow opt-out customers to participate in Business Demand Response.

OPC Witness Dr. Marke states that there has been very little realized energy/demand savings value to date for the Company's MEEIA Cycle 2 DRI program and

[66] Rebuttal testimony of John Rogers, EO-2012-0009, p. 9.

that opt-out customers should not be able to participate. Dr. Marke fails to recognize that the Company did not file for DRI energy savings goals within Cycle 2, therefore no energy savings value should be expected in reporting. DRI is a peak demand reduction resource only and therefore has only demand goals. Additionally, Dr. Marke's opt-out stance also disregards the value opt-out customers have contributed to the realized demand savings that DRI has achieved. Lastly, in MEEIA 3, the Company pursues its mission of continuous program improvement by replacing DRI with the redesigned Business Demand Response program to achieve further operational improvements, higher realized demand savings and increased cost effectiveness.

Company Expert/Witness: Brian File

f. Business demand response generators[67]

For the Business Demand Response program, the Staff recommends that the Commission require the Company to only allow on-site generation that is dispatchable and has verified compliance with applicable performance and emissions standards[68]. The Company specifies in the approved Demand Response Incentive (DRI)[69] tariff for MEEIA Cycle 2 that customer self-generation enrolled in the Demand Response Incentive program is restricted to "…customers who can provide documentation validating Compliance pursuant to Environmental Protection Agency ("EPA) regulations…". Additionally, customers' contract with the Company further state that by executing the DRI contract, "…the Customer certifies that it has reviewed the EPA regulations pertaining to its specific

[67] Staff Report. p. 91 lns. 16-18.
[68] Staff Report p. 73 lns. 1-3.
[69] Cycle 2 Demand Response Incentive program is comparable to Cycle 3 Business Demand Response Program.

generating equipment and it hereby represents and warrants that it is in compliance with all of the currently-applicable regulations." The Company intends to continue the precedent of the customer being responsible for their own facility on-site generation if they choose to enroll it in the BDR program. The Company is willing to add this detail clarifying customers EPA compliance requirements to the BDR tariff.

Company Expert/Witness: Brian File

g. Thermostat program specific topics

Staff raised a concern that thermostats were "free of charge" in Cycle 2. While the offer in Cycle 2 includes a free thermostat to a customer, the Company will continue to evaluate the terms of this program. With the incentive level ranges presented in Appendix 8.6 of the Company's Application, the Company has the opportunity to make changes to the program in relation to incentive levels. The Company will evaluate customer participation levels at a new offer point, optimize the residential thermostat budget and assess the value of the changes across the entirety of the portfolio.

Company Expert/Witness: Brian File

ii. Business energy efficiency programs

a. Business Process Efficiency ("BPE") free ridership

With respect to the Business Process Efficiency Program (BPE), Staff raises concerns regarding customer eligibility and free ridership, suggesting "a more objective method and customer eligibility requirements" are necessary "to minimize free-ridership in the BPE program." [70] The Company has outlined eligibility for the BPE in tariff as filed

[70] Staff Report, p. 55 lns. 1-8.

in YE-2019-0103. Per the MEEIA 3 tariff sheets, "BPE is available to all customers served under SGS, MGS, LGS, LP, SGA, MGA, LGA, or TPP rate schedules who have not opted out." Free ridership concerns were raised in Staff's Report and Company's failure to account for changing energy efficiency measures (EEMs) in the baseline. In the Final EM&V Report for Program Year (PY) 2017 from Navigant[71], the Company's third-party evaluator, states that BPE programs "identify and address potential energy efficiency opportunities that are above their current practice (i.e. baseline activity)". Without these programs, customers would not have the tools or ability to address the savings identified and would have continued to operate in the same manner as the baseline operation. In other words, the nature of BPE program precludes free-ridership because the participants must identify EEMs that they are *not* engaging already. With the other proposed BPE tracks, only measures customers are not engaged in will be considered eligible. In addition, KCP&L will continue to demand the same high level of assessment of quantitative and qualitative impact of energy efficiency programs from a third-party EM&V contractor. This effort continues to ensure program benefits are real, significant and advantageous to customers within all participating rate classes.

Company Expert/Witness: Brian File

b. Business Process Efficiency market need

OPC states that "the role of an energy management professional can be met internally by commercial and industrial businesses or can be procured through third-party

[71] Navigant Report November 2018, p. 70.

businesses or organizations."[72] Dr. Marke's statement fails to acknowledge the barriers inherent to this market as identified in the State Auditor's report, Evergreen Economic/Michaels Energy's Independent EM&V Audit for PY2017. In that report, the State Auditor references the barrier originally identified in the 2016 EM&V analysis (p. 62):

> The primary market imperfections are that customers have a limited amount of time and money to devote to energy conservation…. [including]
>
> - The cost of having an outside expert perform an extensive onsite assessment
> - The cost and time to submit a report outlining identified measures
> - The cost and time to develop the onsite expertise on how to implement the recommended measures
> - In addition, many C&I customers do not have the time needed to oversee or facilitate an effort such as SEM or Retro-Commissioning.

The majority of Retro-Commissioning ("RCx") projects utilize a trade ally that specializes in RCx measures, usually to a much deeper level than an in-house energy professional.

Company Expert/Witness: Brian File

c. Business social services

OPC recommends that the Company proposes a Business Social Services program that specifically targets non-profits and social service facilities[73]. The Company has targeted these organizations in the prior MEEIA cycles through outreach with community

[72] Witness Marke rebuttal, p. 24 lns. 14-19.
[73] Witness Marke rebuttal, p. 33 lns. 6-10.

organizations such as Bridging the Gap and Metropolitan Energy Center. The Company would be receptive to targeting underserved customers through the Business Custom and Standard programs utilizing tools and mapping data to geotarget eligible businesses with a specific budget if the Commission desires.

Company Expert/Witness: *Brian File*

d. Combined Heat and Power ("CHP")

The Missouri Division of Energy recommends that the Company improve the depth and quality of the CHP option in the Business Custom program through a collaborative effort.[74] Since MEEIA Cycle 2, CHP projects are eligible under the Business Custom program. While a number of custom projects have been considered by industrial customers in the past, no CHP projects have been submitted. The Company would consider additional efforts for developing awareness of this technology. To create more awareness of CHP incentives the Company is willing to work specifically with the Division of Energy and/or other interested parties on opportunities to educate customers and market actors around CHP benefits. At that point any potential projects could be preliminarily evaluated as to whether energy efficiency benefits will be present to bring into MEEIA approved programs.

Company Expert/Witness: *Brian File*

[74] Missouri Dept. of Economic Development Rebuttal, p. 15 lns. 13-21.

iii. Home Energy Report and analyzer programs

a. Cost-effectiveness

The TRC scores for the Home Energy Report cited in Staff's comments reflect those included in the Company's filing from November 2018. While the Company hasn't filed any updates since that time, the Company has worked with the implementation partner, Oracle, to provide a redesign to the Home Energy Report program for Cycle 3 to rely more on digital communications than the legacy program design and has negotiated better pricing for the services. With these changes and continuing to utilize the Company's proposed avoided costs, the programs in each territory have a total resource cost test score greater than 1.0, making them cost-effective programs within the Cycle 3 portfolio. If the Commission approves the Cycle 3 application, the Company requests that the order include these changes to budget and savings for this program.

TRC scores for the HER programs in each territory are as follows:

- KCP&L-MO: 1.59
- KCP&L-MO-Low Income: 1.22
- GMO: 1.32

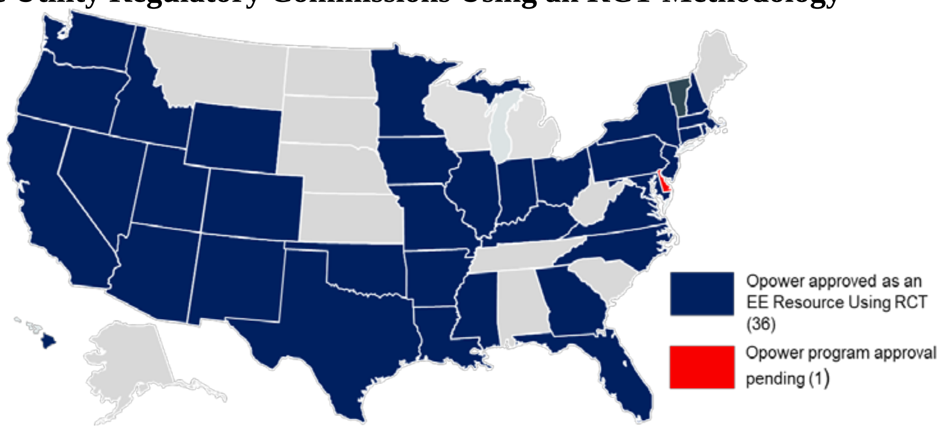
b. Randomized Control Trial ("RCT")

The methodology used to determine the energy and demand impacts of the Company's behavioral energy efficiency program is the randomized control trial, the most rigorous and reliable evaluation design for behavior programs according to the U.S. Department of Energy's State & Local Energy Efficiency Action Network's report, *Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based*

Energy Efficiency Programs: Issues and Recommendations.[75] Randomization generates balance in all observable and unobservable customer characteristics in the treatment and control groups. More than 100 independent evaluations of Oracle's behavior programs have been completed.[76] Independent third-party evaluators review the randomization of the treatment and control groups in addition to measuring and verifying the savings reported.

The RCT has been accepted by 36 state utility regulatory commissions across the country as a credible experimental design and methodology for measuring energy savings from behavior programs, including Missouri, as seen in Figure 5 below.

Figure 5
Behavioral Energy Efficiency Approved by
State Utility Regulatory Commissions Using an RCT Methodology



c. HER is not duplicative

Commission Staff and OPC contend that HER program does not provide value to customers, is duplicative and should be discontinued.[77] The Company will show to the

[75] "Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations. U.S. Department of Energy. May 2012. www.seeaction.energy.gov
[76] Oracle Utilities. https://www.oracle.com/industries/utilities/verification-reports/
[77] Staff Report, p. 48; Witness Marke rebuttal, p. 22.

contrary that many customers benefit from the HER program and the report works in harmony with other offerings and is not duplicative.

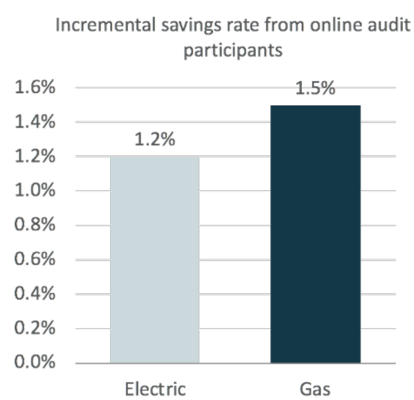
Over 36 GWh savings were achieved in Cycle 2 from the HER program, which is evaluated by the Company’s third party EMV consultant and audited by Evergreen Economics. This evaluated level of savings alone demonstrates significant value and benefit created by this proactive report. The technical and analytical capabilities drive savings, which turn data into personalized, dynamic, and actionable insights so that it can be communicated in a way that is meaningful to customers. No other MEEIA program does this more so than the HER program.

The HER and Home Energy Analyzer programs work in harmony and are not duplicative. One of the suggestions of Staff was to include a link to the online Energy Analyzer on a customer’s bill. The assumption is that the HER is redundant and not needed to drive savings. By reviewing existing customer web engagement metrics, we can confidently say that Staff’s assumption is flawed.

Oracle’s analytics show that in April, May, and June of 2019, 225,503 households were part of the HER treatment group (i.e., receiving reports). During that same time period, only 3,025 KCP&L customers logged on to the web portal. This demonstrates that the HER reaches customers at scale. The HER (print and email) is the primary vehicle to deliver personalized energy data, actionable energy saving tips, and differentiated marketing campaigns to customers. If only the web portal was used to engage customers in their energy management, less than 1% of the Company’s customers would ever see *any* personalized energy insights, energy saving tips, or promotions for other beneficial energy efficiency programs that HER recipients currently receive.

HERs (print and email) are the basis of the behavior program's success in reliably delivering savings year over year. HERs are proactive communications delivered through an opt-out program design that reaches more than five times the number of customers who logged in to the web portal this past spring.

Analysis of data across Oracle's clients show that those receiving eHER online audit promotions are five times more likely to log in to the online portal, 20 times more likely to take the online audit, and 80% of customers who start the audit complete it. It is important to get customers online via HERs as online audit participants nearly double their savings rates. Online audit participants save an additional 1.2 – 1.5% incremental to the HER savings.[78] Many more customers will be eligible to receive email HERs ("eHER") in Cycle 3 (~45%) compared to Cycle 2 (~12%). Increasing eHER distribution will likely boost online engagement as it is easier to prompt a customer to visit the Energy Analyzer from a digital communication than a print Home Energy Report.



The behavioral energy efficiency program design for Cycle 3 is crafted to take advantage of higher email penetration and layering behavioral offerings on top of one

[78] http://www.calmac.org/publications/EDRes9_UAT_ResReport_CALMAC_final.pdf

another to drive incremental savings. Even with these program enhancements, print HERs must be a part of the ongoing behavioral offering in order to achieve the forecasted levels of savings.

d. Low and moderate-income customers

Home Energy Reports are one of the most equitable offerings within the MEEIA Cycle 3 portfolio. Customers can receive HERs and save at similar rates regardless of income, household size, and age. Moreover, HERs can be personalized to ensure that income qualified customers are only receiving low or no-cost energy saving tips and that renters only receive energy saving tips that they, as renters, can act on. A promotion of the weatherization program in the HER in 2017 was the most frequently recalled energy efficiency program promoted through the behavioral program.[79] The population of customers who are energy burdened is much broader than those identified by traditional LMI definitions used in the utility industry. For this reason, it is important to provide HERs as part of MEEIA Cycle 3 as they are a far-reaching measure that provide an equal opportunity for all households to save.

Company Expert/Witness: Brian File

iv. Income-eligible programs

a. Income-eligible single-family program

In response to NRDC's interest in a single-family income-eligible program, the Company is not proposing a stand-alone MEEIA single-family program. However, the Company has and will continue to explore opportunities to leverage DSM program

[79] GMO Evaluation, Measurement, and Verification Report – FINAL. Navigant Consulting, Inc. December 21, 2018.

synergies with the Low-Income Weatherization program, which is offered outside of MEEIA. Synergies with programs such as Heating, Cooling and Home Comfort and Energy Savings Products which offer customers additional ways to save with a variety of low to no cost options. Also, through neighborhood associations, customer event engagement and other community outreach, the Company can provide education and engagement for underserved customers on how to better manage their energy consumption. One example today is providing no cost LEDs at events and at the Company's Connect Center, which is centrally located in Kansas City's urban core.

Company Expert/Witness: Brian File

b. Income-eligible Multi-Family ("IEMF") program design - NHT

Witness Brink on behalf of NHT recommends the Company continue to find best practice improvements for income-eligible programs, specifically multi-family. The Company has actively collaborated with stakeholders over the past several years as to design a turn-key program design for Income-Eligible Multi-Family (IEMF) program participants in Cycle 3. The proposed program will target underserved customers with a comprehensive suite of measures providing savings impacts at a whole building level. To drive savings, the Company has increased incentive levels for qualifying measures and proposed an escalated budget which reflects an increase in budget while accounting for the removal of the food bank distribution sub program that was offered in Cycle 2.

Company Expert/Witness: Brian File

v. Research and pilot

a. Electric Vehicle ("EV") home charging pilot program

Staff has recommended that the Commission reject the residential electric vehicle EV Level 2 charging station pilot program proposed by the Company because (1) there is no expectation that participants or non-participants will receive a benefit from this pilot program, (2) they believe it is ripe for free-ridership, and (3) there is no information provided about how the Level 2 charging stations would be used in a Demand Response program. The Commission should reject Staff's recommendation.

1. Benefits to participants and non-participants

There are clear and distinct financial benefits to the utility and to all ratepayers from EV charging that result from not only additional electricity sales, but also from more efficient utilization of the grid. The pilot proposed by the Company will provide the foundation to understand the benefit of EV charging between a Level 1 and Level 2 charger. The Company expects the EV Home Charging Pilot Program to reduce the energy consumed to charge the vehicles, increase grid utilization, and reduce the grid impact during residential and system peak usage times by shifting the charging to off-peak hours. While not quantified, these benefits were described in the Company's response to Staff DR No. 0100 attached as **Exhibit B**.

2. Free Ridership

Staff seems to conclude that the majority of participants would have purchased an L2 charging station anyway. This is not necessarily the case. Many EV drivers with limited daily commutes or drive PHEVs with limited battery range choose to continue using the 110v garage outlets. Some EV drivers do choose to install a L2 charger, but many of them purchase less efficient, lower cost non-communicating EV chargers that have no ability to receive demand response or other charge management control signals from the utility. As with any program there may be some free ridership, but any free ridership would be identified and evaluated as part of the EM&V process.

3. Lack of information for EV charging pilot

This pilot is no different than any other end-use measure that would be studied for energy efficiency purposes. The Company has stated in Staff DR No. 0100 that Energy Star certification of chargers would be a likely requirement of the program. Per DOE, "ENERGY STAR certified EV chargers, on average use 40% less energy than a standard EV charger when the charger is in standby mode (i.e., not actively charging a vehicle). EV chargers are typically in a standby mode for about 85% of the lifetime of the product."

In addition, Staff states that the proposed home EV charging pilot does not require the program participant to be on a time-of-use (TOU) rate or participate in residential demand response. It is accurate to the extent that specific program requirements have not yet been established. However, in describing the pilot program, we state that the program is to understand demand response capabilities with home charging and to explore the potential for maximizing technology platforms, such as DERMS. The grid peak coincidence of EV home charging can be managed in several of ways:

- TOU rates with significant super off-peak price differentials.
- DR program participation to limit charging during utility DR events.
- Direct Charge Control to shift charging to residential non-peak usage times

The Company has not decided on any one method as a program requirement. In fact, as a Pilot, it may be appropriate to test and evaluate all three methods for relative benefits and customer preferences.

Company Expert/Witness: Brian File

b. Urban Heat Island ("UHI")

In OPC Witness Dr. Marke's testimony, page 36, line 11 he proposes spending an additional $2 million in targeted annual Research and Pilot ("R&P[80]) costs to inform alternative MEEIA valuation opportunities. Additionally, on page 52, beginning on line 7, Dr. Marke calls out Urban Heat Island ("UHI"), and recommends allocating up to $2 million on R&P with funds directed at two specific UHI deliverables.

If the MEEIA application is approved, the Company is willing to proceed with idea vetting and value planning with the R&P budget filed in the application (~$2.2 million combined both jurisdictions over three years). There is a roadmap with concepts for inclusion in the R&P funding. Including, but not limited to, UHI, Business Social, Market-Rate Multi-Family, Building Codes and HVAC Duct Efficiency.

The Company is willing to proceed with UHI as one of our R&P concepts evaluated. However, OPC is recommending spending $2 million for informing alternate MEEIA valuation opportunities on the UHI, which is nearly the total of the Companies filed Cycle 3 budget, leaving only $160k for the other Company vetted concepts. Under the existing MEEIA 3 filing, the Company calls out a maximum budget per

[80] OPC Report refers to the funds as R&D, whereas Company application is Research & Pilot ("R&P").

concept/program of $500,000 to allow for what the program is designed for - to test out concepts before commercializing. OPC's $2 million is certainly outside this range and leaves little to no funds for other opportunities to explore under the Company's R&P budget.

Company Expert/Witness: Brian File

c. Real estate education of heating, cooling and weatherization

In OPC Witness Dr. Marke's testimony, page 23, line 22 he presents OPC's interest in targeting the real estate market. The Company continues to recognize this as a potential entry point for energy savings upgrades, as we are currently and have been members of the Kansas City Realtors Association ("KCRAR") for years. The Company is unclear if OPC is referring to existing homes being resold or new homes being built and sold or both.

The Company has concluded this solo path into housing purchases has not been effective because there are other players in this arena, including but not limited to - home appraisers, home builders and other home material and equipment vendors that also require buy-in. All these separate, but connected and related entities need to be on board and understand the value of energy efficiency to be best optimized and most effective. The Company is willing to discuss with other utilities a strategy for addressing this with a more holistic path to entry.

Company Expert/Witness: Brian File

vi. Pay as you Save™ - financing

OPC,[81] Renew MO,[82] and NHT[83] all have specific interest in a Pay as you Save ("PAYS") program.

Summarizing from the context of these testimonies, at the very highest level, OPC and Renew MO support the PAYS model inclusion into MEEIA 3 (for all single family and multifamily housing types). NHT is neutral with offering PAYS, as long as there are checks and balances for consumer protection safeguards for the low to middle income customers. The position of the Company, as shared previously[84], is that the Company does not have interest in being a financial institution that holds loans or liens on equipment on the customer's side of the meter. The Company is willing to explore alternate paths for helping customers overcome financial hurdles and has provided some alternative options with outside financing options 'off-bill'. An example of an alternate option that the Company has partnered with includes Property Assessed Clean Energy ("PACE") loans that can be utilized by residential or commercial facilities to finance energy efficiency or other clean energy projects.

In the Company's Application Appendix 8.9 "Financing Research", Cadmus also outlines a multitude of additional financing options for customers who require capital in order to invest in energy efficiency. Those include credit card, personal loan, home equity loan, PACE, on-bill financing and PAYS and provides a comparison in Table 5 (p. 32) of

[81] OPC Rebuttal Testimony, p. 36, ln. 3.
[82] Renew Missouri Rebuttal Testimony, p. 2, ln. 12.
[83] NHT Rebuttal Testimony, p. 21, ln 3.
[84] ER-2016-0285, KCP&L Rebuttal Testimony – B. File.

the report. All of these solutions have trade-offs of benefits and limitations, but cover most all of the needs of individuals desiring capital.

Company Expert/Witness: Brian File

vii. Other modifications to tariff sheets

The Commission Staff requests that the Company "Modifies its tariff sheets to contain sufficient detail on individual program information (i.e., description, administration, availability, qualifications and rebates) along with providing any direct website program links when directing a customer to the KCPL/GMO website for additional program information."[85] Additionally, the Staff requests that the Company "Update the term definitions on Sheet Nos. 1.73 and 1.74 so they are not lacking details and are sufficient to provide customer understanding of the terms."[86]

The Company is open to working with Staff to further clarify the language that would be used in the Commission approved tariffs to best represent the program attributes while allowing for program flexibility. For example, the Company has attached tariff sheet updates to Sheets 1.73 and 1.74 as **Exhibit C**, for both residential and businesses that provides for additional clarifications on definitions and customer eligibility.

Staff requests a modification to the tariff sheets to "Include 3-Year Savings Targets which properly account for annual energy and demand savings from program measures which have no persistence." [87]

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[85] Staff Report, p. 90, lns. 1-5.
[86] Staff Report, p. 90, lns. 6-8.
[87] Staff Report, p. 90, lns. 9-10.

The Company recognizes that the programs or measures with a 1-year measure life requires additional clarification to ensure savings are properly accounted for three-year cycles. The Company has updated tables in **Exhibit D** to clarify savings as suggested by Staff. The tables reflect only "incremental" annual savings for those programs with a 1-year measure life.

Company Expert/Witness: Brian File

viii. Cycle length

Staff has requested that the Cycle 3 end after two years on December 31, 2021. The Company opposes this recommendation for two main reasons: the overlap of Cycle 4 planning with Cycle 3 implementation and the amount of time it takes to educate the marketplace on new programs. For proper planning for Cycle 4 to start in January 2022, program design work would effectively need to start in June 2020 as Cycle 3 programs are ramping up. However, the next DSM potential study will not be complete until May 2020, incorporated into the April 2021 triennial IRP filing, which would then be used for Cycle 4 planning. To complete Cycle 4 planning before that time would require using the same DSM potential study as was used for Cycle 3. Second, when a new set of programs come to the marketplace the first year is a slow ramp based on the education needed to trade allies, systems put in place and customers marketing. Two years of program operation does not allow for significant traction on program sets to drive deeper savings and results in "quick turn" type projects. A related example is the Cycle 2 extension period of nine months. Even though the programs are the same as the prior year, just communicating that programs are only available for nine months inhibits customers, implementers and trade allies from focusing on longer term savings opportunities and instead of focusing on easier projects, primarily lighting.

Company Expert/Witness: Brian File

ix. OPC recommendation of reduction in programs and default level

The recommendation of a "default" level of MEEIA programs for KCP&L and GMO is not acceptable to the Company. The minimized scale that OPC proposes is not reflective of the strong efforts by the state of Missouri to drive efficiency in homes and businesses. In fact, if the level of $4.7 million per year were adopted that would put the Company at 0.26% of annual revenues[88] spent on efficiency. This would rank in the bottom 20% of states nationwide for the most recent data available[89].

Company Expert/Witness: Brian File

x. Syncing the IRP and potential study timing

OPC witness Dr. Geoff Marke expresses concern in his rebuttal testimony that the Company has utilized its 2016 DSM potential study as the basis for its proposed programs in 2020-2023. First, the Company respectfully corrects Dr. Marke in that the DSM potential study was completed in 2017 and not in 2016[90]. Thus, the DSM potential study is not "coming up on being four years old", as he alleges, but was in fact, completed just two years ago. At the time the Company filed its Cycle 3 application, the study was slightly over one year old.

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[88] 2018 KCP&L-MO and GMO combined electric revenues.
[89] ACEEE – average spend as % of Statewide electric revenues (2010-2014).
[90] The Potential Study was filed as part of the 2018 triennial IRP cases EO-2018-0268 and EO-2018-0269.

The timing of the study is the result of two MEEIA rule requirements. First, the MEEIA rules require that the potential study be updated as least every three years.[91] Secondly, 20 CSR 4240-20.094(4)(B)1 actually requires that the Company provide a DSM potential study as a part of its MEEIA application.

> 1. A current market potential study. If the market potential study of the electric utility that is filing for approval of demand-side programs or a demand-side portfolio encompasses more than just the utility's service territory, the sampling methodology shall reflect the utility's service territory and shall provide statistically significant results for that utility:[92]
>
> 2. The second requirement is that the proposed programs have been analyzed in the IRP process and included in the utilities preferred plan.
>
> 3. Are included in the electric utility's preferred plan or have been analyzed through the integration process required by 4 CSR 240-22.060 [sic] to determine the impact of the demand-side programs and program plans on the net present value of revenue requirements of the electric utility.[93]

Furthermore, Dr. Marke's concern over the timeliness of the Company's use of the potential study is exaggerated. He fails to understand that the Company updates individual measure characteristics (e.g. measure energy and demand savings and measure life) annually with EM&V results. These measure characteristics are the main driver in program savings thus keeping the study reasonably up-to-date in between studies. Also, new measures can be added throughout the cycle as new technologies are developed.

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[91] 20 CSR 4240-20.094(3)(A)2.
[92] 20 CSR 4240-20.094(4)(B)1.
[93] 20 CSR 4240-20.094(4)(I)3.

The DSM potential study and IRP are both a lengthy and complicated processes. There is no practical way to shorten these processes to provide for a comprehensive study that addresses all necessary requirements of the potential study. Missouri's detailed and prescriptive requirements for DSM potential studies in the MEEIA and IRP rules cause the study to be expensive (approximately $1 million). Given the restrictions imposed by the Commission's rules, it makes little sense for the Company not to use this rigorous and detailed 2017 DSM potential study.

Company Expert/Witness: *Tim Nelson*

xi. OPC rate case commitment issues

OPC witness Marke alleges that the Company has not met its settlement obligations in its last rate cases regarding a consolidation study, green button platform, privacy policy statements and FAQs, and results of third party privacy impact assessments[94]. In fact, the Company has met all of its settlement obligations concerning these items.

With regards to the consolidation study, the Company met its obligations, including quarterly updates. However, OPC was inadvertently omitted from the quarterly updates which only went to the rate case stipulation signatories. The Company has now provided OPC the required information and is working to complete the study. As the consolidation study will make detailed recommendations regarding the consolidation of rates it is inappropriate for the Commission to adopt OPC's request that the Commission condition MEEIA approval on KCP&L and GMO filing a request for consolidation in its next rate

[94] Marke rebuttal testimony, pp. 3-4; 27-28.

case. As the Commission was made aware in the SJLP and MPS rate consolidation, there are many issues to resolve in any future consolidation of rates and the two companies. The Company cannot make any commitments regarding rate consolidation until after the study is completed and a decision is made on whether the GMO and KCP&L operating fleets should remain as separately identified on the individual company's books and records.

With regards to green button and customer privacy, condition #18 in the non-unanimous partial stipulation and agreement[95] reads as follows:

> CUSTOMER PRIVACY
> The Company will adopt the Green Button platform no later than the second half of 2020. The Company commits to producing a privacy policy statement and frequently asked questions ("FAQ") website section for customers regarding use of customer data. The Company will receive input from OPC, Staff, and DE on the privacy policy statement and FAQs. The Company will hold annual meetings with Staff, OPC, and DE regarding the results of the third party privacy impact assessments. The meetings and any material discussed at the meetings may be designated as confidential by the Company.

The stipulation and agreement was approved by the Commission with new tariffs approved on November 26, 2018 with an effective date of December 6, 2018. Contrary to OPC's contention that the Company is not adhering to the terms of its stipulation and agreement, the Company is not out of compliance with condition #18. The Company fully intends to adopt the green button platform no later than the second half of 2020, as well as hold its first annual meeting prior to December 6, 2019 with Staff, OPC and DE to discuss

[95] ER-2018-0145 and ER-2018-0146 Non-unanimous partial stipulation and agreement p. 9.

this effort, privacy policy statement and FAQs and results of the third-party privacy impact assessment.

Company Expert/Witness: Darrin Ives

III. REQUEST FOR WAIVERS

The Company reiterates its request for the variances it requested in its Application. Staff agrees that the first four variances should be approved if MEEIA Cycle 3 is approved by the Commission. Staff's recommendation of no variance of 20 CSR 4240-20.092 (1)(C) should be disregarded by the Commission. This variance is needed so that demand-side and supply-side resources are valued equivalently. Without this variance, the Company cannot rely on the avoided cost methodology that it used at the time the demand side programs were adopted.

IV. CONCLUSION

For the above reasons, the Company requests the Commission approve its Application.

VERIFICATION

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

Burton Crawford, being first duly sworn, on his oath and in his capacity as Director, Energy Resource Management, states that he is authorized to execute on behalf of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company the foregoing document, and has knowledge of the matters stated in this application, and that said matters are true and correct to the best of his knowledge and belief.

Burton Crawford

Subscribed and sworn to before me this 16th day of September 2019.

Notary Public

My Commission Expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

VERIFICATION

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

Brian A. File, being first duly sworn, on his oath and in his capacity as Senior Manager Products and Services, states that he is authorized to execute on behalf of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company the foregoing document, and has knowledge of the matters stated in this application, and that said matters are true and correct to the best of his knowledge and belief.

Brian File

Brian A. File

Subscribed and sworn to before me this 16th day of September 2019.

Notary Public

My Commission Expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

VERIFICATION

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

Mark Foltz, being first duly sworn, on his oath and in his capacity as Special Projects Director, Controller, states that he is authorized to execute on behalf of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company the foregoing document, and has knowledge of the matters stated in this application, and that said matters are true and correct to the best of his knowledge and belief.

Mark a. Foltz
Mark Foltz

Subscribed and sworn to before me this 16th day of September 2019.

Notary Public

My Commission Expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

VERIFICATION

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

Darrin R. Ives, being first duly sworn, on his oath and in his capacity as Vice President, Regulatory Affairs, states that he is authorized to execute on behalf of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company the foregoing document, and has knowledge of the matters stated in this application, and that said matters are true and correct to the best of his knowledge and belief.

Darrin R. Ives

Subscribed and sworn to before me this 16th day of September 2019.

Notary Public

My Commission Expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

VERIFICATION

STATE OF MISSOURI)
) ss.
COUNTY OF JACKSON)

Tim Nelson, being first duly sworn, on his oath and in his capacity as Manager Analytics, Energy Solutions, states that he is authorized to execute on behalf of Kansas City Power & Light Company and KCP&L Greater Missouri Operations Company the foregoing document, and has knowledge of the matters stated in this application, and that said matters are true and correct to the best of his knowledge and belief.

Tim M Nel

Tim Nelson

Subscribed and sworn to before me this 16th day of September 2019.

Notary Public

My Commission Expires: 4/26/2021

ANTHONY R WESTENKIRCHNER
Notary Public, Notary Seal
State of Missouri
Platte County
Commission # 17279952
My Commission Expires April 26, 2021

Kansas City Power & Light Home Energy Reports

2019 Customer Engagement Tracker Results

January 2019

Research Methodology

Phone survey of 808 KCP&L customers

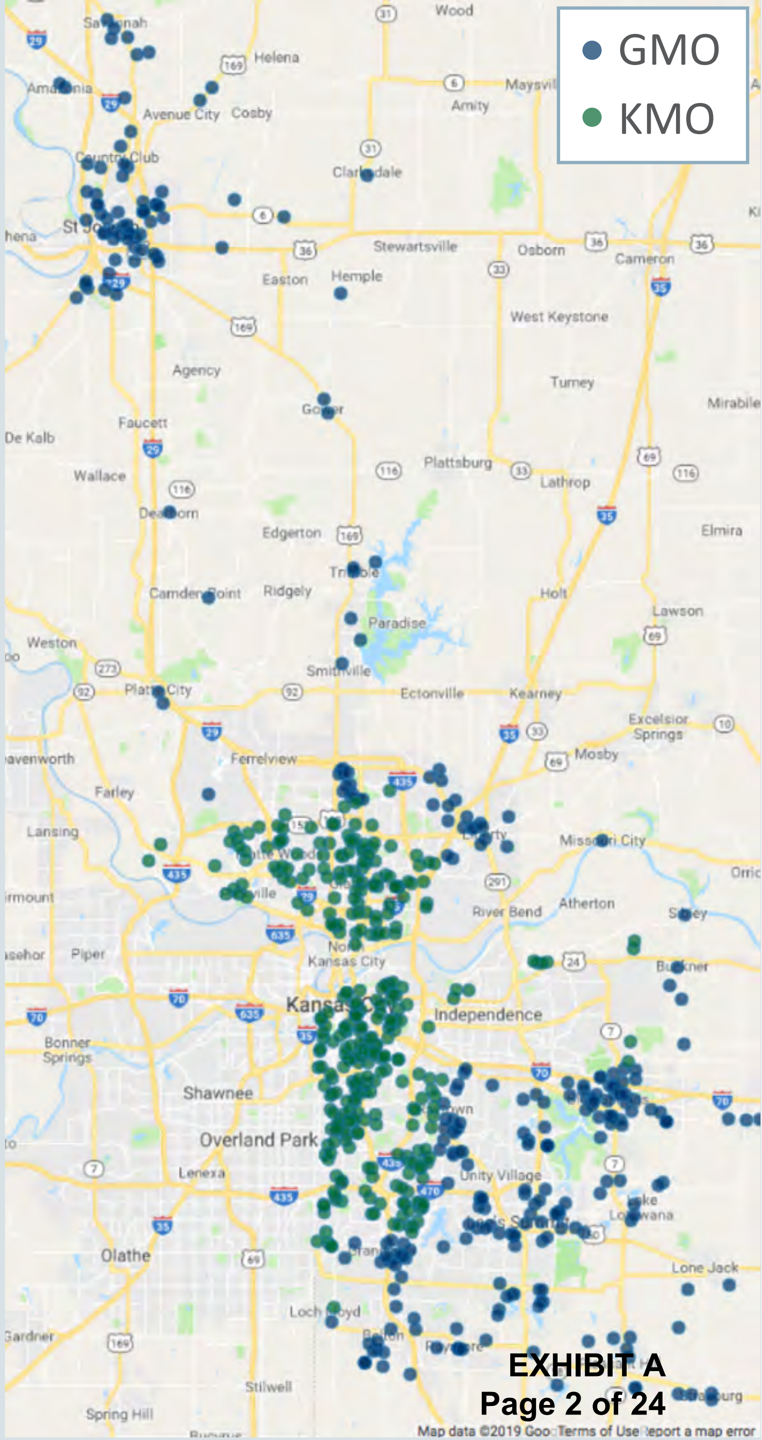
- **503 interviews** with Home Energy Report recipient customers
- **305 interviews** with control customers

Random selection of customers across all 8 deployment waves

- Fifth survey of Home Energy Reports program participants

Survey fielded between December 4 and December 16, 2017

- Interviews conducted by CASRO/ESOMAR-certified provider, ISA
- Semi-standard questionnaire designed in conjunction with KCP&L – based off of 2017 survey
- **35% completion upon successful contact;** 6% overall response rate



ORACLE

Key Findings

79% of recipients are remembering and reading the reports, including customers 5 years into the program

72% of recipients are satisfied with the reports, stable from last year

While recipients are more neutral that KCP&L provides a variety of energy-efficiency programs, they are more familiar with these programs than non-recipients

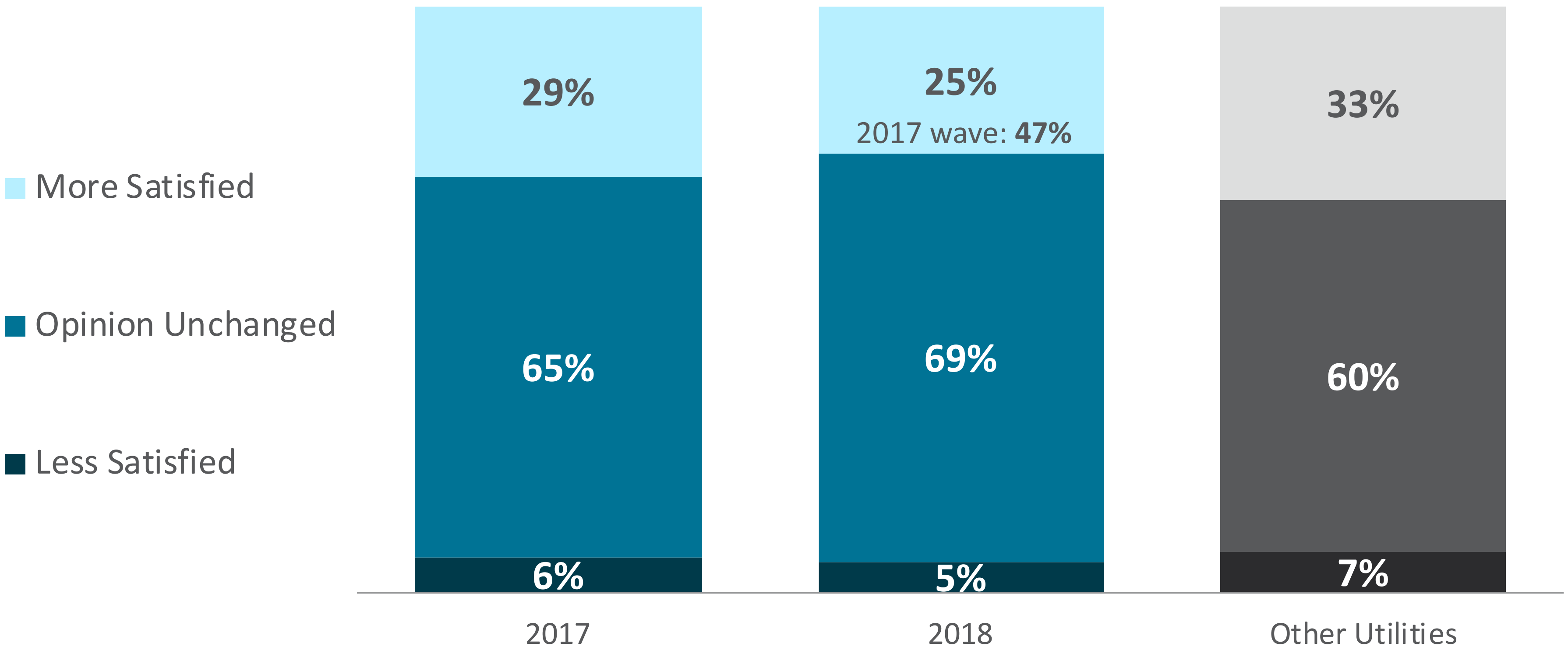
+6% increase in familiarity with KCP&L programs among report recipients

Program Impact

One quarter of recipients more satisfied with KCP&L after receiving reports; nearly half of newest wave satisfied

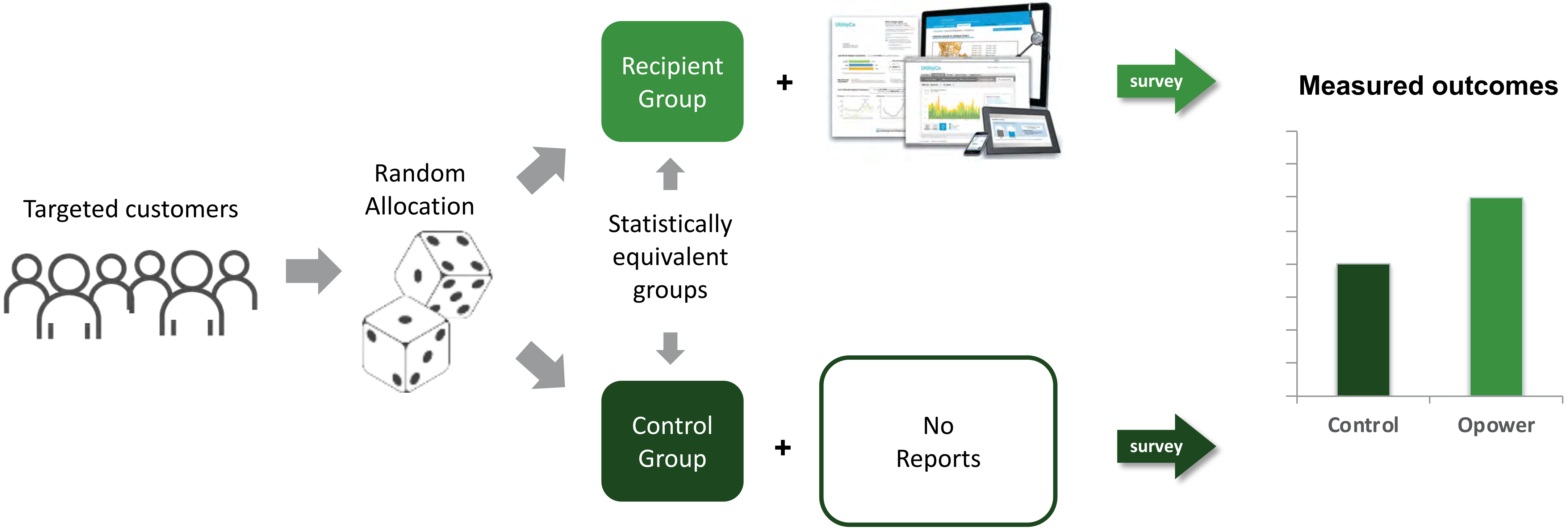
Impact on Relationship with KCP&L

389 recalling Home Energy Report recipients

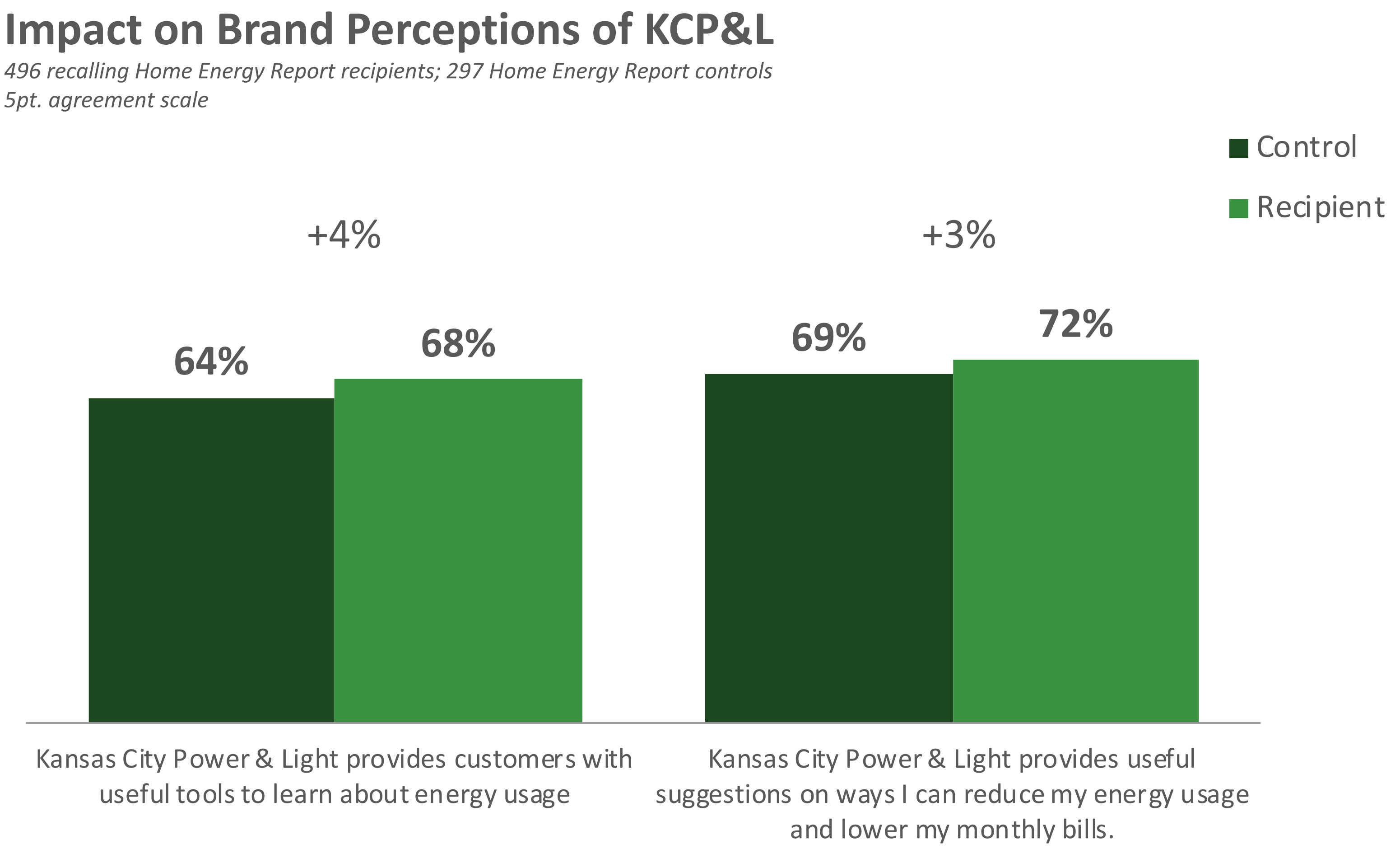


Did receiving the report make you less satisfied or more satisfied with KCP&L or did your opinion not change?

Experimental design enables precise measurement of impact on key outcomes



Directional increases to perceptions of KCP&L as partner in energy management among report recipients



ORACLE

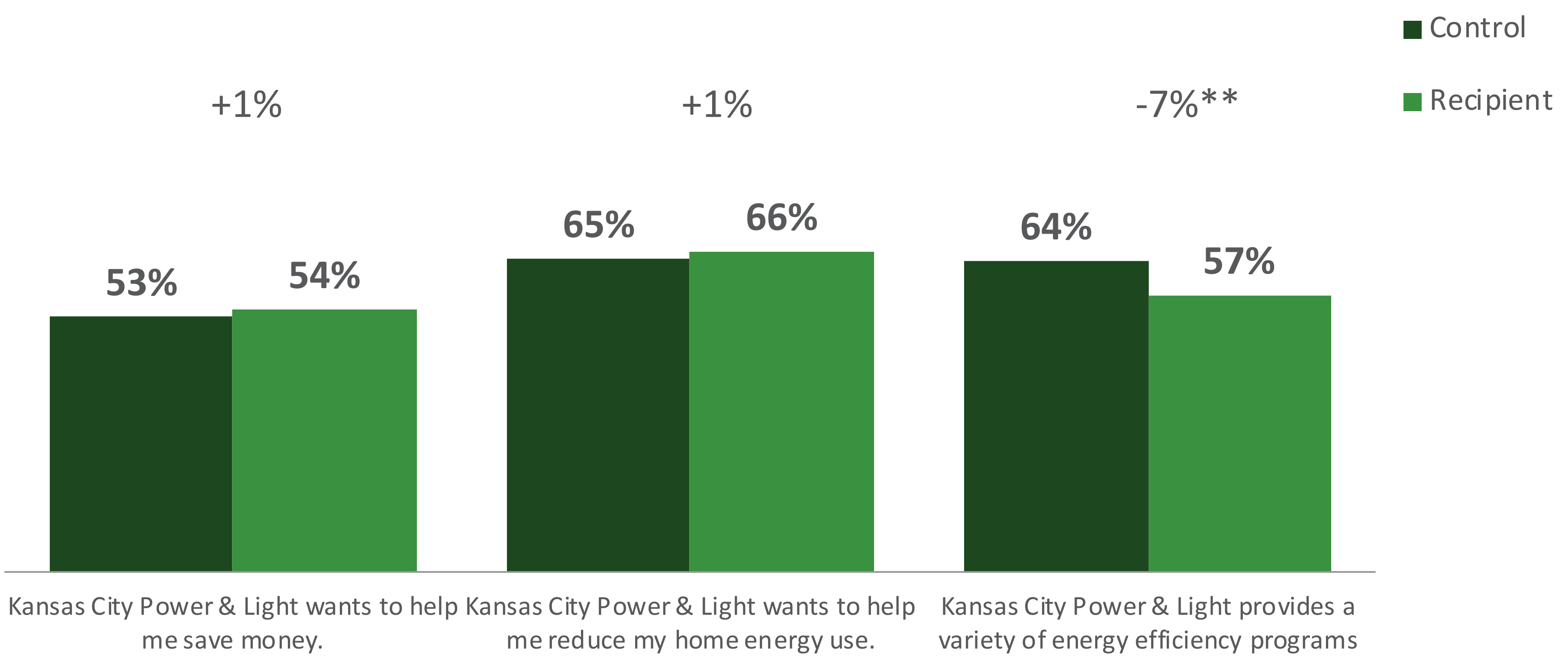
Tell me whether you strongly agree, somewhat agree, neither agree nor disagree, somewhat disagree, or strongly disagree with each of the following statements:

**95% significant difference
*90% significant difference

More report recipients neutral towards KCP&L providing a variety of programs…

Impact on Brand Perceptions of KCP&L

496 recalling Home Energy Report recipients; 297 Home Energy Report controls
5pt. agreement scale



ORACLE

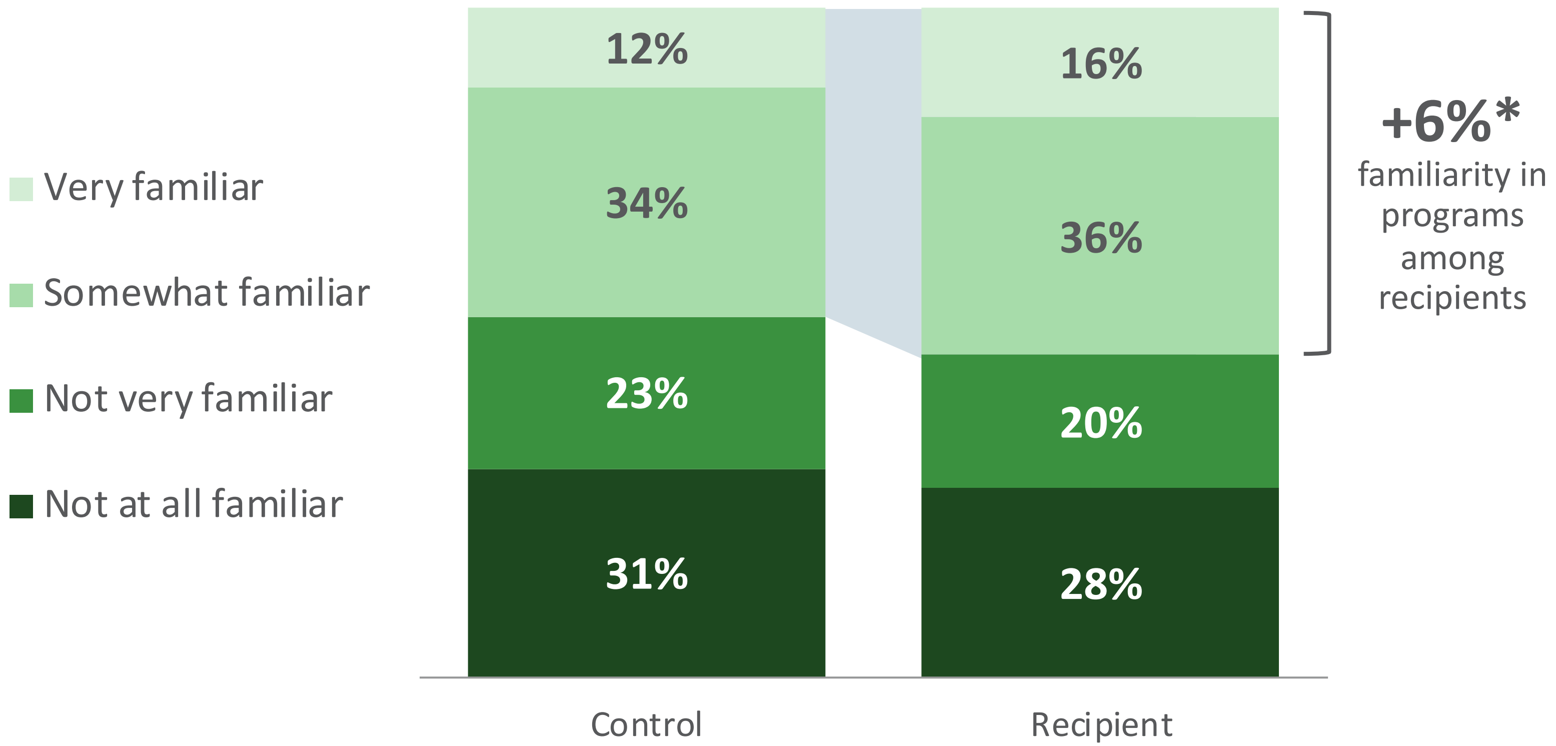
Tell me whether you strongly agree, somewhat agree, neither agree nor disagree, somewhat disagree, or strongly disagree with each of the following statements:

**95% significant difference
*90% significant difference

…but recipients more likely to state they are familiar with KCP&L's energy efficiency and conservation programs…

Impact on KCP&L Program Familiarity

601 recalling Home Energy Report recipients; 299 Home Energy Report controls; weighted
100 recalling Low Income Home Energy Report recipients



ORACLE

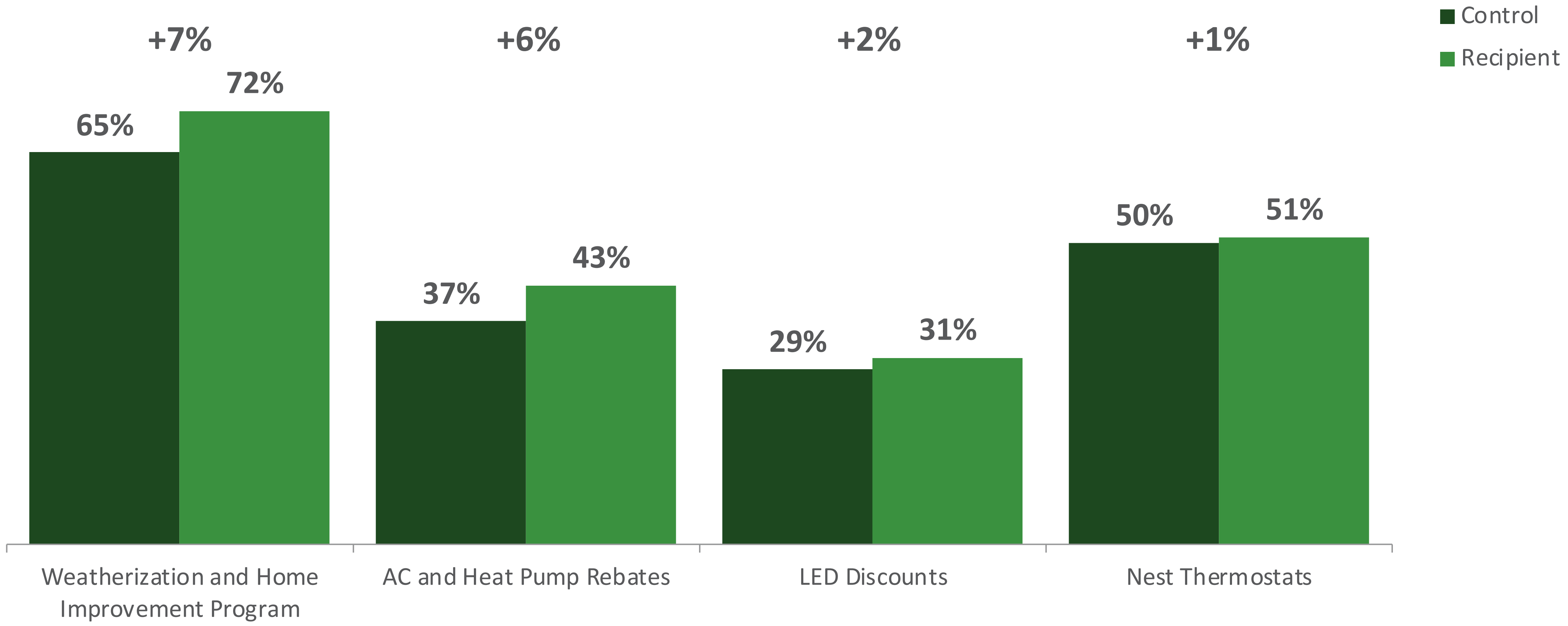
How familiar are you with energy efficiency or conservation programs from Kansas City Power & Light that help you with ways to use less energy?

**95% significant difference
*90% significant difference

…and directional increases observed in familiarity with specific programs among report recipients

Impact on Specific Program Familiarity

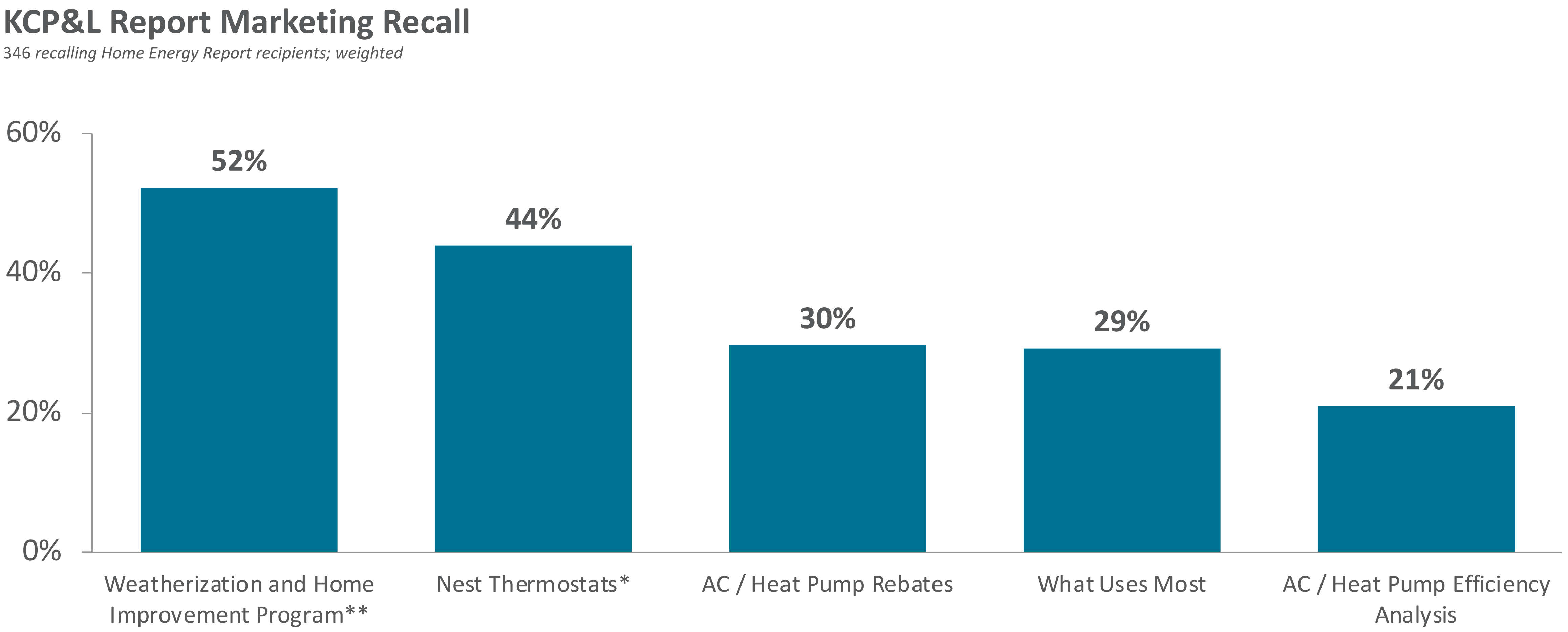
357 recalling Home Energy Report recipients; 205 Home Energy Report controls; weighted



Which of the following Kansas City Power & Light programs are you familiar with?

**95% significant difference
*90% significant difference

Weatherization and Home Improvement program and Nest thermostats most salient marketing modules in reports



Only shown to KCPL-MO and GMO customers
*** Only shown to Low Income customers*

Do you remember receiving information on the following KCP&L offerings and within your Home Energy Report?

Report Engagement

ORACLE

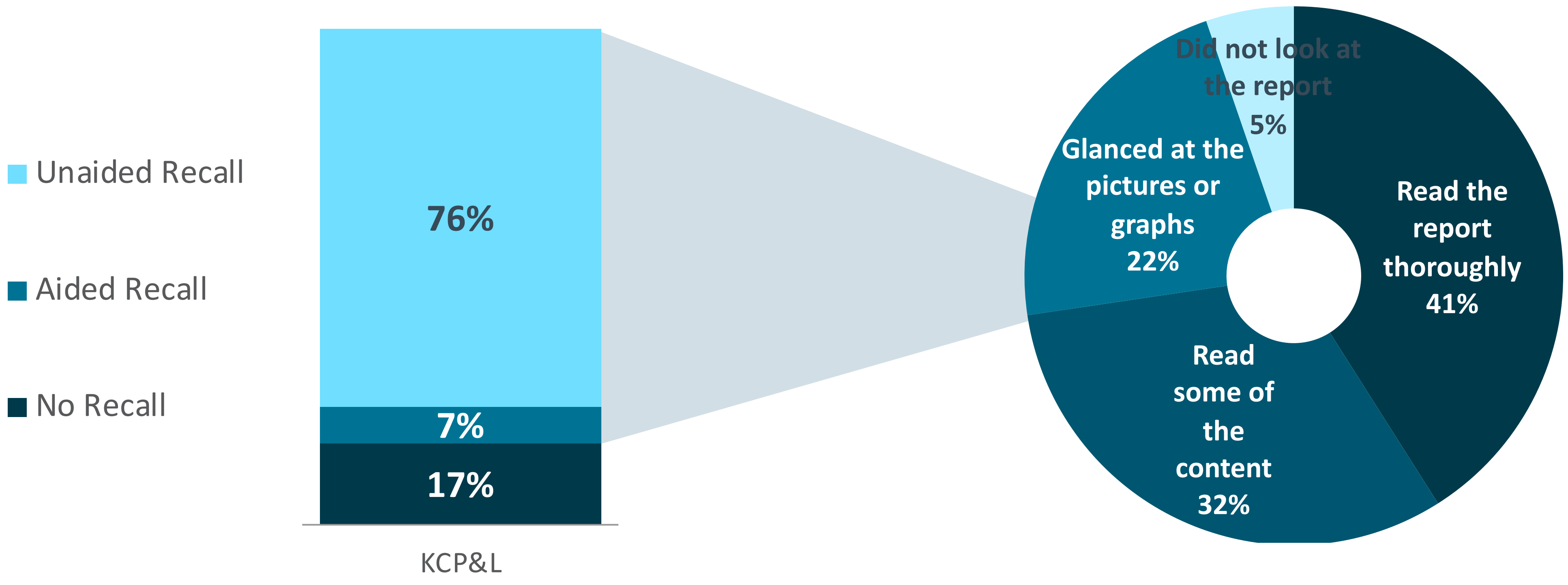
83% of recipients remember reports; 41% read thoroughly

Home Energy Report Recall

503 Home Energy Report recipients

Home Energy Report Reading

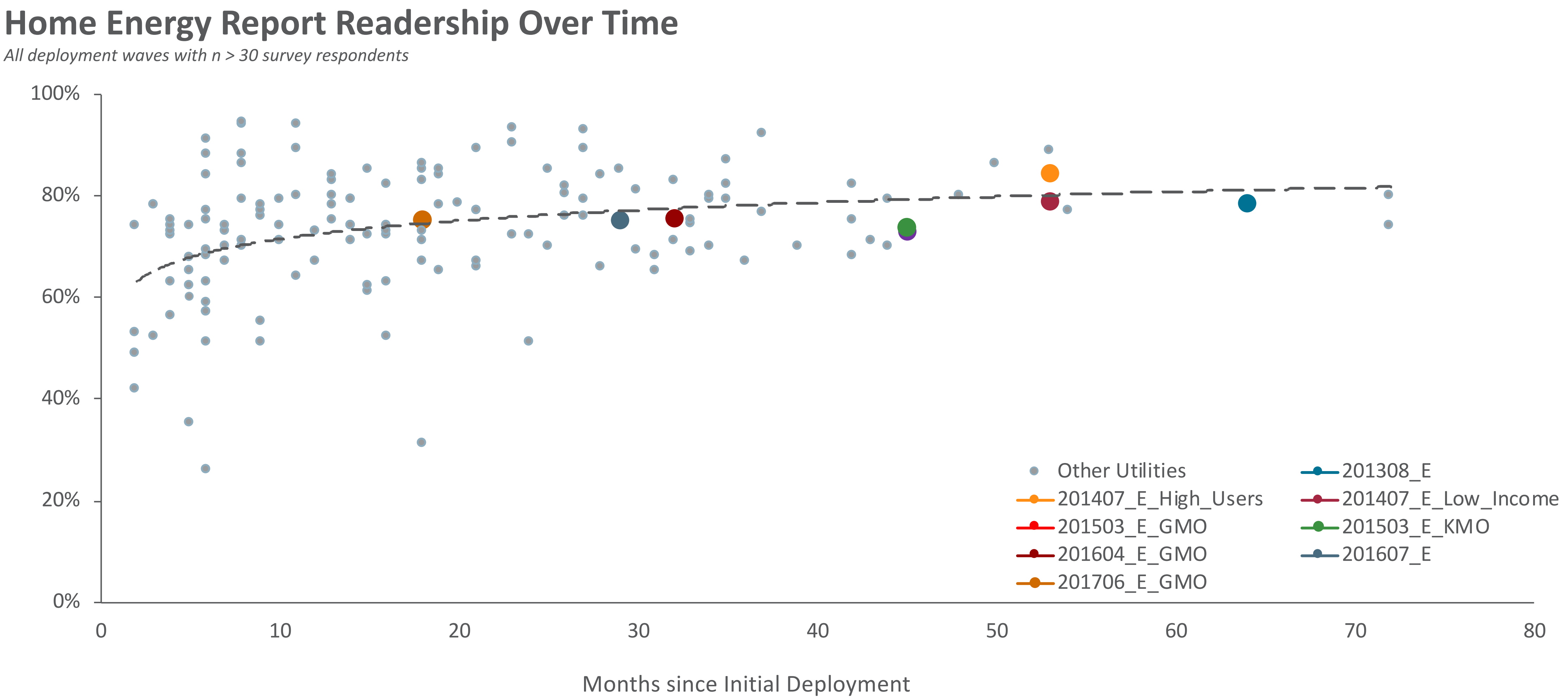
420 recalling Home Energy Report recipients; weighted



79% Overall Readership

In the past three months, do you remember receiving a Home Energy Report from KCP&L about your in-home energy usage? / Thinking of all the reports you have received, in general, what have you done with them?

Customers in program over 5 years continue to read reports

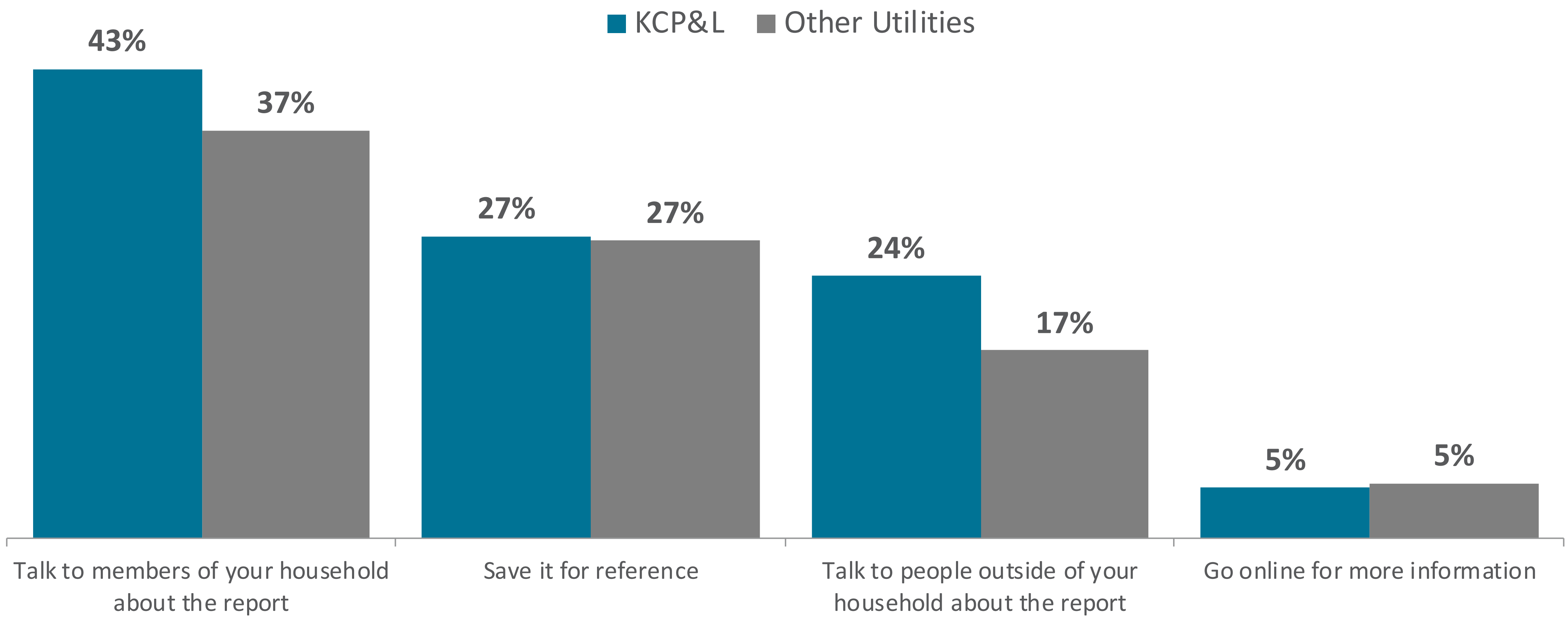


In the past three months, do you remember receiving a Home Energy Report from KCP&L about your in-home energy usage? / Thinking of all the reports you have received, in general, what have you done with them?

KCP&L customers continue to discuss reports within household, exceeding other utilities

Home Energy Report Interaction

395 recalling and reading HER recipients

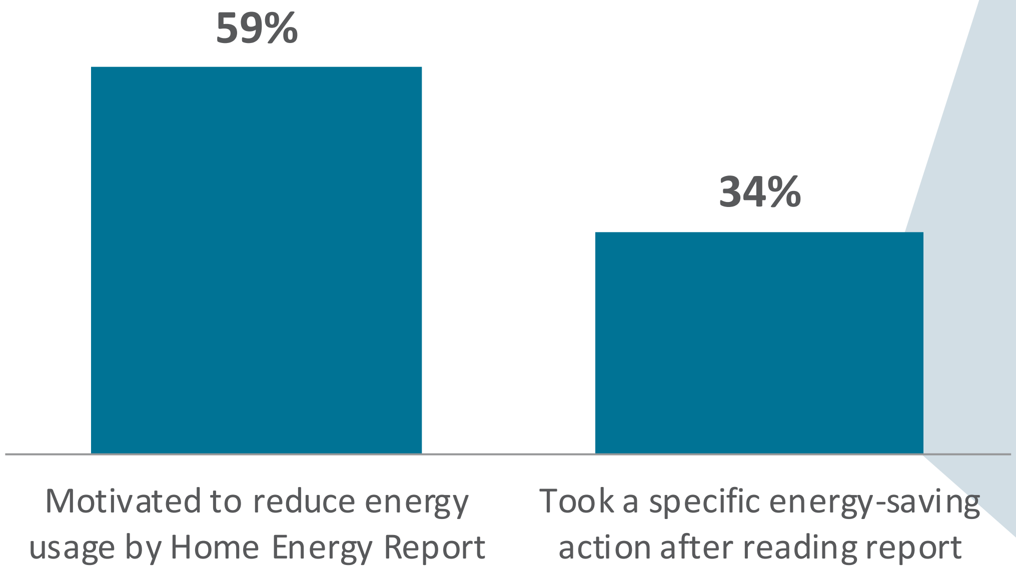


After reviewing your report, what do you typically do with it?

Over half of customers report being motivated to reduce their usage, in line with last year

Energy-Saving Actions

395 recalling and reading HER recipients



Which actions did you take?

133 coded open-ended responses

“I’m more mindful about turning anything off that’s not in use.”

“I bought LED lights and a Nest thermostat.”

“I turned off things that I didn’t realize are using energy, like my coffee maker – I reduce what I keep on 24 hours a day.”

“Looked at the energy star items when determining appliance purchases.”

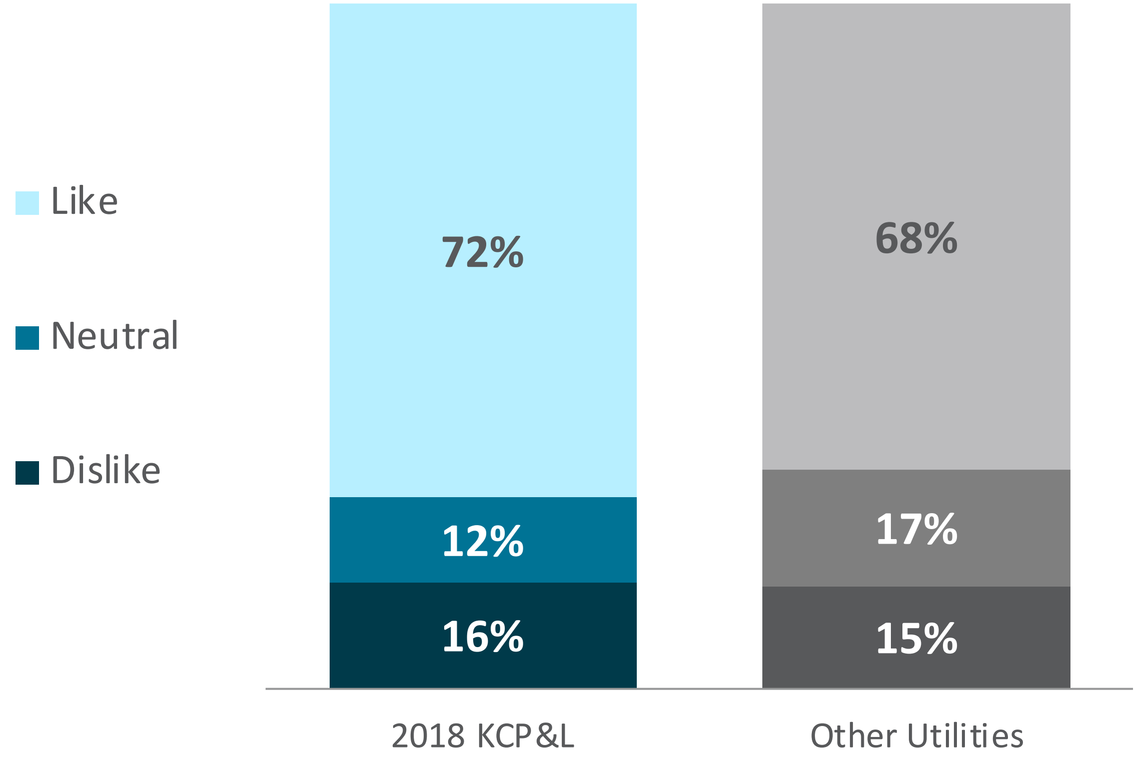
“I called KCP&L to come and check my heating and cooling when I saw my energy usage is high.”

Did the Home Energy Report motivate you to reduce your energy usage? / After reviewing your reports, did you…Take a specific energy-saving action? What actions did you take?

72% of customers satisfied with reports, slightly above peer programs

Home Energy Report Liking

392 recalling Home Energy Report recipients
5 pt. agreement scale



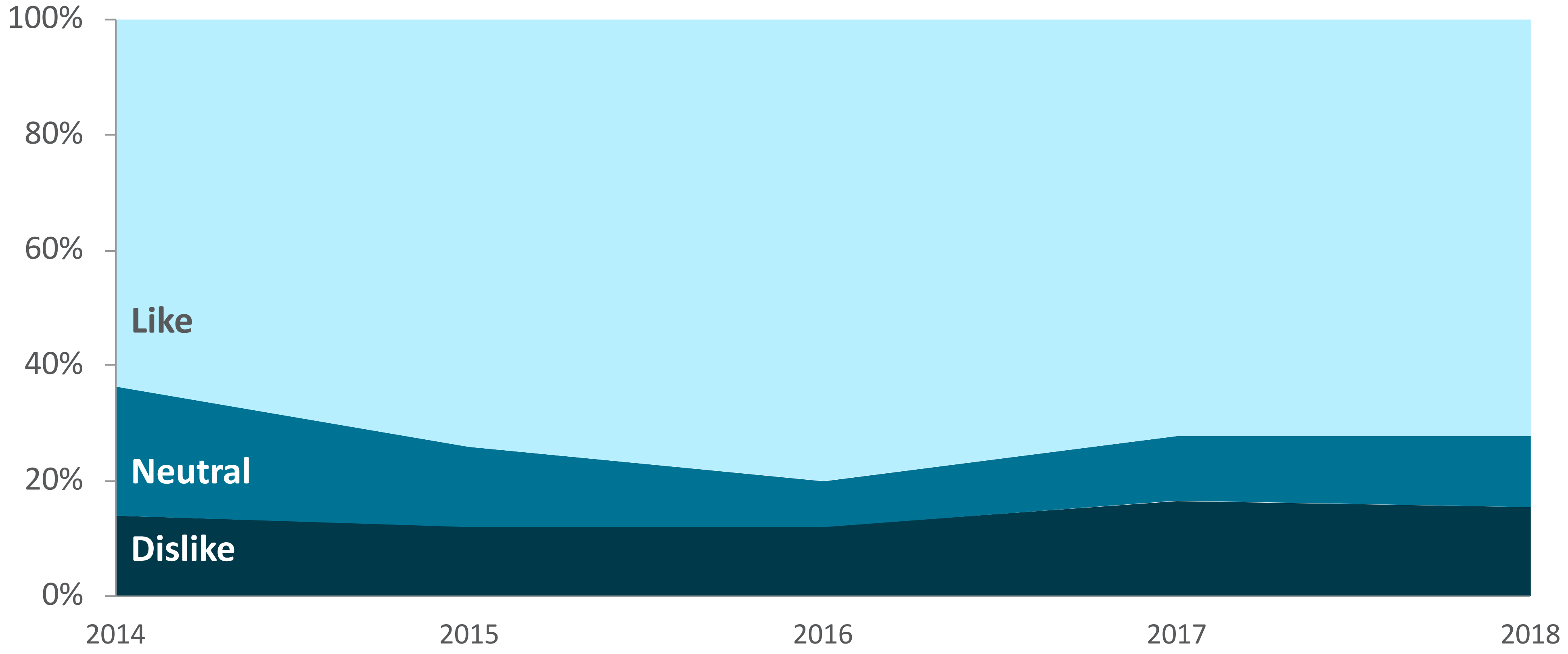
ORACLE

Tell me whether you strongly agree, somewhat agree, neither agree nor disagree, somewhat disagree, or strongly disagree with each of the following statements: I like the Home Energy Reports.

Satisfaction with reports stable from last year

Home Energy Report Liking

392 recalling Home Energy Report recipients
5 pt. agreement scale

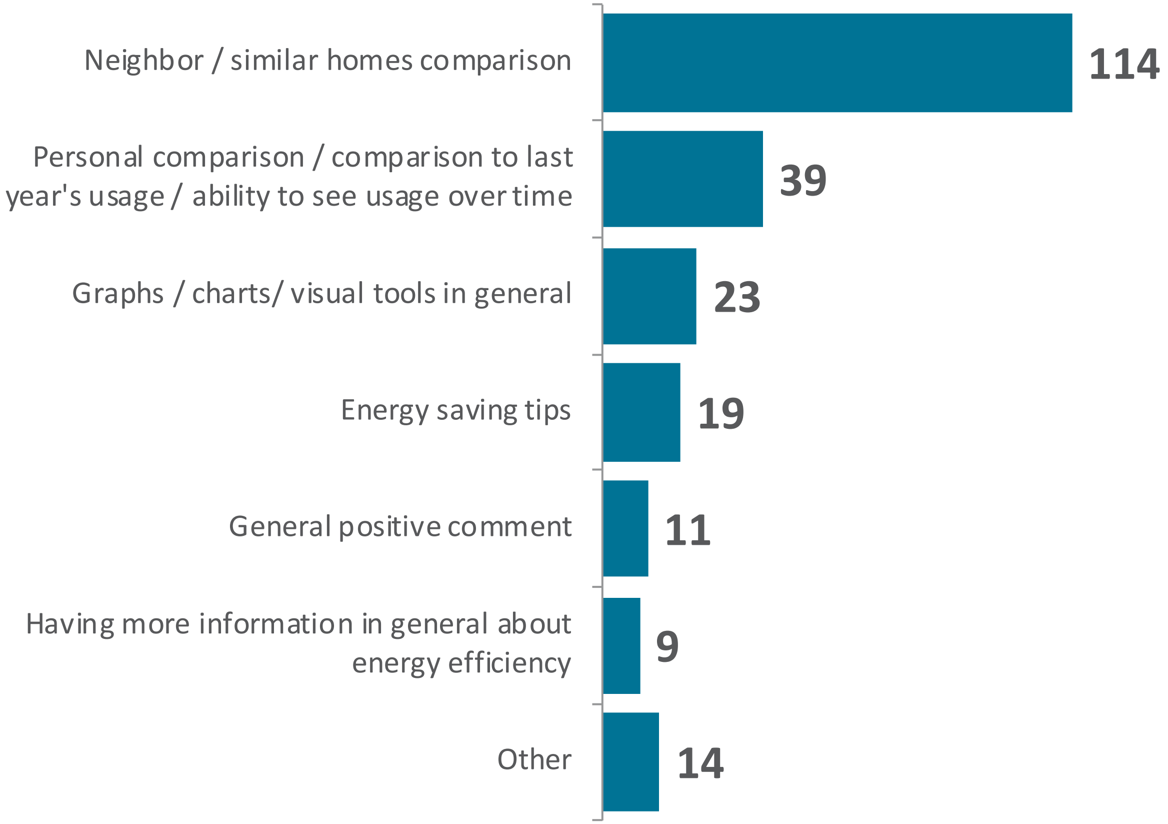


Tell me whether you strongly agree, somewhat agree, neither agree nor disagree, somewhat disagree, or strongly disagree with each of the following statements: I like the Home Energy Reports.

Neighbor comparison most liked component of reports…

[Likers] What aspect of the Home Energy Reports do you like the most?

224 open-ended responses



"I like to see what our neighbors' levels are – even though they are better than me, I like seeing the comparisons."

"It's very clear and I like the charts. It doesn't take me 20 minutes to read."

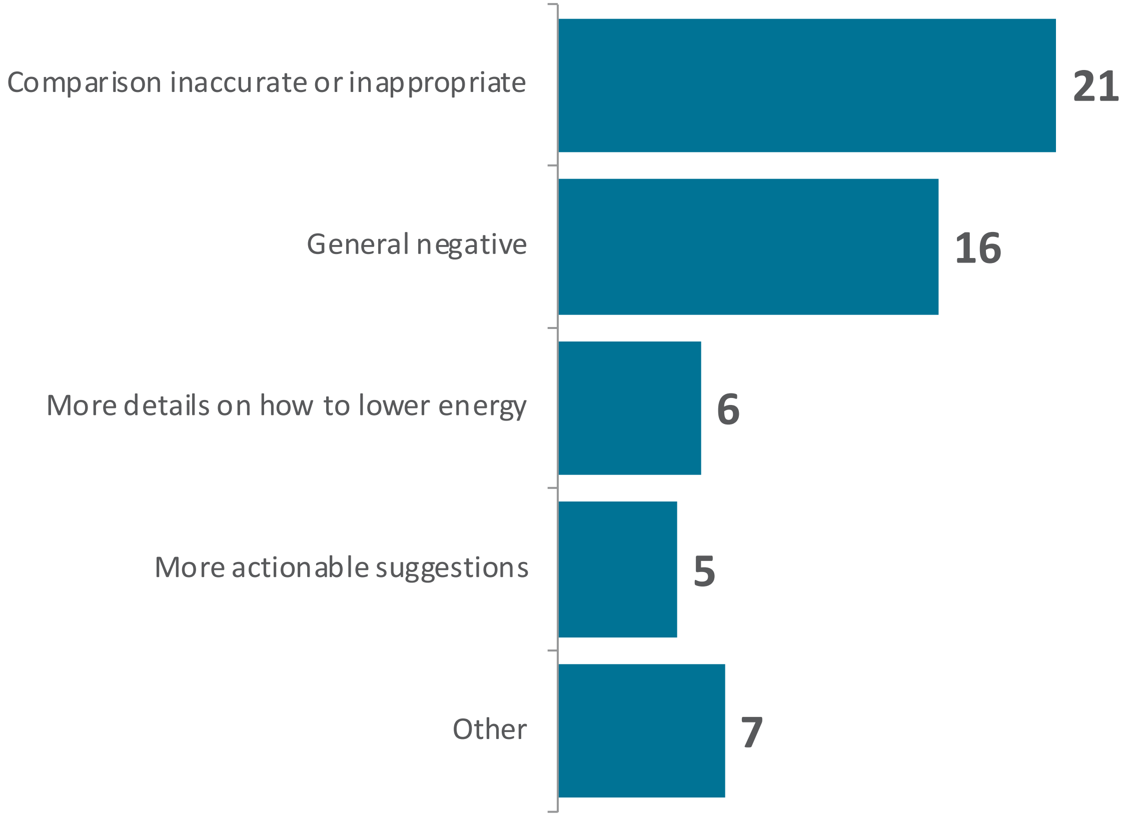
"The comparison with other home owners – it motivates me to continue conserving energy."

"Shows me how to save money and the programs they have to offer."

…but also the aspect most cited for improvement

[Neutral/Dislikers] What aspect of the Home Energy Reports should be improved?

56 open-ended responses



"The accuracy of the comparison with neighbors – some homes are bigger than others, some people work during the day and others don't. It's like comparing apples to oranges.

"They should specify why my electricity is higher than my neighbors."

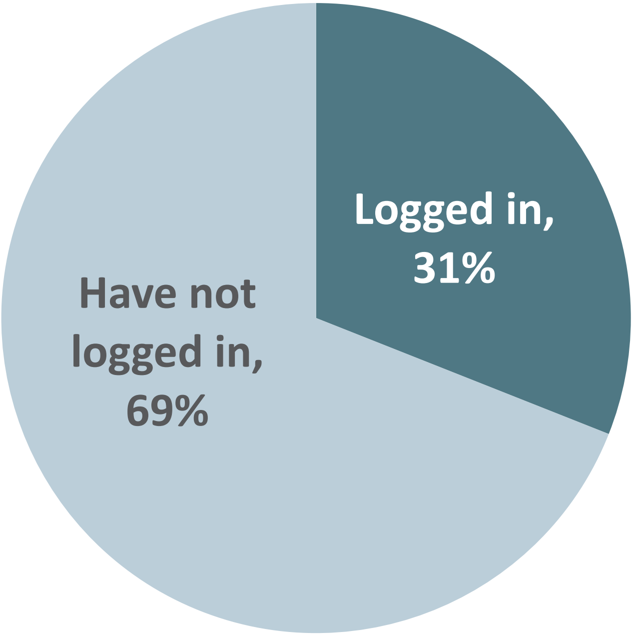
"My house is all electric and my neighbors have gas and electric."

Web Engagement

One third of customers recall having logged into web; those that have logged in are very satisfied with experience

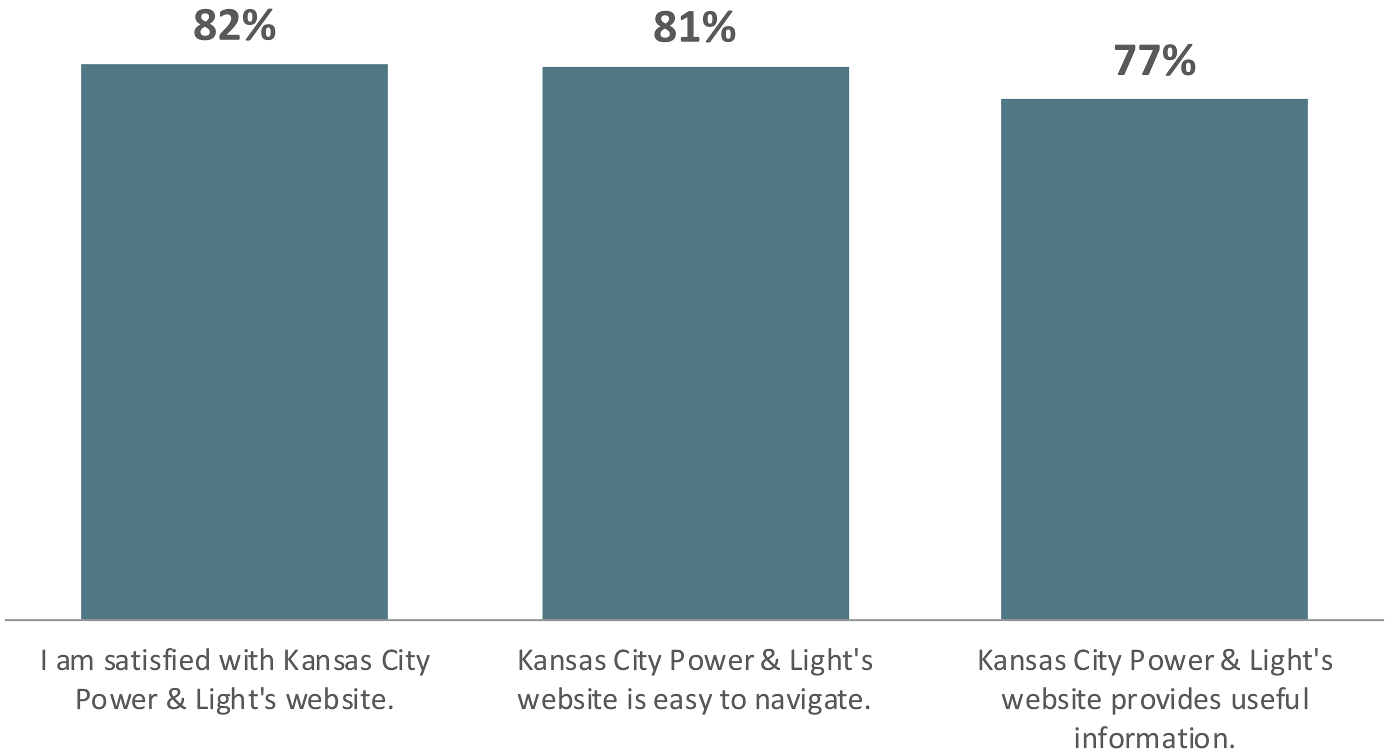
KCP&L Website Login Recall

808 KCP&L customers



KCP&L Web Reception

249 customers that have logging into web;
5pt. agreement scale (Top2, Bottom2 Box)



ORACLE

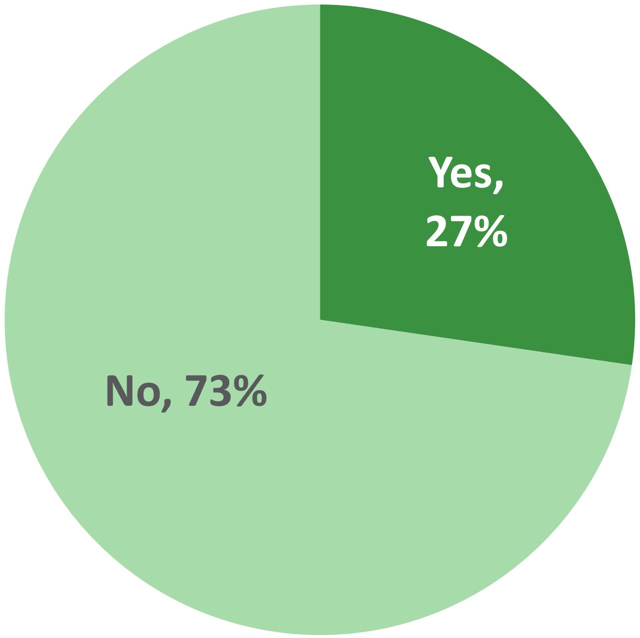
Have you ever logged into your account on Kansas City Power & Light's website? / Why have you logged into your account?

**95% significant difference
*90% significant difference

Users who have used Energy Analyzer very satisfied with tool

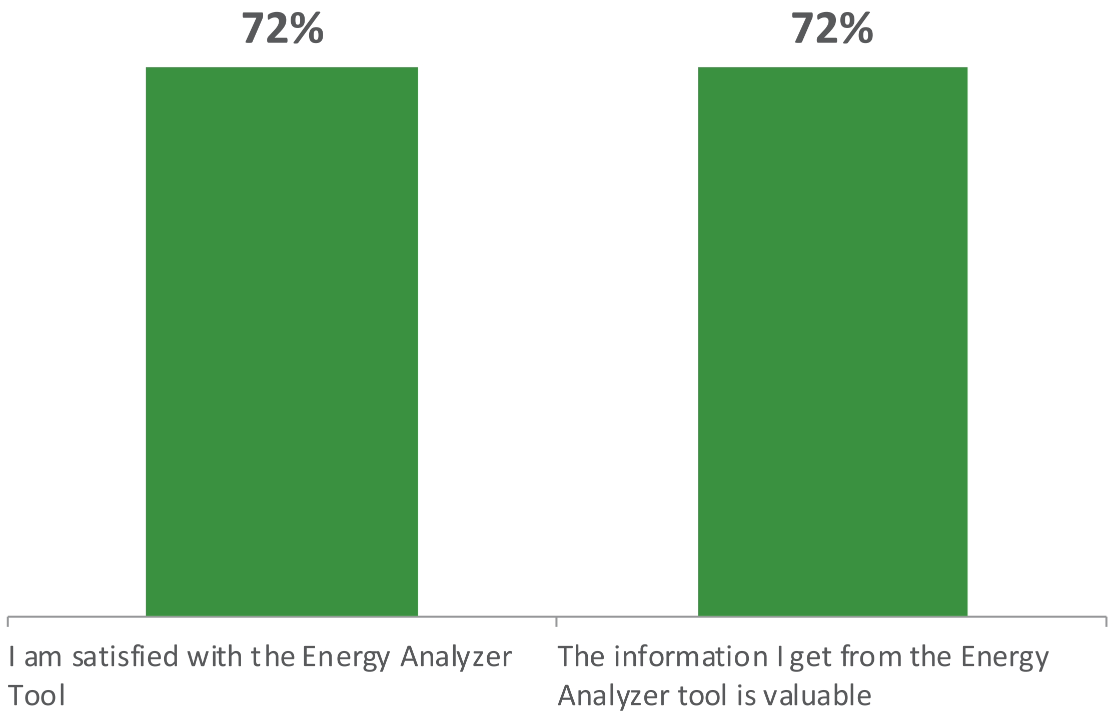
Have you ever used the Energy Analyzer tool?

249 customers that have logged in



Energy Analyzer Tool Reception

68 Energy Analyzer Tool users



ORACLE

Have you ever used the Energy Analyzer Tool? / Thinking about the Energy Analyzer tool, please tell me whether you strongly agree, somewhat agree, neither agree nor disagree, somewhat disagree, or strongly disagree with each of the following statements:

Final Recommendations

We have a highly engaged and receptive group of customers to tap into – let's experiment with different communications to:

A. Keep the experience fresh for customers in the program for multiple years

B. Test designs to see what resounds better with customers (or specific segments)

We know that the customer who login are very satisfied with the tools they encounter, so in addition to building and refining these tools, let's focus on how to push more customers to the web

We're expanding the energy management suite for customers, and that yields the opportunity for more consumer data that digs into reception for each of these products (future CETs, user feedback module)

KCPL MO
Case Name: 2018 KCPL MEEIA Cycle 3
Case Number: EO-2019-0132

Response to Murray Byron Interrogatories - MPSC_20181218
Date of Response:

Question:0100

1. What is the proposed funding level of the program by utility by quarter?

2. What are the brands and models of the level 2 charging stations being considered for the EV residential charging stations in the proposed MEEIA Cycle 3 program? Please provide a list of the recommended charging stations in an Excel spreadsheet. Please indicate if any brands or models of level 2 charging stations are proposed to be specifically excluded from eligibility.

3. Please provide the manufactures' recommended instantaneous demand capability, and recommended continuous demand capability for each of the level 2 charging stations listed in question number 1.

4. What specific limitations on the level of instantaneous demand capability and continuous demand capability will the program include for level 2 charging stations eligible for program participation?

5. Please provide the company's estimated residential charging load shape without the program. Assuming participating customers are not required to take service on a Time of Use rate or demand-charge rate, (a) Please provide the company's estimated residential charging load shape with the program at the proposed funding levels. (b) Please provide the company's estimated residential charging load shape with the program at 50% of the proposed funding level. (c) Please provide the company's estimated residential charging load shape with the program at 200% of the proposed funding level.

6. Assuming participating customers are required to take service on a Time of Use rate or demand-charge rate, (a) Please provide the company's estimated residential charging load shape with the program at the proposed funding levels. (b) Please provide the company's estimated residential charging load shape with the program at 50% of the proposed funding level. (c) Please provide the company's estimated residential charging load shape with the program at 200% of the proposed funding level.

7. Are the EV charging stations being considered in the MEEIA Cycle 3 Energy Star Certified EV charging stations?

8. Has the Company performed any analysis on the Demand Response (DR) capabilities of the various brands and models being promoted or recommended by the Company? If so, please provide the findings of the Company's analysis.

9. Can any of the charging stations perform the grid services listed below? a. Connected Functionality: i. Grid Communications:

1. Communications Link - Capable of Supporting DR?

2. Open Access – Interconnection Enabled; An interface specification, application programming interface (API), intended to enable DR functionality?

3. Consumer Override – Capable of supporting DR event override-ability by consumers?

4. Capabilities Summary – 500 words or less summary description of the EVSE system's and/or associated Service Provided DR capabilities/services: a. DR Support Services: load dispatch, ancillary services (including V2G), price notification and price response.

b. Steps needed to enable these capabilities

c. Support for locational DR i. Zip Code(s)

ii. Feeders

iii. EVSE Endpoints specified by the Load Management Entity

10. Do the charging stations contain various Modes and States of Readiness as stated below? a. No Vehicle Mode with Power Allowances – State A

b. Partial On Mode – State B1 or B2

c. Idle Mode – State C

d. In Use Mode

11. Has the Company performed any analysis on the current demand and energy impacts of Level 1 and Level 2 EV charging stations on the distribution system including the impact on a customer's meter and transformer? If so, please provide the analysis.

12. Has the company performed any cost effectiveness test on the proposed residential Level 2 EV charging station measure? If yes, please provide any analysis.

13. What is the current count of the EV charging stations installed in the Clean Charge Network by KCP&L and GMO in the respective jurisdictions? Please provide an Excel spreadsheet showing the model number, location, usage and status of each charging station.

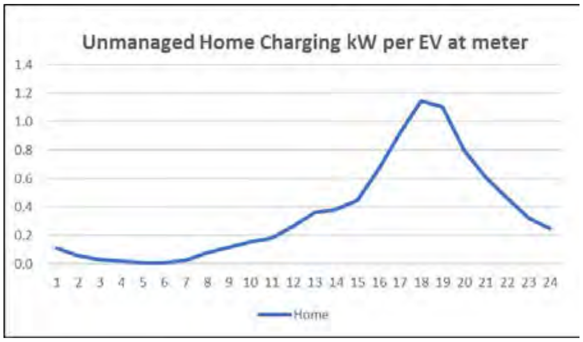
Data Request submitted by Byron Murray (Byron.Murray@psc.mo.gov)

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

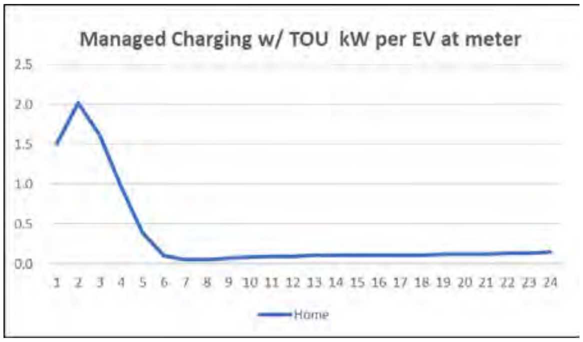
The Company is evaluating a potential MEEIA Cycle 3 program to capture the improved EV charging efficiency and demand management potential of Level 2 home charging over Level 1 charging. We are considering some research expenditure, but no specific program parameters have been developed to date.

1. A program budget has not been established.
2. Specific EV charging stations have not yet been identified.

3. Specific EV charging station requirements have not yet been identified.
4. Specific EV charging station parameters have not been established, but the focus would be on chargers that could support EV charging levels up to 7.6 kW.
5. As a specific program design has not yet been formulated, program level energy efficiency and system capacity impacts have not yet been estimated. The following figure illustrates the Company's current estimated system level average load shape for unmanaged home EV charging.



6. As a specific program design has not yet been formulated, program level energy efficiency and system capacity impacts under TOU have not yet been estimated. The following figure illustrates the Company's current estimated system level average load shape for managed home EV charging under a TOU rate with significant super off-peak price differentials.



7. Specific EV charging station requirements for a program have not yet been established, but we believe Energy Star certification will be a requirement. Per DOE, "ENERGY STAR certified EV chargers, on average use 40% less energy than a standard EV charger when the charger is in standby mode (i.e., not actively charging a vehicle). EV chargers are typically in a standby mode for about 85% of the lifetime of the product."
8. Specific EV charging station requirements for a program have not yet been established, but we believe a Demand Response (DR) capability is a likely requirement. The Company has not yet performed any analysis on DR capability of any specific vendor's home EV chargers.
9. The Company has not yet performed any analysis of specific vendor's home chargers to provide the grid service listed.
10. The Company has not yet performed any analysis of specific vendor's home chargers to provide the modes and states of readiness listed.

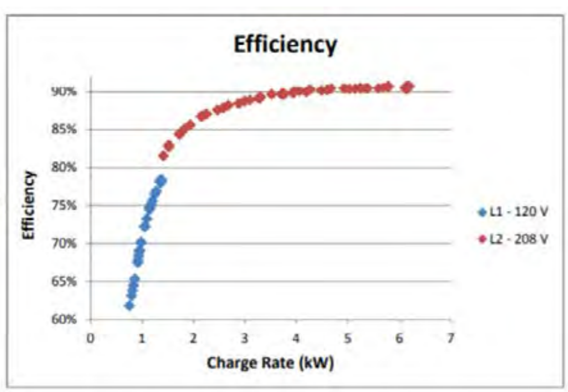
11. In 2018 EPRI completed the Phase 2 Analysis and Valuation of PEV Adoption for the KCP&L Clean Charge Network and published the attached report. The EPRI analysis found that the Company's generation, transmission, and distribution grid has sufficient capacity available to support a large number of PEVs with modest localized impacts on residential neighborhood distribution grid. The study also found that with managed home charging the impacts to the Company generation, transmission and distribution systems can be reduced significantly.

    The home charging profiles provided in responses 5 and 6 above are system level profiles and take into account the diversity of charging that naturally occurs. The table below illustrates the range of additional demand EV charging will place on a residential usage profile. The demand that EV charging places on the residential service is governed by two factors; 1) the capacity available from the electric plug or charging station and 2) the capacity of the EVs on-board charger. Level 1 charging is constrained by the electric outlet which, in most garages, is a shared 15 amp circuit. Level 2 charging is most commonly constrained by the capacity of the EVs on-board charger. While on-board chargers are increasing, 3.6 kW is typical for the average PHEV and 6-7 kW is typical for the average BEV. The table below also shows that the time required to achieve an average daily charge of 12.2 kWh (36.5 mi. @ 3.0 mi/kWh) with Level 1 charging affords limited opportunities to shift charging to super-off peak periods. Level 2 allows the average daily charge to be accomplished during a 6-hr. super off-peak period, but affords additional opportunities to shift the charging within the super off-peak period to further minimize grid impacts.

Charge Level	Circuit Voltage	Circuit Breaker	Charge Amps Available	Charge Capacity Available	EV Charge Capacity	Hours to Charge 12.2 kWh
L1	120v	15a	12a	1.44kW	Any	8.50 hrs
L1	120v	20a	16a	1.92kW	Any	6.35 hrs
L2	240v	40a	32a	7.68kW	3.6 kW	3.4 hrs
L2	240v	40a	32a	7.68kW	6.6 kW	1.85 hrs

Industry literature also indicates that the efficiency of L2 charging may be 10-15 % more efficient than L1 charging. The decreased efficiency of L1 charging is driven by two main factors; 1) the power draw of the EV battery management system for the longer charge time, and 2) the decreased EV charger efficiency when operated at L1 power levels. Most EV chargers are optimized for operation at the L2 charge rating.

The following graph from Idaho National Labs shows EV charging efficiency for the 2015 Nissan Leaf.



The following test results and studies of L1 vs L2 charging efficiencies are attached:

- INL Stead State Vehicle Charging Fact Sheet-2015 Nissan Leaf
- INL Stead State Vehicle Charging Fact Sheet-2015 Mercedes B-Class
- INL Stead State Vehicle Charging Fact Sheet-2014 BMW i3
- INL Stead State Vehicle Charging Fact Sheet-2012 Chevrolet Volt
- Assessment of L1-and L2 EV Charging Efficiency

12. As a specific program design has not yet been formulated, the Company has not yet performed a cost effectiveness test for the program.

Responses to parts1-12 provided by: Ed Hedges

13. The current count of installed EV charging stations by jurisdiction is as follows:

CCN without Company Locations	
GMO	242
KCP&L – MO	364

Company Locations	
GMO	21
KCP&L – MO	44

Please see the attached Excel spreadsheet, Q0100_CCN 2018 Station Data by Jurisdiction, for the list of charging stations including model number, location, usage and status.

Response to part 13 provided by: Wendy Marine

Attachments:
Q0100-Phase 2 Analysis and Valuation of PEV Adoption.pdf
Q0100-INL Stead State Vehicle Charging Fact Sheet-2015Leaf.pdf
Q0100-INL Stead State Vehicle Charging Fact Sheet-2015MercedesBclass.pdf
Q0100-INL Stead State Vehicle Charging Fact Sheet-2014BMWi3.pdf
Q0100-INL Stead State Vehicle Charging Fact Sheet-2012Volt.pdf
Q0100-Assessment of L1 and L2 EV Charging Efficiency.pdf
Q0100_CCN 2018 Station Data by Jurisdiction.xlsx
Q0100_Verification.pdf

GENERAL RULES AND REGULATIONS
APPLYING TO ELECTRIC SERVICE
22.01 BUSINESS DEMAND-SIDE MANAGEMENT

DEFINITIONS:
Unless otherwise defined, terms used in tariff sheets or schedules in Section 22 have the following meanings:

Applicant – A customer who has submitted a program application or has had a program application submitted on their behalf by an agent or trade ally.

Demand-Side Program Investment Mechanism (DSIM) – A mechanism approved by the Commission in KCP&L's filing for demand-side programs approval in Case No. EO-2019-0132.

Business Program – An energy efficiency program that is available to a customer receiving electric service under Service Classifications Small General Service Rate, Medium General Service Rate, Large General Service Rate, Large Power Service Rate.

Deemed Savings Table – A list of measures derived from the Company's filed TRM that characterizes associated gross energy and demand savings with specific measure parameters where available.

Energy Efficiency - Measures that reduce the amount of electricity required to achieve a given end use.
Incentive – Any consideration provided by KCP&L directly or through the Program Administrator, including in the form of cash, bill credit, payment to third party, or public education programs, which encourages the adoption of Measures.

Long-Lead Project- A project committed to by a Customer, accepted by the Company, and a signed commitment offer received by the program administrator by March 31, 2023 according to the terms and implementation of the MEEIA 2019-2022 Energy Efficiency Plan that will require a date after March 31, 2022, but no later than March 31, 2023 to certify completion.

Measure – An end-use measure, energy efficiency measure, and energy management measure as defined in 4 CSR 240-22.020(18), (20), and (21).

Participant – An energy related decision maker who implements one or more end use measures as a direct result of a demand side program.

Program Administrator – The entity selected by KCP&L to provide program design, promotion, administration, implementation, and delivery of services.

Program Partner – A retailer, distributor or other service provider that KCP&L or the Program Administrator has approved to provide specific program services through execution of a KCP&L approved service agreement.

Program Period – The period from January 1, 2020 through December 31, 2022, unless sooner terminated under the term provision of this tariff. Programs may have slightly earlier termination dates for certain activities, as noted on the KCP&L website – www.kcpl.com.

Project – One or more Measures proposed by an Applicant in a single application.

Trade Ally – An independent contractor that the Company or the Program Administrator has approved to provide specific program services through execution of a Company approved service agreement.

Measure Benefit/Cost Test- Each non-prescriptive Project must pass the B/C Test by having a value of 1.0 or greater. B/C Test value equals the present value of the benefits of each Measure over the useful life of each Measure divided by the incremental cost to implement the Project Measures. The benefits of the Measure include the Company's estimated avoided costs.

GENERAL RULES AND REGULATIONS
APPLYING TO ELECTRIC SERVICE
22.01 BUSINESS DEMAND-SIDE MANAGEMENT

Total Resource Cost (TRC) Test – A test of the cost-effectiveness of demand-side programs that compares the avoided utility costs to the sum of all incremental costs of end-use measures that are implemented due to the program (including both KCP&L and Participant contributions), plus utility costs to administer, deliver and evaluate each demand-side program.

TERM:
These tariff sheets and the tariff sheets reflecting each specific Business DSM program shall be effective for three years from the effective date of the tariff sheets, unless another termination date is approved by the Commission.

If the Programs are terminated prior to the end of the Program Period, only Incentives for qualifying Measures that have been preapproved or installed prior to the Programs' termination will be provided to the customer.

DESCRIPTION:
The reduction in energy consumption or shift in peak demand will be accomplished through the following Programs:

- Business Energy Efficiency Rebates – Standard
- Business Energy Efficiency Rebates- Custom
- Business Smart Thermostat
- Business Process Efficiency
- Business Demand Response

In addition, KCP&L customers also have access to the Online Business Energy Audit.

Program details regarding the interaction between KCP&L or Program Administrators and Participants, such as Incentives paid directly to Participants, available Measures, availability of the Program, eligibility, and application and completion requirements may be adjusted through the change process as presented below. Those details, additional details on each Program, and other information such as process flows, application instructions, and application forms will be provided by the KCP&L website, www.kcpl.com

Business Programs

	Expected Annual Incremental kWh Energy Savings Targets at Customer Side of Meter						3-Year Savings Target
	2019	2020	2021	2022	2023	2024	
Business Standard	14,019,243	19,107,931	20,850,204	-	-	-	53,977,377
Business Custom	5,216,973	11,114,231	13,908,599	-	-	-	30,239,803
Business Process Efficiency	3,273,111	7,191,746	8,989,682	-	-	-	19,454,539
Business Demand Response	0	0	0	0	0	0	-
Business Smart Thermostat	29,156	58,312	87,468	-	-	-	174,936
Total	22,538,482	37,472,221	43,835,953	-	-	-	103,846,656

	Expected Annual Incremental kW Demand Savings Targets at Customer Side of Meter						3-Year Savings Target
	2019	2020	2021	2022	2023	2024	
Business Standard	2,181	3,013	3,328	-	-	-	8,523
Business Custom	834	1,777	2,223	-	-	-	4,834
Business Process Efficiency	24	70	87	-	-	-	182
Business Demand Response	15,000	-	-	-	-	-	15,000
Business Smart Thermostat	213	426	639	-	-	-	1,279
Total	18,253	5,286	6,278	-	-	-	29,817

Residential Programs

	Expected Annual Incremental kWh Energy Savings Targets at Customer Side of Meter						3-Year Savings Target*
	2019	2020	2021	2022	2023	2024	
Energy Saving Products	12,153,179	9,722,590	7,555,117	-	-	-	29,430,886
Heating, Cooling & Weatherization	3,346,358	4,814,841	5,426,432	-	-	-	13,587,631
Home Energy Report	9,579,000	-	-	-	-	-	9,579,000
Income-Eligible Energy Report	2,928,146	-	-	-	-	-	2,928,146
Income-Eligible Multi-Family	1,368,009	1,160,994	1,160,994	906,913	945,949	992,465	6,535,323
Residential Demand Response	1,171,048	1,329,516	1,466,157	-	-	-	3,966,721
Total	30,545,741	17,027,941	15,608,700	906,913	945,949	992,465	66,027,707

*6-Year Savings Target for IEMF

	Expected Annual Incremental kW Demand Savings Targets at Customer Side of Meter						3-Year Savings Target*
	2019	2020	2021	2022	2023	2024	
Energy Saving Products	889	725	558	-	-	-	2,172
Heating, Cooling & Weatherization	1,607	2,225	2,480	-	-	-	6,312
Home Energy Report	1,200	-	-	-	-	-	1,200
Income-Eligible Energy Report	366	-	-	-	-	-	366
Income-Eligible Multi-Family	248	228	228	183	197	214	1,297
Residential Demand Response	8,679	9,957	11,135	-	-	-	29,772
Total	12,989	13,134	14,401	183	197	214	41,119

*6-Year Savings Target for IEMF

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Business Programs

	Expected Annual Incremental kWh Energy Savings Targets at Customer Side of Meter						3-Year Savings Target
	2019	2020	2021	2022	2023	2024	
Business Standard	13,647,812	16,447,377	16,551,009	-	-	-	46,646,197
Business Custom	2,663,601	3,676,320	3,676,320	-	-	-	10,016,241
Business Process Efficiency	3,618,889	7,639,682	9,212,103	-	-	-	20,470,674
Business Demand Response	0	0	0	0	0	0	-
Business Smart Thermostat	28,368	56,736	85,104	-	-	-	170,208
Total	19,958,670	27,820,115	29,524,536	-	-	-	77,303,321

	Expected Annual Incremental kW Demand Savings Targets at Customer Side of Meter						3-Year Savings Target
	2019	2020	2021	2022	2023	2024	
Business Standard	2,161	2,653	2,700	-	-	-	7,514
Business Custom	423	582	582	-	-	-	1,587
Business Process Efficiency	31	87	109	-	-	-	227
Business Demand Response	49,488	2,605	2,742	-	-	-	54,834
Business Smart Thermostat	207	415	622	-	-	-	1,244
Total	52,309	6,342	6,755	-	-	-	65,406

Residential Programs

	Expected Annual Incremental kWh Energy Savings Targets at Customer Side of Meter						3-Year Savings Target*
	2019	2020	2021	2022	2023	2024	
Energy Saving Products	13,038,632	10,416,978	8,079,124	-	-	-	31,534,734
Heating, Cooling & Weatherization	7,236,542	7,767,640	8,338,188	-	-	-	23,342,370
Home Energy Report	20,355,375	-	-	-	-	-	20,355,375
Income-Eligible Multi-Family	1,388,947	1,181,931	1,181,931	923,401	963,321	1,010,700	6,650,231
Residential Demand Response	1,220,615	1,402,388	1,549,459	-	-	-	4,172,461
Total	43,240,111	20,768,937	19,148,702	923,401	963,321	1,010,700	86,055,171

*6-Year Savings Target for IEMF

	Expected Annual Incremental kW Demand Savings Targets at Customer Side of Meter						3-Year Savings Target*
	2019	2020	2021	2022	2023	2024	
Energy Saving Products	955	756	582	-	-	-	2,293
Heating, Cooling & Weatherization	3,133	3,392	3,655	-	-	-	10,180
Home Energy Report	2,550	-	-	-	-	-	2,550
Income-Eligible Multi-Family	243	223	223	180	193	210	1,271
Residential Demand Response	9,221	10,609	11,774	-	-	-	31,604
Total	16,102	14,980	16,233	180	193	210	47,898

*6-Year Savings Target for IEMF