Exhibit No.:	
Issue:	Retail Revenues; Economic Relief Pilot Program; Fuel Adjustment Clause; Property Tax Tracker; Critical Information Protection/Cybersecurity Tracker; Vegetation Management Tracker; Solar Rebates; Income Illegible Weatherization Program; LED Street and Area Lighting; Class Cost of Service Studies; Rate Design
Witness:	Tim M. Rush
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Kansas City Power & Light Company
Case No.:	ER-2014-0370
Date Testimony Prepared:	May 7, 2015

MISSOURI PUBLIC SERVICE COMMISSION

CASE NO.: ER-2014-0370

REBUTTAL TESTIMONY

OF

TIM M. RUSH

ON BEHALF OF

KANSAS CITY POWER & LIGHT COMPANY

Kansas City, Missouri
May 2015

Certain Schedules Attached To This Testimony Designated "(Highly Confidential)"
Have Been Removed
Pursuant To 4 CSR 240-2.135.

REBUTTAL TESTIMONY

OF

TIM M. RUSH

Case No. ER-2014-0370

Q: Please state your name and business address.

A: My name is Tim M. Rush. My business address is 1200 Main Street, Kansas City, Missouri 64105.

Q: Are you the same Tim M. Rush who pre-filed Direct Testimony in this matter?

A: Yes, I am.

Q: What is the purpose of your Rebuttal Testimony?

A: The purpose of my Rebuttal Testimony is to address a number of issues presented by the Staff of the Missouri Public Service Commission ("Staff"), the Office of the Public Counsel ("OPC"), the Missouri Division of Energy ("MODOE") and the Midwest Energy Consumers Group ("MECG"). Those issues include:

1.) Retail revenues

2.) Economic Relief Pilot Program ("ERPP") – issue presented by the Staff

3.) The Fuel Adjustment Clause rider ("FAC") – responding to Staff, OPC and MECG

4.) Trackers

  a. Property tax tracker – responding to OPC and MECG

  b. Critical Information Protection ("CIP")/cybersecurity tracker – responding to MECG

  c. Vegetation management tracker – responding to OPC and MECG

5.) Solar rebates – responding to OPC

6.) Income Eligible Weatherization Program– responding to Staff and MODOE

7.) LED Street and Area Lighting – responding to Staff

8.) Class Cost of Service Studies – responding to Staff, OPC, MIEC, and the U. S. Department of Energy (US-DOE).

9.) Rate Design - responding to Staff, OPC, MIEC, MECG, Missouri Department of Energy, US Department of Energy, and Sierra Club.

a. Time of Use Rates – responding to OPC

b. Decoupling – Responding to Sierra Club

c. Return Check Charge and Collection Charge – responding to Staff

d. Bill Identification – responding to MECG

e. EDR/UCR and Standby Tariff– responding to OPC

RETAIL REVENUES

Q: Have you reviewed the Staff's Report entitled "Revenue Requirement cost of Service" as it addresses the retail revenues filed in the Staff cost of service?

A: Yes. The Staff Report on pages 70 through 79 addresses the retail revenues supported by the Staff. Witnesses for Staff's adjustment are Robin Kliethermes, Seoung Joun Won, Ph.D. and Keith Majors.

Q: Briefly explain what the basis of the retail revenues are and what they are used for in this case.

A: Retail revenues are used as the basis for determining the rate levels for the increase/decrease in the rate proceeding. The test period retail revenues are established based on weather normalized and customer annualized retail sales levels, at current retail rates. The test period in this proceeding is 12 months ending March 31, 2014, adjusted for known and measurable items through May 31, 2015. The Company's filing followed that process and developed its test period retail sales levels based on actual test period results by weather adjusting the sales of customers for that period (i.e. weather normalization). It then projected what the expected customer levels would be as of May 2015 and applied the weather normalized retail sales of customers to reflect customer levels as of May 2015 for all months in the test period (i.e. customer annualization). The current rates were then applied to the May 2015 customer normalized/annualized sales levels to determine the retail revenues to be used as the basis in the case.

If the overall cost of providing service to customers exceeds these retail revenues, an increase in current retail rates is warranted. Likewise, if the cost of service is less than the retail revenues, a decrease in current rate levels is warranted.

Q: Did Staff apply the current rates to the Staff's weather normalized/customer annualized revenues?

A: Yes. Staff updated the sales, net system inputs (including losses) and revenues, using current rates, and many of the allocations factors through December 31, 2014, and will update those factors to reflect normalized/annualized revenues through May 31, 2015.

ECONOMIC RELIEF PILOT PROGRAM

Q: Please explain the Company's Economic Relief Pilot Program ("ERPP") proposal offered in this proceeding.

A: The ERPP program currently delivers up to $50 dollars per month "fixed credit" to income eligible customers to help improve energy affordability. More details about the current program are offered in my direct testimony. I am proposing to continue with the ERPP and to double the amount of available funds for the ERPP. The proposed modification would double the funding to $1,260,000 while retaining the 50/50 cost split between customers and shareholders of the Company. I am to implement the increased funding by raising the current limit of 1,000 customer participants to 1,500 and increase the available monthly maximum bill credit from $50 to $65. Finally, I propose to use unspent ERPP dollars to fund the existing Dollar-Aide program.

Q: Have you reviewed the Staff's Report entitled "Revenue Requirement Cost of Service" as it addresses the ERPP filed in the Staff cost of service, as well as the policy recommendations by Staff?

A: Yes. The Staff Report on pages 136 through 138 addresses the ERPP proposals supported by the Staff. Witnesses for Staff's adjustment are Kory Boustead and Matthew R. Young.

Q: What position has Staff taken in the case pertaining to the Company's proposal to expand the ERPP program?

A: Staff recommends to continue the program at the current funding level of $630,000 due to what Staff has determined to be a surplus of $654,980 in that the current funding level is not being utilized in the program year. Despite the recommendations concerning the overall amount, Staff accepts the recommendation to increase the number of customers enrolled from 1,000 to 1,500. Additionally, Staff recommends the Company change the eligibility requirement from 185% of the Federal Poverty Level ("FPL") to 200% of FPL and make the unspent funds be made available for future ERPP expenditures.

Q: What is your response to the Staff proposal?

A: I disagree with Staff's proposal as I believe they misunderstood the information provided concerning the funding. Later email communications with Mr. Young explored the misunderstanding of the adjustment and the data request responses and provided more detail around the program. The amount of unspent funds is much less than noted by Staff. For expenditures through December 2014, the unspent funds attributable to customers were $51,230. The unspent funds were not because of underutilization of the program, but instead due to the administrative effort associated with verifying the eligibility of participants, responding to participant turn-over, periodic closure of the Program due to reaching enrollment capacity, and the fact that not all participants qualify for the full, $50 monthly credit. I believe the program is working as intended and will provide more support to more customers if the Company's proposal is accepted and used to complement the proposed change to the Residential Customer Charge.

Q: How are the ERPP expansion and the proposed Residential Customer Charge related?

A: I would say the ERPP expansion is contingent on the increased residential customer charge. As noted elsewhere in my testimony, I am proposing to increase the Customer Charge on Residential customers to recover the full amount of customer-related costs as well as the cost of local facilities. In outlining the customer charge proposal, we acknowledge that low-usage customers will be impacted more than the typical customer. We also acknowledge that while usage of low-income customers is largely the same as other customers, there will be low-income customers who are also low-usage customers. The ERPP expansion is offered to assist those customers in transitioning to the increased cost. Absent approval of an increased customer charge, this expansion is not warranted.

Q: Do you have any other comments concerning the ERPP expansion?

A: Yes. I urge the Commission to reject Staff's proposal to maintain the funding level while increasing the enrollment. The key elements of the expansion; the credit amount, participants, and total funding were purposefully proposed and work together mathematically to distribute the funding to customers. Adjusting the numbers as proposed by Staff will create an imbalance where the credit amount will need to be artificially set to keep the Program within the participant and funding limits.

Finally, Staff recommends changing the eligibility requirement from 185% of the Federal Poverty Level (FPL) to 200% of FPL and make the unspent funds available for future ERPP expenditures. I do not have issue with these proposals but suggest these should be made regardless of the final Commission determination concerning the Residential Customer Charge and the ERPP expansion.

FUEL ADJUSTMENT CLAUSE

Q: Staff witness Dietrich makes the claim that KCP&L's request for a Fuel Adjustment Clause ("FAC") violates the Regulatory Plan Stipulation. Do you agree?

A: No. KCP&L's FAC request is consistent with the Regulatory Plan Stipulation because the tariff implementing the FAC will not become effective until after June 1, 2015.

Q: Please explain.

A: Staff's argument is based upon a misinterpretation of when the FAC is allowed to become effective. In Missouri, public utilities file tariff sheets with a specific date that determines when the rates or programs contained on the tariff sheet may be utilized. The approved effective date of the tariffs determines the first day that the new rates and programs contained on those tariff sheets may be utilized by the public utility. Thus, there is no violation of the language contained in the Regulatory Plan because prior to June 1, 2015, the Company is not seeking to use an FAC.

Q: On page 192 of the Staff's Revenue Requirement Cost of Service Report ("Staff Report"), Staff witness Natelle Dietrich, cites to your testimony in Case No. ER-2012-0174 for the proposition that the Company had previously agreed with Staff's interpretation of the Regulatory Plan. Does your testimony in that case contradict the Company's position on an FAC in this case?

A: No it does not. In my response to questions, I state that the Company's ability to request a fuel adjustment clause is authorized. KCP&L is following the language of the Regulatory Plan Stipulation by making September 29, 2015, as the anticipated effective date of the FAC tariff. In other words, KCP&L is seeking to utilize the FAC on and after September 29, 2015.

Q: On page 193 of Staff's Report, Witness Dietrich also cites an exchange between Mr. Jim Fischer, Company's counsel, and Regulatory Law Judge Daniel Jordan in KCP&L's last rate case regarding the FAC, and concludes that even KCP&L once recognized that its Regulatory Plan prohibits it from asking for a FAC prior to June 1, 2015, not just from making a FAC effective prior to June 1, 2015. How do you respond?

A: Ms. Dietrich has misinterpreted this discussion. Mr. Fischer was not discussing the timing or logistics of filing tariffs to implement a fuel adjustment clause for KCP&L. He was observing that he expected that KCP&L would seek to have a fuel adjustment clause approved when it was eligible to utilize an FAC in 2015. He was not suggesting, and KCP&L does not believe, that the Regulatory Plan Stipulation limits its ability to file tariff sheets containing a FAC as long as the effective date of the tariff sheet is on or after June 1, 2015.

Q: Staff claims that the Regulatory Plan prohibits KCP&L from even requesting an FAC in a rate case filed prior to June 1, 2015. Is this what the Regulatory Plan says?

A: No. The language in the Regulatory Plan follows:

> **III.B.1.c. Single-Issue Rate Mechanisms**
>
> KCPL agrees that, prior to June 1, 2015, it will not seek to utilize any mechanism authorized in current legislation known as "SB 179" or other change in state law that would allow riders or surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors. In exchange for this commitment, the Signatory Parties agree that if KCPL proposes an Interim Energy Charge ("IEC") in a general rate case filed before June 1, 2015 in accordance with the following parameters, they will not assert that such proposal constitutes retroactive ratemaking or fails to consider all relevant factors. (Stipulation And Agreement, pp. 7, Case No. EO-2005-0329)

According to the Merriam-Webster online dictionary, while "seek" means to try to get or achieve something, "utilize" means to use something for a particular purpose. Using these definitions, the disputed phrase would read: "KCP&L agrees that prior to June 1, 2015, it will not try to use for a particular purpose any mechanism . . . that would allow riders or surcharges of changes in rates outside of a general rate case based upon a consideration of less than all relevant factors." As explained above, KCP&L is not trying to use the FAC until the effective date of new rates in this rate case. The FAC cannot be utilized by the Company until the effective date of rates in this case which is several months after June 1, 2015. Therefore, KCP&L is not violating the Regulatory Plan stipulation by including a request for an FAC in this rate case. In fact, the hearing where this will be tried will not occur until after the June 1st date.

Q: Ms. Dietrich also claims that the second sentence in the Regulatory Plan language quoted above somehow proves that KCP&L is not permitted to request a FAC before June 1, 2015. Do you agree?

A: No. In fact the language of the second sentence reinforces the Company's interpretation of the Regulatory Plan. The second sentence shows that the parties to the Regulatory Plan knew how to draft language that would have prohibited KCP&L from filing a rate case with an FAC before June 1, 2015. The second sentence uses the word "propose" instead of the words "seek to utilize". Had the parties meant to prohibit KCP&L from filing a rate case with an FAC before June 1, 2015, the language of the first sentence would have read along the lines of "KCPL agrees that it will not propose in a general rate case filed before June 1, 2015 any mechanism authorized in current legislation known as "SB 179" or other change in state law that would allow riders or surcharges or changes in rates outside of a general rate case based upon a consideration of less than all relevant factors."

Q: Staff's excludes from the FAC all charges associated with SPP Schedule 11, "Base Plan Zonal Charge and Region-Wide Charge"? How do you respond to this exclusion?

A: Staff appears to ignore the Commission's determination that these types of RTO transmission charges are volatile and appropriate for inclusion in an FAC.[1] Moreover, in ER-2012-0166, the Commission clearly determined that the FAC statute (Section 386.266.1 RSMO.) permits the inclusion in an FAC of transmission charges and that

[1] See Report and Order, Case No. ER-2012-0166, p. 88 (Dec. 22, 2012).

"passing those costs through the fuel adjustment clause is the most logical manner of" recovery.[2]

Q: Was this determination appealed?

A: Yes. The Court of Appeals upheld the Commission's determination that the words "including transportation" in the FAC statute meant transmission costs and that transmission costs associated with purchased power should be included in a fuel and purchased power cost recovery mechanism approved by the Commission. The Court specifically pointed to Jaime Haro's testimony that

> Ameren Missouri purchases and settles with the MISO for 100% of its load and sells 100% of its generation into the MISO. Network service enables Ameren Missouri to transmit energy acquired from the MISO market, including that injected by Ameren Missouri's own generators, to Ameren Missouri's customers. That service is governed by the MISO tariff. Ameren Missouri is required to pay the MISO transmission charges in order to participate in the MISO market.

as its reason for finding the Commission's decision to include transmission costs in the FAC was reasonable. [3]

Q: Did the Commission give the Company any guidance as to the appropriateness of including transmission expenses in an FAC?

A: It sure did. In its application for a transmission cost Accounting Authority Order ("AAO") in Case No. EU-2014-0077, the Commission found that the transmission expenses for which KCP&L sought an AAO are the type of expenses which may be collected through an FAC authorized during a general rate proceeding.[4] In that same Order, the Commission, while rejecting the AAO application, stated that "[a]s part of a general rate case, KCP&L may seek an FAC to include transmission costs in June of

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[2] Id. at pp. 89-90.
[3] Union Electric Company v. PSC, 422 S. W. 3d 358, 367 (Mo. App. 2013).

2015.[5] Based in part on this guidance, KCP&L is requesting an FAC which includes SPP transmission charges.

Q: Are the SPP transmission fees which the Company is requesting to be recovered through its FAC necessary to serve retail load and make off-system sales?

A: Yes. The transmission costs incurred by the Company from SPP allow KCP&L to participate in selling electricity into the SPP IM and buying electricity out of the SPP Integrated Market ("IM"). These transactions are necessary for KCP&L to serve its retail load and make off-system sales and require payment of the SPP transmission fees in question. The result is the Company gains efficiency of the SPP IM that benefit customers through serving retail load and buying and selling power off-system.

Q: If it is determined that SPP transmission fees should not be included in the FAC, what do you recommend?

A: I'd first reiterate my belief that SPP transmission fees need to be included in the FAC, but if that is not possible for some reason, or if an FAC is not authorized for KCP&L, then the Commission should grant tracker treatment for these costs. This is appropriate because basing the rate allowance for SPP transmission fees on historical levels, with no ability to account for changes in those cost levels likely to occur in the future, will lead to a mismatch of costs and revenues with significant detrimental earnings impacts during the future period when rates will be effective.

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[4] See Report and Order, Case No. EU-2014-0077, p 8.
[5] Id. at p. 11.

Q: Did you review parts 1, 2, and 3 of Section XIV.B on pages 194-200 of Staff's Revenue Requirement Cost of Service Report?

A: Yes. That portion of Staff's Revenue Requirement Cost of Service Report did not identify an Expert/Witness. Consequently when I am referring to that part of Staff's presentation I will cite "Staff".

Q: Did you review the testimony of Staff regarding the structure of the FAC?

A: Yes. Staff indicates that the Company hasn't met the three criteria evaluated by the Commission in assessing the use of a FAC. Those three are:

1. Magnitude of costs have a material impact on the Utility. (Staff indicates that the Company met this requirement),
2. Inability to manage these costs (Staff believes that the Company has not met this requirement),
3. Demonstrated that the costs are volatile. (Staff believes that the Company has not met this requirement).

Staff goes on to state that if the Commission approves an FAC for the Company, Staff recommends several changes to the Company's proposed FAC. Those changes include:

1. 95/5 percent sharing between the customer and the Company,
2. An exclusion of SPP Admin charges Schedule 1A,
3. An exclusion of SPP costs & revenues associated with Schedule 11, Base Plan Funding Costs ("BPF").

Q: Do you agree with the 95/5 percent sharing between the customer and the Company for any over/under recovered net fuel and purchased power costs?

A: No. As I stated in my direct testimony, the vast majority of FACs in place for electric utilities in this part of the country reconcile recovery at the 100% level. KCP&L competes for capital with these companies and would be disadvantaged if its FAC limits recovery through the FAC to 95%. So too would its customers not see the benefit of a 100% reconciliation should recovery be limited. It is also important to remember that fuel costs are volatile. Because fuel costs are not controlled by the Company it is only fair that customers should enjoy 100% of the benefits of fuel cost reductions and that the Company should recover 100% of fuel cost increases.

Q: What are your thoughts on the exclusion of SPP Administrative charges through its Schedule 1A?

A: I stand by what I stated in my direct testimony that as an RTO, SPP is a transmission provider currently administering transmission service over portions of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma and Texas. The Company is a member of, and has transferred control of its transmission facilities to SPP. With the exception of certain grandfathered agreements, transmission service over the Company's transmission facilities is provided pursuant to the SPP Open Access Transmission Tariff ("OATT"). SPP exercises functional control over all of the Company's transmission assets, and offers point-to-point and network integration transmission services and generator interconnections on the Company's transmission system pursuant to the OATT. The SPP is a not-for-profit entity that must remain revenue neutral; its costs must be recovered from its users (transmission customers). Consequently, the Company pays SPP an administration charge for performing the aforementioned RTO functions on its behalf. These costs are rising, are out of the Company's control and are necessary to transport electricity to its customers.

Q: How do you respond to Staff's points regarding the FAC (Staff Cost of Service Report pages 197 – 198)?

A: Staff comments that although the Company cannot control the national or international market costs for coal, it has considerably more control over the prices it pays for fuel and purchased power than do its ratepayers. Staff's comparison is to who can control costs better, the Company or customer and yet Staff indicates that the company cannot control either the national or international markets for coal. I disagree with Staff's comparison as a foundation for whether the Company can manage costs includable in the FAC. I believe the Company has a responsibility to customers to manage the services it provides to customers, including those costs includable in the FAC in the best way it can, but it essentially has little influence in truly controlling costs includable in the FAC. Mr. Blunk also addresses this issue.

Q: Staff goes on to indicate that the Company has multi-year coal contracts and thus experiences no volatility. How do you respond?

A: As I indicated in my testimony above addressing the testimony of Mr. Brosch, this comparison is unfair in that the prices we are reflecting in the FAC are those costs driven by the SPP IM, netted against the generation costs incurred by the Company. The SPP IM prices are well outside of the control or management of the Company. Mr. Blunk explains how Staff misrepresented the Company's coal contract position and why it faces much coal price volatility.

Q: Staff goes on to say that SPP schedule 11 costs, while increasing, are known and thus are not volatile. How do you respond?

A: The future Schedule 11 costs are not known. There are no contracts fixing those charges. What we do know is, as Mr. John Carlson discusses, history has shown they are material and volatile. Moreover we have reason to believe they will continue to be large and volatile.

Q: Have you read the testimony section supported by Staff witness Dana Eaves and Alan Bax beginning on page 200 of the Staff Cost of Service Report?

A: Yes. Mr. Eaves indicates that he has reviewed the filing by the Company and that the Company has met the filing requirements for making a request for an FAC. Mr. Bax supports the use of the Company's line loss study in the computation of the FAC factors by voltage level.

Q: Does Mr. Eaves have any other testimony relating to the FAC?

A: Yes, Mr. Eaves has filed testimony relating to the FAC in the MPSC Staff Rate Design and Class Cost-of-Service Report filed April 16, 2015 as well as redline/strikeout exemplar tariff sheets filed as Schedule DEE-1.

Q: What are Staff's recommendations regarding the FAC tariff as represented in Mr. Eaves testimony?

A: Mr. Eaves states that if the Commission grants the Company's request, he would propose that the FAC reflect the following modifications:

1. Reflect the 95/5 split which allows the Company to recover and return only a portion of the fuel changes,
2. Exclude SPP Admin charges found in the Schedule 1A,

3. Exclude SPP costs & revenues associated with Schedule 11 ("BPF") and Schedule 12,
4. Provide additional monthly filings that will aid the Staff in performing FAC tariff, prudence and true-up reviews,
5. Adjust base rate according to the inclusion/exclusion of costs supported by Staff. $0.01406/kWh to be trued-up.

Q: Do you agree with the changes proposed by Mr. Eaves?

A: No. Please see my previous testimony regarding the first three proposals made by Mr. Eaves. One additional comment I would make is that there are no Schedule 12 revenues as Schedule 12 represents FERC assessments fees charged to member companies by SPP.

Q: Do you agree with Mr. Eaves' exclusion of SPP costs & revenues associated with Schedule 11 or BPF costs and revenues?

A: No. Schedule 11 or base plan funding costs and revenues are attributable to enhancing the SPP market and increasing efficiencies in the marketplace. Costs and revenues associated with Schedule 11 are a requirement for being able to participate in the SPP IM. Mr. Blunk provides additional rebuttal testimony on the topic.

Q: Please discuss item number 4, Mr. Eaves' proposal for additional monthly filings.

A: While the Company already provides a significant amount of information monthly, quarterly and semi-annually, it is hard to understand specifically what information the Staff is seeking. The Company is not aware of any issues with the information the Company currently provides and is not aware of any issues with the Company's sister company KCP&L Greater Missouri Operations Company ("GMO") has with reporting to Staff.

Q: What is the specific additional information that Mr. Eaves has requested on a monthly basis?

A Mr. Eaves has added the following requirement to the list of items that are currently provided monthly for KCP&L's sister company KCP&L GMO: *The monthly as-burned fuel report supplied by KCPL required by 4 CSR 3.190(1)(B) shall explicitly designate fixed and variable components of the average cost per unit burned including commodity, transportation, emission, tax, fuel blend, and any additional fixed or variable costs associated with the average cost per unit reported (Staff is willing to work with KCPL on the electronic format of this report).*

Q: Do you have an issue providing this information?

A: Other than my thoughts on the ever expanding reporting requirement mentioned above, I do not have an issue at this time based upon Mr. Eaves willingness to work with the Company on the form of this requested report.

Q: Do you agree with the proposed base rate presented by Mr. Eaves?

A: The Company agrees that the base kWh factor will need to be updated with true-up information at the true-up date of May 31, 2015. The Company does not, however, agree with Mr. Eaves' calculation of the base rate. Much of this disagreement will be discussed as I review the changes he made to the Company's proposed FAC tariff sheets.

Q: What other concerns do you have with the testimony presented by Mr. Eaves?

A: Mr. Eaves has proposed to remove the term "accessorial charges" included in the 501 fuel cost definition on the tariff stating that he does not know what those costs represent so they should not be included in the KCP&L MO fuel clause.

Q: Do you agree with this assessment?

A: No, Mr. Blunk describes the Company's position on this issue in his rebuttal testimony.

Q: What other concerns do you have?

A: Mr. Eaves misrepresents what FERC Accounts 501 and 547 are for. He states that Account 501 is to record coal costs and related costs, and that 547 is for fuel stock. This is incorrect. Account 501 is used for fuel costs of any kind that are used to produce steam to produce electricity. Account 547 includes all fuel costs associated with other power generation.

Q: What are your thoughts on the redline/strikeout exemplar tariff sheets filed as Schedule DEE-1 by Mr. Eaves?

A: I have a number of concerns with the changes made by Mr. Eaves to the Company's exemplar FAC tariff sheets filed in this case. I will discuss each of them now.

Tariff Sheet No. 50:

- Mr. Eaves struck the Second Revised and the First Revised from the tariff sheet heading. This tariff sheet already exists as a "held for future use" so the striking out of the Second/First designation is incorrect.
- On Tariff Sheet 50, Mr. Eaves has added the word "billing" to the definition of a recovery period. The addition of the word billing causes problems for KCP&L. KCP&L's billing system bills on a prorated basis and cannot be changed to a non-prorated process.
- Mr. Eaves has added the wording, "All penalties accessed associated with The North American Electric Reliability Corporation and other regional entities compliance and reliability standards shall be excluded from the FAC." This statement is unnecessary

as these types of costs, if incurred, would not be included in the FERC Uniform System of Accounts identified as recoverable within the FAC by the FAC tariffs.

Tariff Sheet 50.1:

- Mr. Eaves struck accessorial charges, bio-fuels, broker commissions, fees and margins and propane from the 501 description. Additionally, he struck natural gas used to cross hedge purchased power or sales from the 547 description. Mr. Blunk discusses these points. As Mr. Blunk stated, the Company will most likely cease to hedge power purchases or sales if cross hedge costs are excluded from the FAC.

Tariff Sheet 50.2:

- Mr. Eaves added wording to the PP definition to exclude all SPP Schedule 1-A fees. As discussed before, the Company does not agree with this exclusion.
- Mr. Eaves also struck the following wording from the PP definition: "other miscellaneous SPP IM charges including but not limited to". Under the TC definition Mr. Eaves struck everything except for 565 and 456. He also modified 456.1 by making it just 456. While it might seem like that is a simplification it significantly changes what is included in the FAC. Effective January 1, 2006, FERC changed its Uniform System of Accounts to better identify various RTO costs. One of those changes was the creation of Account 456.1. Account 456 represents "Other electric revenues" which include "revenues received from operation of fish and wildlife, and recreation facilities whether operated by the company or by contract concessionaires, such as revenues from leases, or rentals of land for cottage, homes, or campsites" while Account 456.1 represents "Revenues from transmission of electricity of

others."[6] The Company stands by its original exemplar tariff page 50.2 relating to the definition of TC. Please see my earlier discussions on the Company's proposed inclusion of the costs in FERC accounts 561.4, 561.8, 565, 575.7 and 928 relating to transmission costs that should be allowed to flow through the FAC.

- In the OSSR definition, Mr. Eaves struck make whole and out of merit payments and distributions but added ancillary services, revenue sufficiency and neutrality.

Tariff Sheet 50.3:

- Mr. Eaves explicitly excludes all impacts of cross-hedging.
- Mr. Eaves also made a change to the definition of the jurisdictional allocation calculation of J =. Mr. Eaves has suggested that the Missouri Retail Energy Ration = Missouri Retail kWh sales divided by Total Net System Input. The Company believes that it is a miss-match to compare retail sales to net system input. The Company believes that to be consistent with how costs are allocated between the jurisdictions in a rate case this calculation should be as follows: J = Missouri Retail Energy Ration = Missouri Retail kWh Sales/Total Retail kWh Sales (KS and MO) + Sales for Resale (Account 447.100 – Municipals).

Sheet 50.5:

- The Company believes that since base rates are being set in this rate case, the original tariff calculation sheet should contain all zeros until the first accumulation period has passed.

[6] http://www.ecfr.gov/cgi-bin/text-idx?rgn=div5&node=18:1.0.1.3.34

Q: Does the Company agree with MIEC witness Maurice Brubaker on page 35 of his rate design testimony that if a FAC is approved for KCP&L that the rates should be set at four voltage levels instead of two?

A: No. The Company believes that the two voltage levels identified in its proposed FAC are sufficient to appropriately distinguish the cost recovery.

Q: Do you agree with Mr. Brosch when he says beginning on page 39 of his Direct Rate Design Testimony that a reasonable alternative to an FAC for this utility could be the installation of a limited FAC tracking mechanism for only variations in off-system sales margins because only OSS profit margins exhibit any significant volatility and lack of management control therefore the FAC should be limited to variations in OSS profit margins?

A: No. This approach is short-sighted and unfair to the utility. That Mr. Brosch's proposal is unreasonable and misses the mark of what a fuel adjustment clause is intended and can be readily observed by looking at the significant earnings shortfalls KCP&L has experienced, and continues to experience, since its last rate order.

Because KCP&L's earnings levels have fallen so significantly below the Commission-authorized level since its rates were last set, there is no basis whatsoever to reduce those earnings levels further by granting a tracker on off system sales revenues while not allowing for the recovery of excess fuel, purchased power and transmission costs.

Q: Mr. Brosch claims, beginning on page 7 of his Testimony that the Company's proposed FAC includes complex transaction details like SPP charges as well as many other "non-fuel" additives, hedging costs and emission allowances that vastly complicates the time and expense required for effective regulatory oversight and periodic audit activities. Do you agree with this assertion?

A: No, the MPSC Staff auditors who have the task of monitoring, analyzing and auditing fuel adjustment clauses in Missouri have had no issue with the ability to audit the past 15 GMO tariff filings. In addition, no other party has indicated an issue either. As a matter of fact, the level of detail included in the proposed FAC tariffs mimics that included in the KCP&L GMO tariff

Q: Did you review the testimony of OPC witness Lena Mantle regarding the structure of the FAC?

A: Yes, Ms. Mantle suggested that if the FAC were approved for KCP&L MO, it should be modified in the following ways:

A. KCPL's FAC should include a mechanism that requires KCPL to absorb 50 percent of any cost increases/revenue decreases and allows it to retain 50 percent of any cost savings/revenue increases;

B. The costs and revenues that are to be included in the FAC should be approved by the Commission and explicitly identified along with the FERC account and the resource code in which KCPL will record the actual cost/revenue;

C. The types of costs/revenues that are included in KCPL's FAC should not change until the next rate case;

D. The FAC should include no costs or revenues that KCPL is not currently incurring or receiving and has not documented that it expects to incur/receive before its next rate case other than insurance recoveries, subrogation recoveries and settlement proceeds related to costs and revenues included in the FAC;

E. The FAC tariff sheets should reflect accurately the accounts and cost/revenue descriptions that are approved by the Commission;

F. KCPL's SO2 amortization should not be included in its FAC;

G. FAC costs and revenues should be allocated in the accumulation period's actual net energy cost in a manner consistent with the allocation methodology utilized to set permanent rates in this case; and

H. The recovery periods should be changed to October through September and April through March with the corresponding accumulation periods changed to January through June and July through December respectively.

Q: Did Ms. Mantle make any other assertions relating to the approval of the FAC?

A: Yes, Ms. Mantle has claimed that the Company has not met the minimum filing requirements for the establishment of an FAC found in 4 CSR 240-3.161(2) and has not identified the specific costs and revenues in appropriate detail to be deemed complete by Ms. Mantle.

Q: Do you agree with Ms. Mantle's assertion?

A: No. Ms. Mantle is imposing a level of burden on the utility that is not required by the Code of State Regulations. Certain types of costs are included in certain FERC accounts based upon the FERC Uniform System of Accounts. The company chooses to break these FERC accounts down further for its own management purposes.

The information provided in my testimony to fulfill the filing requirements for a new FAC is consistent with the information that has been provided for GMO since its FAC began in 2007. The level of detail provided in the tariff itself is based upon the Company's experience in implementing its GMO FAC as well as the discussions and interactions with the Commission Staff over the last eight years regarding that FAC. Changes have been made based upon those discussions/negotiations in the past and thus the Company had no reason to believe that the parties would be unable to understand the intention of the proposed FAC.

The Company follows the rules associated with recording its revenues and expenses in accordance with the FERC Uniform System of Accounts. The Company's books and records are audited annually by external auditors. The Company's GMO FAC has had 15 accumulation period filings (tariff changes), 12 true-up filings, and five prudence reviews. There have been numerous discussions with all parties in each rate case proceeding since the FAC was implemented for GMO (formerly Aquila, Inc.) in 2007. The Company has continually attempted to provide the level of information needed and wanted by the parties. The Commission Staff, who are tasked with scrutinizing the appropriateness of the implantation of the FAC have had no complaints related to the level of information provided. A reasonable person would interpret that to mean that if the Company continued to perform and provide information in the same manner it would be sufficient for the parties involved. Any party to the rate case where an FAC is established remains a party to all future FAC filings. Any party is welcome to request data/information from the Company. The Company provides such information as it is able.

Each of the three columns that Ms. Mantle identifies in her Schedule LMM-2, represent the same costs. If the Commission would like for the tariff to list each cost detail, the Company would be glad to do that. However, based upon past discussions and in relation to the FACs already in place in the state along with the fact that the Company follows the FERC Uniform System of Accounts in its recording of revenues and expenses, I believe that the explanation in my direct testimony along with the proposed tariff gave a complete view of what it expected to include in its KCP&L MO fuel adjustment clause. It should be noted that the Commission Staff, who are tasked with managing the approval of fuel clause tariff changes determined that the information provided was complete.

Q: Do you agree with the modifications proposed by Ms. Mantle?

A: Relating to requirement A., I have already addressed the sharing of costs that flow through the FAC and explained why those costs should be flowed through at 100%.

Q: Relating to requirement B., why is Ms. Mantle's recommendation regarding explicit identification of FERC account and resource code problematic?

A: FERC is the only one who can change their Uniform Chart of Accounts and they don't do that very often. Resource codes are part of the Company's managerial accounting system. They can and do change to meet the then prevailing needs of the Company. Requiring that resource codes be specified in a Company's tariff will not improve the information provided to support FAC calculations. Instead it will interfere with the Company's efforts to manage the costs reflected in those accounts.

I believe that Ms. Mantle's concept is that using resource codes will limit what is included in the FAC. FERC Account numbers do have such limits because FERC defines what is included in one of its account numbers and KCP&L cannot change FERC's definitions. The Company defines what is included in a resource code and can change that definition at any time, but any such change made by KCP&L would have no effect on the FERC account definition. Assuming Ms. Mantle wants only a subset of those items included in the specific FERC accounts to be included in the FAC, her objective would be better served following the Company's approach in its proposed FAC. Using words to describe what is included in or excluded from the FAC in a manner consistent with the Company's proposed FAC allows the Company to manage its business while giving the Commission and our customers assurance about what is in or not in the FAC.

Ms. Mantle's position on her requirement B and her discussion at pages 32-33 begs the question of at what level of granularity and minutiae should the costs be identified. The FAC would be much simpler to administer, audit, and compare to other utilities, or evaluate the past if it was constructed at the FERC Account level. What the Company has proposed here is consistent with the existing FACs but moving to Account level with perhaps the exception of Company labor would yield a better FAC on many counts.

Q: Do you agree with Ms. Mantle's item C?

A: Yes, if Ms. Mantle means by type, the costs included in the specified FERC accounts or the verbiage addressed in the FAC tariff. However, if she is referring to details that are more specific, then I would disagree.

Q: Do you agree with Ms. Mantle's item D?

A: No.

Q: Does the Company agree with Ms. Mantle's item E?

A: The Company believes that its exemplar tariff sheets reflect accurately the accounts and cost/revenue descriptions that it is asking the Commission to approve.

Q: Does the Company agree with Ms. Mantle's item F?

A: No, the Company believes that the costs reflected in FERC account 509 should be flowed through the FAC. If, as Ms. Mantle asserts the costs do not fluctuate, then the base costs and actual costs will be the same and there will be no impact to the customer. The costs, however, have been shown to be FAC includable costs and therefore should be included in the proposed FAC.

Q: Does the Company agree with Ms. Mantle's item G?

A: Yes. Although the Company believes that a minor change to the wording associated with the jurisdictional allocation (see my rebuttal to Mr. Eaves' testimony) is needed in order to make the jurisdictional allocation in the same manner as is used to set rates, the

Company does agree that they should be the same. We intend to use an energy allocator to allocate costs between jurisdictions.

Q: Does the Company agree with Ms. Mantle's item H?

A: The Company would be open to discussing a change in accumulation/recovery periods as proposed by Ms. Mantle as long as the Company is allowed to start accumulating as soon as new rates go into effect. For instance, if the Company changes the accumulation/recovery as proposed, the first FAC tariff filing would be filed on February 1 covering October through December with recovery beginning April 1, 2016.

Q: At page 23, Ms. Mantle argues that fuel and purchased power costs are not volatile. Then at page 26 she argues that the proposed FAC will create significant swings in customers' bills. Those positions seem inconsistent. What do you have to say about these seemingly inconsistent positions?

A: Ms. Mantle's conflicting positions represent misunderstandings of both the volatility of fuel and electricity costs and revenues and the FAC mechanism. By arguing that KCP&L's fuel and purchased power costs could create significant swings in customers' bills Ms. Mantle is acknowledging they are volatile. The costs and revenues associated with KCP&L's fuel, purchased power and transportation of such are indeed volatile but the FAC mechanism will dampen much of that volatility. So while the Company faces all of the volatility the customers only see a portion of it.

Q: How is it that the FAC mechanism will dampen the volatility in the costs and revenues associated with KCP&L's fuel, purchased power and transportation of such for the Company's customers?

A: The accumulation periods capture six months of movement in the costs and revenues associated with KCP&L's fuel, power and transportation of such and then spread that six months of movement over twelve months as a constant value without the movement the Company experienced. The customers will experience the overall trend but not the volatility.

Q: As one last point, how has the FAC worked for GMO, a sister company to KCP&L?

A: GMO has had an FAC in place since 2007. The FAC has covered the rate jurisdictions of L&P, formerly St. Joseph Light & Power Company, and MPS, formerly Missouri Public Service Company. As with the FAC expectation in this case, the first FAC started at a price of zero. From September 2008, to current, GMO has had 14 FAC's in place. In the MPS rate jurisdiction, there have been seven increases and seven decreases. In L&P, there have been nine increases and five decreases.

FAC MPS Effective Date	Increase/Decrease	Change
9/1/2008	Increase	$ 0.00230
3/1/2009	Increase	$ 0.00110
9/1/2009	Increase	$ 0.00100
3/1/2010	Increase	$ 0.00070
9/1/2010	Decrease	$ (0.00060)
3/1/2011	Decrease	$ (0.00100)
9/1/2011	Decrease	$ (0.00080)
3/1/2012	Decrease	$ (0.00070)
9/1/2012	Decrease	$ (0.00220)
3/1/2013	Decrease	$ (0.00060)
9/1/2013	Increase	$ 0.00090
3/1/2014	Decrease	$ (0.00095)
9/1/2014	Increase	$ 0.00282
3/1/2015	Increase	$ 0.00217

FAC

L&P Effective Date	Increase/Decrease	Change
9/1/2008	Increase	$ 0.00080
3/1/2009	Increase	$ 0.00130
9/1/2009	Decrease	$ (0.00040)
3/1/2010	Decrease	$ (0.00200)
9/1/2010	Increase	$ 0.00100
3/1/2011	Increase	$ 0.00010
9/1/2011	Increase	$ 0.00040
3/1/2012	Increase	$ 0.00380
9/1/2012	Decrease	$ (0.00170)
3/1/2013	Decrease	$ (0.00300)
9/1/2013	Increase	$ 0.00149
3/1/2014	Decrease	$ (0.00127)
9/1/2014	Increase	$ 0.00138
3/1/2015	Increase	$ 0.00108

TRACKERS

INTRODUCTION

Q: Did any parties take a position in direct testimony regarding the Company's tracker proposals (for property taxes, CIP/cybersecurity costs and vegetation management costs?

A: MECG is the only party which took a position regarding all three of the Company's tracker proposals in direct testimony. MECG witness Brosch opposed all three of the Company's tracker proposals. OPC witness Addo indicated very briefly that he opposed implementation of a tracker for vegetation management costs. (Addo Direct, p. 17, ll. 1-11)

Q: On what basis has MECG opposed the Company's tracker proposals?

A: MECG witness Brosch first expresses opposition to trackers generally (Brosch Direct, pp. 9-16), then offers "evaluative criteria" that he argues should be applied to determine whether trackers are appropriate (Brosch Direct, pp. 16-18) and finally applies the evaluative criteria he offers to the trackers proposed by KCP&L in this case (Brosch Direct, pp. 18-38).

Q: How do you respond?

A: I disagree with much of what MECG witness Brosch has to say about the Company's tracker proposals. Because his general opposition to trackers and his proposed evaluative criteria apply to all three of the Company's tracker proposals, I will first address those topics. I will then proceed to address MECG witness Brosch's application of his evaluative criteria to each of the trackers proposed by the Company in this proceeding.

a. MECG's general opposition to trackers ignores the facts and MECG's evaluative criteria are inappropriate

Q: MECG witness Brosch alleges (on pp. 7-8 of his direct testimony) that the Company has achieved acceptable financial results historically. Is this allegation accurate?

A: No. Since new rates last took effect in early 2013, KCP&L's actual Missouri-jurisdictional return on equity ("ROE") has fallen substantially short of the 9.7% ROE authorized by the Commission in Case No. ER-2012-0174, specifically:

a. For 2013, KCP&L's actual Missouri-jurisdictional ROE was 6.5% (a shortfall of about $33.8 million compared to KCP&L's Commission-authorized ROE);

b. For 2014, KCP&L's actual Missouri-jurisdictional ROE was 5.9% (a shortfall of about $45 million compared to KCP&L's Commission-authorized ROE); and

c. For 2015, KCP&L does not expect improved earnings performance – compared to 2013 and 2014 – until after new rates take effect in late September of 2015.

Q: Do you consider that financial performance acceptable?

A: No. For earnings to fall so substantially short of the Company's Commission-authorized ROE is clear evidence that the last rate order did not properly match KCP&L's future revenues with its future costs. To suggest, as MECG witness Brosch does, that it would be acceptable to continue this financial performance in the future for KCP&L is simply wrong. As described in more detail in the rebuttal testimony of KCP&L witness Darrin Ives, Commission rejection of the Company's tracker proposal will result in continued earnings for KCP&L falling well short of its Commission-authorized ROE beginning the first year new rates take effect.

Q: Why is Mr. Brosch wrong in his position that (on pp. 9-11 of his direct testimony) that trackers should be granted only for costs that are unusual and infrequent in occurrence?

A: MECG witness Brosch has conflated accounting authority orders ("AAOs") with trackers and ignored or omitted a substantial body of Commission precedent which supports adoption of the Company's tracker proposals in this case. Trackers can and should be utilized if basing the rate allowance for such costs on historical levels, with no ability to account for changes in those cost levels likely to occur in the future, is likely to lead to a mismatch of costs and revenues with resulting earnings impacts during the future period when rates will be effective. Factors relevant to the determination could include: the magnitude of the earnings impacts associated with changes in levels of the relevant cost of service item; the degree to which the relevant cost of service item is subject to management control; and overall cost of service trends for the Company under consideration.

Q: How does MECG witness Brosch inappropriately conflate AAOs with trackers?

A: MECG witness Brosch (on p. 10, lines 9-15 of his direct testimony) cites the Commission's order in Case No. EU-2014-0077 as announcing a standard which applies to trackers. The quoted passage makes very clear however, that the issue at hand in that case was the Company's request for an AAO, not a tracker. Although trackers and AAOs have not always been discussed as separate and distinct regulatory tools in the past in Missouri, they are indeed distinct from one another and should be assessed by different standards. For a more detailed discussion of the difference between trackers and AAOs, see the rebuttal testimony of KCP&L witness Overcast.

Q: How does MECG witness Brosch's inappropriate conflation of AAOs with trackers ignore a substantial body of Commission precedent?

A: KCP&L has had a tracker for its pension (FAS 87) costs for many years and implemented a tracker in recent years for other post employment benefits ("OPEB"). GMO has tracked pension and OPEB costs for many years also and I understand that most, if not all, of the major utilities in the State of Missouri use trackers for pension and OPEB costs as well. Obviously, pension and OPEB costs are not "unusual and infrequent". The Commission has clearly not applied the "unusual and infrequent" occurrence standard in determining that a tracker mechanism for pension and OPEB costs is appropriate.

But even with AAOs (as opposed to trackers) the standards are not immutable. From about 1990-2002 the Commission issued a series of gas safety AAOs to a number of gas utilities that authorized the utilities to defer depreciation expense, carrying costs and property taxes related to the replacement of natural gas distribution facilities (such as service lines and mains) required by a gas safety rule promulgated by the Commission in the late 1980's (4 CSR 240-40.030). I have been able to find fourteen (14) such AAOs issued by the Commission in connection with four (4) natural gas distribution systems. Those cases are as follows:

<u>Case No.</u> (<u>Company)</u>
GO-90-51 (Kansas Power & Light "KPL"; subsequently became MGE)
GO-90-115 (Missouri Public Service)
GO-90-215 (United Cities Gas)
GO-91-359 (Missouri Public Service)
GO-92-67 (United Cities Gas)
GO-92-185 (KPL, subsequently became MGE)
GO-94-133 (Western Resources f/k/a KPL; subsequently became MGE)
GR-94-220 (Laclede Gas)
GO-94-234 (MGE)
GR-96-193 (Laclede Gas)
GO-97-301 (MGE)
GR-98-140 (MGE)
GR-99-315 (Laclede Gas)
GR-01-292 (MGE)

Replacing natural gas distribution facilities like service lines and mains is multi-year construction work that was mandated by the government (in the form of a Commission rule passed in the late 1980's). The replacement of natural gas distribution facilities did not enable the affected gas utilities to serve new customers or provide for greater load. The fact that the Commission issued these gas safety AAOs repeatedly – at least fourteen (14) times in a roughly eleven-year period and at least seven (7) times for the same natural gas distribution system – demonstrates that, contrary to MECG witness Brosch's assertion, the fact that gas safety replacement costs were not "unusual or infrequent occurrences" did not prevent the Commission from granting repeated AAOs. In this regard, it should be noted that infrastructure system replacement surcharge legislation enacted in 2003 rendered further gas safety AAOs unnecessary.

Q: Mr. Brosch argues (on pp. 11 of his direct testimony) that predictions of higher future expenses are not a reasonable basis for the adoption of trackers. How do you respond?

A: First, MECG witness Brosch notes the possible existence of future cost reductions that might offset the cost increases in property taxes, CIP/cybersecurity costs and vegetation management costs, but he does not identify them or quantify them in any way. Moreover, property taxes, CIP/cybersecurity costs and vegetation management costs are not the only cost of service items that KCP&L expects will add upward pressure on its revenue requirements in the coming years. Significantly, capital expenditure forecasts over the next few years indicate that capital spending will exceed annual depreciation expense in the coming years, which means that rate base will continue to grow. All else equal, rate base growth increases cost of service. Similarly, KCP&L is not operating in an environment where substantial year over year revenue growth (in terms of either or both per customer kWh consumption and overall customer numbers) can be expected to cover the increases expected for these cost items. Under these circumstances, the Company's tracker proposals are reasonable.

Q: Do you agree with the evaluative criteria proposed by Mr. Brosch?

A: No. The AAO standard should not be applied to tracker requests, and the additional evaluative criteria offered by MECG witness Brosch are similarly inappropriate. These are addressed in more detail by KCP&L witness Overcast. Instead, consistent with the Commission's approval of trackers for pension and OPEB costs for major utilities across the State and its repeated authorization for gas utilities to defer gas safety replacement costs, tracker requests made during rate cases should be granted if it is determined that basing the rate allowance for such costs on historical levels, with no ability to account for changes in those cost levels likely to occur in the future, is likely to lead to a mismatch of costs and revenues with resulting earnings impacts during the future period when rates will be effective. Factors relevant to the determination could include: the magnitude of the earnings impacts associated with changes in levels of the relevant cost of service item; the degree to which the relevant cost of service item is subject to management control; and overall cost of service trends for the company under consideration.

PROPERTY TAX TRACKER

Q: What are the specific bases of MECG witness Brosch's opposition to the Company's proposed property tax tracker?

A: Mr. Brosch argues that the Commission should reject the tracker for property taxes because they are 1) not unusual or infrequent, and 2) of insufficient magnitude and volatility. Mr. Brosch concedes that property taxes are largely beyond the control of management, he questions whether the Company would diligently manage property taxes if tracker treatment is adopted. As discussed earlier, "unusual or infrequent" is not an appropriate standard to judge a tracker request. I'll confine this part of my response to his assertions regarding magnitude and volatility as well as what level of diligence the Company will undertake regarding property tax levels in the event a property tax tracker is adopted.

Q: What evidence does MECG witness Brosch point to in support of his assertion that property taxes are not of sufficient magnitude to warrant tracker treatment?

A: MECG witness asserts (on pp. 19-20 of his direct testimony) that because property taxes amount to about 5.1 percent of overall electric revenues, they do not have a material impact on financial performance between rate cases. This evidence misses the point, however, by ignoring the impact forecasted property tax increases will have on the Company's earnings. Company witness Darrin Ives presents evidence and insight into the this issue by presenting the impacts to the Company earnings, both historically and in the future, due to differences between the rate allowance for property taxes and property taxes actually paid by the Company. KCP&L witness Overcast also addresses this assertion by Mr. Brosch.

Q: What evidence does MECG witness Brosch point to in support of his assertion that property taxes are not of sufficient volatility to warrant tracker treatment?

A: On page 20, lines 13-15, Mr. Brosch states that because property tax increases can be predicted, they can be reasonably handled through rate cases. He then goes on to say that because property taxes have been steadily rising annually at single-digit percentage increases, they are not of sufficient volatility to warrant tracker treatment.

Q: How do you respond?

A: This MECG evidence misses the point also because it does not provide any insight into how the mismatch between property taxes included in cost of service (i.e., revenues) and property taxes actually paid (i.e., costs) affected the Company's earnings. As presented in the Rebuttal testimony of Darrin Ives which shows both some financial impacts on back-casting as well as a forward view of the impacts that property taxes has on the financial condition of the Company. KCP&L witness Overcast also addresses this assertion by Mr. Brosch.

Q: On page 20, lines 7-9 of his direct testimony, MECG witness Brosch states "[O]ne would wonder whether KCP&L would take such steps [i.e., management efforts to control property taxes] if it was guaranteed recovery of all property tax increases. Would Commission adoption of the property tax tracker proposed by KCP&L amount to a "guarantee" of recovery of property tax increases?

A: No. Property tax increases deferred under the proposed tracker mechanism could be included in rates only after review and approval by the Commission in a general rate case. KCP&L expects that such review would include questions about management efforts to control property taxes during the deferral period and because the Company desires to recover all of its property tax expenses, it would have ample incentive to diligently manage property tax costs during the deferral period. This logic applies to other requests for trackers as well.

Q: Has the Commission granted deferral accounting treatment for property taxes in previous cases?

A: Yes. My understanding is that each of the cases mentioned above in which the Commission granted an AAO for gas safety replacement-related costs authorized the deferral, among other things, of property taxes in connection with the replaced facilities. Additionally, in at least one case the Commission granted an AAO to Missouri Gas Energy ("MGE") which authorized MGE to defer property taxes on gas held in storage in the State of Kansas.[7]

[7] *Report and Order*, Re: Missouri Gas Energy, Case NO. GR-2006-0422.

Q: Absent a tracker mechanism, can the Company eliminate the negative earnings impact of rising property taxes simply by filing another rate case immediately after the conclusion of this rate case?

A: No. Without a tracker, any earnings shortfall resulting from a mismatch between actual property taxes and the rate allowance for those costs included in rates will be lost forever. Although rates can be adjusted on a going forward basis to reflect the increased property taxes experienced during the historical test year for the second rate case, those increased cost levels will only be recovered on a going forward basis, and if property tax costs continue to rise after the test period as updated in the second rate case, then the Company will experience another earnings shortfall due to under-recovery of property taxes that can never be recovered.

<u>CIP/CYBERSECURITY TRACKER</u>

Q: Why is Mr. Brosch wrong in his opposition to the Company's proposed CIP/cybersecurity cost tracker?

A: Mr. Brosch compares CIP/cybersecurity cost levels to overall electric revenues, and erroneously concluding that CIP/cybersecurity cost increases will have an immaterial impact on the Company.

Q: What is a relevant comparison to determine magnitude?

A: The relevant comparison is a comparison of incremental CIP/cybersecurity costs (i.e., those not included in base rates) to net operating income. Only by comparing these factors can the earnings impact of not granting tracker treatment for CIP/cybersecurity costs be assessed. Company witness Darrin Ives demonstrates the impact on the

Company in this Rebuttal Testimony. KCP&L witnesses Ed Overcast and Joshua Phelps-Roper also addresses this assertion by Mr. Brosch.

Q: Absent a tracker mechanism, can the Company eliminate the negative earnings impact of rising CIP/cybersecurity costs simply be filing another rate case immediately after the conclusion of this rate case?

A: No. In his Rebuttal Testimony, KCP&L witness Joshua Roper demonstrates that CIP/cybersecurity costs will continue to increase significantly after the May 31, 2015 true-up in this case. Without a tracker, any earnings shortfall resulting from a mismatch between actual CIP/cybersecurity costs and the allowance for those costs included in rates will be lost forever. Although rates can be adjusted on a going forward basis to reflect the increased CIP/cybersecurity costs experienced during the historical test year for the second rate case, those increased cost levels will only be recovered on a going forward basis, and if CIP/cybersecurity costs continue to rise after the test period as updated in the second rate case, then the Company will experience another earnings shortfall due to under-recovery of CIP/cybersecurity costs that can never be recovered.

VEGETATION MANAGEMENT TRACKER

Q: Have you reviewed the testimony of William Addo of the Office of the Public Counsel pertaining to the Vegetation management tracker recommended by the Company?

A: Yes. Mr. Addo is recommending that the vegetation management expenses should be $14,966,267 based on 2014 data. He further states that Public Counsel believes that a tracking mechanism is not needed to determining an ongoing level of costs.

Q: What do you say to Public Counsel's position?

A: Public Counsel appears confused as to why the Company is requesting a tracker for vegetation management in the first place. The Company is not requesting a vegetation management tracker primarily because of increasing costs as most trackers may address. Instead, KCP&L Missouri operations are requesting a tracker for two (2) very specific reasons other that traditional increasing costs. First, KCP&L serves both Kansas and Missouri service territories and has an affiliate GMO. These combined service territories all have tree trimming requirements and cover a fairly large geographic territory. In order to maximize the overall efficiencies, the Company believes that it needs to be able to target certain areas of tree trimming. This may result in an imbalance of expenses in one territory over another, but in the overall plan, would balance over time. Under these circumstances, use of a tracker would enable customers to get full credit for each dollar of vegetation management expense built into rates every year. Secondly, the Company is recommending the addition of three program improvements that were addressed in the testimony of Jamie Kiley. These new programs are tree-trimming enhancements that should improve reliability.

Q: What does MECG witness Michael Brosch say about the vegetation management tracker?

A: Consistent with his position regarding the Fuel Adjustment Clause, the proposed property tax tracker, the CIP/Cybersecurity tracker, he again is opposed to the tracker mechanism and presents a consistent position for each of the mechanisms. The argument against Mr. Brosch's position has been addressed throughout my rebuttal testimony, as well as the rebuttal testimonies of Darrin Ives and Ed Overcast.

SOLAR REBATES

Q: Have you read the testimony of Geoffrey Marke regarding Solar Rebates?

A: Yes. Mr. Marke indicates that he is still reviewing actions of KCP&L and has not yet determined whether KCP&L has violated or not violated the Commission's affiliate transactions rules through their unregulated affiliate, KCP&L Solar Inc. OPC indicates that it is currently investigating the prudency of solar rebates obtained by the unregulated affiliate and is awaiting responses from data requests issued to KCP&L.

Q: Have you provided the responses to Mr. Marke?

A: All outstanding data requests pertaining to the solar rebates have been answered and provided to OPC.

INCOME ELIGIBLE WEATHERIZATION PROGRAM

Q: Did the Company offer a proposal concerning Income Eligible Weatherization ("IEW") in this proceeding?

A: No. However, Kory Boustead, Thomas M. Imhoff and Matthew R. Young on behalf of Staff and John Buchanan on behalf of the Missouri Department of Economic Development-Division of Energy ("MO-DOE") offered testimony.

Q: Would you please explain the testimony?

A: Yes. The Staff witnesses cite the "Non-Unanimous Stipulation and Agreement Regarding Low-Income Weatherization" from the November 7, 2012 Commission Order in ER-2012-0174 where, in part, it states "this low-income weatherization program should not be funded in rates at the same time KCPL's retail customers are funding a low-income weatherization program the Commission approves under the MEEIA". Staff made an Adjustment to remove the Program expenses from the revenue requirement calculation of this rate case, leaving the recovery to occur through the MEEIA program. Further, Staff recommended that any surplus Program funds be used to offset any expenditures relating to the Program through KCPL's MEEIA recovery mechanism.

MO-DOE witness Mr. Buchanan suggests a different approach. In his testimony, he recommends KCP&L should recover any outstanding program costs, throughput disincentive and performance incentive components for the period that the program was under MEEIA through the Company's DSIM and authorize KCP&L to recover customer contributions to annual low-income weatherization service program funding through base rates.

Q: What is your response to these proposals?

A: I believe the IEW recovery should occur through the MEEIA program as suggested by Staff. Aligning the recover with the other utilities as recommended by Mr. Buchanan does not provide any direct value. The IEW program has experienced conditions that I believe are unique to the Kansas City metro area. In the past, our largest recipient of program funding, the City of Kansas City, discontinued its participation and United Services Community Action Agency assumed their place. Additionally, other Program participants had been slow to utilize available funds. As a result, the past funding levels achieved have been quite variable. We have noticed that performance is improving as the Agencies have deployed more staff and resources to utilize the funds. These challenges have been discussed within the Company's MEEIA collaborative meetings. The issue of recovery has also been discussed within the MEEIA collaborative meetings and provided the IEW program could comply with the MEEIA requirements; parties were open to including IEW recovery through the DSIM. Given that it is much easier to react to Program changes within the MEEIA program and it is unclear how the throughput disincentive – net shared benefit associated with IEW would be treated if it were outside of a rate case, I would recommend that it be left in the MEEIA programs. Concerning the additional recommendation addressing surplus Program funds, I again support Staff's recommendation that the surplus be used to offset any expenditures relating to the Program through KCPL's MEEIA recovery mechanism.

LED STREET AND AREA LIGHTING

Q: Did the Company offer a proposal concerning LED lighting in this proceeding?

A: No, however Staff provided testimony in their Cost of Service Report regarding LED Street and Area Lighting.

Q: Please explain the Staff testimony?

A: Staff recommends that the Commission order the Company to continue to study the cost-effectiveness of replacement of all or parts of existing company-owned street lights with LED lights. Further, Staff recommends the Company file a proposed LED lighting tariff sheet or update to the Commission on when it will file a proposed LED lighting tariff, within twelve months of the order in this case.

Q: What is your response to the Staff proposal?

A: I believe the proposal is unnecessary, but unopposed. The Company has been actively reviewing LED options and has been communicating with Staff concerning the status. As reported in the Staff Report, The Company is not yet ready to propose a tariff for this evolving technology. The Company has made progress and has been focused on defining how to offer and deploy LEDs.

CLASS COST OF SERVICE STUDIES

Q: Please explain the Company's Class Cost of Service Study offered in this proceeding.

A: The Company prepared a Class Cost of Service ("CCOS") Study based on the Average & Peak production allocation method. The CCOS study is used to directly assign or allocate each relevant component of cost on an appropriate basis in order determine the contribution that each customer class makes toward the Company's overall rate of return. The CCOS analysis strives to attribute costs in relationship to the cost-causing factors of demand, energy and customers. Based on the results of the CCOS study, the Company identified four proposals for this case;

1.) no class revenue shifts based on the rate of return results

2.) increase the residential customer charge to include customer costs and local distribution facility costs,

3.) adjustments of the residential summer and winter rates, and

4.) Equal percentage increase to each rate component for all remaining classes.

Q: Have you reviewed the Direct Testimony provided by the parties in this case concerning the CCOS?

A: Yes. I have reviewed the Direct Testimony of Michael Scheperle on behalf of Staff, David Dismukes on behalf of OPC, Maurice Brubaker on behalf of MIEC, and Michael Schmidt representing the US Department of Energy ("US-DOE").

Q: Could you show a comparison of the various CCOS presented in this filing?

A: The following identifies the relative rates of return for the provided studies. Rates below 1.0 indicate the class is not providing revenues to cover its costs. Rates greater than 1.0 indicate the class is providing more revenue than is needed to cover its costs.

Comparison of Class Cost of Service Studies - Relative Rate of Return								
Party	**Production Allocation**	**Total**	**RES**	**SGS**	**MGS**	**LGS**	**LPS**	**Lighting**
KCP&L	Ave. & Peak	1.00	0.74	1.42	1.28	1.32	0.83	2.43
Staff	BIP	1.00	0.93	1.93	1.31	1.07	0.57	0.86
OPC	Alt. Ave. & Excess (4NCP)	1.00	0.49	1.47	1.32	1.52	1.32	0.69
MIEC	Ave. & Excess (4NCP)	1.00	0.50	1.33	1.24	1.55	1.35	1.08
US-DOE	4CP	1.00	0.47	1.25	1.27	1.58	1.28	7.23

Review of these results reveals some consistent themes. The Residential rates provide at or below their relative rate of return. The Small, Medium, and Large General Service Rates are consistently shown to provide a higher relative rate of return than the average. The Large Power relative rates of return are less consistent across the studies. Further, the relationship between the residential relative rate of return and the Large Power relative rate of return varies based on the method used to allocate production plant. Production allocation methods that rely more heavily on peak demands allocate more cost to the residential class while methods that rely more heavily on energy allocate more cost to the Large Power class. The Lighting class shows extreme variation in results which has been common in previous cases and is likely due to the unique characteristics of lighting.

Q: Please describe the fundamental differences between the Company's CCOS study approach and the CCOS study offered by the other parties?

A: The primary difference is with the method used to allocate production costs. Production costs are the largest cost allocated within the study and as a result, the method used can change the results of the study. The Company study utilized an Average & Peak allocation method. This method seeks to recognize that production plant is utilized for both demand and energy. By contrast, the 4CP method proposed by US-DOE focuses entirely on coincident peak demands, particularly the demands in the four summer months. The Staff utilized the Base, Intermediate, Peak method, a hybrid method that uses three different allocations based on the use of the production assets. Finally, MIEC and the alternate study offered by OPC utilize an Average & Excess method which is essentially a non-coincident peak allocation.

Q: What is your opinion concerning the Base-Intermediate-Peak (BIP) method utilized by Staff?

A: The Company has utilized the BIP method previously in Missouri. I believe the BIP method is reasonable but I also have concerns that it is difficult to use for our generation portfolio in that the Company has a lot of base load generation. The recent transition of the SPP to an Integrated Marketplace (IM) with centralized dispatch has raised some concern about the BIP allocator. To utilize the BIP allocator one must assign the generating units into base, intermediate, and peak groups based on their use. Prior to the IM market, the Company provided its own generation to meet its load requirements. With the introduction of the IM market, we no longer use our generation to meet the Company's load requirements, but instead sell generation into the SPP market and buy our load requirements for the SPP market. I believe the IM market change in impacts the suitability of the BIP method as the production allocation.

Q: What is your preferred method?

A: I believe an Energy Weighted approach, such as the Average & Peak method is more cost effective, less subjective than the BIP method proposed by Staff, and properly gives classes recognition for both usage and contribution to peak load. I believe it provides the most balanced and reasonable results of the studies offered in this case.

Q: Do you agree with MIEC and OPC's recommended use of a 4CP or A&E-4 NCP allocation from production and transmission facilities?

A: I realize that there are many allocation methods that can be used in the class cost of service studies in a case. While I do not support the methods proposed in this proceeding, I realize that provide some merit, but would not support them in this proceeding. I do not believe these methods match our situation.

Q: What is your impression of the studies offered?

A: Each study follows the normal structures and utilizes allocation methods, particularly for production plant, which are recognized by NARUC in their cost allocation manual. The respective allocation methods allow the parties allocate costs on the basis of their point of view. Review of the other methods and allocations identified only a few areas of concern. In review of Staff implementation of the BIP allocator, I was concerned to see that the wind and hydroelectric units contributing to our base generation were not used in allocator development. I believe this had the impact of including other generation sources in the base segment that would have otherwise been assigned to the intermediate segment. In review of US-DOE testimony, it would appear witness Mr. Schmidt chooses to allocate fuel costs based on his 4CP demand allocator instead of the energy allocation as proposed by the Company.

Q: How should the Commission utilize the studies and the varied results?

A: I believe that each CCOS study holds value and that some collective view might be warranted. Regardless, the CCOS results should only be used as a guide and that bill impacts, revenue stability, rate stability and public acceptance must be considered. In making my proposal, I considered the rates of return between the classes and noticed our study did show some opportunity for a class shift from the General Service Classes to the Residential and Large Power classes. However, in reviewing the magnitude of change needed to move the residential and Large Power rates of return and the potential impact of those shifts combined with the proposed revenue increase, I recommend no shift in revenues to classes based on the outcome of my class cost of service study at this time. I was able to utilize other aspects of the CCOS study to evaluate the summer and winter pricing as well as the appropriate amount for my customer charge proposal. The CCOS study provides the Commission good information concerning those topics.

RATE DESGN

Q: Please explain the Company's position regarding rate design in this proceeding.

A: The Company is requesting an increase in rates of $120.9 million (15.75%). The Company is proposing that the requested increase be applied to the classes on an equal percentage basis. Within the classes, the Company is proposing a number of changes. In summary, those changes include:

Residential

- Adjust the customer charges are designed to recover customer and local distribution costs.
- Shift some pricing from the winter season to the summer season.
- Clean up references to unused programs.
- Realign the Residential – Other Use rate.

Commercial and Industrial (C&I)

- Rate designs are applied on an equal percentage basis across all classes and bill elements.
- Make several corrections to misaligned rate elements.

Special Rates (Such as Two Part-Time of Use, Special Interruptible, Real Time Pricing, Special Contracts – Customer Specific, and Standby or Breakdown Service)

- Propose freezing or eliminating special rates not used or no longer functional.
- Rate design is applied on an equal percentage basis across all bill elements.

Lighting

- Clean up obsolete rates
- To provide customers usage details needed to calculate the proposed Fuel Adjustment Clause amounts, add kWh usage information to the tariffs.
- Rate designs are applied on an equal percentage basis across all bill elements.

Rules & Regulations

- Clean up obsolete sections
- Propose changes will better align the rules & regulations with current costs or planned business practices.

Q: Have you reviewed the Direct Testimony provided by the parties in this case concerning rate design?

A: Yes. I have reviewed the Direct Testimony of Michael Scheperle on behalf of Staff, David Dismukes on behalf of OPC, Maurice Brubaker on behalf of MIEC, Michael Brosch representing MECG, Jane Lohraff on behalf of the Missouri Department of Energy, Michael Schmidt representing the US Department of Energy, and Tim Woolf representing Sierra Club.

Q: Please describe those testimonies.

A: The Direct Testimony filed by Staff witness Scheperle proposes an equal percentage increase to each class. Mr. Scheperle recommends the first energy block rate of the winter SGS, MGS, and LGS All-Electric Service rate schedules be increased by an additional 5%. Then Mr. Scheperle recommends that each rate component of each class be increased across-the-board for each class on an equal percentage basis. Mr. Scheperle recommends that the residential and all other customer charges increase by the average increase for each applicable class.

Mr. Dismukes, representing OPC, proposes the revenue increase should be distributed to the customer classes on an across the board basis at the system average increase. Concerning the Residential class, he recommends the existing customer charges should not be increased and remaining components should be increased according to the results of the CCOSS with the prescribed increase allocated to the volumetric and demand components on an equal percentage basis. The Residential Other Use rates should be set to the mid-point of the Residential and SGS rates as proposed by the Company. Concerning the Small General Service class, Mr. Dismukes supports setting the second and third winter rate blocks for the SGS All-Electric rate schedules equal to the second and third winter rate blocks of the SGS general use schedule consistent with the results of the CCOS study and the Company's proposal.

Mr. Brubaker, representing the Industrials, supports a revenue neutral cost of service adjustment moving each class 25% of the revenue differential. The Residential class would experience an increase while all other classes would receive a decrease. Any remaining increase would then be applied on an equal percentage basis to all classes with the exception of the Large General Service and Large Power classes. For these classes Mr. Brubaker proposes that the tail-blocks of the energy charge should not be changed, the middle blocks be increased by 75% of the remaining increase, and the balance of the remaining increase applied equally to the remaining billing components.

Mr. Schmidt, representing US-DOE, supports movement toward cost based rates in this case subject to principles of gradualism. Specifically, Mr. Schmidt suggests the Commission cap rate increases for any particular rate class at the greater of one-third (33 percent) more than the system average percentage rate increase or three percent above the system average percentage rate increase. Class rate changes below the system average should be limited to double these levels (e.g. two thirds less than the system average) prior to any reallocation of revenues necessitated by the proposed caps on rate increases.

Mr. Woolf, representing Sierra Club, recommends the rejection of the Company's proposal to increase the customer charge for residential customers and instead require the Company to increase the residential customer charge and energy rate by the same amount. Mr. Woolf then recommends the Commission should investigate revenue decoupling as a means of addressing several issues in this rate case.

Q: What is your initial impression of the proposals offered?

A: The proposals follow largely traditional lines, recommending equal increases to the rates and rejecting the Company proposal concerning the Residential Customer Charge and instead proposing equal percentage changes or no change at all to the Residential Customer Charge.

Q: Please describe your concerns with the proposals?

A: Beginning with the Residential Customer Charges, I believe the other witnesses fail to acknowledge the need to address fundamental changes that are occurring in the electric utility industry and in this context, particularly within the Residential customer class. Company witness H. Edwin Overcast addresses those broad conditions in his rebuttal testimony. For residential users, because of increasing appliance efficiencies, increasing focus of energy efficiency, and the availability of distributed generation at the customer home, residential customers are using less electricity, as well as using electricity differently. The long-standing, two-part rates (Customer Charge and Energy Charge) are a simplified way to bill for utility service. By comparison, the non-residential rates utilize a more complete, four-part rate (Customer Charge, Facility Charge, Demand Charge, and Energy Charge).

Q: What makes the four-part rate more complete?

A: The four-part rate divides the customer bill into segments that are largely representative of the functions utilized to provide service. Theoretically, the Customer Charge is intended to represent customer costs unrelated to usage, the Facility Charge is intended to recover costs associated with distribution facilities, the Demand Charge is intended to recover costs associated with transmission and generation facilities, and the Energy

Charge is intended to recover costs associated with energy production. Although the actual costs recovered by the four-part rates can vary, the rate design provides the customer a complete view of the cost to provide service. With the two-part rate, most of this transparency is lost.

Q: Please detail how the two-part rate works.

A: With the two-part rate, all of the cost recovery must occur through the Customer Charge or the Energy Charge. Pricing and related price signals associated with the Facilities Charge and the Demand Charge are hidden. Since the Customer charge is generally held at an artificially low level, the Facilities and Demand components are consolidated into the Energy Charge. As a result, customers do not always understand where the components are in relation to their electric bill.

Q: How is electric bill misunderstood?

A: First, customers often believe the bill they pay is simply for the electricity they use. This is only partly true. A significant part of the bill is to pay for the availability of electric service. When a customer is connected with the Company system, equipment is put in place to service the anticipated needs of the customer. The system is ready and standing by to service the complete energy need of that customer, even if they never use it. The system is then maintained so that electric service is nearly always available. It is only through the subsequent usage that the Company begins any meaningful recovery of its costs to serve that customer. Since the bulk of the charges are reflected in the variable energy charge, the customer's bill goes down when they use less energy, while the costs for serving may remain. Nowhere in the current structure and relationship does the customer see the charges associated with energy availability. It is simply buried in the energy charges. This confusion is much less prominent in the non-residential rates where the four-part rates, particularly the Facilities and Demand Charges serve to recover costs of the infrastructure. Since Facilities and Demand charges are based on the maximum demand placed on the Company system during the month or year, depending on the charge, a better signal concerning the impact to the system is sent.

Q: Could the four-part rate be used for Residential customers?

A: Certainly. It is not common, but it could be done. Many of the historic limitations caused by to metering technology are going away as electronic meters are better capable to measure these various components. I am not recommending that change. In some jurisdictions, I have noticed Commissions are approving three-part residential rates where a Demand Charge is added. Although I can see the merit in that choice, I believe the two-part rate is very workable and easily understood by customers.

Q: How can the two-part rate be made to work?

A: The two-part rate is a simple structure suitable for use with residential customers. I believe customer generally understand that the customer charge is fixed and covers the costs associated with being a customer and the energy charge is for the energy received. My proposal keeps that relationship. My proposal is to make the rate more rational by moving some of the costs of making electricity available from the energy components to the customer charge. My proposal is to move the full amount of the customer-related costs and incorporating the costs of the local facilities to provide a clearer representation of the costs to provide energy and the costs to make electricity available around the clock.

Q: Why is it reasonable to include the local facilities cost in the customer charge?

A: At its root, the local facilities are a logical extension of the common definition of customer charge. As defined in the Staff report on page 34, line 16, "*Costs included in the calculation of the residential customer charge are the costs necessary to make electric service available to the customer, regardless of the level of electric service utilized*." I consider the local facilities, representing the transformer and the secondary conductors, to be part of that cost. Using a new customer as an example, when service is requested to a new home, it is common that we will install a transformer, some mix of secondary or service conductor depending on the need, and a meter. The transformer converts the energy to a voltage suitable for use in the home, the secondary or service conductors move the electricity from the transformer to the meter, and the meter measures the electricity for billing purposes. This entire infrastructure is put into place before the customer is billed for any usage. Since the infrastructure is necessary, it seems reasonable to ask the customer to pay for the local facilities as part of the customer charge. Including the local facilities charge helps insure each customer pays their respective portion of these costs and avoids potential subsidization of other customers with small volumetric use.

Q: The other parties have offered testimony concerning the customer charge. What did they say?

A: A compelling finding offered by Staff and OPC is worth repeating. Both parties acknowledge that the current charges do not even cover the customer costs identified in the class cost of service studies absent any local facilities. In the Company CCOS study, the customer costs are identified to be $13.54 and are accepted by OPC. The Staff CCOS study identifies the customer costs at $16.49. Both are well above the current $9 charge. The parties go on, explaining why they believe the lesser charge is reasonable.

Q: How do you respond to those justifications?

A: I would group the justifications into two categories, concerns about bill impact and concerns about policy. Concerning the bill impact, all parties agree that the proposed customer charge will have different impacts depending on the level of usage. Looking at the total bill, customers with below average usage will see an increase slightly greater than the class average while customer with above average usage will see and increase slightly less than the class average. These impacts are made possible because the increase in customer charge is being offset by a lower increase than the average in the energy charges.

Q: Turning to the policy concerns, what is your response?

A: First, OPC witness Mr. Dismukes and Sierra Club witness Mr. Woolf, provide testimony comparing the Company proposal to other utilities. The data seems too imply the Company proposal represents an outlier to other customer charges. In the Company's review of current activity, we have identified a different trend. In the following table, I identify a number of current proposals in which utilities are seeking to change their customer charges. Most are still pending before their respective Commissions, but the table clearly shows that customer charge proposals are happening and that in some jurisdictions, are moving beyond the levels seen in the past.

Table 1.

Known Proposals Concerning Electric Utility Customer Charges

Utility	Case #	Proposed Customer Charge	Final Customer Charge
Madison Gas & Electric	3270-UR-120	$21.83 in 2015 $48.65 in 2016 (was $10.44)	$19 (Settlement)
Wisconsin Public Service	6690-UR-123	$25 (was $10.40)	$19 (Settlement)
WE Energies	3270-UR-107	$16 (was $9)	$16 (Settlement)
Central Maine Power	2013-00168	$12 (was $5.71)	$10.65 (Settlement)
Connecticut Light & Power	14-05-06	$25.50 (was $16)	$19.25
Indianapolis Power & Light	44576	$17 (was $11)	Pending
Kentucky Utilities	2014-00371	$18 (was $10.75)	Pending
Louisville Gas & Electric	2014-00372	$18 (was $10.75)	Pending
Kentucky Power	2014-00392	$16 (was $8)	Pending
DTE	U-17767	$10 (was $6)	Pending
Entergy	2014-UN-132	$8 (was $4.57)	$6.75 (Settlement)
Public Service of New Mexico	14-00332-UT	$12.80 (was $5)	Pending
Orange & Rockland	14-E-0493	$25 (was $20)	Pending
Central Hudson Gas & Electric	14-E-0318	$29 by 2017 (was $24)	Pending
First Energy – West Penn	R-2014-2428742	$7.35 (was $5)	Pending
First Energy – Penn Electric	R-2014-2428744	$12.71 (was $8.86)	Pending
First Energy – Met Edison	R-2014-2428745	$13.29 (was $8.11)	Pending
Northwest Energy	EL14-106	$9 (was $5)	Pending
Appalachian Power	PUE-2014-00026	$16 (was $8.35)	$8.35

PacifiCorp	UE-140762	$14 (was $7.75)	Pending
Appalachian Power	14-1152-E-42T	$10 (was $5)	Pending

An additional policy issue is raised by Staff and OPC in their reference to the Commission's order in a recent Ameren case (ER-2012-0166). In that order, the Commission cites concerns about impacting Ameren's Missouri Energy Efficiency Investment Act programs by reducing a customer's incentive to save electricity. The Commission position was repeated again recently in the Report and Order from the Ameren ER-2014-0258 case. I have reviewed those orders and noticed a consistent set of points being made to evaluate the customer charge proposals. Restated, those points are:

- Customer-related costs are the minimum costs necessary to make electric service available to the customer, regardless of how much electricity the customer uses.
- Any increase in the company's customer charge should be accompanied by a decrease in volumetric rates so that, in theory, the company recovers the same amount of revenue.
- The customer charge should be based on the results of a particular class cost of service report; however, the Commission is not bound to set the customer charges based solely on the details of the cost of service studies.
- The Commission must also consider the public policy implications of changing the existing customer charges.
- Residential customers should have as much control over the amount of their bills as possible.

In reviewing these "tests" for this case, I believe our proposal warrants new consideration. Working through the points, I would offer the following:

- <u>Customer-related costs represent the minimum costs necessary to make electric service available to the customer.</u>

- The Company's proposed customer charge is inclusive of only the customer and local facilities costs spent by the Company independent of usage by the customer and installed in order to provide service to an individual customer. Other costs, for distribution, transmission, and generation facilities, although to some degree also necessary for electric service to customers, remain as part of the volumetric energy charge.

- <u>Any increase in the company's customer charge should be accompanied by a decrease in volumetric rates.</u>
  - The Company's proposed tariffs are configured to offset customer charge increase through reduction of the energy charge.

- <u>The customer charge should be based on the results of a particular class cost of service report.</u>
  - Both the customer and local facilities amounts are derived from the study and support the $25 charge. Amounts from studies performed by Staff and OPC support similar amounts.

- <u>The Commission must also consider the public policy implications of changing the existing customer charges.</u>
  - The policy noted in the Ameren orders relates to the Missouri Energy Efficiency Act codified at section 393.1075, RSMo (Supp. 2011). In that act is written:

    "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."*

I would offer that this policy is written as such to balance the needs of the utility and the needs of the customer in both cost and benefit. I am concerned that focusing on preservation of the incentive or pay-back periods is only addressing the customer perspective. I have not noticed similar parallel efforts to provide similar support concerning supply and delivery infrastructure investments.

- <u>Residential customers should have as much control over the amount of their bills as possible.</u>
  - If approved as proposed a typical, residential general use customer will have approximately 80% of their annual bill associated with the volumetric charges and under their control for energy efficiency or conservation purposes. This leaves the remaining 20% for the utility to makes some, relatively small recovery of the fixed costs necessary to maintain the electric infrastructure and make service available to the customer.

Q: Are there other aspects of the rate design you wish to address?

A: Yes, there are a handful of recommendations offered by other parties I wish to address. They are:

- the OPC proposal concerning the residential time of use rate,
- the Staff proposal concerning the General Service Heating Rates,
- the MO-DOE proposals concerning the Stand-by and EDR/UDR rates,

- and the Sierra Club proposal concerning decoupling.

TIME OF USE RATE

Q: Please describe OPC's proposal regarding Time of Use (TOU) rates.

A: OPC proposal concerning the residential TOU rate recommends the Company not be allowed to freeze the TOU rate in this proceeding, suggesting that the Company be required to re-file a modified and improved TOU tariff in its next rate case. The Company agrees that a TOU rate should be part of our portfolio of rates offered to customers however, the time is not right for offering a rate. As noted in my direct testimony, the current rate is not performing and continuing to offer the outdated rate does not make sense. In considering a new rate we find ourselves near the beginning of two projects that will fundamentally impact a TOU design, our AMI metering roll-out and the implementation of a new billing system. We need to understand more about the capabilities of these systems so we may design a rate that is effective to manage and delivers the results expected from a TOU rate. Additionally, a TOU rate should complement the goals of our Integrated Resource Plans and the goals of our MEEIA programs. Given these dependencies, we are hesitant to commit to a schedule for a proposed tariff.

Turning to the Staff proposal concerning the General Service Heating Rates, Staff is recommending that the winter first block energy charge be increased by an additional 5% to bring the frozen small, medium, and large general service rate components closer to the existing standard rate. Based on previous cases I believe Staff intent with this proposal is to move toward elimination of the rate. However, based on the results of the Company CCOS study offered in this case, continual movement of the winter rate upwards is unsupported. Reviewing the seasonal results detailed in Schedule TMR-8 of my direct testimony, one will find that the winter, general service rates are overpriced and should be reduced from their current levels. I did not propose seasonal changes for these rates, instead deciding to postpone changes of this type until the Company is better prepared to determine the impact of such proposals. That being said, it does not change the fact the winter , general service rates are already overpriced and additional movement of the first block of the General Service Heating Rates will only expand that condition.

DECOUPLING

Finally, concerning the Sierra Club proposal, witness Mr. Woolf recommends the Commission investigate revenue decoupling as a means of addressing several issues in this rate case. While I appreciate this proposal and agree with many of the details offered concerning the benefit of decoupling to allow the Company to respond to fundamental changes in our industry, I believe this rate case is not the suitable venue for this investigation. Decoupling would represent a significant change to the regulatory structure used in the state and as such, would likely need to be part of a larger, generic proceeding. For this reason, I recommend the Commission reject this proposal in this rate case.

RETURN CHECK CHARGE AND COLLECTION CHARGE

Q: Are there any positions offered by the other parties concerning the Rules & Regulations you wish to discuss?

A: Yes. Staff recommended rejection of two Company proposals concerning Returned Check and Collection Charge. In the case of the Returned Check Charge, I believe Staff misunderstands our request. On page 218, line 22 of Staff's report *"Staff recommends* *the Commission reject KCPL's request for the increase of the current return check charge."* I am not proposing to increase the charge in this proceeding. Our request is to only change the application of the charge. Currently the charge is specifically associated with paper checks. This fact was communicated through our response to Staff data request 298.2. We have a large number of customers who no longer utilize paper checks for payment but instead use electronic payment methods. I am proposing to revise the language to extend this returned payment charge to all forms of payment received by the Company. This change will bring these tariffs in line with the language currently used in our GMO area, providing a more consistent customer experience. I continue to recommend the Commission accept this proposal.

Concerning the collection charge, in the same report on page 219, *"Staff recommends the Commission reject the requested increase in the collection charge for in-field payments"* because of a lack of support for the charge increase. Staff references data request 298 as the basis for this recommendation. There were two additional data request responses provided on this issue. Responses to data request 298.1 and 298.2 provided the requested support concerning the proposed increase. The data request responses are offered in Schedule TMR-11. In addition to updating the charge to reflect current costs, this proposal seeks to align this charge with the current GMO collection charge. I continue to recommend the Commission accept this proposal.

BILL IDENTIFICATION

Q: Are there any other tariff related issues to discuss?

A: Yes. Mr. Brosch, representing MECG included a recommendation in his testimony concerning adding Company identification on the bill. I disagree with the recommendation. The decision to serve all customers under the KCP&L name was made at the time of the acquisition of Aquila and has been operating as such since that time. Currently, the customer's rate code is present on the bill and would serve to direct the customer to the correct tariffs. To further clarify this relationship, we have proposed adding specific tariff codes to the tariff sheets. Finally, all employees and particularly our Customer Service employees are available to help customers identify the applicable tariff sheets. Changing the bill language and presentation is not a trivial undertaking as space on the bill is generally limited and can impact various systematic billing processes. Unless there is evidence that customers are unsatisfied and having difficulties, I recommend the Commission reject this suggestion.

EDR/UCD AND STANDBY SERVICE TARIFF

Q: Does the Missouri Department of Energy (MO DOE) propose changes to some the current programs and tariffs of the Company?

A: Yes. Ms. Lohraff, representing the MO DOE, proposes to modify KCP&L's Economic Development Rate (EDR)/Urban-Core Development Rate (UDR) rates EDR and UCD to include participation in applicable KCP&L MEEIA Programs as an eligibility requirement for taking service under the special rate. Ms. Lohraff also recommends formation of a working group to review the design and rates associated with the Standby Service Tariff.

Q: What is the position of the Company on these recommendations?

A: Concerning the MO-DOE proposals related to the Stand-by and EDR and UCD rates. I believe requiring participation may be in violation of the MEEIA statutes. The MEEIA statue allows customers who meet specific criteria to opt out of MEEIA participation. If a customer meets those criteria, I don't think we can exclude them from participation in the EDR and UCD programs. I also think that we cannot require participation in MEEIA programs as a prerequisite for receiving an EDR or UCD. Additionally, Mr. Lohraff's proposal requires participation in **all** cost effective energy efficiency programs. This would be nearly impossible to police.

Concerning the Stand-by rate working group review proposal I am concerned that the proposal would be duplicative of discussions underway within the Company's MEEIA initiative. Additionally, the proposal regarding Combined Heat and Power (CHP) systems is being addressed in that same effort and addressing it separately within the rate case proceeding would cause issues. I propose that any changes, including tariff related changes to accommodate CHP should occur as part of the Company's MEEIA filing and not be address here.

Q: Does that conclude your testimony?

A: Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement A General Rate Increase for Electric Service	)))	Case No. ER-2014-0370

AFFIDAVIT OF TIM M. RUSH

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Tim M. Rush, being first duly sworn on his oath, states:

1. My name is Tim M. Rush. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Director, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes is my Rebuttal Testimony on behalf of Kansas City Power & Light Company consisting of Sixty-five (65) pages, having been prepared in written form for introduction into evidence in the above-captioned docket.

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

Tim M. Rush
Tim M. Rush

Subscribed and sworn before me this 7th day of May, 2015.

Nicole A. Wehry
Notary Public

My commission expires: Feb. 4 2019

NICOLE A. WEHRY
Notary Public - Notary Seal
State of Missouri
Commissioned for Jackson County
My Commission Expires: February 04, 2019
Commission Number: 14391200

KCP&L
Case Name: 2014 KCPL Rate Case
Case Number: ER-2014-0370

Response to Williams Nathan Interrogatories - MPSC_20150318
Date of Response: 04/13/2015

Question:0298.1

In its response to data request 557, KCPL stated that Staff inquired about the formulation of the collection charge in ER-2010-0355, in which KCPL also argued for a collection charge of $25 and provided a copy of its witness's testimony on that issue and its in-field analysis in that case. 1. Have any of KCPL's computations or motives in proposing a $25 collection charge changed since the conclusion of ER-2010-0355? If so, please provide a detailed explanation of these changes and copies of all supporting documentation. 2. Has the return on investment or expenses this charge tries to recover changed since the conclusion of ER-2010-0355? If so, please provide a detailed explanation of these changes and copies of all supporting documentation. Data Request submitted by Byron Murray (Byron.Murray@psc.mo.gov).

Number of Attachments:

Response:

1. Yes. There have been changes to labor computations since the conclusion of ER-2010-0355. The Labor Only Analysis of In-Field Collections as of March 27, 2015 is attached.
2. Yes. See response to 1. Above.

Information Provided By:
Allyson Erickson, Manager Credit & Collections

Attachments:
Q0298.1_HC_In Field Collection Analysis.xls
Q0298.1_Verification.pdf

SCHEDULE TMR-11, Page 2

THIS DOCUMENT CONTAINS HIGHLY CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC

Verification of Response

Kansas City Power & Light Company
AND
KCP&L Greater Missouri Operations

Docket No. ER-2014-0370

The response to Data Request # 0298.1 is true and accurate to the best of my knowledge and belief.

Signed: Tim Rush

Date: April 7, 2015

KCP&L
Case Name: 2014 KCPL Rate Case
Case Number: ER-2014-0370

Response to Williams Nathan Interrogatories - MPSC_20150318
Date of Response: 04/13/2015

Question:0298.2

In its response to data request 557, KCPL stated that the current returned check charge was set at $30 in the Company's 2006 rate case and provided a copy of its witness's testimony in that case. 1. How much of an increase in the returned check charge, expressed in either a dollar amount or percentage increase, is KCPL seeking in this case? 2. Have any of KCPL's computations or motives in proposing an increase to the returned check charge changed since the conclusion of the Company's 2006 rate case? If so, please provide a detailed explanation of these changes and copies of all supporting documentation. 3. Has the return on investment or expenses this charge tries to recover changed since the conclusion of the Company's 2006 rate case? If so, please provide a detailed explanation of these changes and copies of all supporting documentation. Data Request submitted by Byron Murray (Byron.Murray@psc.mo.gov).

Number of Attachments:

Response:

1. KCPL is not seeking a change to the existing fee structure in the $30 charge. KCPL is proposing a language change to include other methods of payment for this charge to the following:
Returned Payment Charge: A charge in the amount of $30.00 may be assessed when a Customer's payment is returned for reasons other than bank error.
2. No changes to the computations for the existing charge.
3. The Company is not seeking a change to the existing fee of $30 in this case and has not conducted an analysis of the expenses associated with returned checks in 2006 vs. 2015.

Additional Details on 298.2 response: Current language on the above charge reads:
8.07 RETURN CHECK CHARGE: A charge not to exceed $30.00 may be assessed when a Customer's check is returned due to insufficient funds.
The above language in 8.07 above is specific to a Customer's check being returned due to insufficient funds. The company is requesting to change the language to include other forms of payment and also for return reasons that are not created by a bank error.

Information provided by: Allyson Erickson, Manager Credit and Collection

Attachment: Q0298.2_Verification.pdf

Verification of Response

Kansas City Power & Light Company
AND
KCP&L Greater Missouri Operations

Docket No. ER-2014-0370

The response to Data Request # 0298.2 is true and accurate to the best of my knowledge and belief.

Signed: Tim Rush

Date: April 7, 2015