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Issue(s):	*Class Cost of Service, Customer Discounts*
Witness:	*Sarah Kliethermes*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Rebuttal Testimony*
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MISSOURI PUBLIC SERVICE COMMISSION

COMMISSION STAFF DIVISION

OPERATIONAL ANALYSIS DEPARTMENT

TARIFF/RATE DESIGN UNIT

REBUTTAL TESTIMONY

OF

SARAH KLIETHERMES

UNION ELECTRIC COMPANY
D/B/A AMEREN MISSOURI

ER-2016-0179

Jefferson City, Missouri
January 2017

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CASE NO. ER-2016-0179

Q. Are you the same Sarah Kliethermes that contributed to Staff's Report on Revenue Requirement Cost of Service, Staff's Report on Class Cost of Service and Rate Design ("CCoS Report"), Staff's Report on Commission Raised Issues, and Revenue Requirement Rebuttal?

A. Yes.

Q. What is the purpose of your rate design rebuttal testimony?

A. I will respond to Union Electric Company d/b/a Ameren Missouri's ("Ameren Missouri") Witness William R. Davis concerning Ameren Missouri's proposed Standby Tariff, and Economic Redevelopment and Efficient Infrastructure Utilization Pilot. I will also respond to Missouri Industrial Energy Consumers' (MIEC) witness Maurice Brubaker concerning class cost of service and MIEC's proposed Economic Development and Retention Rider tariff, and The Midwest Energy Consumers Group's (MECG) witness Steven Chriss concerning large customer rate design.

INTERCLASS SHIFTS

Q. Do you agree with Mr. Brubaker that a kilowatt hour ("kWh") is not a kWh, as he testifies on page 13 of his direct testimony?

A. Yes. I agree with Mr. Brubaker that the cost of producing a kWh of energy will vary depending on which plant is producing that energy, and which plants are operating to produce energy at a given time. However, unlike Mr. Brubaker, I take this reality into account in developing allocators for Staff's Class Cost of Service Study ("CCoS"). Unlike the other submitted CCoS studies, Staff bases energy–related allocations on an assignment of time-differentiated pricing.

Q. Is a kW a kW?

A. No. As I discussed and demonstrated in the CCoS Report, base capacity is quite expensive to install and operate, while peaking capacity is relatively cheap to install and operate. The cost of intermediate capacity is somewhere between those two.

Q. Did Mr. Brubaker address the relative capacity costs of different unit types in his study?

A. No. While Mr. Brubaker did weight his capacity allocation by load factor, he effectively treats the capacity cost of a nuclear plant as equal to the capacity cost of a simple cycle gas plant. As discussed and demonstrated in the CCoS Report, these types of units have very different installed capacity costs. Of the studies filed in this case by all parties, only Staff's detailed Base-Intermediate-Peak ("BIP") study recognizes this disparity in capacity cost.

Q. Do you agree with Mr. Brubaker's assertion at page 3 of his direct testimony that, "[t]here are two generally accepted methods for allocating generation and transmission fixed costs that would apply to Ameren Missouri. These are the coincident peak methodology and the average and excess ("A&E") methodology."?

A. No, I do not. Mr. Brubaker's statement ignores this Commission's recent acceptance of production allocators that recognize that a kW is not a kW and a kWh is not a kWh when it comes to capacity and energy costs associated with different types of production plant. Specifically, the Commission explicitly relied on Staff's detailed BIP allocation study in The Empire District Electric Company's 2014 rate case, Case No. ER-2014-0351, stating, "[o]f the four CCoS studies submitted by the parties, Staff's most reasonably recognizes the relationship between the cost of the plant required to serve various levels of demand and energy requirements and the cost of producing energy."[1]

Q. Do any of the studies filed by the parties indicate that any class is subsidized in this case?

A. Ameren Missouri's study identified a subsidy in Customer-Owned Lighting. Staff did not study the lighting customers as separate classes and takes no position on this issue at this time.

Q. What costs were used by the parties in performing their CCoS studies?

A. Staff's CCoS study is based on Staff's cost of service study, while the other CCoS studies are based on Ameren Missouri's cost of service study. Ameren Missouri's revenue requirement calculation includes a higher level of expense and a lower level of revenue than Staff's revenue requirement calculation. Because Ameren Missouri-based

[1] Report and Order in Case No. ER-2014-0351, page 15. See also Order Clarifying Report and Order, at page 2, stating "The Commission will grant the Motion and clarify that based on Staff's CCoS, which the Commission found in its Report and Order to most reasonably recognize the relationship between the cost to serve and the cost of producing energy, no decrease on a revenue neutral basis shall occur for the SC-P rate class." See also Report and Order in Union Electric Company d/b/a Ameren Missouri, Case No. ER-2014-0258, at page 39, "because the results of the A&E and BIP studies are similar, the Commission does not need to decide which particular study is most appropriate;" and in Case No. ER-2012-0175, the Commission stated that it relied on the non-detailed BIP study performed by Mr. Paul Normand, on behalf of Kansas City Power & Light.

studies assume a higher level of expense, each class has less net income as calculated for that class's rate of return on its studies.

Q. Did parties other than Staff conduct a CCoS that is consistent with that party's recommended revenue requirement?

A. No. MIEC's witness Mr. Brubaker used Ameren Missouri's CCoS calculation; however, MIEC's revenue requirement filing is approximately $71.3 million lower than Ameren Missouri's. MECG's witness did not do a study. Office of Public Counsel's witness Don Johnstone used the company's revenue requirement.

Q. What is the significance of a decrease of $71.3 million to Ameren Missouri's revenue requirement, as recommended by MIEC?

A. Incorporating MIEC's recommended decrease to Ameren Missouri's revenue requirement would reduce the class-level under-recoveries that Mr. Brubaker calculated. It is unlikely that this reduction would apply evenly among all classes.

Q. Did other parties rely on Ameren Missouri's allocations for plant accounts such as distribution and customer costs?

A. Yes.

Q. Are these allocators appropriate?

A. No. Staff witness Robin Kliethermes' concurrently filed rebuttal testimony describes Staff's concerns with Ameren Missouri's allocators for certain plant accounts, as well as Ameren Missouri's segregation of certain costs among accounts.

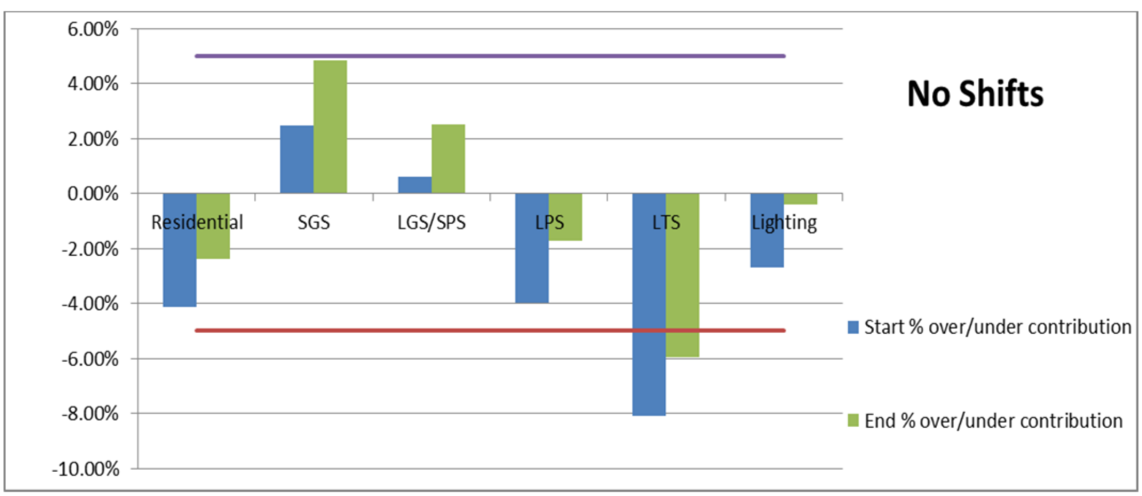
Q. Would addressing these concerns change the CCoS results of the parties that relied on Ameren Missouri's study?

A. Yes. These allocations appear to account for over $20 million of inappropriately allocated costs being allocated to the Residential classes. Addressing these misallcoations would increase the Residential class's studied rate of return, and reduce the studied rates of return for other classes. This would also reduce the under-contribution other parties identify for the Residential class.

Q. Has Staff updated its CCoS study?

A. Yes. As discussed in the concurrently filed testimony of Robin Kliethermes, Staff has revised its study to address the improper allocation of a meter-related account. The study has also been revised to correct an error in Staff's Production Capacity allocator calculation. The results are provided below:

	Current Revenue *plus Allocated Other Revenue*	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost of Service	Start RoR	System Average Increase + Energy Efficiency	End RoR	Additional Revenue Change to Equalize Class Rates of Return	End % over/under contribution
Residential	$ 1,572,570,791	$54,791,978	-4.14%	4.32%	5.61%	$ 23,204,455	6.23%	$31,587,524	-2.39%
SGS	$ 379,064,599	-$7,419,875	2.47%	-2.41%	8.02%	$ 7,125,598	8.93%	-$14,545,473	4.84%
LGS/SPS	$ 1,059,700,437	-$5,174,870	0.62%	-0.62%	7.34%	$ 15,826,355	8.11%	-$21,001,226	2.51%
LPS	$ 270,049,117	$8,575,233	-3.96%	4.12%	5.35%	$ 4,880,399	6.34%	$3,694,834	-1.71%
LTS	$ 1,870,794	$123,668	-8.08%	8.79%	3.09%	$ 32,800	4.15%	$90,868	-5.94%
Lighting	$ 45,840,057	$1,120,623	-2.68%	2.76%	5.94%	$ 947,158	6.90%	$173,465	-0.42%
System Average:					6.35%		7.08%		



Q. Does this modify Staff's recommended interclass shifts in revenue responsibility?

A. Yes. These corrections bring the small general service class ("SGS") within the 5% band of reasonable precision for a study of this nature. While the Large Transmission Service (LTS) class continues to be under-contributing by more than 5%, no other class is over-contributing by more than 5%. It would not be reasonable to rely on the results of a CCoS that has not synchronized to ordered rates to implement revenue shifts within this +5/-5% band.

Q. What was Staff's error in its Production Capacity allocator calculation?

A. I had inadvertently referred to the wrong set of cells in the final calculation of the allocator, such that the absolute intermediate and peak demands were used to calculate each class's portions of installed capacity requirements, instead of the incremental intermediate and peak demands. Corrected versions of the effected charts and tables provided in Staff's CCoS Report are attached as Schedule SLK-r1.[2]

LARGE CUSTOMER RATE DESIGN

Q. Does Staff fully understand MECG's proposed Large General Service and Small Primary Service (LGS/SPS) rate design?

A. No. MECG's proposal is provided as a series of adjustments for various contingencies.

Q. For the contingency of an increase less than that Ameren Missouri requested, is MECG's apparent proposal reasonable?

A. No. Staff is concerned that MECG's proposal would almost certainly result in Ameren Missouri paying more for a kWh of energy through the MISO market than what it

[2] These charts and tables are also corrected for a mislabeling of kWh and kW values as megawatt hours ("MWh") and megawatt ("MW") values. While this typographical error does not impact any recommendations, much of the informational values provided in the CCoS Report are off by a factor of 1000 due to this error. I apologize for any inconvenience.

receives to sell that kWh at retail, although this would depend on the level of increase awarded. All energy rates should be designed to recover, at a minimum, the average cost of market energy at generation for each class, provided in Table 14 of the Staff CCoS Report, plus an allowance for ancillary services and other related Regional Transmission Organization (RTO) costs, from each class's energy charges. This metric supports an equal percentage increase to all LGS/SPS rate components, should an overall increase be ordered in this case.

Q. Were you informed of a typographical error in the table provided in Table 14 of the Staff CCoS Report?

A. Yes. I inadvertently labeled class kWh as MWh, and continued this error in the dollar amounts provided.[3] A corrected version of Table 14 is provided below:

Table 14

	Res.	SGS	LGS/SPS	LPS	LTS	Ltg.
Cost of Energy at Market Prices used in Fuel Run:	$ 340,945,168	$ 88,898,120	$ 307,975,083	$ 94,580,444	$ 769,513	$ 5,044,198
Cost of Energy at Actual Market Prices:	$ 315,229,282	$ 81,437,494	$ 281,572,398	$ 86,380,183	$ 701,456	$ 4,676,085
MWh at Generation:	13,798,071	3,595,783	12,639,222	3,942,837	32,371	236,403
$/MWh at Market Prices used in Fuel Run (at Generation):	$ 24.71	$ 24.72	$ 24.37	$ 23.99	$ 23.77	$ 21.34
$/MWh at Actual Market Prices (at Generation):	$ 22.85	$ 22.65	$ 22.28	$ 21.91	$ 21.67	$ 19.78
MWh at Meter:	14,848,127	3,869,428	13,587,386	4,122,604	32,816	253,881
$/MWh at Market Prices used in Fuel Run (at Meter):	$ 22.96	$ 22.97	$ 22.67	$ 22.94	$ 23.45	$ 19.87
$/MWh at Actual Market Prices (at Meter):	$ 21.23	$ 21.05	$ 20.72	$ 20.95	$ 21.38	$ 18.42
Class % of Total Cost of Energy at Market Prices used in Fuel Run:	40.675%	10.606%	36.742%	11.284%	0.092%	0.602%
Class % of Total Cost of Energy at Actual Market Prices:	40.939%	10.576%	36.568%	11.218%	0.091%	0.607%

[3] I made a similar typographical error in Table 13, in that the "Non-Summer MWh at Generation" should be relabeled "Non-Summer kWh at Generation."

Based on Ameren Missouri's response to DR 0154, approximately $1.85 per MWh at generation should be included as an allowance on a $/MWh basis for ancillary service, real time market, and transmission expenses.

Q. Would MECG's contingency of an increase less than that Ameren Missouri requested result in unequal impacts within the LGS and SPS classes?

A. Yes. Again, depending on the amount of overall increase awarded, it would appear that some customers would receive a noticeable ***decrease*** in their bills, while other customers would receive significant increases that may be of a sufficient magnitude to promote rate switching.

ECONOMIC REDEVELOPMENT AND EFFICIENT INFRASTRUCTURE UTILIZATION PILOT

Q. Could you summarize Ameren Missouri's requested Economic Redevelopment and Efficient Infrastructure Utilization Pilot ("EREIU") tariff sheet 165-165.2?

A. Yes. Under the EREIU, customers taking service at qualifying premises would receive a discount in the form of reduction of facility or relocation charges associated with modifications to local distribution facilities, or an ongoing rate reduction.

Q. Under what circumstances are these discounts awarded?

A. Discounts are available to qualifying premises within a designated "blighted" or "conservation" area. Qualifying premises must be unoccupied for a minimum of 120 days or be undeveloped land. These discounts may be awarded to the incremental load of existing customers expanding load. Total payout of discounts under the program through the program's expiration is limited to $10 million and the pilot is set to expire June 1, 2022. The tariff sheet states that a newly-established Collaborative including Staff, Ameren Missouri, Office of the Public Counsel, and other intervenors to this docket "will determine the final discounts offered for each project as well as the terms of such discounts." It is not clear if "terms" is intended to refer to the length of the application of the discounts or to conditions that must be satisfied to maintain the discounts.

Q. Based on Ameren Missouri's current facilities and expansion tariff provisions, would you expect a new or expanding customer that is utilizing existing distribution infrastructure efficiently to incur substantial "facility and/or relocation charges associated with modifications to local distribution facilities"?

A. No. Under Ameren Missouri's current facilities and expansion tariff provisions, unless a customer is requiring expansion of some facility, there would be little to no charge to that customer to acquire or expand service. If a customer requires relocation of already-installed facilities, those are new distribution system costs that that customer is causing to the distribution system, that would not exist but-for that customer's request.

As recommended in Staff's Report on Commission Raised Issues, Staff recommends that Ameren Missouri modify its facility extension tariff provisions to more fully consider the incremental costs a customer causes to a system in determining how much, if any, customer advance is required. KCP&L Greater Missouri Operations Company's ("GMO") current tariff provides a model of this approach.[4] By considering these costs, a customer causing new utility investment is more likely to bear some offset to that investment than under other approaches that do not consider incremental costs. As it applies to a customer accessing

[4] GMO's tariff calls for consideration of the relationship between "Estimated Margins" and "Fixed Carrying Costs", where Estimated Margins are determined by first multiplying the effective rates for each customer class by the estimated incremental usage – and then subtracting 1) applicable margin allocation for network and infrastructure support costs; and 2) incremental power and energy supply costs. Fixed Carrying Costs are determined as the Company's cost of capital to provide the requisite return on its investment as well as the costs for depreciation, property taxes, and property insurance.

infrastructure already in place and not requiring any upgrades, this means that the customer would not have to have any significant up-front costs versus if that customer required infrastructure expansion, in which case that customer would have to provide revenues in excess of the cost of the expansion or provide an up-front payment to hold other customers harmless for the costs of its expansion.

Were Ameren Missouri to so modify its facilities extension tariff provisions to bring it in line with GMO's, the proposed EREIU proposed discounts would bear a more meaningful relationship to the stated purpose of the EREIU.

Q. What information does the EREIU require be provided to the newly-formed Collaborative?

A. The proposed EREIU provides:

> The Company shall file, in the Commission's Electronic Filing Information System ("EFIS"), an annual report summarizing the activities conducted under this Pilot. Such report shall include the following information: a physical description of each project evaluated, the infrastructure assessment performed for each project, the status of each project, the amount of capital investment associated for each project area, the amount of temporary and full-time jobs expected for each project area, a qualitative description of socio-economic benefits expected for each project, an assessment of the economic benefit expected for all other Company customers, and any other information that the Collaborative deems relevant.

The EREIU also provides that, "the Company shall present a package of proposed electric rate discounts to the Collaborative for approval."

Q. Does the EREIU provide guidance to the newly established Collaborative to inform award decisions?

A. To a limited extent. The EREIU provides that, "[s]ervice under this Pilot is limited to loads which in the Collaborative's judgment utilize existing infrastructure in a manner which is beneficial to the local electric service delivery system;" and, "[a]s a general rule, this Pilot is not intended for electric service to a customer that results merely from load shifted from one location on Company's system to a qualifying site; however, exceptions to this rule may be granted by the Collaborative." These qualitative evaluations are well-outside the typical work area of Staff or what existing collaboratives handle.

Q. What is Staff's recommendation concerning the EREIU?

A. Staff does not recommend approval of Ameren Missouri's EREIU Pilot. If the Commission; (1) adopts Staff's recommendation to modify Ameren Missouri's facility extension tariff provisions to more fully consider the incremental costs a customer causes to a system in determining how much, if any, customer advance is required, and; (2) orders Ameren Missouri to provide quantitative criteria to be contained in its tariff for the award of EREIU discounts, Staff does not oppose approval of a revised EREIU Pilot.

<u>MIEC ECONOMIC DEVELOPMENT AND RETENTION RIDER PROPOSAL</u>

Q. Have you reviewed MIEC's proposed Economic Development and Retention Rider, Schedule EDRR?

A. Yes.

Q. Do you agree that Mr. Brubaker's proposed EDRR is patterned after that offered by Kansas City Power & Light Company ("KCPL")?

A. The Brubaker proposal bears little, if any, resemblance to the KCPL rider. In particular, under the KCPL rider a customer seeking a discount must demonstrate that a competitive rate from a different supplier of electricity at a competing location is available, and that some governmental entity is willing to offer incentives. These elements are removed from the Brubaker proposal. The Brubaker proposal also implements a convoluted calculation of incremental cost of service that appears to exclude any consideration of the cost of transmission or distribution infrastructure that the customer may require. While some proposed language appears to suggest that an analysis of the impact on the customer on the system is to be done, other language appears to suggest that any requesting customer would receive the specified discounts without any utility discretion. The Brubaker proposed language states that continued availability for a customer is contingent on the customer meeting the "applicability criteria"; however, no applicability criteria are specified.

Q. Does Staff support the MIEC's requested revisions to the EDRR?

A. No.

SUPPLEMENTAL SERVICE AND STANDBY RATES

Q. Has Ameren Missouri complied with the *Nonunanimous Stipulation and Agreement Regarding Supplemental Service Issues* as ordered by the Commission in File No. ER-2014-0258 ("Supplemental Service Stipulation"), as described by Mr. Davis at pages 60-65 of his direct testimony?

A. Generally, yes. At page 2, the Supplemental Service Stipulation provided that, "[t]he rates included in this Standby Tariff will be consistent with Ameren Missouri's class cost of service analysis from File No. ER-2014-0258, adjusted for the approved revenue requirement plus any adjustments to the class cost of service methodology ordered by the Commission." It appears that Ameren Missouri has based the tariff it filed in this case, File No. ER-2016-0179, on its CCoS filed in this case, File No. ER-2016-0179, as opposed to the CCoS it filed in File No. ER-2014-0258. However, Staff would note that the Commission entered subsequent orders in File No. ER-2014-0258, deferring the filing of the tariff to this pending rate case, File No. ER-2016-0179. Although the subsequent order is silent on the issue, Staff believes Ameren Missouri's use of the current case's CCoS is not inconsistent with the Commission's deferral order.

Q. What concepts did Ameren Missouri agree to incorporate into its proposed standby service tariff under the Supplemental Service Stipulation?

A. The Supplemental Service Stipulation provides that the Standby Tariff will incorporate the following concepts:

> a) The Standby Tariff will contain definitions for supplementary power, back-up power, and maintenance power, and rules for determining when, and in what amount, these services are actually used;
>
> b) Unbundled rates for services (e.g. generation, transmission, and distribution);
>
> c) The customer's generator availability - the Standby Tariff will take into account the fact that no generator system achieves 100% availability with the following criteria considered when developing the rate structure: i) the generator's historical availability and/or predicted availability, ii) any differences in cost impact of scheduled reductions in availability (maintenance) vs. unscheduled reductions in availability (i.e. forced outages, de-ratings, changes in load), and iii) the operational constraints of the generator system;
>
> d) Maintenance scheduling - to the extent that unique pricing provisions are provided for scheduled (vs. unscheduled) reductions in availability, the mechanisms for setting scheduled reductions in generation will: i) allow more than one scheduled event per year, ii) provide flexibility in establishing or adjusting the time period(s) of the event(s) and iii) establish the maximum time period permitted (individually or cumulatively);
>
> e) Seasonally differentiated charges;
>
> f) Time differentiated charges (e.g. on-peak vs. off-peak);
>
> g) Charges will be differentiated by voltage level (i.e. secondary, primary, high voltage primary).

Q. Did the Supplemental Service Stipulation bind other stakeholders to recommend inclusion of each of those concepts in Ameren Missouri's filed tariff?

A. No.

Q. After reviewing Ameren Missouri's filed tariff, does Staff have any alternative suggestions for design of this rider?

A. Yes. Staff is cognizant of the differing drivers and customer needs that would give rise to that customer seeking service under this rider. Staff is aware that the intent of the Division of Energy in File No. ER-2016-0179 in seeking Ameren Missouri to file this tariff is to facilitate and encourage customer-owned combined heat and power systems ("CHP"). With this driver in mind, and recognizing the differing service characteristics of customers who may install CHP systems, Staff suggests a more streamlined approach may better facilitate customer adoption of CHP systems.

Q. What are combined heat and power systems?

A. CHP systems are used to generate on-site electricity and useful waste heat from a single fuel source. The waste heat can be utilized by customers for heating, cooling, or other non-heating purposes. CHP is also commonly referred to as "cogeneration".

Q. How do customer-owned CHP systems vary?

A. There are two common cogeneration processes. Most commonly, CHP systems are designed primarily to produce electrical energy first with the waste heat recovered to be used as beneficial thermal energy. This is often referred to as "topping-cycle systems." Another process is "bottoming-cycle systems",[5] in this system the waste heat from an existing process is used to generate electricity.

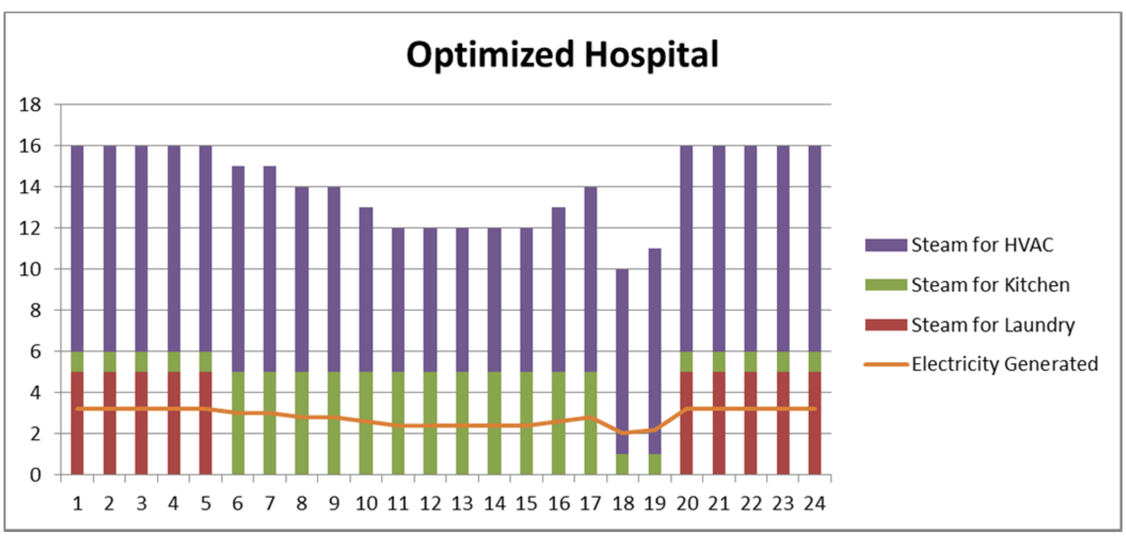
Q. Could you give an example of an application of a topping-cycle system?

[5] Bottoming-cycle systems are also referred to as "waste heat to power" or "indirect fired CHP systems".

A. Yes. A topping-cycle system could be used in manufacturing, such as plastics. The CHP system would produce electricity for the manufacturing equipment and the waste heat would be recovered for drying the plastic.

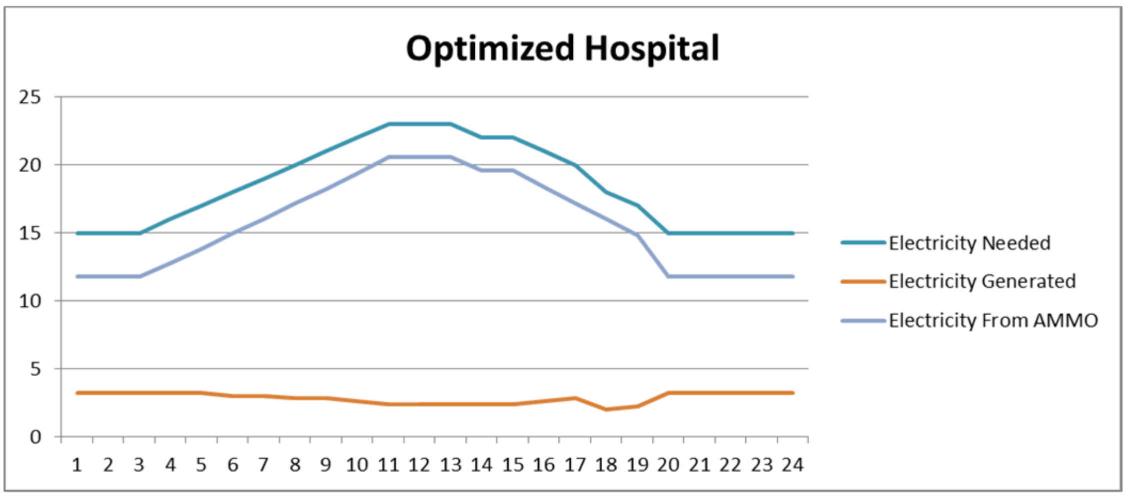
Q. Could you give an example of bottoming-cycle system utilization?

A. Yes. An example of a bottoming-cycle system would be a hospital6 with an existing steam system. It uses steam for its thermal loads, such as heating, cooling, and in its kitchen and laundry facilities. In this example, a fuel is used to produce high-pressure steam in a boiler. The high-pressure steam would be used for both the hospital thermal loads and to operate the CHP system. In this example, the operation of the system is driven by when the customer needs steam in the kitchen, laundry, or for heating or cooling. Electricity is generated to offset load based on when steam is being used; from the customer's perspective this system is beneficial when there is high coincidence of its thermal and electrical loads generally, without regard to the price of electricity, absent some rate-related incentive from the utility. A hypothetical example of steam production to electricity generated is provided below for a 24 hour period:



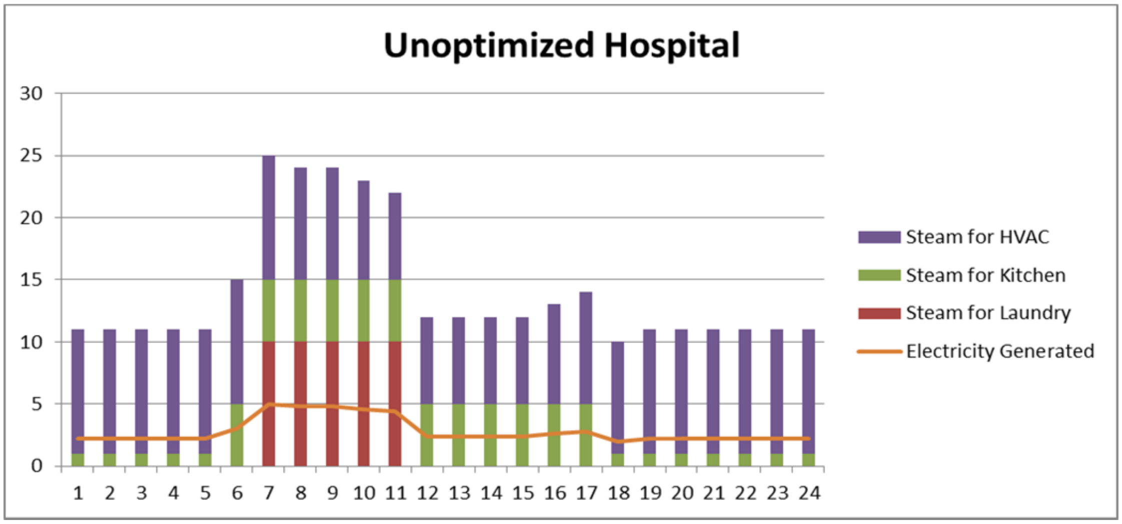
[6] Hospital CHP systems could also be designed as topping-cycle systems.

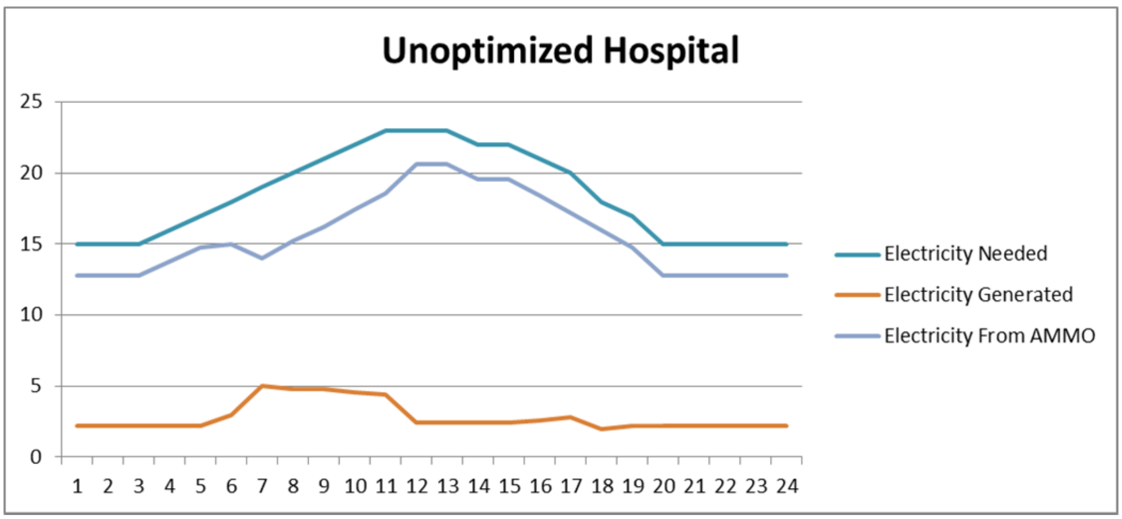
Provided below is an example of how the electricity generated through the CHP system would offset the hospital's electricity requirements from Ameren Missouri. Notice how the orange "electricity generated line" that is included in each graph is shaped by the steam needs depicted above, not the electricity needs depicted below. In this example, the reduction in energy needed from the utility is relatively constant.



Q. Do all CHP applications provide a constant reduction in the level of electricity needed from the utility?

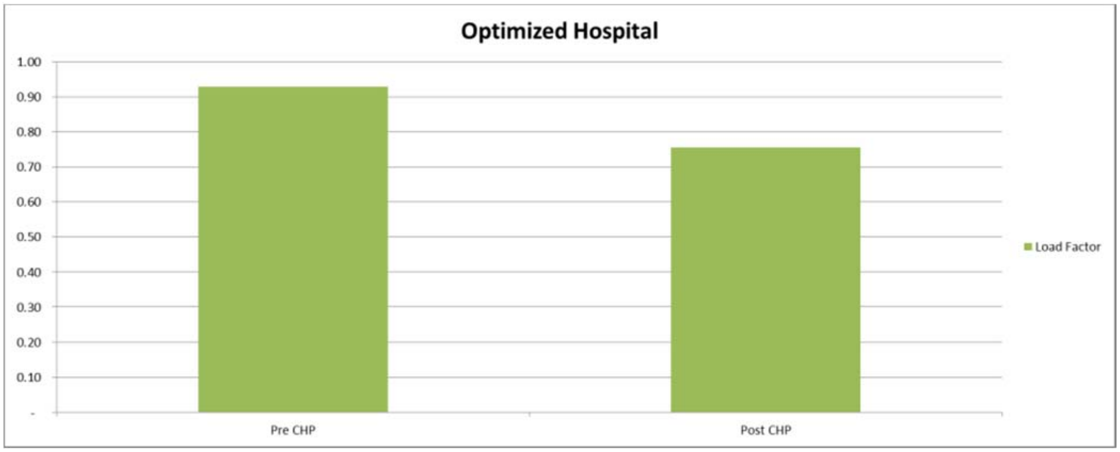
A. No. The example below shows the same system with the same total energy usage, but where the timing of the steam-related processes is less level over the course of the day. In this example, more energy is generated in the morning, and generation dips in the afternoon and evening.



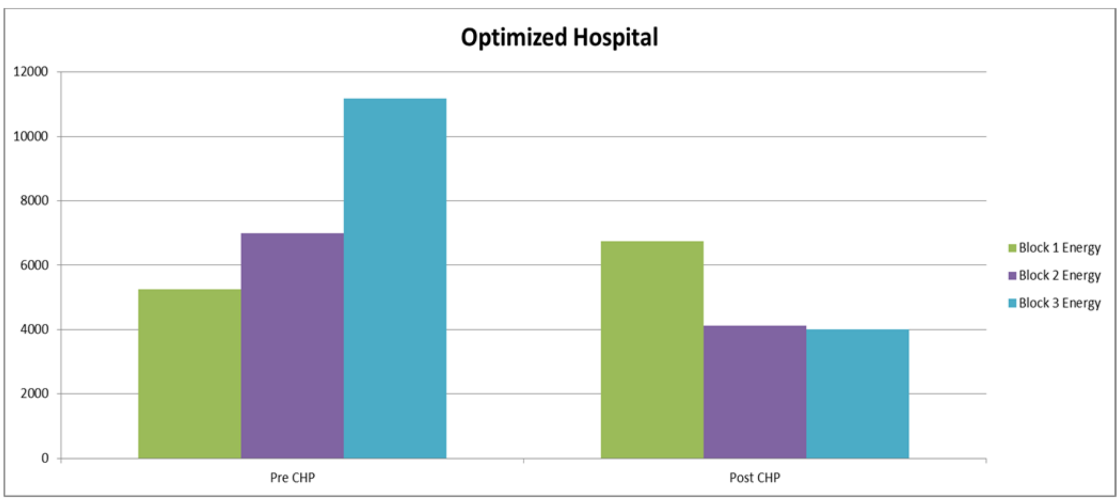


Q. How would these different variations impact a customer's billing determinants?

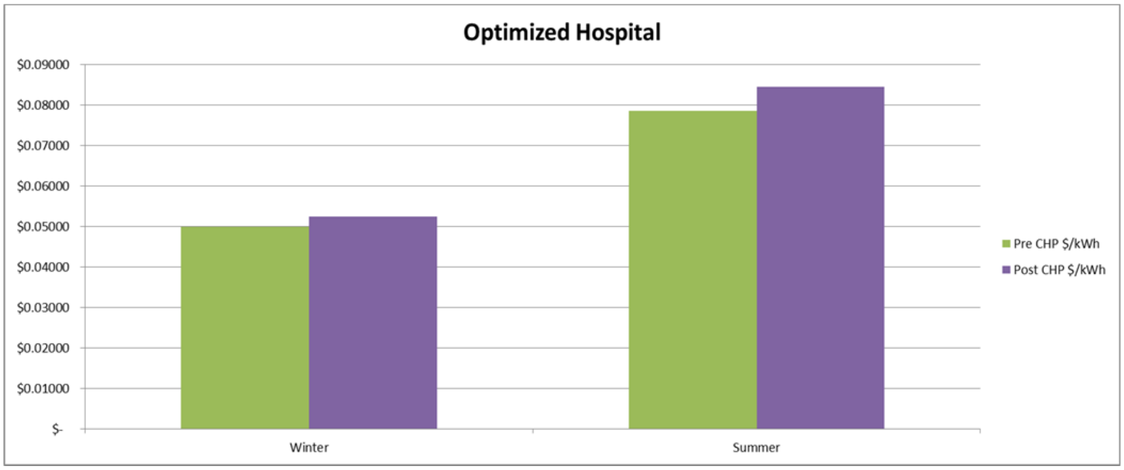
A. For customers in Ameren Missouri's LGS and SPS classes, an hour's use rate design is in place. That means that the blocks a customer's energy is billed on are set relative to that customer's non-coincident peak demand for the relevant month, typically. Comparing the Optimized Hospital and the Unoptimized Hospital, we see that the move to CHP caused the Optimized hospital to have a lower load factor:



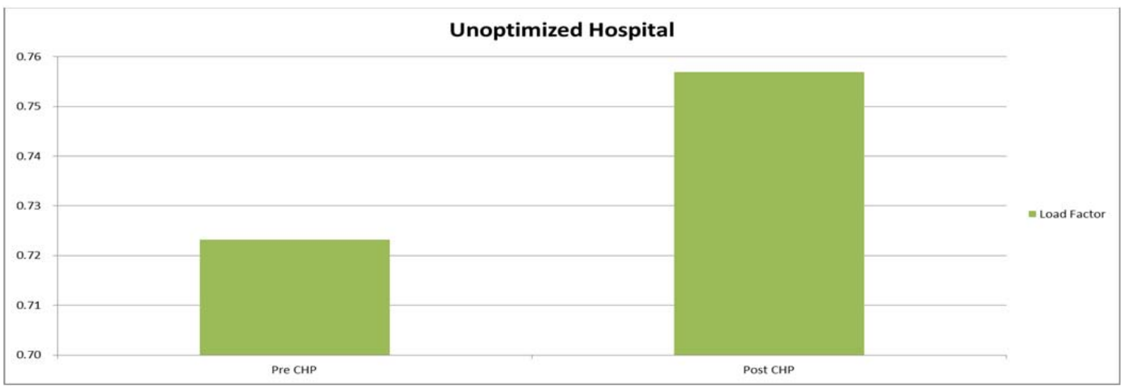
This reduced load factor coupled with the hours use rate design results in a greater percentage of the Optimized Hospital's energy usage falling into the first block and second block, and a lower percentage falling into the third block.



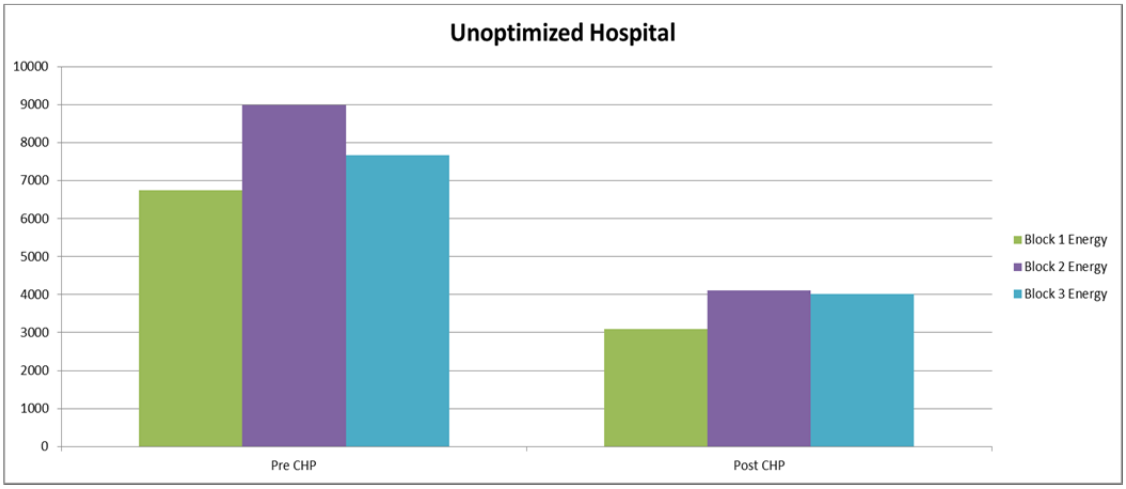
Not surprisingly, this change in the blocks in which its energy fell increased the average cost per-kWh (excluding customer charge) the Optimized hospital experienced, as shown below:



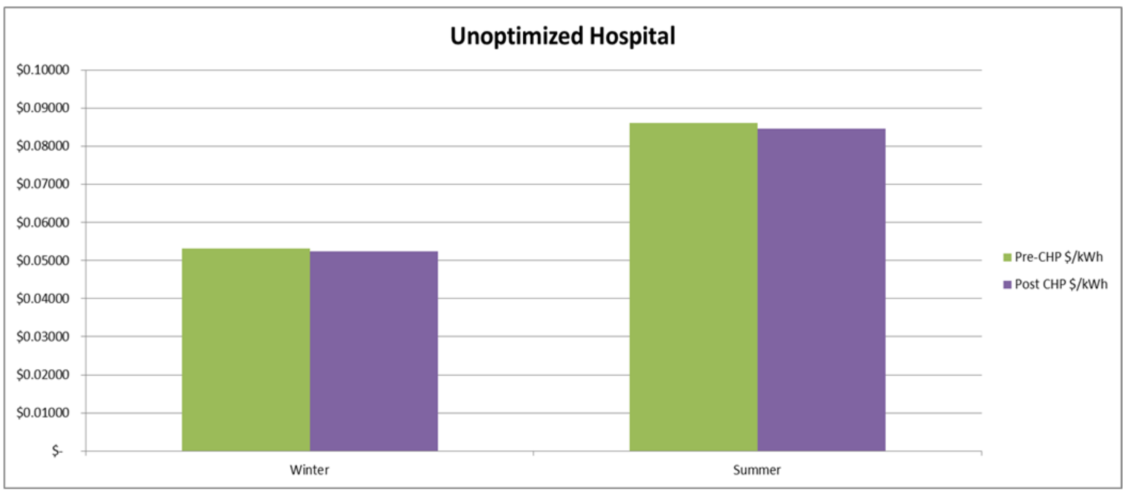
However, for the Unoptimized Hospital, the move to CHP has the opposite impact. First, the Load Factor improves:



This increases the percent of its energy usage that falls into the tail block, and reduces the percent that falls into the first and second blocks:

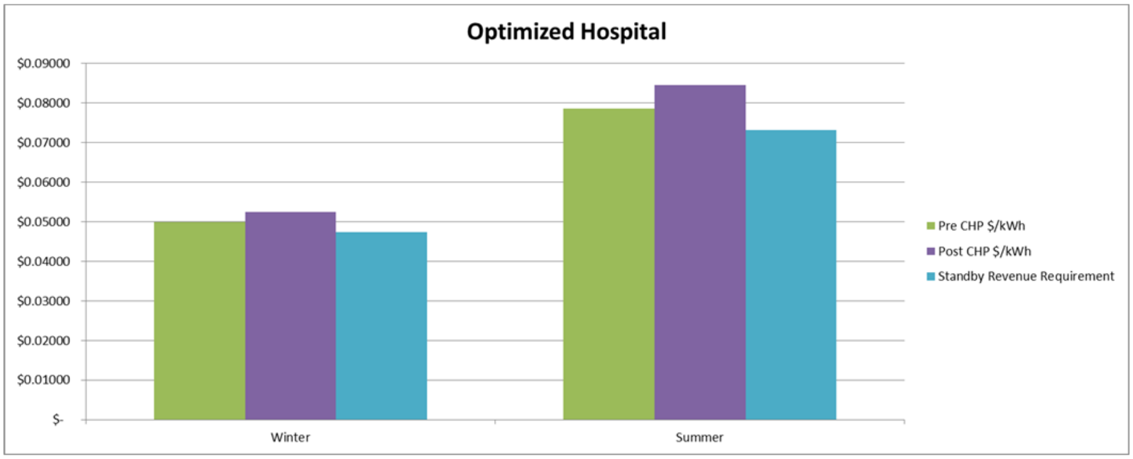


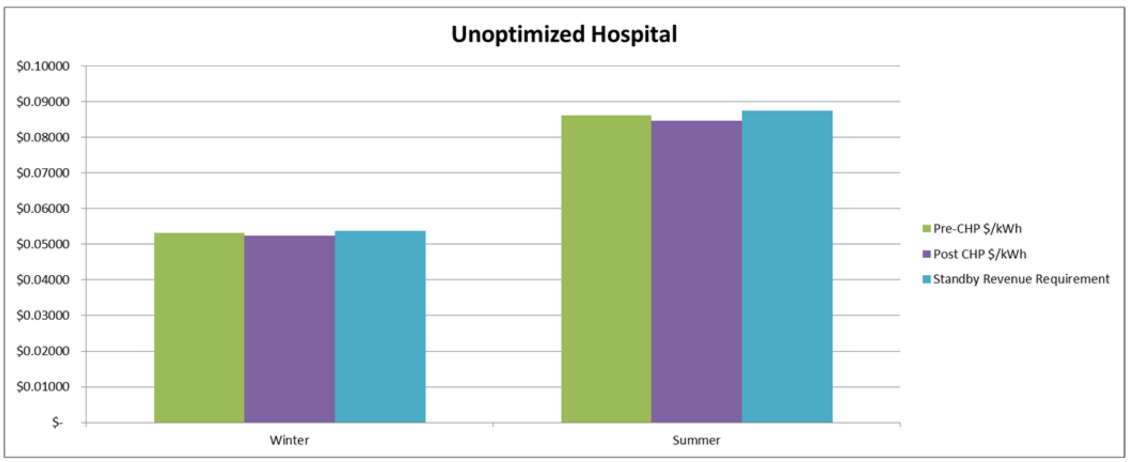
That change reduces the average non-customer-charge cost per kWh consumed:



Q. On a per kWh basis, what is the average cost per kWh that Ameren Missouri would need to recover from each customer for standby service to be in the exact revenue position that Ameren Missouri would be in as if that customer were taking service normally?

A. These amounts are essentially the inverse of the change to the average cost per kWh provided above. They are the teal lines included below, and indicate that more costs would need to be recovered under a tariff specifically designed for the Unoptimized example and that less costs would need to be recovered under a tariff specifically designed for the Optimized example:





Q. What is the relevance of these differences in the average cost per kWh between the Optimized and Unoptimized examples?

A. It is twofold. From Ameren Missouri's perspective, the purpose of a standby tariff is to make the company whole for revenues it is not receiving for providing service around the clock, but being obligated to provide service at a moment's notice. From parties with a policy objective to promote CHP, the purpose of a standby tariff is to promote price parity to induce customers to invest in CHP and reduce retail utility sales. When the installation of CHP has opposite impacts on different types of customers, it is important to account for that additional revenue to the company or additional savings to the customer in evaluating the balancing of those two interests.

Q. How do the differences in average cost per kWh relate to design of the standby tariff?

A. As shown in the above examples, due to the hours use rate design and lack of time-varied rates for non-standby service, customers installing CHP and utilizing CHP in a manner that improves that customer's load factor will see their average cost per kWh increase, while customers utilizing CHP in a manner that reduces their load factor will see their average cost per kWh decrease. Absent a program to shave peaks and fill valleys, that result is counterintuitive. This counterintuitive result leads to the development by Ameren Missouri of standby rates that are designed to recover costs from all CHP customers without regard to whether the revenue not collected from that customer is above-or below the average revenue per kWh. This means that the same customers who pay more per kWh on their standard service will also pay more per kWh on their standby service.

Q. What is the relevance of this to the economic analysis a potential CHP customer will make?

A. Without imposing a more clear time-based pricing signal, the impact of this design is that customers who are decreasing the energy usage more than their demand are going to have a lower cost hurdle to install CHP, while customers who are decreasing their demand more than their energy usage will have a higher cost hurdle to install CHP. This result is counterintuitive.

Q. Is there a way to mitigate these counterintuitive results?

A. Yes. Requiring CHP customers to be on a Time-of-Use rate for the entire load, as opposed to only the stand-by portion proposed by Ameren Missouri will mitigate these average cost per kWh concerns brought about by the current use of an hour's use rate design. This change should be reflected in the applicability paragraph of William Davis' proposed Rider SSR.

Q. Is it possible to stream line Ameren Missouri's proposed Rider SSR?

A. It appears that it is, particularly for customers with less than 5MW of on-site generation. Rider SSR includes the following rate elements:

1) Administrative charge (fixed per month)
2) Generation and Transmission access charge (per kW of contracted Standby demand)
3) Facilities charge with summer and winter rates (per kW of contracted Standby demand)
4) Daily standby demand rates with distinction for summer/winter and backup/maintenance (per kW of standby service actually taken, per day taken)
5) Back-up energy charge, with distinction for summer/winter and on-peak/off-peak (per kWh actually consumed normally generated through CHP)
6) High voltage facilities charge discount for Small Primary and Large Primary classes.

Q. For customers with 5MW or less of on-site generation, what is a reasonable way to consolidate these charges?

A. The daily standby demand rate appears to be designed to incent customers to schedule outages with the company versus taking unplanned outages. This is not necessarily a bad thing, and for larger customers this would appear to be a good thing. However, for smaller customers the added complexity of this distinction does not appear worthwhile as compared to a flat rate with a simple limitation on the number of calls one can make on this reserve while remaining eligible to remain on the Rider SSR. Instead, Staff recommends incorporating these charges into the on-peak back-up energy charges for summer. For customers with less than 5MW of standby demand, this would eliminate item 4 above, and would also strengthen the price signal that on-peak summer energy is not only more costly than energy most other hours of the year, but also that it is a driver of Ameren Missouri's generation, transmission, and distribution capacity requirements.

Q. Is the design of item 2 above, Ameren Missouri's Generation and Transmission Access charge, the most optimal?

A. No. The better determinant than total contracted standby demand is the contracted standby demand coincident with summer afternoon usage that typically sets RTO capacity requirements. While it is possible that this is the same level of demand for many customers, that is not necessarily the case for all customers, particularly those using a boiler-based CHP system ancillary to space heating. Staff recommends this change be made to the rates applicable to all customers (above or below 5MW of on-site generation capacity).

Q. Are their additional concerns with the design of a standby tariff?

A. Yes. The parties do not have available billing determinants to calculate tariff rates. If a potential CHP customer is known, study of their current usage and intended CHP generation would significantly mitigate the uncertainty of designing one-size-fits all rates where no one's size is known. A further caveat is that the design of standby rates can and will vary over time based on the usage of standby customers. Staff appreciates the difficulty of the analysis a potential CHP customer would do in determining whether or not it makes economic sense for that customer to invest in a CHP system, however the variability of these rates from rate case to rate case as real experience is gained could result in some systems that were expected to be cost-beneficial based on the rates in place at a particular time being no longer cost-beneficial when those rates are adjusted in a later rate proceeding.

Q. Do you have any corrections concerning your sections of the Staff's Report on Commission Raised Issues?

A. Yes. In Section IV. Residential Time-of-Use and Time-of-Day Rate Design at page 8 of the Staff's Report on Commission Raised Issues, I stated that Ameren Missouri's tariff limits participation in Time of Use rates to 5,000 customers for all classes. In fact, that limitation only applies to Residential customers.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Table 1

	Current Revenue plus Allocated Other Revenue	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost of Service	Start RoR
Residential	$ 1,572,570,791	$54,791,978	-4.14%	4.32%	5.61%
SGS	$ 379,064,599	-$7,419,875	2.47%	-2.41%	8.02%
LGS/SPS	$ 1,059,700,437	-$5,174,870	0.62%	-0.62%	7.34%
LPS	$ 270,049,117	$8,575,233	-3.96%	4.12%	5.35%
LTS	$ 1,870,794	$123,668	-8.08%	8.79%	3.09%
Lighting	$ 45,840,057	$1,120,623	-2.68%	2.76%	5.94%

Table 2 and Chart

	Start % over/under contribution	System Average Increase + Energy Efficiency	End % over/under contribution
Residential	-4.14%	$23,204,455	-2.39%
SGS	2.47%	$7,125,598	4.84%
LGS/SPS	0.62%	$15,826,355	2.51%
LPS	-3.96%	$4,880,399	-1.71%
LTS	-8.08%	$32,800	-5.94%
Lighting	-2.68%	$947,158	-0.42%

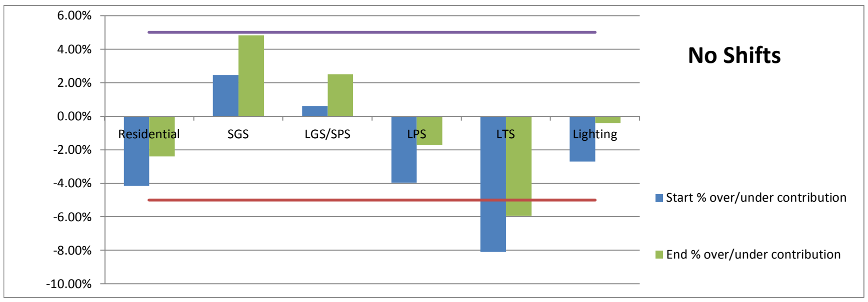


Table 3 and Chart

	Revenue Responsibility Shift	Retail Increase + Energy Efficiency	End % over/under contribution	End RoR	% Increase to Retail Non-EE Revenues
Residential	$ -	$23,204,455	-2.39%	6.23%	1.8%
SGS	$ -	$7,125,598	4.84%	8.93%	2.3%
LGS/SPS	$ -	$15,826,355	2.51%	8.11%	1.9%
LPS	$ -	$4,880,399	-1.71%	6.34%	2.3%
LTS	$ -	$32,800	-5.94%	4.15%	2.3%
Lighting	$ -	$947,158	-0.42%	6.90%	2.3%
	System Average:			7.08%	2.0%

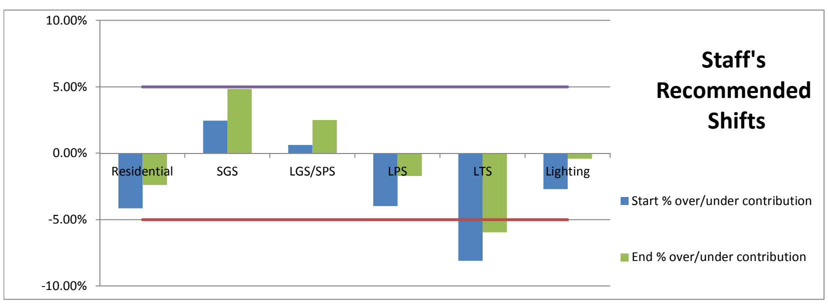
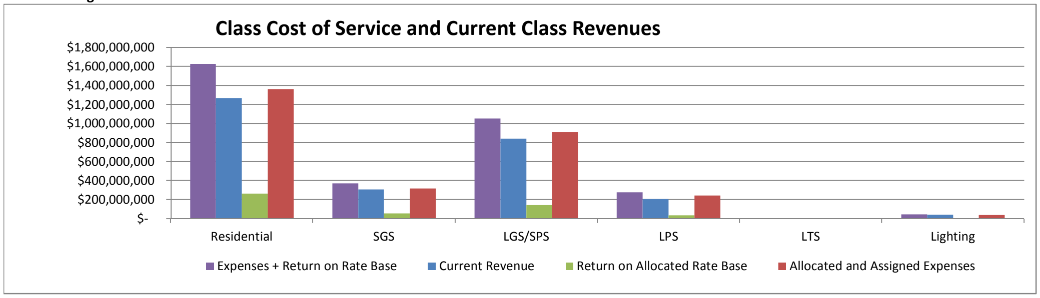
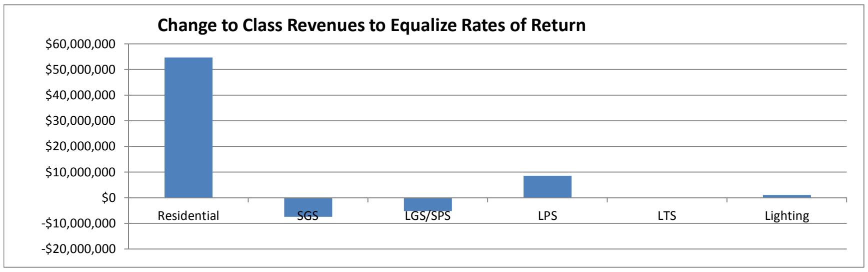


Table 4

	1	2	3	4	5	6	7	8	9
	Current Revenue plus Allocated Other Revenue	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost of Service	Start RoR	System Average Increase + Energy Efficiency	End RoR	Additional Revenue Change to Equalize Class Rates of Return	End % over/under contribution
Residential	$ 1,572,570,791	$54,791,978	-4.14%	4.32%	5.61%	$ 23,204,455	6.23%	$31,587,524	-2.39%
SGS	$ 379,064,599	-$7,419,875	2.47%	-2.41%	8.02%	$ 7,125,598	8.93%	-$14,545,473	4.84%
LGS/SPS	$ 1,059,700,437	-$5,174,870	0.62%	-0.62%	7.34%	$ 15,826,355	8.11%	-$21,001,226	2.51%
LPS	$ 270,049,117	$8,575,233	-3.96%	4.12%	5.35%	$ 4,880,399	6.34%	$3,694,834	-1.71%
LTS	$ 1,870,794	$123,668	-8.08%	8.79%	3.09%	$ 32,800	4.15%	$90,868	-5.94%
Lighting	$ 45,840,057	$1,120,623	-2.68%	2.76%	5.94%	$ 947,158	6.90%	$173,465	-0.42%
	System Average:				0.063519804		0.070800001		

Charts on Page 10





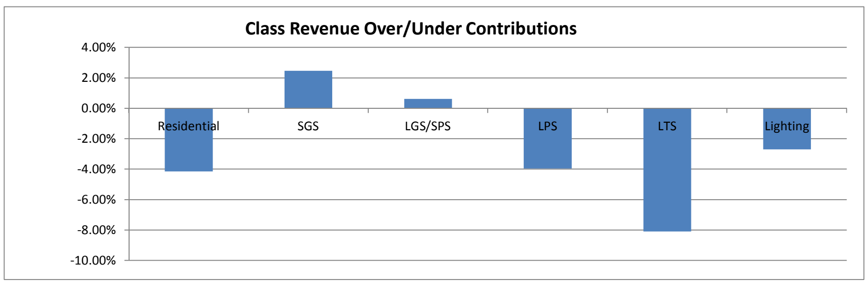


Chart on Page 12

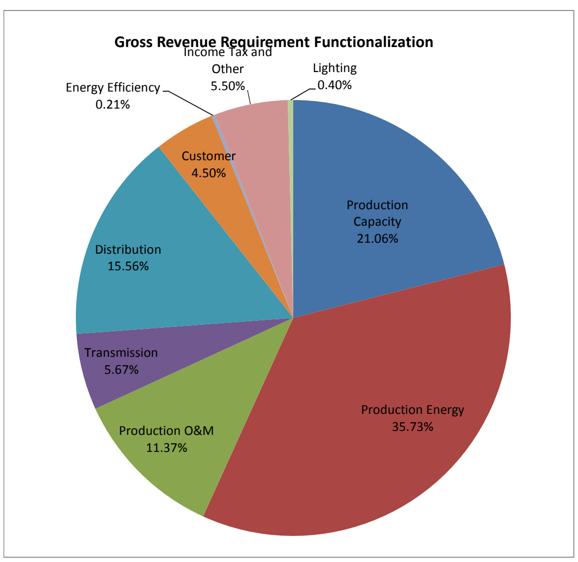


Table 5 and Chart

	Residential	SGS	LGS/SPS	LPS	LTS	Lighting	Total
Production Capacity	$ 340,165,478	$ 78,634,728	$ 229,191,587	$ 60,386,262	$ 435,507	$ 3,171,514	$ 711,985,076
Production Energy	$ 492,558,174	$ 126,586,717	$ 442,869,294	$ 135,780,557	$ 1,070,104	$ 9,328,497	$ 1,208,193,343
Production O&M	$ 171,993,251	$ 41,531,489	$ 129,654,860	$ 35,882,023	$ 291,193	$ 5,138,480	$ 384,491,296
Transmission	$ 90,420,922	$ 21,552,967	$ 62,903,050	$ 16,222,591	$ 124,507	$ 383,391	$ 191,607,428
Distribution	$ 332,323,465	$ 58,871,682	$ 107,161,038	$ 17,129,866	$ -	$ 10,535,103	$ 526,021,154
Customer	$ 110,931,663	$ 18,280,712	$ 18,659,166	$ 1,672,736	$ 33,955	$ 2,604,783	$ 152,183,015
Energy Efficiency	$ 3,197,317	$ 325,578	$ 3,092,992	$ 651,156	$ -	$ -	$ 7,267,043
Income Tax and Other	$ 85,772,494	$ 25,860,844	$ 60,993,575	$ 10,899,161	$ 39,201	$ 2,402,370	$ 185,967,645
Lighting	$ -	$ -	$ -	$ -	$ -	$ 13,396,543	$ 13,396,543

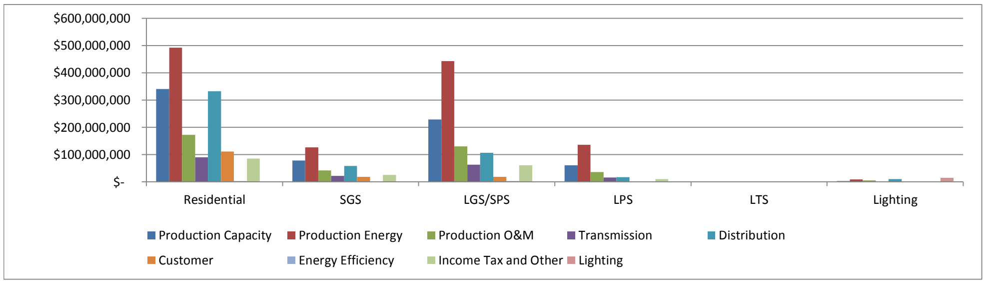


Table 6 and Chart

	Residential	SGS	LGS/SPS	LPS	LTS	Lighting	Total
Production Capacity	21%	21%	22%	22%	22%	9%	21%
Production Energy	30%	34%	42%	49%	54%	28%	36%
Production O&M	11%	11%	12%	13%	15%	15%	11%
Transmission	6%	6%	6%	6%	6%	1%	6%
Distribution	20%	16%	10%	6%	0%	31%	16%
Customer	7%	5%	2%	1%	2%	8%	5%
Energy Efficiency	0.20%	0.09%	0.29%	0.23%	0.00%	0.00%	0.22%
Income Tax and Other	5%	7%	6%	4%	2%	7%	6%
Lighting	0%	0%	0%	0%	0%	40%	0.40%

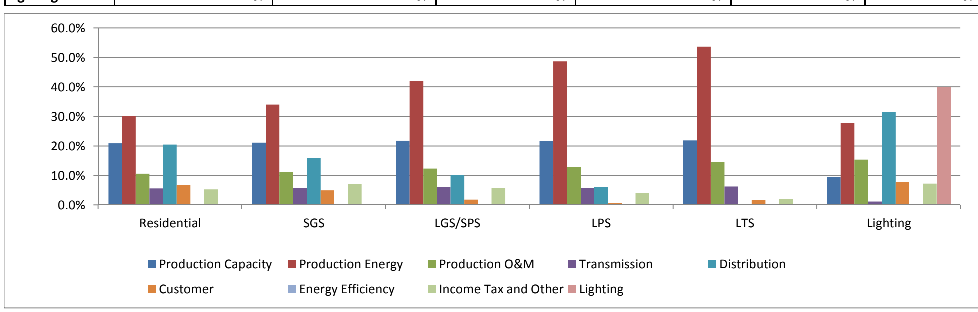


Table 7 and Chart

	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Demand	1,580	411	1,461	453	4	27
Incremental Intermediate Demand	1,140	238	431	34	0.17	-
Incremental Peak Demand	739	125	271	67	0.01	-

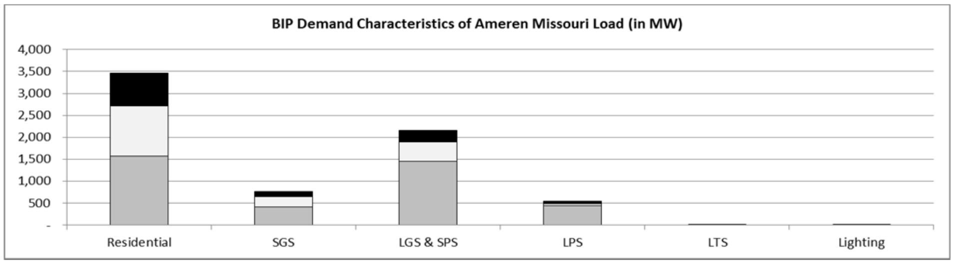


Table 8 and Chart

	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Energy	11,715,549	3,167,592	11,943,541	3,826,840	30,293	122,676
Intermediate Energy	2,049,452	416,254	815,316	96,636	1,042	115,409
Peak Energy	114,185	22,754	75,368	51,293	44	-

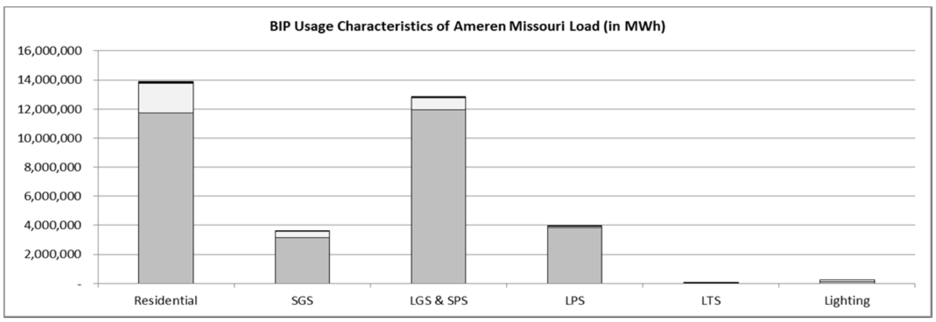


Table 9 and Chart

BIP Installed Capacity Allocator							
	Total	Residential	SGS	LGS & SPS	LPS	LTS	Lighting
Base Capacity	$ 1,513,860,771	$ 607,887,024	$ 157,963,534	$ 562,119,371	$ 174,088,758	$ 1,374,328	$ 10,427,756
Incremental Intermediate Capacity	$ 592,299,739	$ 366,327,788	$ 76,408,536	$ 138,582,421	$ 10,925,153	$ 55,840	$ -
Incremental Peak Capacity	$ 258,021,580	$ 158,541,700	$ 26,880,891	$ 58,201,188	$ 14,394,819	$ 2,982	$ -
Totals:	$ 2,364,182,089	$1,132,756,512	$261,252,962	$758,902,980	$199,408,731	$1,433,149	$10,427,756
BIP Installed Capacity Allocator:		47.91%	11.05%	32.10%	8.43%	0.06%	0.44%

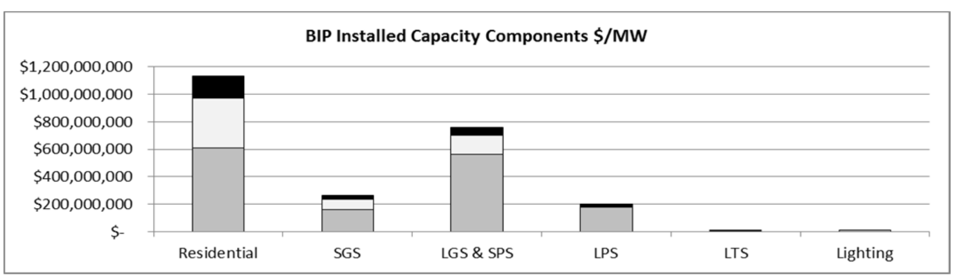


Table 10 and Chart

	Total		Residential		SGS		LGS & SPS		LPS		LTS		Lighting
BIP Fuel and Energy Allocator													
Base Energy Usage	$	593,916,294	$	225,863,293	$	61,067,797	$	230,258,741	$	73,777,389	$	584,016	$ 2,365,057
Incremental Intermediate Usage	$	89,790,051	$	52,665,897	$	10,696,715	$	20,951,632	$	2,483,308	$	26,764	$ 2,965,735
Incremental Peak Usage	$	7,137,846	$	3,091,430	$	616,027	$	2,040,504	$	1,388,694	$	1,190	$ -
Totals:	$	690,844,191		$281,620,619		$72,380,539		$253,250,877		$77,649,391		$611,971	$5,330,793
BIP Fuel and Energy Allocator:				40.76%		10.48%		36.66%		11.24%		0.09%	0.77%

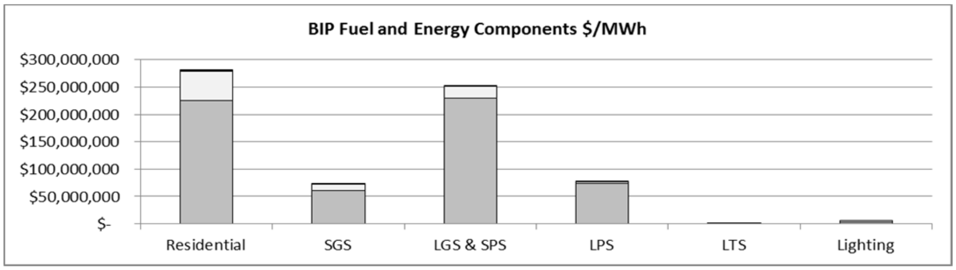


Table 11 and Chart

	Total		Residential		SGS		LGS & SPS		LPS		LTS		Lighting
BIP Fuel in Storage Allocator													
Base Capacity	$	193,987,823	$	77,895,328	$	20,241,625	$	72,030,609	$	22,307,929	$	176,108	$ 1,336,224
Incremental Intermediate Capacity	$	43,493,983	$	26,900,324	$	5,610,861	$	10,176,438	$	802,260	$	4,100	$ -
Incremental Peak Capacity	$	587,753	$	361,145	$	61,233	$	132,578	$	32,790	$	7	-
Totals:	$	238,069,559		$105,156,796		$25,913,719		$82,339,624		$23,142,980		$180,215	$1,336,224
BIP Fuel in Storage Allocator:				44.17%		10.88%		34.59%		9.72%		0.08%	0.56%

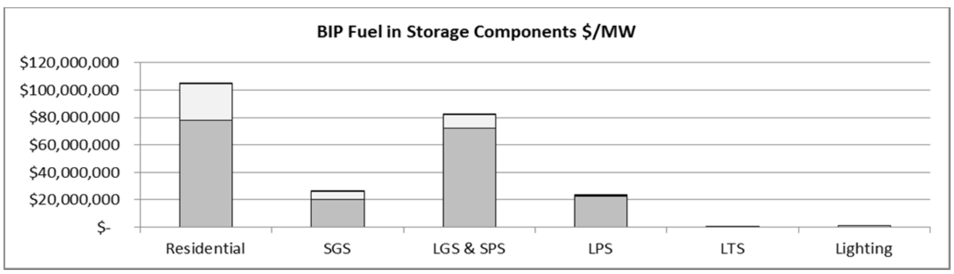
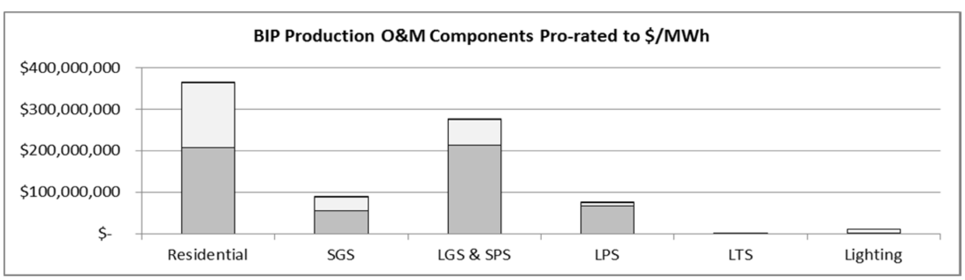


Table 12 and Chart

	Total		Residential		SGS		LGS & SPS		LPS		LTS		Lighting
BIP O&M Allocator													
Base Usage	$	549,368,129	$	208,921,856	$	56,487,256	$	212,987,613	$	68,243,533	$	540,211	$ 2,187,660
Incremental Intermediate Usage	$	264,941,563	$	155,400,123	$	31,562,565	$	61,821,527	$	7,327,443	$	78,972	$ 8,750,932
Incremental Peak Usage	$	4,180,057	$	1,810,400	$	360,757	$	1,194,958	$	813,246	$	697	$ -
Totals:	$	818,489,748		$366,132,379		$88,410,578		$276,004,098		$76,384,221		$619,880	$10,938,592
BIP O&M Allocator:				44.73%		10.80%		33.72%		9.33%		0.08%	1.34%



BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2016-0179

AFFIDAVIT OF SARAH L. KLIETHERMES

STATE OF MISSOURI	)	
	)	ss.
COUNTY OF COLE	)	

COMES NOW SARAH L. KLIETHERMES and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Rebuttal Testimony; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L. Kliethermes

SARAH L. KLIETHERMES

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 23rd day of January, 2017.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 12, 2020
Commission Number: 12412070

D Suzie Mankin

Notary Public