MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

KANSAS CITY POWER & LIGHT COMPANY

CASE NO. ER-2016-0285

Jefferson City, Missouri
December 14, 2016

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I. Executive Summary

Kansas City Power & Light Company ("KCPL") current revenues from retail sales are approximately $847,677,823 on a normalized and annualized basis. As described in detail in Staff's *Revenue Requirement Cost Of Service Report ("COS Report")*, based on the information available at the time of filing Staff's *COS Report*, Staff does not have enough information to support a change in rates.[1]

Staff's class cost-of-service ("CCOS") study is designed to determine what rate of return[2] is produced by each customer class on that class's currently tariffed rates, for recovery of any calculated revenue requirement amount.[3] Typically, Staff's recommended interclass revenue responsibility shifts, as applicable, are designed to reasonably bring each class closer to producing the system-average rate of return used in determining Staff's recommended revenue requirement.[4] Staff's recommended intra-class shifts will, where appropriate, redesign the rates that collect a particular class's revenues to better align that class's method of recovering revenue with the cost-causation for that class that was indicated by the class

[1] The *Order Adopting Procedural Schedule and Delegating Authority*, issued August 1, 2016, established the true-up period ending December 31, 2016. The agreed-to test year in this case is the twelve months ending December 31, 2015, and an update period ending June 30, 2016.

[2] Staff's CCOS study assumes a system average ROE of 8.655, which when combined with capitalization ratios and senior capital cost rate produces an overall rate of return cost of capital for KCPL of 7.01%.

[3] Appendix 2, Schedule CCOS-1 provides a glossary of class cost of service and rate design terms. Appendix 2, Schedule CCOS-2 provides information from the *NARUC Manual* on class cost of service studies in general.

[4] In its *COS Report*, Staff indicated it did not have enough information available at the time of filing to support a change in rates. Therefore, Staff recommends various inter-class shift options, depending on the revenue requirement ordered by the Commission.

cost-of-service study. Staff's intra-class recommendations largely focus on customer charge valuation.

KCPL has six (6) service classifications:

1. Residential ("Res.")
2. Small General Service ("SGS")
3. Medium General Service ("MGS")
4. Large General Service ("LGS")
5. Large Power Service ("LPS")
6. Total Lighting ("Ltg.")

Each service classification has several rate schedules and tariff rate riders.

Due to the unavailability of hourly load research data to develop demand allocators for each individual rate schedule to be used in Staff's class cost of service study Staff combined the rate schedules described above into each of the six designated service classifications ("classes"): Res., SGS, MGS, LGS, LPS and Ltg.

Staff recommends an adjustment of KCPL's rates with the following five-step process:

1. Staff recommends a revenue neutral shift in revenue responsibility from the Lighting, SGS, MGS, and LGS classes to the Large Power ("LPS") class if no change in overall revenue requirement is ordered. Specifically, Staff recommends the LPS class's revenue responsibility be increased by approximately $2.35 million, with a reduction to the Lighting class's revenue responsibility of approximately $100,000, and the remainder of the reductions spread to the General Service classes (SGS, MGS, and LGS) so that the final rates are adjusted downward at an equal percentage to each of those rate classes.[5] If an overall increase is awarded that is up to approximately 0.62% of current revenues, that increase should be applied to the LPS class, though no other class should receive a rate reduction. If an overall increase is awarded in excess of approximately 0.62% of current revenues, the revenue neutral shifts described above in the "no change to revenue requirement" scenario should be implemented.

2. The portion of the revenue increase/decrease that is attributable to energy efficiency ("EE") programs not recoverable through Missouri Energy Efficiency

[5] Expressed as a percentage, this is a 1.6% revenue neutral increase to the LPS class, which reduces the LPS class's level of under-contribution by 20%.

Investment Act ("MEEIA") is allocated to applicable classes based on that class's level of kWh less opt-out customers.[6]

3. The amount of revenue ordered for KCPL not associated with the EE revenue from Pre/Non-MEEIA revenue requirement assigned in Step 2, should be allocated to various customer classes as an equal percent of current base revenues after making the adjustments in Step 1.

4. Staff recommends that each rate component of each class be adjusted across-the-board for each class on an equal percentage basis after consideration of steps 1 through 3 above.

5. Staff recommends that the Commission adopt Rider Fuel and Purchased Power Adjustment Clause ("FAC") tariff sheets consistent with Staff's CCOS Report.

Current Class Revenues and Cost to Serve

Table 1 shows the rate revenue responsibility shifts necessary, in dollars, for the current rate revenues from each customer class to exactly match Staff's determination of KCPL's cost-of-serving that class, assuming each class provides revenues to produce an equal rate of return among classes.[7] Also shown are the over- and under-contributions of each class as percentages, as well as the percent change to class revenue to exactly match cost of service. The final column shows the current rate of return produced by each class.[8] For rate design purposes, Staff is mindful of the aggregated revenue contributions and cost of service results for the SGS, MGS, and LGS service classes, as a single general service rate group, due to rate switching that can occur between these rate classes. Table 1 indicates that while classes do not provide equal rates of return, no class is providing a negative return, and thus no economic subsidies exist in this case.

[6] The Pre-MEEIA program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of Pre-MEEIA program costs.

[7] The results of a CCOS study can be presented either in terms of (1) the rate of return realized for providing service to each class or (2) in terms of the revenue responsibility shifts that are required to equalize the utility's rate of return from each class. Staff presents the results of its analysis in terms of the shifts in revenue responsibilities that produce an equal rate of return for KCPL from each customer class.

[8] Because other revenues, such as those produced by KCPL performing ancillary services through the Southwest Power Pool's integrated market, are offset against KCPL's cost of service, it is reasonable to include that allocation as an increase to each class's rate revenues for purposes of a CCOS study. In this current case, it was necessary to reflect a small portion of Staff's true-up estimate as a negative other revenue.

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	$ 353,700,294	-$1,580,650	0.49%	0.49%	7.17%
Small General Service	$ 55,894,637	-$2,442,863	5.01%	5.01%	8.77%
Medium General Service	$ 133,724,010	-$5,955,964	5.18%	5.18%	8.72%
Large General Service	$ 216,928,887	-$1,219,926	0.64%	0.64%	7.22%
Large Power	$ 167,216,002	$11,751,074	-7.45%	-7.45%	4.53%
Lighting	$ 11,566,182	-$551,671	5.54%	5.54%	9.27%
System Average:					7.01%

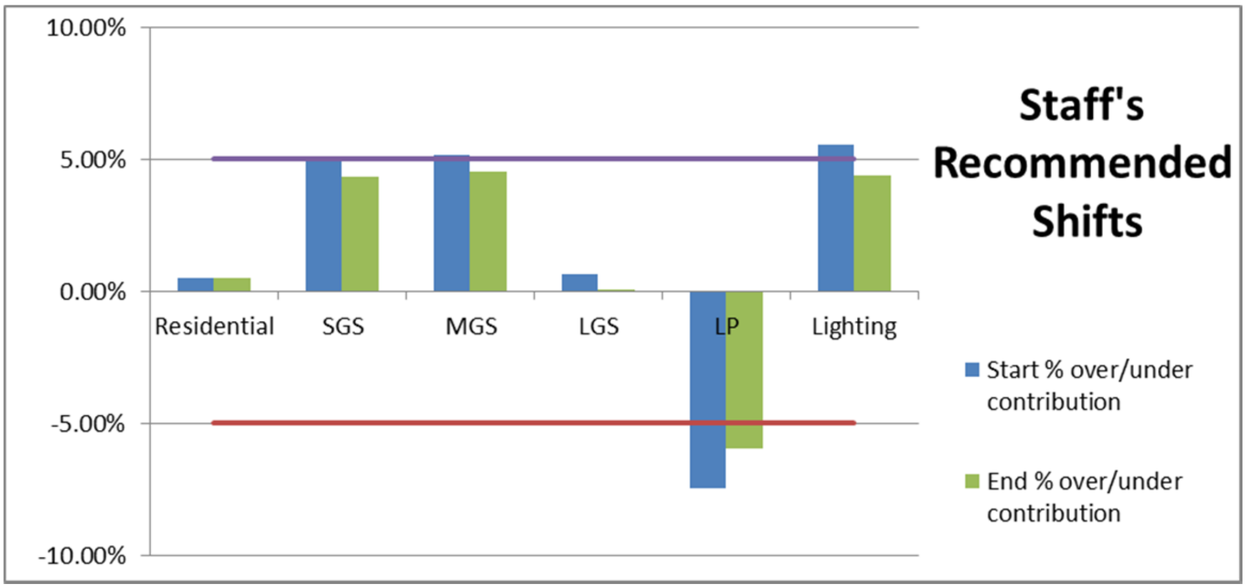
Reviewing the column "Revenue Change to Equalize Class Rates of Return," above, a negative dollar amount indicates revenue from the customer class exceeds the cost of providing service to that class at an equalized rate of return. Therefore, to equalize revenues and cost of service, rate revenues for that class would be reduced, because the class is over-contributing to the utility's return. A positive dollar amount indicates revenue from the class is less than the cost of providing service to that class at an equal rate of return. Therefore, to equalize revenues and cost of service, rate revenues for that class would be increased, because the class is under-contributing to rate of return. In rare instances, a class will fail to provide revenues sufficient to match the non-capital-related expenses assigned and allocated to that class. In those instances, a class will provide a negative rate of return. If a class fails to provide revenues sufficient to meet variable expenses that is properly known as a "subsidy." As indicated above, no class is being subsidized.

As Table 2 and its accompanying chart indicate, Staff's recommended interclass shifts in revenue responsibility will minimize certain classes' exceedance of a +/-5% threshold.[9]

[9] In providing its rate design recommendation, Staff recommends revenue-neutral shifts so a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.

Table 2

	Start % over/under contribution	Revenue Shift	Energy Efficency Increase	End % over/under contribution
Residential	0.49%	$ -	$ 504,623	0.47%
Small General Service	5.01%	$ (315,673)	$ 73,305	4.34%
Medium General Service	5.18%	$ (745,833)	$ 223,013	4.55%
Large General Service	0.64%	$ (1,188,708)	$ 385,725	0.05%
Large Power	-7.45%	$ 2,350,215	$ 234,326	-5.97%
Lighting	5.54%	$ (100,000)	$ -	4.36%
Total / System Average:		$ 1,420,993		7.01%



Overall, these adjustments bring classes closer to their costs of service, while still maintaining rate continuity, rate stability, and revenue stability, and while minimizing rate shock to any one-customer class.[10] Staff bases its recommendations for interclass shifts in revenue responsibility on its CCOS study results, Staff's review of KCPL's revenue-neutral adjustments in previous general rate increases, and Staff's expert judgment regarding the impact of revenue shifts for all classes.

Staff Expert/Witness: James A. Busch

[10] For example, if two similar classes receive different levels of increases, customers may leave the higher-cost class in favor of the lower-cost class. Then, at the next rate case, the lower-cost class will likely have a higher allocated cost of service, while the higher-cost class will likely have a lower allocated cost of service. The resulting redesign of rates would likely cause an undoing of the initial movement of customers, with the results creating a seesawing of both rates and customers.

II. Class Cost-of-Service Study Results

Staff performed a Detailed Base, Intermediate, and Peak ("BIP") study that is the basis for Staff's allocated revenue responsibility results. The results of Staff's CCOS study are summarized in Table 1 above and are provided in Table 4 below. Staff developed its class allocators using the six designated classes discussed in the Executive Summary. The purpose of a CCOS study is to determine whether each class of customers is providing the utility with the level of revenue necessary to cover: (1) the utility's ongoing expenses directly assigned or allocated to provide electric service to that class of customers, and (2) a return on the utility's investments directly assigned or allocated to provide service to that class of customers.

A CCOS study allocates and/or assigns the utility's total cost of providing electric service to all the customer classes in a manner reasonably reflecting cost causation. Staff's CCOS study is a continuation and refinement of Staff's cost-of-service revenue requirement study, resulting in a reasonable allocation of the costs incurred in providing electric service to each of KCPL's customer classes.[11] Staff's CCOS study compares:

1. The revenues currently provided by each class at their currently tariffed rates;
2. The changes in class revenues needed to exactly match the allocated class cost of service at equalized rates of return;
3. The percentage difference between current class revenues and the class revenues needed to exactly match the allocated class cost of service at equalized rates of return;
4. The percent increase or decrease to current class revenues that would exactly match future class revenues to the allocated class cost of service at equalized rates of return;
5. The rate of return currently provided by each class on the existing tariffed rates, as applied to the newly-determined revenue requirement;
6. The increase in dollars that each class would receive if rates were increased across all classes by an equal percentage;

[11] Since those costs equate to KCPL's revenue requirement as determined by Staff in its *COS Report* filed November 30, 2016, the results of Staff's CCOS study are the initial basis for Staff's recommended class revenue requirements of each KCPL customer class that equitably shares KCPL's total annual cost of providing electric service among them.

7. The rates of return that would be provided by the classes if rates were increased across all classes by an equal percentage;

8. The changes in class revenues needed to exactly match the allocated class cost of service at equalized rates of return, in addition to the system-average increase; and

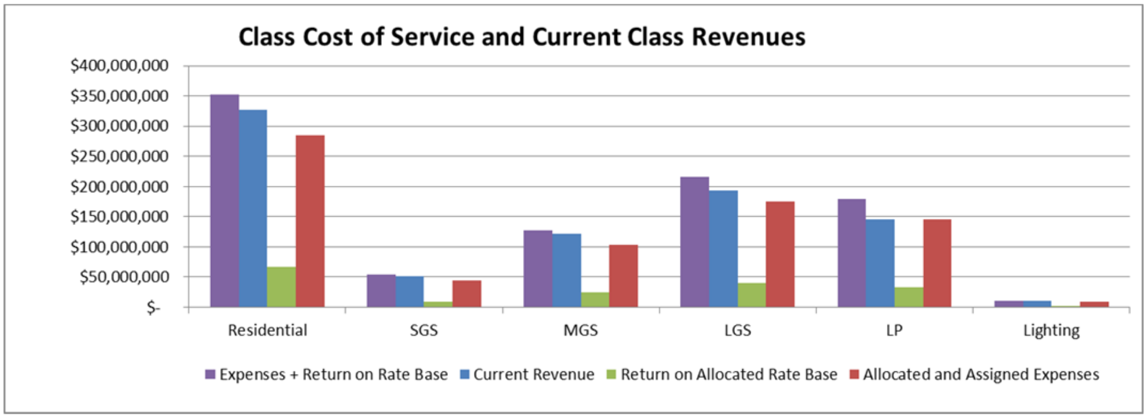
9. The percentage difference between the increased class revenues and the class revenues needed to exactly match the allocated class cost of service at equalized rates of return.

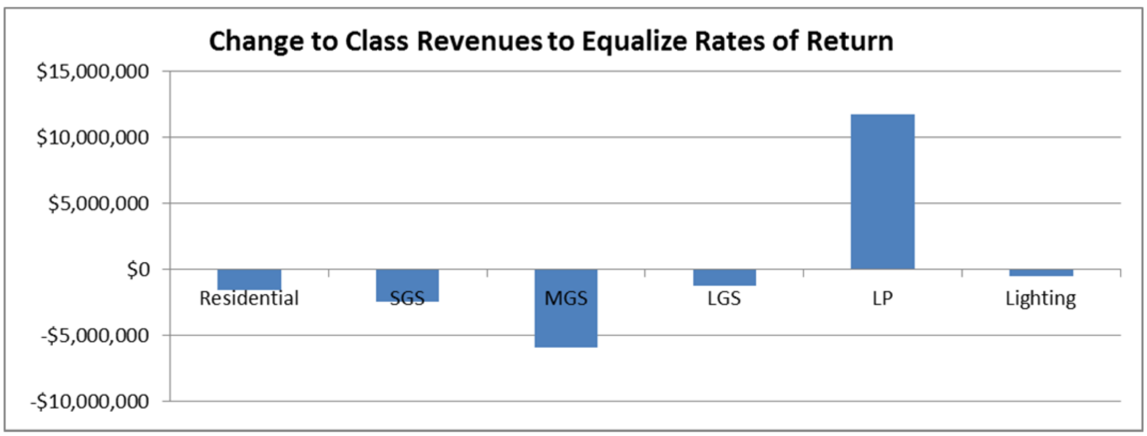
Table 3

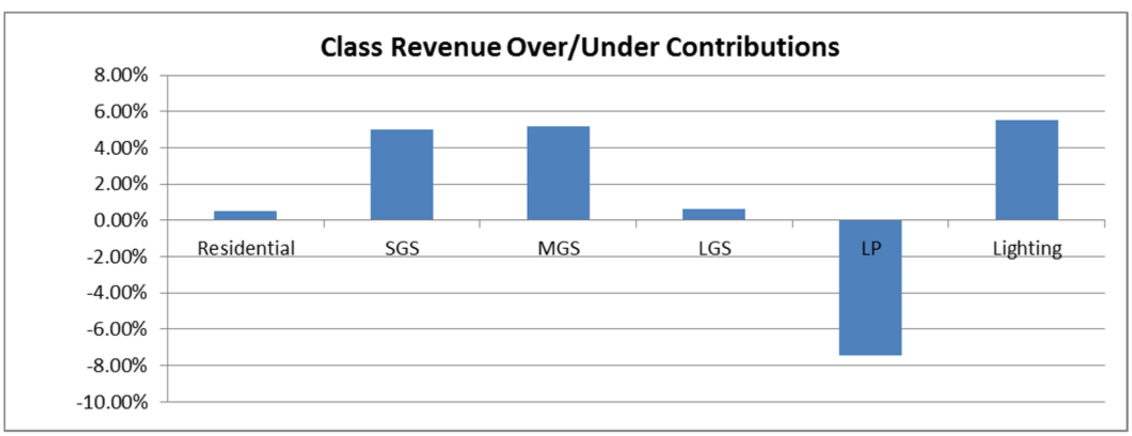
	1	2	3	4	5	6	7	8	9
	Current Revenue *plus Allocated Other Revenue*	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost of Service	Start RoR	System Average Increase + Energy Efficiency	End RoR	Additional Revenue Change to Equalize Class Rates of Return	End % over/under contribution
Residential	$ 353,700,294	-$1,580,650	0.49%	0.49%	7.17%	$ (43,394)	7.17%	-$1,537,255	0.47%
Small General Service	$ 55,894,637	-$2,442,863	5.01%	5.01%	8.77%	$ (12,643)	8.76%	-$2,430,220	4.98%
Medium General Service	$ 133,724,010	-$5,955,964	5.18%	5.18%	8.72%	$ 20,649	8.73%	-$5,976,612	5.20%
Large General Service	$ 216,928,887	-$1,219,926	0.64%	0.64%	7.22%	$ 63,624	7.23%	-$1,283,550	0.67%
Large Power	$ 167,216,002	$11,751,074	-7.45%	-7.45%	4.53%	$ (10,383)	4.52%	$11,761,457	-7.45%
Lighting	$ 11,566,182	-$551,671	5.54%	5.54%	9.27%	$ (17,852)	9.19%	-$533,819	5.36%
System Average:					7.01%		7.01%		

The changes shown in columns 2 and 3 of Table 3 are the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with KCPL's allocated cost to serve that class. The results are also presented, on a revenue-neutral basis, in column 8 as the revenue shifts that are required to equalize KCPL's rate of return from each class after a system-average increase.

"Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. The revenue-neutral format aids in comparing revenue deficiencies between customer classes and makes it easier to discuss revenue-neutral shifts between classes, if appropriate. Discussed below are two methods of calculating revenue-neutral increases. The first method is to calculate the revenue-neutral increase that would be necessary for each class to match its cost of service by subtracting the overall system average increase from each customer class's required percentage increase. This provides the revenue-neutral adjustment to rate revenue that would be necessary to match the revenues KCPL should receive from that class to KCPL's cost to serve that class, as shown in Table 3, if the increase is spread evenly among the classes at the rate of return currently provided by each class. A second method of finding revenue-neutral increases is to examine the expense level of each class's cost of service independent of that class's contribution to return on rate base. This second method finds the revenue-neutral shifts needed to exactly match each class's revenue responsibility to its cost of service while providing an equalized return on rate base among those classes. The required revenue increase to match cost of service is provided below, expressed graphically in both dollars and percentages, as well as on the revenue-neutral bases.







Staff's detailed BIP method takes into consideration the differences in the capacity costs associated with units that run at a stable level much of the year, versus the capacity costs associated with units that quickly dispatch only a few hours a year, as well as those units that have a cost and operation characteristic in between those extremes. Staff's detailed BIP method also considers the inverse relationship between the cost of capacity and the cost of energy produced by base, intermediate, and peaking units. Other common CCOS methods tend to assume that energy costs are the same amount regardless of the hour of consumption or the source of the energy, and/or do not consider the operating characteristics of plants and assume that capacity costs are equal among types of plants. Because the detailed BIP method most reasonably recognizes the relationship between the cost of the generating units required to serve various levels of demand and energy requirements relative to the cost of producing energy at those units, Staff recommends reliance on its detailed BIP study.

Staff Experts/Witnesses: Sarah L. Kliethermes, James A. Busch

III. Staff's Class Cost-of-Service Study

A. Data Sources

Staff's CCOS study utilized Staff's revenue requirement recommendations as filed on November 30, 2016, in Staff's *COS Report*. This data includes:

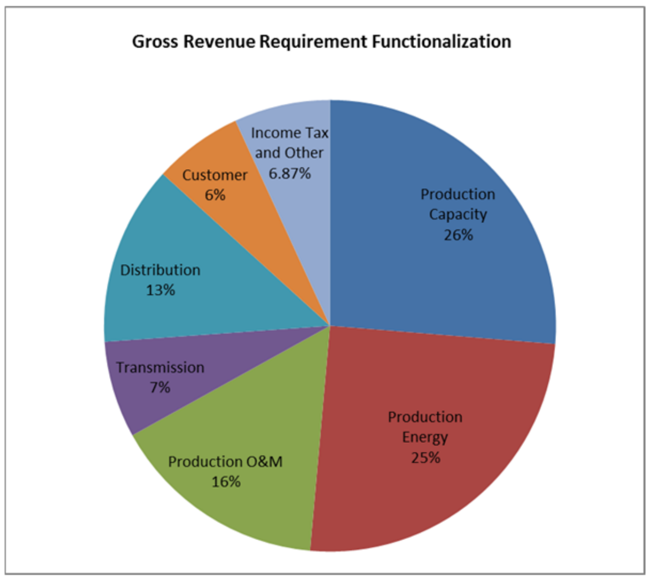
- Adjusted Missouri investment and expense data by FERC account;
- Normalized and annualized rate revenues;
- Net fuel and purchased power costs and revenues;
- Other operating and maintenance expenses;
- Depreciation and amortizations;
- Taxes; and
- For each class, Staff's determination of customer-coincidental peaks, customer-non-coincidental peaks, customer-maximum peaks, and annual energy that has been weather-adjusted.

In addition, Staff's study relies on data obtained from KCPL, which includes allocation factors for specific customer costs allocations. These allocation factors relate to information on services, meters, meter reading, uncollectible accounts, customer service, and customer deposits.

Staff Expert/Witness: James A. Busch

B. Functions

The major functional cost categories Staff used in its CCOS study are Production, Transmission, Distribution, and Customer. Within the Production function, a distinction is often made between Capacity and Energy. "Production Capacity" costs are those costs directly related to the capital cost of generation. "Production Energy" costs are those costs related directly to the customer's consumption of electrical energy (i.e., kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs. The pie chart below shows the approximate percentage of total costs associated with each major function.



Tables 4 and 5 and the accompanying charts provided below show the functionalization in dollars by class and by the percent of each function in that class's class cost of service. For class revenue requirements, this gross functionalized revenue requirement is offset by other revenues, reducing class revenue requirements.

Table 4

	Residential	SGS	MGS	LGS	LPS	Lighting	Total
Production Capacity	$ 86,501,289	$ 12,438,165	$ 34,312,861	$ 59,865,151	$ 51,682,885	$ 1,320,232	$ 246,120,583
Production Energy	$ 68,339,506	$ 11,899,741	$ 33,038,443	$ 62,822,911	$ 56,193,345	$ 2,920,146	$ 235,214,092
Production O&M	$ 46,878,646	$ 7,476,461	$ 20,456,427	$ 35,402,408	$ 33,301,575	$ 1,851,134	$ 145,366,651
Transmission	$ 23,850,095	$ 3,505,456	$ 9,037,650	$ 15,970,457	$ 12,185,493	$ 390,919	$ 64,940,070
Distribution	$ 52,737,962	$ 7,194,770	$ 16,696,660	$ 25,485,459	$ 17,119,678	$ 1,271,524	$ 120,506,053
Customer	$ 49,357,000	$ 6,447,828	$ 3,173,915	$ 381,340	$ 404,779	$ -	$ 59,764,862
Income Tax and Other	$ 24,946,844	$ 4,433,482	$ 11,062,622	$ 15,286,478	$ 7,799,525	$ 824,681	$ 64,353,632
Lighting	$ -	$ -	$ -	$ -	$ -	$ 2,764,081	$ 2,764,081

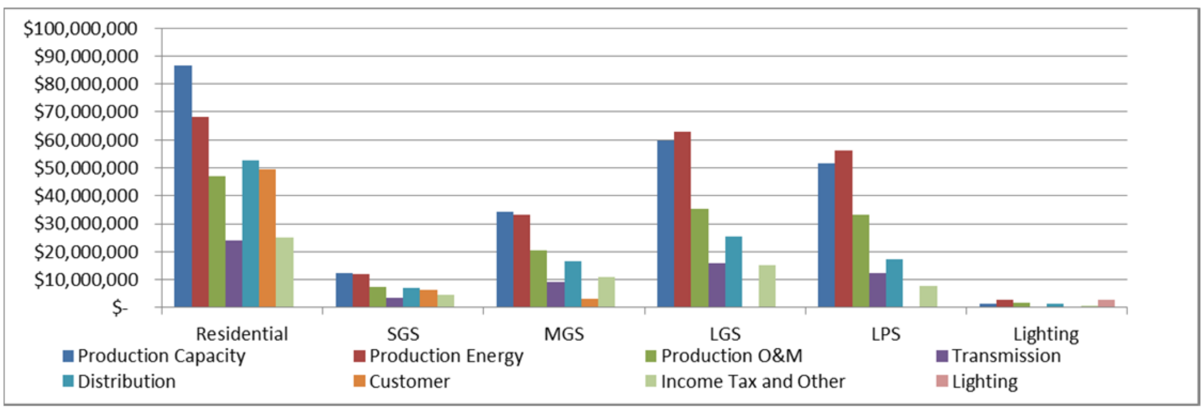
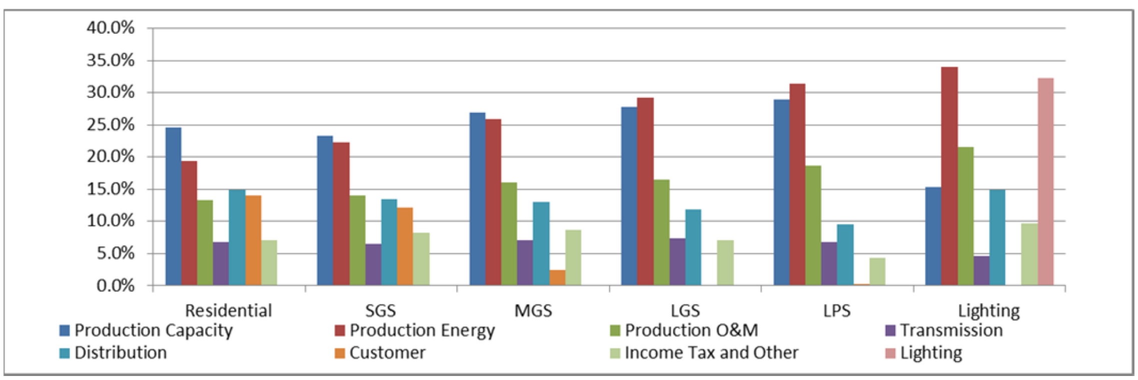


Table 5

	Residential	SGS	MGS	LGS	LPS	Lighting	Total
Production Capacity	24.5%	23.3%	26.9%	27.8%	28.9%	15.4%	26.3%
Production Energy	19.4%	22.3%	25.9%	29.2%	31.4%	34.0%	25.1%
Production O&M	13.3%	14.0%	16.0%	16.4%	18.6%	21.6%	15.5%
Transmission	6.8%	6.6%	7.1%	7.4%	6.8%	4.6%	6.9%
Distribution	15.0%	13.5%	13.1%	11.8%	9.6%	14.8%	12.9%
Customer	14.0%	12.1%	2.5%	0.2%	0.2%	0.0%	6.4%
Income Tax and Other	7.1%	8.3%	8.7%	7.1%	4.4%	9.6%	6.9%
Lighting	0.0%	0.0%	0.0%	0.0%	0.0%	32.2%	0.3%



As indicated most clearly in the graph version of Table 5, the portion of a class's revenue requirement related to that class's consumption of energy varies greatly across classes.

Staff Experts/Witnesses: Sarah L. Kliethermes, James A. Busch

C. Allocation of Production Costs

For CCOS purposes, Staff assumes that KCPL uses the Missouri-allocated portion of all of KCPL's generation facilities primarily to produce electricity for KCPL's retail customers. A production-capacity (demand) or a production-energy (energy) allocator appropriately allocates KCPL's costs for plant investment and the production expenses provided on its income statement. KCPL's generation facilities are predominantly considered fixed assets for purposes of setting rates, and so the capital cost of these assets are considered demand-related and apportioned to the rate classes based on the production-capacity allocator. Fuel expense related to running the generation plants and net purchased power used to serve load are considered energy-related and are allocated to rate classes based on the production-energy allocator. The demand and energy characteristics of KCPL's load requirement are both important determinants of production cost and expense allocations, since load must be served efficiently over time throughout the day and year.

To establish class revenue responsibilities for production costs and expenses, Staff relied on assumptions about the relationship between KCPL's generation fleet characteristics and its load characteristics. In practice, because KCPL participates in the Southwest Power Pool's Day-Ahead, Real-Time, and Ancillary Services integrated markets ("SPP IM"), its generation is dispatched as part of the larger SPP fleet. SPP's dispatch is ordered according to security-constrained economic merit, which results in price signals stacking in a manner consistent with those experienced by a utility with a generation fleet that includes the relative amounts of each base, intermediate, and peak generation units assumed in the *NARUC Manual*. Unlike other common CCOS methods, Staff's BIP method most reasonably assumes that some plants will run virtually year round (Base), only part of the year (Intermediate), and rarely during the year (Peak). The BIP method also recognizes the fact that Base plants tend to be more expensive to install, but have a lower average cost of energy, while Peak plants tend to be less expensive to install, but have a high average cost of energy, and that Intermediate plants tend to be somewhere between the two.

Staff's application of the BIP method takes into consideration the differences in the capacity/energy cost trade-off that exists across a company's generation mix, giving weight to both considerations. Because it reasonably allocates the investment and expenses of KCPL's generation fleet among the retail classes, Staff recommends using these BIP allocation factors to reasonably allocate the return on production related plant investment and production related expenses to the retail classes.

KCPL's generation fleet characteristics

KCPL's non-renewable, "Base"-designated, generating plants are the Wolf Creek nuclear unit, the Iatan Unit 2 supercritical coal plant, and the Iatan Unit 1, Hawthorn 5, and

LaCygne Units 1 & 2 coal plants.[12] Staff determined the average capacity cost, net of depreciation reserve, for each of these plants. The majority of these plants have emissions control equipment that increases their capacity costs and the operating costs, while also slightly decreasing the net amount of electrical energy produced by burning the same amount of coal. Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Base generation is approximately $1,094,345/MW. However, Staff found that the average fuel cost for these plants was only $13.28/MWh. Taken together, KCPL's Base generation ran at a 78% capacity factor in Staff's fuel model.

KCPL's "Intermediate" generating plants are the combined-cycle unit at the Hawthorn site (Unit 9 Heat Recovery Steam Generator ("HRSG"), fired by Unit 6 Combustion Turbine ("CT")), and the units at Montrose.[13] Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Intermediate generation is approximately $374,630/MW, and the average fuel cost for these plants was $21.06/MWh. Taken together, KCPL's Intermediate generation ran at a 17% capacity factor in Staff's fuel model.

KCPL's "Peaking" generating plants include the units at West Gardner, Osawatomie, and Hawthorn 7 & 8.[14] Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Peaking generation is only approximately $230,268/MW. Based on

[12] These types of units tend to be ideal for meeting the around-the-clock capacity needs; however, they are slow-ramping and cannot quickly react to sudden changes in the level of demand. These units can be ramped as needed to provide regulating services to SPP, but aside from this sort of ancillary service activity, Staff would expect these plants to be operated as "price takers" in most hours, as opposed to dispatching quickly to benefit from short-term price spikes in the SPP market. KCPL also has wind investment, and wind and hydroelectric PPAs. Staff did allocate these expenses and costs to the classes using the BIP allocators; however, Staff did not assign these expenses and costs in its allocator development.

[13] These units can be dispatched to meet the changing system demand in a matter of hours, and are capable of operating at high capacity factors. However, as a practical matter, these units are rarely operated at a high capacity factor, because the role of intermediate units to the generation fleet is to meet the demand requirements of loads that occur often, but not constantly. Intermediate units can be dispatched in the SPP to follow load and to provide regulating reserves, but given current gas prices, it would not be surprising if these units were offered into the SPP as price takers.

[14] Gas combustion turbines are quick ramping, and because they can be cold-dispatched quickly, they are ideal for meeting spiky changes in the level of load – for example – when air conditioners fire on as a heat wave moves into an area. Gas combustion turbines are capable of high capacity factors, but tend to have the lowest capacity factors of any units, as operated. However, because KCPL participates in the SPP IM; its generation is dispatched as part of the larger SPP fleet, so its combustion turbines may be dispatched at night to assist in wind integration, as opposed to operating at times of peak demand when another utility may have less expensive energy available.

information provided by KCPL, the average fuel price for these units is approximately \$37.27/MWh.[15]

KCPL's load characteristics

The interaction of class energy requirements over the course of a year is generally studied in terms of class coincident and non-coincident peak demands. Coincident-peak demand is the demand of each customer class at the hour when the overall system peak occurs. Coincident-peak demand reflects the maximum amount of diversity because most customer classes are not at their individual class peaks at the time of the coincident peak. Class peak demand, which is the maximum hourly demand of the class as a whole, often does not occur at the same hour, i.e., does not coincide with, the system peak. Although not all customers within a class peak at the same time due to intra-class diversity, to achieve the class peak a significant percentage of the customers in the class will be at or near their peak demand. Therefore, class-peak demand will have less diversity than the class's load at the time of system peak.

Finding Class Demands

1. Staff found each class's average demand in MW. That MW of demand value is the "base demand" used for each class in the BIP calculation.

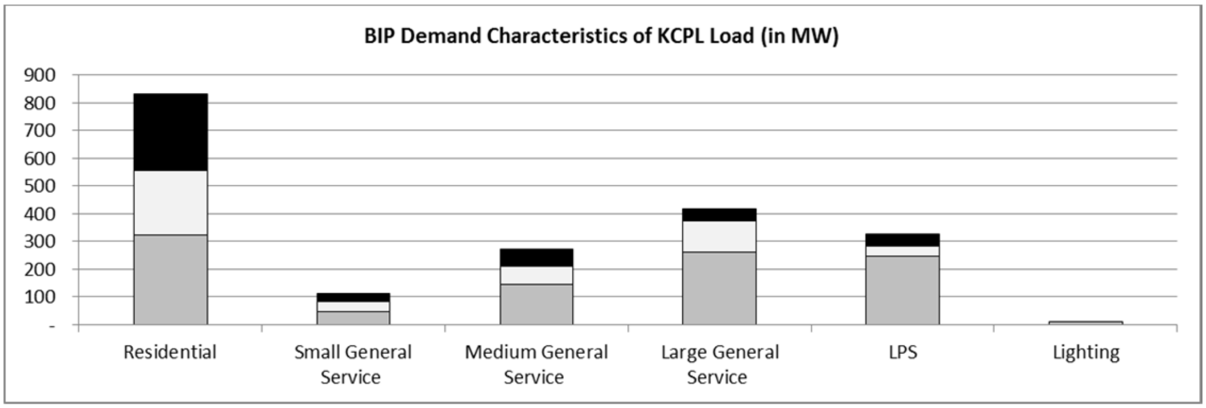
2. Staff found each class's demand in MW at the time of each month's system peak. Staff then averaged each class's 12 demands to a single MW value. That additional MW value over the base demand MW value is each class's intermediate demand. The difference between each class's base demand and its intermediate demand is its incremental intermediate demand.

3. Staff found each class's demand in MW at the time of the four system peaks. Staff then averaged each class's demands at those four peaks to a single MW value. That MW value is each class's peak demand. The difference between each class's intermediate demand and its peak demand is its incremental peak demand.

The BIP Demand Characteristics of each class (in MW) are provided in the table and graph below:

[15] KCPL has additional peaking units at the Northeast site. None of KCPL's oil or simple-cycle gas units ran in Staff's fuel model at modeled market and fuel prices. This value is based on Staff's direct-filed fuel prices and KCPL-provided heat rates for the indicated units.

	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Demand	324.62	47.21	144.32	261.84	245.66	10.41
Intermediate Demand	557.48	81.94	211.25	373.30	284.83	-
Peak Demand	834.05	114.36	271.96	417.69	328.34	-



Finding Class Energy Usage

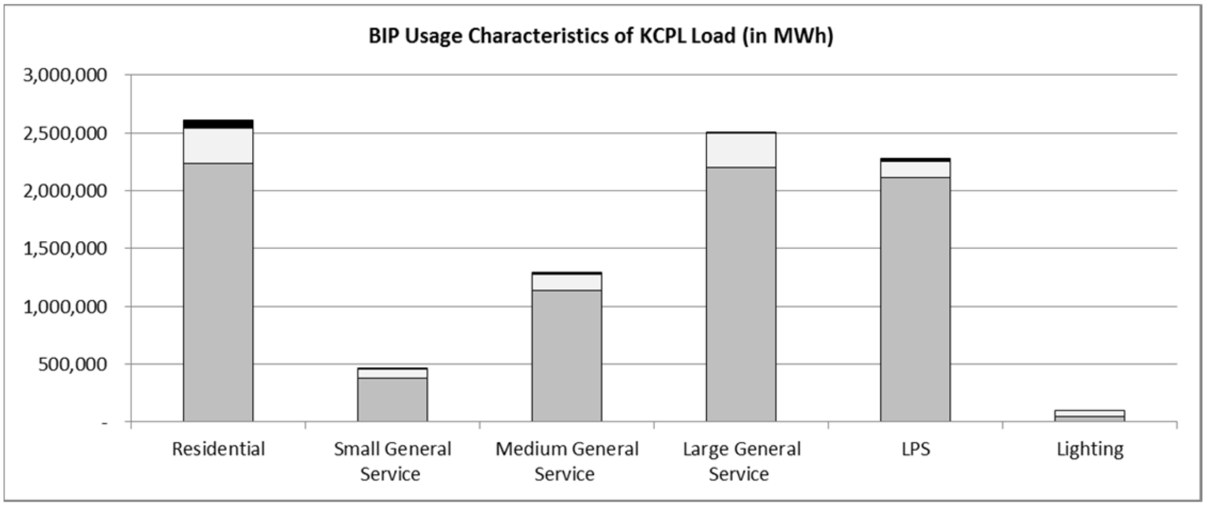
1. Staff analyzed each class's weather-normalized energy usage for each hour of the year. In a given hour, if a class had energy usage (MWh) equal to or below its base demand (MW), then Staff recorded that energy usage as base usage. If, in that hour, a class had energy usage in excess of its base demand, Staff recorded that hour's energy usage for that class as being equal to that class's base demand.

2. Staff then analyzed if in each hour a class had energy usage in excess of its intermediate demand. If so, Staff recorded that hour's energy usage up to the class's intermediate demand (less the previously allocated base usage) as that class's intermediate usage.

3. Finally, Staff recorded all energy usage in excess of a particular class's intermediate demand as peak usage.

The BIP Energy Characteristics of each class (in MWh) are provided in the table and graph below:

	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Energy	2,236,023.26	381,059.82	1,133,000.99	2,201,358.96	2,117,667.60	46,947.01
Intermediate Energy	307,775.72	71,672.20	145,369.86	292,400.71	133,896.69	50,049.60
Peak Energy	68,303.98	6,284.61	18,664.88	11,966.19	27,848.46	-



Calculating BIP Allocators

Staff developed production-capacity and production-energy allocators by matching the average capacity cost of each type of capacity cost with the BIP demands of each customer class, and by matching the average energy cost of each type of energy cost with the BIP energy requirements of each class.

Staff relied on the demand characteristics of each customer class to appropriately assign: (1) the relatively expensive capacity costs of base generation on each class's base level of demand, (2) the relatively moderate capacity costs of intermediate generation on each class's intermediate level of demand, and (3) the relatively inexpensive capacity costs of peaking generation on each class's peak level of demand. Under this approach, KCPL's net investment in each of the plants assigned to each of the BIP components is allocated to the classes based on each class's base, intermediate, and peak demand (in MW). The relative value – by class – of the investment allocated to each class is used as the Production-Capacity allocator.[16]

Staff relied on the energy characteristics of each customer class to appropriately assign (1) the relatively inexpensive fuel costs of base generation on each class's base energy usage, (2) the relatively moderate fuel costs of intermediate generation on each class's intermediate

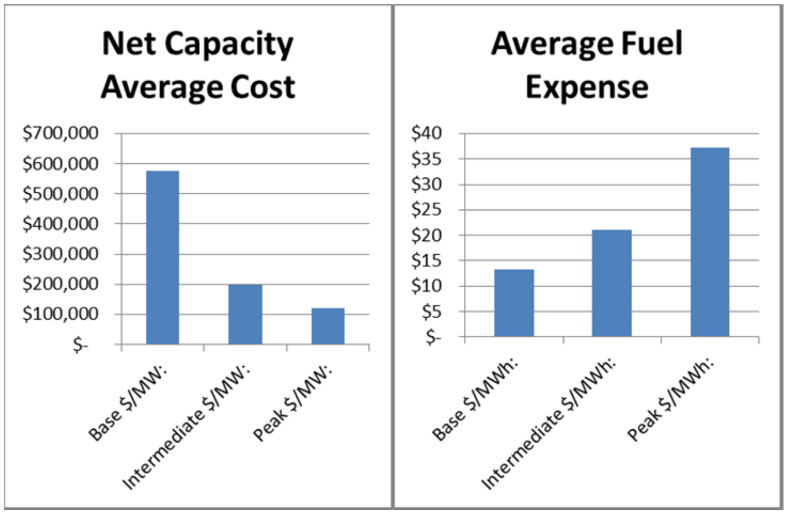
[16] A separate capacity-related allocator is used to allocate the return on investment associated with fuel stored at the various generation stations.

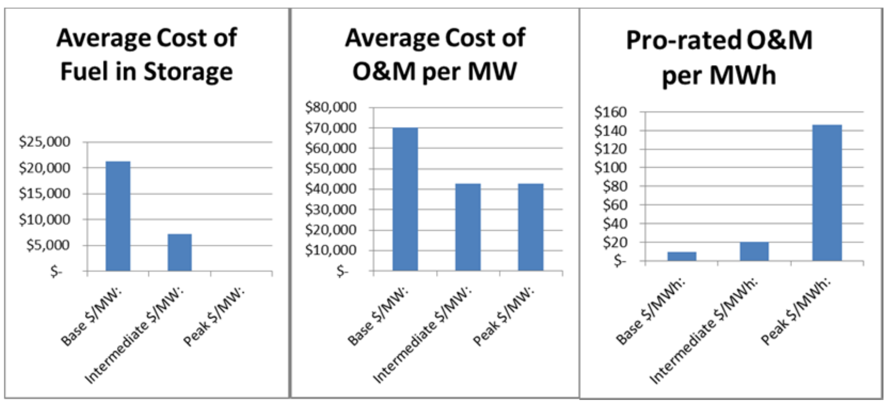
energy usage, and (3) the relatively expensive fuel costs of peaking generation on each class's peak energy usage. The fuel cost on a per MWh basis for each plant, as used in the Staff revenue requirement, is used as the price to serve each class's base, intermediate, and peak load (in MWh). The relative value – by class – of the fuel to serve the load requirements of each class is used as the Production-Energy allocator.[17]

Staff also used the assignments of generating plant to BIP components to develop allocators for KCPL's production-related operating and maintenance expense, and fuel stored on site. This method expressly assigns the expenses of each plant to follow that plant. Each of the generating plants causes production plant operating and maintenance expenses. Staff found the level of expense for each plant assigned under the BIP components, and developed allocation factors to apply to all production-related O&M based on each customer class's assigned plant responsibility. Similarly, fuel stored at each plant is associated with particular plants, so Staff developed factors to allocate the fuel associated with particular plants with the plant allocated to each customer class.

Staff's detailed BIP study reasonably balances the offsetting impacts of the relative costs of energy, capacity, O&M, and fuel-in-storage associated with meeting the demand and usage characteristics of KCPL's load. Thus, Staff's BIP method is a reasonable method for allocating the production-related costs and expenses, as well as the capacity-related and energy-related portions of off-system sales revenues. This consistency is appropriate, as production plant expenses and production plant investment are interrelated. The graphs provided below indicate the relative values of each of these items.

[17] A separate energy-related allocator is used to allocate the operations and maintenance expense associated with each of the various generation stations.

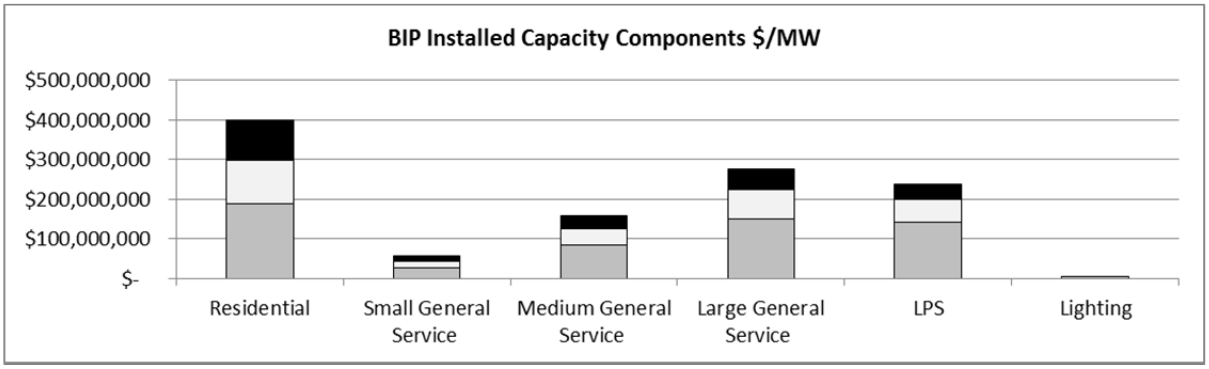




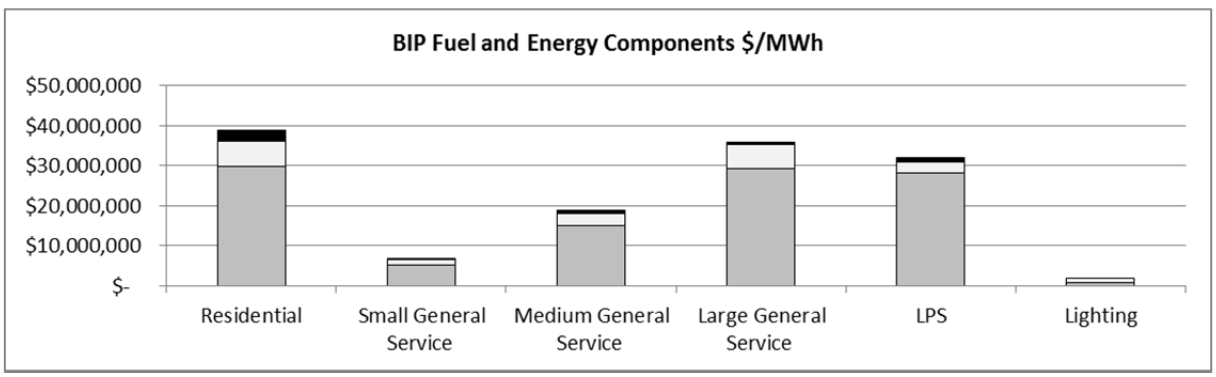
The allocators that result from applying these values to KCPL's BIP load characteristics are provided in the graphs and tables below.

BIP Installed Capacity Allocator

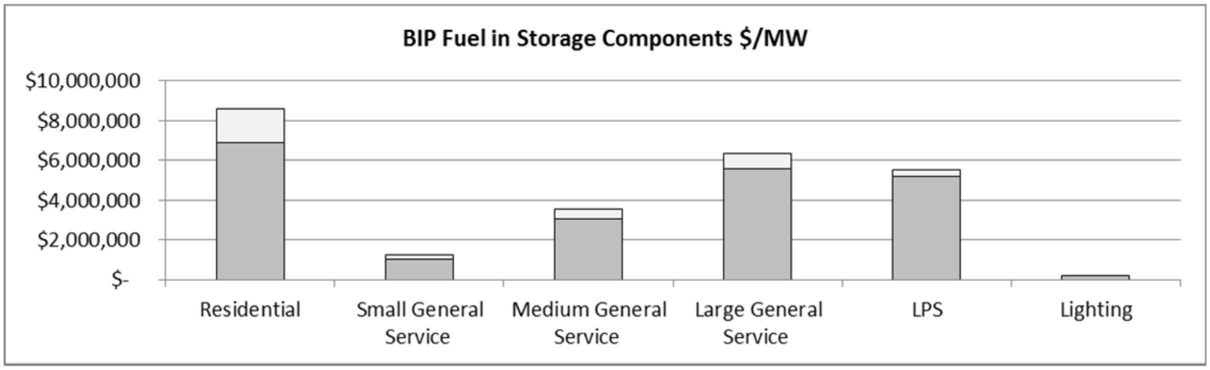
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Capacity	$ 596,823,511	$ 187,361,696	$ 27,247,972	$ 83,294,759	$ 151,127,261	$ 141,786,418	$ 6,005,405
Incremental Intermediate Capacity	$ 298,109,036	$ 110,147,596	$ 16,189,302	$ 41,738,869	$ 73,756,688	$ 56,276,580	$ -
Incremental Peak Capacity	$ 238,810,134	$ 101,291,287	$ 13,888,583	$ 33,028,574	$ 50,726,769	$ 39,874,920	-
Totals:	$ 1,133,742,682	$398,800,580	$57,325,858	$158,062,202	$275,610,718	$237,937,919	$6,005,405
BIP Installed Capacity Allocator:		35.18%	5.06%	13.94%	24.31%	20.99%	0.53%



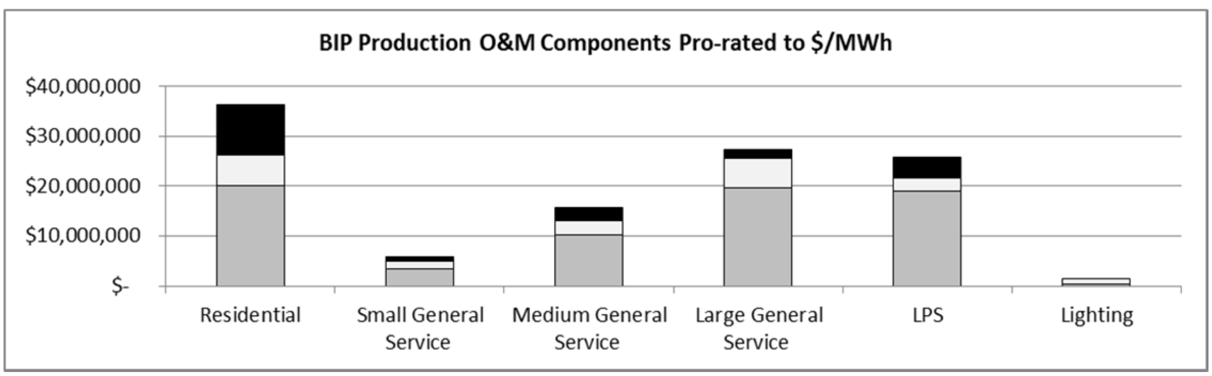
BIP Fuel and Energy Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Energy Usage	$ 107,774,296	$ 29,692,474	$ 5,060,148	$ 15,045,283	$ 29,232,162	$ 28,120,812	$ 623,416
Incremental Intermediate Usage	$ 21,083,445	$ 6,481,423	$ 1,509,339	$ 3,061,332	$ 6,157,642	$ 2,819,719	$ 1,053,990
Incremental Peak Usage	$ 4,959,201	$ 2,545,562	$ 234,216	$ 695,605	$ 445,957	$ 1,037,860	$ -
Totals:	$ 133,816,942	$38,719,459	$6,803,703	$18,802,220	$35,835,762	$31,978,392	$1,677,407
BIP Fuel and Energy Allocator:		28.93%	5.08%	14.05%	26.78%	23.90%	1.25%



BIP Fuel in Storage Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Capacity	$ 21,936,129	$ 6,886,442	$ 1,001,494	$ 3,061,482	$ 5,554,652	$ 5,211,331	$ 220,727
Incremental Intermediate Capacity	$ 3,509,939	$ 1,684,706	$ 251,252	$ 484,250	$ 806,362	$ 283,369	$ -
Incremental Peak Capacity	$ -	$ -	$ -	$ -	$ -	$ -	-
Totals:	$ 25,446,068	$8,571,148	$1,252,746	$3,545,732	$6,361,015	$5,494,700	$220,727
BIP Fuel in Storage Allocator:		33.68%	4.92%	13.93%	25.00%	21.59%	0.87%



BIP O&M Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Usage	$ 72,669,811	$ 20,020,975	$ 3,411,945	$ 10,144,700	$ 19,710,597	$ 18,961,238	$ 420,356
Incremental Intermediate Usage	$ 20,216,386	$ 6,214,874	$ 1,447,267	$ 2,935,434	$ 5,904,408	$ 2,703,758	$ 1,010,645
Incremental Peak Usage	$ 19,488,002	$ 10,003,208	$ 920,389	$ 2,733,497	$ 1,752,464	$ 4,078,444	$ -
Totals:	$ 112,374,199	$36,239,057	$5,779,601	$15,813,631	$27,367,469	$25,743,441	$1,431,001
	BIP O&M Allocator:	32.25%	5.14%	14.07%	24.35%	22.91%	1.27%



Staff Expert/Witness: Sarah L. Kliethermes

D. Allocation of Transmission Costs

The transmission system moves electricity, at a very high voltage, from generating plants over long distances to local service areas. Transmission costs consist of costs for high voltage lines and transmission substations, along with labor to operate and maintain these facilities. KCPL’s transmission investment and transmission costs comprise approximately 7.2% of the functionalized investment and costs that Staff allocated to KCPL’s customer classes. KCPL's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines, and substations that transmit power to other transmission or distribution voltages. Staff allocated transmission investment and costs to the customer classes based on each class's 12 coincident peak (CP).[18] Staff recommends the 12 CP allocation method for this purpose because, by including periods of normal use and intermittent peak use throughout all twelve months of the year, it takes into account the need for a transmission system designed both to transmit electricity during peak loads and to transmit electricity throughout the year.

Staff Expert/Witness: James A. Busch

E. Allocation of Distribution and Customer Service Costs

Distribution is the final link in the chain built to deliver electricity to customers' homes or businesses. The distribution system converts high voltage power from the transmission system into lower primary voltage and delivers it to large industrial complexes, and further converts it into even lower secondary voltage power that can be delivered into homes for lights and appliances. A utility's distribution plant includes distribution substations, poles, wires, and transformers, as well as service and labor expenses incurred for the operation and maintenance of these distribution facilities. Voltage level is one factor that Staff considered when allocating distribution costs to customer classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level needs of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages. Only those customers in customer classes served at substation voltage or below were included in the calculation of the allocation factor for distribution substations. Staff used each class's annual coincident peak to allocate substation costs.[19]

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[18] Coincident peak refers to the load of each class at the time of the system peak. A 12 CP is the average of each class's load at the times of the system peak for each of the 12 months of the year.

[19] Staff was only able to determine each class' NCP and CP at meter and at generation. It was not possible from the hourly load data used to develop class non-coincident peaks and coincident peaks to find each class' NCP and CP at the different voltage levels.

KCPL divided the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines, conductors, and conduit between primary and secondary voltage. Staff relied on this information to also divide the distribution investment categories between primary and secondary voltage.

Staff allocated the costs of the primary distribution facilities on the basis of each customer class' annual non-coincident peak demand measured at the class meter. All customers, except those served at transmission level, (i.e., primary and secondary customers), were included in the calculation of the primary distribution allocation factor, so that distribution primary costs were allocated only to those customers that used these facilities.

Staff allocated the costs of secondary distribution on the basis of each customer class' annual non-coincident peak demand at meter, weighting that class demand by the number of secondary distribution customers. Consideration of load diversity is important in allocating demand-related distribution costs because the greater the amount of diversity among customers within a class or among classes, the smaller the total capacity (and total cost) of the equipment required for the utility company to meet those customers' needs. Load diversity exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time within a customer class reflects the diversity of the class load. Therefore, when allocating demand-related distribution costs that are shared by groups of customers, it is important to choose a measure of demand that corresponds to the proper level of diversity. Since the hourly class load data provided by KCPL does not contain the level of detail necessary to calculate the factors Staff generally uses to develop allocators, Staff could only determine each class' NCP and CP at meter or at generation, and not at the substation, primary, and secondary voltages. Staff did attempt to weight each class' NCP at meter to account for the absence of primary voltage customers in allocating secondary distribution costs. Staff allocated the cost of line transformers on the same basis as secondary distribution.

Customer costs include labor expenses incurred for billing and customer services. Customer-related costs are costs necessary to make electric service available to the customer, regardless of the electric service utilized. Examples of such costs include meter reading, billing, postage, customer accounting, and customer service expenses. Staff recommends allocating costs for service drops and meter costs using data provided in KCPL's workpapers relating to the specific level of investment per class. Also, Staff recommends using KCPL's data for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using KCPL studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to each customer class.[20] The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

Staff Expert/Witness: James A. Busch

F. Revenues

Operating revenues consist of (1) the revenue that a utility collects from the sale of electricity to Missouri retail customers ("rate revenue") and (2) the revenue it receives for providing other services ("other revenue"). Staff also uses rate revenues in developing its rate design proposal, and to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for KCPL. The normalized and annualized class rate revenues in Staff's *COS Report* filed November 30, 2016, were used in Staff's CCOS study.

Staff allocated off-system revenues from the sale of energy on dollar-weighted energy, and other off-system revenues on dollar-weighted capacity. Because the CCOS software imports these values as separate line items, it was not necessary to develop a weighted off-system sales allocator to weight the fuel-related and capacity-related components of the off-system sales.

Staff Experts/Witnesses: Sarah L. Kliethermes, James A. Busch

G. Allocation of Taxes

Taxes consist of real estate and property taxes, payroll taxes, and income taxes. Real estate and property taxes are directly related to KCPL's investment in plant, so these taxes are allocated to customer classes based on the sum of the previously allocated net production, transmission, distribution, and general plant investment.

[20] Staff has reviewed the results of applying the direct assignments resulting from KCPL's study. Because these results appear reasonable, Staff accepts KCPL's direct assignments of customer-related costs for CCOS purposes.

Payroll taxes are directly related to KCPL's payroll, so these taxes are allocated to customer classes based on previously allocated payroll expense.

Staff estimated income tax liability separately for each customer class as a function of the return-based revenues provided by each customer class. Staff allocated KCPL's income taxes based on class earnings.

Staff Expert/Witness: James A. Busch

H. Allocation of Seasonal Energy Costs

KCPL's rates are seasonal as certain charges differ for summer versus non-summer billing months. To allocate energy-related costs by season, Staff found the ratio of summer-to-non-summer energy cost for each class. Staff found this ratio by applying each class's annual normalized load to the market costs of energy used in Staff's production cost modeling, and the actual test year market price, for that applicable hour. Staff then found the percentage of market energy cost for each class incurred during the summer billing months, as well as for the total company. On average, summer billing season wholesale energy costs are 120-137% of non-summer billing season wholesale energy costs. Table 6 provides the seasonal costs per class below.

Table 6

	Res.	SG	MG	LG	LP	Ltg.	Total / Average
Summer $/MWh at Market Prices used in Fuel Run (at Generation):	$ 26.87	$ 26.62	$ 26.54	$ 26.11	$ 25.72	$ 23.56	$ 26.34
Summer $/MWh at Actual Market Prices (at Generation):	$ 28.11	$ 26.80	$ 26.57	$ 25.77	$ 25.14	$ 21.42	$ 26.53
Summer % of total kWh:	35%	30%	29%	27%	28%	21%	33%
Summer % of total $ (Fuel Run):	42%	36%	35%	33%	34%	24%	40%
Summer % of total $ (Actual):	41%	34%	33%	30%	31%	22%	37%
Summer to NonSummer Index (Fuel Run):	139%	138%	137%	135%	134%	125%	137%
Summer to NonSummer Index (Actual):	126%	121%	119%	117%	116%	108%	120%

Staff recommends that as part of its next rate case, KCPL evaluate the reasonableness and practicality of moving towards Seasonal and Shoulder rates, as opposed to Summer and Non-Summer rates. Such a rate structure would consist of two sets of rates, but would apply to (1) the summer and winter months, and (2) the fall and spring months.

Staff Expert/Witness: Sarah L. Kliethermes

J. Energy Costs

The total cost of energy procured through the SPP Day Ahead Market for each class and the average cost of energy based on each class's load shape are provided in Table 7 below. Ancillary service, real time market, transmission, and capacity costs are not included in these amounts.

Table 7

	Res.	SG	MG	LG	LP	Ltg.
Cost of Energy at Market Prices used in Fuel Run:	$ 58,164,872	$ 10,027,490	$ 28,277,863	$ 53,749,512	$ 48,685,687	$ 1,948,900
Cost of Energy at Actual Market Prices:	$ 63,778,852	$ 10,851,453	$ 30,604,874	$ 57,895,170	$ 51,503,224	$ 1,948,450
MWh @ Generation:	2,612,103	459,017	1,297,036	2,505,726	2,279,413	96,997
$/MWh at Market Prices used in Fuel Run (at Generation):	$ 22.27	$ 21.85	$ 21.80	$ 21.45	$ 21.36	$ 20.09
$/MWh at Actual Market Prices (at Generation):	$ 24.42	$ 23.64	$ 23.60	$ 23.11	$ 22.59	$ 20.09
MWh @ Meter:	2,784,602	489,299	1,382,432	2,661,021	2,377,141	103,402
$/MWh at Market Prices used in Fuel Run (at Meter):	$ 20.89	$ 20.49	$ 20.46	$ 20.20	$ 20.48	$ 18.85
$/MWh at Actual Market Prices (at Meter):	$ 22.90	$ 22.18	$ 22.14	$ 21.76	$ 21.67	$ 18.84
Class % of Total Cost of Energy at Market Prices used in Fuel Run:	28.959%	4.992%	14.079%	26.760%	24.239%	0.970%
Class % of Total Cost of Energy at Actual Market Prices:	29.448%	5.010%	14.131%	26.731%	23.780%	0.900%

Staff Expert/Witness: Sarah L. Kliethermes

IV. Rate Design

In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that after an applied rate increase, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.[21] Any misalignment of the revenues produced by the recommended revenue requirement of a class is mitigated by Staff's recommended revenue-neutral interclass

[21] Staff is also mindful that in the course of general rate increase cases, no class should receive a rate reduction under ordinary circumstances.

shifts. However, in the course of making interclass shifts, Staff is mindful of a number of things.

1. If any general rate case results in an increase in a utility's overall revenue requirement, Staff is reluctant to recommend reducing any class's rates while the overall revenue requirement is increasing.

2. CCOS studies should serve as a guide to setting revenue requirements and are not precise. For example, CCOS studies are based on a direct-filed revenue requirement, and the allocation of that revenue requirement among specific accounts, using a specific rate of return. Unless the Commission approves that exact set of accounting schedules, as well as the direct-filed billing determinants in setting the revenue requirement in a particular case, there is an inherent disconnect between the CCOS study results used in providing a party's class cost of service and rate design recommendations, and the actual class cost of service that would result at the conclusion of a case.

3. Consideration of policy, such as rate continuity, rate stability, revenue stability, minimization of rate shock to any one-customer class, meeting of incremental costs, and consideration of promotional practices are also taken into account in Staff's ultimate recommendation of KCPL class revenue recovery through rate design. Staff endeavors to provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility promoting revenue stability and efficiency. Staff must also balance this, to the extent possible, retaining existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock. Rate schedules should be understood by all parties, customers, and the utility as to proper application and interpretation.

4. Staff endeavors to provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility and yield the total revenue requirement to all classes in a fair manner avoiding undue discrimination, including methods to recover both fixed and variable costs in a timely manner. This ensures KCPL receives an amount above its marginal costs on sales of electricity, and each class is providing a contribution to cover fixed costs.

5. In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that once the rate increase has been applied, a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.

Staff recommends an adjustment of KCPL's rates with the following process:

1. Staff recommends a revenue neutral shift in revenue responsibility from the Lighting, SGS, MGS, and LGS classes to the Large Power ("LPS") class if no change in overall revenue requirement is ordered. Specifically, Staff recommends the LPS class's revenue responsibility be increased by approximately $2.35 million, with a reduction to the Lighting class's revenue responsibility of approximately $100,000, and the remainder of the reductions spread to the General Service classes (SGS, MGS, and LGS) so that the final rates are adjusted downward at an equal percentage to each of those rate classes.[22] If an overall increase is awarded that is up to approximately 0.62% of current revenues, that increase should be applied to the LPS class, though no other class should receive a rate reduction. If an overall increase is awarded in excess of approximately 0.62% of current revenues, the revenue neutral shifts described above in the "no change in overall revenue requirement" scenario should be implemented.

2. Staff recommends allocating the portion of the revenue increase/decrease that is attributable to energy efficiency ("EE") programs not recoverable through Missouri Energy Efficiency Investment Act ("MEEIA") to applicable classes based on that class' level of kWh less opt-out customers.[23]

3. The amount of revenue ordered for KCPL not associated with the EE revenue from Pre/Non-MEEIA revenue requirement assigned in Step 2, should be allocated to various customer classes as an equal percent of current base revenues after making the adjustments in Step 1.

4. Staff recommends that each rate component of each class be adjusted across-the-board for each class on an equal percentage basis after consideration of steps 1 through 3 above.

Rate Structure

Once Staff determines the revenue requirement, Staff must calculate the rates that will be charged to the utility's customers.[24] The use of different charge elements on various rate schedules is discussed in terms of "rate structure." Rate structure is the composition of the

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[22] Expressed as a percentage, this is a 1.6% revenue neutral increase to the LPS class, which reduces the LPS class's level of under-contribution by 20%.

[23] The non/pre-MEEIA program costs consist of the program costs for increases/decreases in the revenue requirement associated with the amortization of non/pre-MEEIA program costs.

[24] Some revenues are recovered through miscellaneous charges such as line extension policies or bad check fees.

various charges for the utility's products. These include customer charges, energy (usage) charges, peak (demand) charges, facilities charges, etc. More elaborate variations include seasonal variations, time-of-day differentials, declining/inclining block rates, and hours-use rates. These variations send price signals to the customer(s). The most simple rate structures consist of two to five elements, while structures that are more complex may have more than 16 elements.

Rate structure is a compromise between the complexity necessary to match cost causation to revenue recovery as precisely as possible, and the level of understandability and predictability of bills and revenues desired by utilities, customers, and regulators. The tension between the interest in providing revenue stability and indicating cost causation should also be considered in reasonably designing rates and selecting rate structure components.[25] Changes to rate structure may require additional metering or customer information system investment, and the cost of that investment should be weighed against the benefit of the increased complexity.

The use of blocked rates adds a level of complexity that allows demand-related cost recovery from customers without the expense of demand metering and minimal expense and complexity increases to billing systems and revenue calculations. Rates can be blocked so that demand-related costs are recovered on an annual-average sale of energy in the first block of each season. Depending on the characteristics of the system, the cost of energy may vary significantly by season or by time of day or be relatively stable. A declining-block non-summer rate design can be viewed as recovering demand costs over the first 600 kWh consumed each month, while recognizing a system's lower cost of energy for usage consumed outside of the summer season. Conversely, a flat or inclining block rate design can be viewed as recovering demand costs over the first 600 kWh consumed each month, while recognizing a system's higher cost of energy for usage consumed during the summer season. This ratio of the first and the second block could also reflect summer peak consumption as a driver of the

[25] For purposes of rate design, cost causation is typically deemed as the distribution of costs that results from the allocation of a vertically integrated utility's gross revenue requirement net of other revenues. It is necessary to make an exception to this general assumption in certain instances when considering costs that would not be incurred but-for a customer, such as the cost of energy purchased through the integrated energy market to serve a customer.

costs of certain demand-related investments. Importantly, different experts may reasonably view a given rate structure as being designed to accomplish different objectives.

Interclass Revenue Responsibility Recommendations

In providing its rate design recommendation, Staff will recommend revenue-neutral shifts so that a given class does not underpay by greater than 5% of its revenue requirement while another class or classes overpay by greater than 5% of its revenue requirement.[26] The relative rate of return levels of contribution of the classes are presented in Table 8 and the accompanying chart. While Staff's current Cost of Service Calculation does not indicate a recommended change of rates, updating the energy efficiency revenue requirements of each class does result in a change to the level of class over and under-contributions.

Table 8

	Start % over/under contribution	System Average Increase + Energy Efficiency	End % over/under contribution
Residential	0.49%	$ (20,555)	0.48%
Small General Service	5.01%	$ (5,989)	5.00%
Medium General Service	5.18%	$ 9,781	5.19%
Large General Service	0.64%	$ 30,138	0.65%
Large Power	-7.45%	$ (4,918)	-7.45%
Lighting	5.54%	$ (8,456)	5.45%

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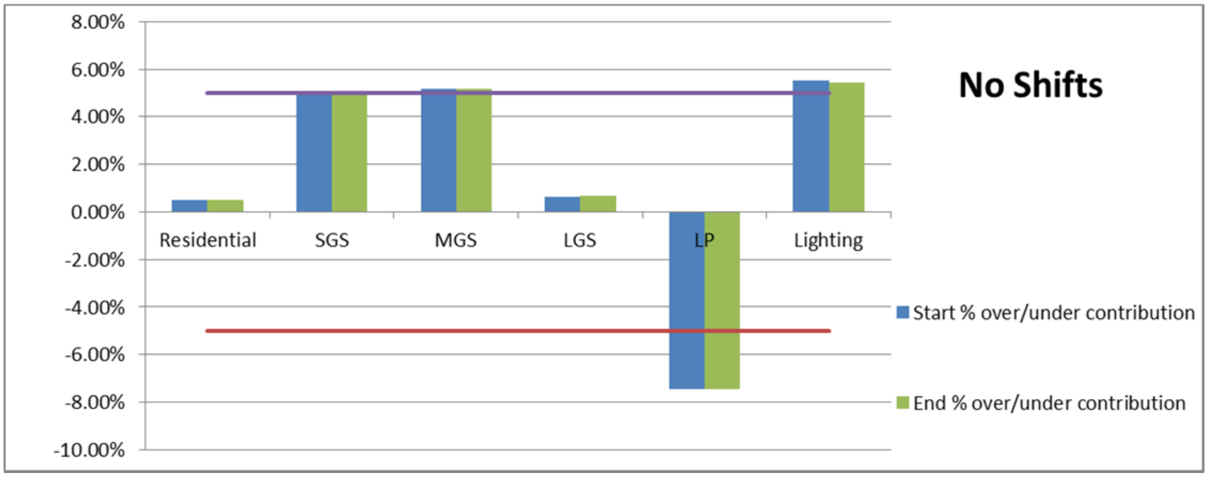
[26] Staff is also mindful that in the course of general rate increase cases, no class should receive a rate reduction under ordinary circumstances.

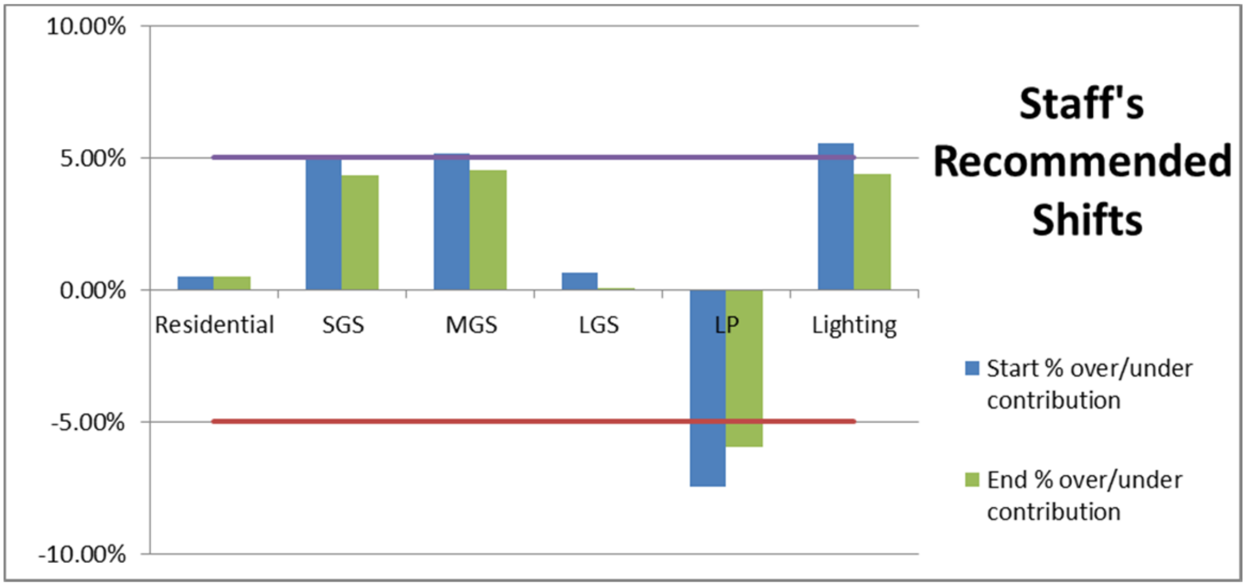


As indicated above, without applying a revenue shift in this case, the Lighting, and MGS classes would be overpaying by an amount greater than 5% of the revenue requirement at an equalized rate of return. Where customers can freely switch among classes in a rate group, as is the case with KCPL's general services classes, it is necessary to consider some level of aggregation for the results associated with those classes. Another consideration is identification of which classes produce revenues that are above and below the system average rate of return.

Again as Table 2 and its accompanying chart indicate, Staff's recommended interclass shifts in revenue responsibility will minimize classes' exceedance of a +/-5% threshold.

Table 2

	Start % over/under contribution	Revenue Shift	Energy Efficency Increase	End % over/under contribution
Residential	0.49%	$ -	$ 504,623	0.47%
Small General Service	5.01%	$ (315,673)	$ 73,305	4.34%
Medium General Service	5.18%	$ (745,833)	$ 223,013	4.55%
Large General Service	0.64%	$ (1,188,708)	$ 385,725	0.05%
Large Power	-7.45%	$ 2,350,215	$ 234,326	-5.97%
Lighting	5.54%	$ (100,000)	$ -	4.36%
Total / System Average:		$ 1,420,993		7.01%



The rates of return produced by each class at current rates, and the rates of return that will result from reallocation of the revenue requirement net of changes to each class's pre/non-MEEIA energy efficiency revenue requirement are provided in Table 9 below.

Table 9

	Current RoR	Revenue Shift	Energy Efficency Increase	Retail Increase	End RoR	% Increase to Retail Non-EE Revenues
Residential	7.17%	$ -	$ 504,623	$ (548,018)	7.17%	-0.01%
Small General Service	8.77%	$ (315,673)	$ 73,305	$ (85,412)	8.54%	-0.64%
Medium General Service	8.72%	$ (745,833)	$ 223,013	$ (201,098)	8.51%	-0.60%
Large General Service	7.22%	$ (1,188,708)	$ 385,725	$ (320,082)	7.03%	-0.58%
Large Power	4.53%	$ 2,350,215	$ 234,326	$ (248,700)	5.02%	1.60%
Lighting	9.27%	$ (100,000)	$ -	$ (17,683)	8.79%	-1.12%
Total / System Average:	7.01%	$ -	$ 1,420,993	$ (1,420,993)	7.01%	0.00%

Overall, these adjustments bring classes closer to the cost of serving them, while still maintaining rate continuity, rate stability, and revenue stability, while minimizing rate shock to any one-customer class if an overall increase is awarded.[27] Staff based its recommendations for interclass shifts in revenue responsibility on its CCOS study results, Staff's review of

[27] For example, if two similar classes receive different levels of increases, customers may leave the higher-cost class in favor of the lower cost class. Then, at the next rate case, the lower-cost class will likely have a higher allocated cost of service, while the higher-cost class will likely have a lower allocated cost of service. The resulting redesign of rates would likely cause an undoing of the initial movement of customers, with the result being a seesawing of both rates and customers.

KCPL's revenue-neutral adjustments in previous general rate increases, and Staff's judgment regarding the impact of revenue shifts for all classes.

Intra-class Rate Design Recommendation

KCPL's Residential, Commercial, and Small Heating rate structures and designs are generally not inconsistent with cost causation in the absence of demand metering or time-differentiated rates. Staff recommends preserving the existing relationship between rate elements.

(1) Residential customer charge

Based on Staff's CCOS study results and rate design principles regarding rate simplicity, stability, and customer understandability, Staff recommends that the residential customer charge increase by an equal percent of any final rate increase to the residential class, if such an increase is ordered by the Commission, up to a level of $18.44.

Costs included in the calculation of the Residential customer charge costs are the costs necessary to make electric service available to the customer, regardless of the level of electric service utilized. Examples of such costs include monthly meter reading, billing, postage, customer accounting service expenses, as well as a portion of the costs associated with the required investment in a meter, the service line ("drop"), and other billing costs. The costs included for recovery through the customer charge consist of the following:

- Distribution – services (investment and expenses)
- Distribution – meters (investment and expenses)
- Distribution – customer installations
- Customer deposit
- Customer meter reading
- Other customer billing expenses
- Uncollectible accounts (write-offs)
- Customer service & information expenses
- Sales expense
- Portion of income taxes

Staff recommends allocating services and meter costs using the same allocators that KCPL used in Case No ER-2014-0370 to allocate these costs. KCPL based these allocators on a KCPL study that weights the number of installations taking service by class and by the cost of the meter and service used to serve that class. In addition, Staff recommends using the same allocators that KCPL used for allocating meter reading costs, uncollectible accounts, customer services expense, and for allocating customer deposits. These allocators are derived using KCPL studies that directly assign the costs of meter reading, uncollectible accounts, customer service expense, and customer deposits to the customer classes. The allocators are the fraction of total costs in these accounts assigned to each class, respectively.

The sum of the residential class' costs allocated to the customer charge determines a residential monthly customer charge sufficient to collect those costs from the customers within the class. Staff's CCOS study and calculation of the residential customer charge, using Staff's *Accounting Schedules* filed on November 30, 2016, resulted in a customer charge of approximately $18.44 per month. This calculation includes revenue requirement associated with KCPL's investment in AMI metering.

Staff's calculated customer charge at the fully allocated class cost of service is $18.44, if all class revenue requirements were adjusted to provide exactly the same rates of return. Because Staff's revenue requirement calculation does not currently support an increase, Staff does not recommend that the residential customer charge be increased absent an overall Residential class increase. Staff is concerned that the impact of increasing the Residential customer charge would decrease the Residential energy charges, sending a price signal that does not support Residential energy conservation.

Staff Expert/Witness: James A. Busch

V. Fuel and Purchased Power Adjustment Clause Tariff Sheet Recommendations

In its *COS Report* in this case, Staff provided its recommendations for the following issues that have an impact on KCPL's fuel adjustment clause ("FAC") and FAC tariff sheets:

1. Continue KCPL’s FAC with the modifications as discussed below:

2. Include a new Base Factor in the FAC tariff sheets calculated from the Net Base Energy Cost[28] that the Commission includes in the revenue requirement upon which it sets KCPL’s general rates in this case;

3. Order KCPL to suspend all of its hedging activities (cross hedging and fuel hedging);

4. Clarify that the only transmission costs that are included in KCPL’s FAC are those that KCPL incurs for purchased power[29] and off-system sales (“OSS”);

5. Order KCPL to continue to provide the additional information as part of its monthly reports[30] as KCPL was ordered to do in the previous Rate Case No. ER-2014-0370, along with the information already required in its monthly reports.

A. Fuel Adjustment Tariff Sheet Modifications

Staff reviewed the current KCPL FAC tariff sheets that were approved by the Commission in Case No. ER-2014-0370 and became effective September 29, 2015. The current FAC tariff sheets reflect KCPL’s participation in the SPP Integrated Market and account for transmission costs in a manner consistent with the methodology used in handling transmission costs in Ameren Missouri’s, Empire’s, and KCP&L GMO’s current FACs.

In summary, Staff proposes the following modifications to the tariff:

1. Replace the current Base Factor with the revised Base Factor of $0.01349 per kWh, that is based upon Staff’s revenue requirement for this case.

2. Replace the current pass-through percentage of SPP transmission costs with the revised pass-through percentage of SPP transmission costs of 17.83%, as Staff calculated for this case.

[28] Net Base Energy Cost is defined in KCPL’s Original Sheet No. 50.7 as Net base energy costs ordered by the Commission in the last general rate case consistent with the costs and revenues included in the calculation of the FPA”.

[29] Purchased power for native load that is served by power that KCPL did not generate.

[30] Monthly reports are required by 4 CSR 240-3.161(5).

3. Replace the current voltage adjustment factors ("VAF's") with three updated VAF's of: $VAF_{TRANS} = 1.0195$ $VAF_{PRIM} = 1.0451$ and $VAF_{SEC} = 1.0707$.

These VAFs are derived from KCPL's most recent loss study and compensate for the line losses experienced at different customer service voltages.

Staff Expert/Witness: David C. Roos

B. Revised Base Factor

Staff calculated the Base Factor rate based upon the following information in Staff's *COS Report* in this case: (1) net base energy costs (fuel and purchased power costs less off-system sales revenue) including Staff's accounting adjustments to test year; and (2) normalized net system inputs:

Base Factor: $0.01349 per kWh[31]

Staff will update the Base Factor when Staff's net base energy costs are updated for the true-up period for this rate case.

Staff Expert/Witness: Ashley Sarver

C. Revised Transmission Percentage

As provided in Staff witness Charles T. Poston's workpapers, Staff calculated the pass-through percentage of SPP transmission costs in the FAC as 17.83%. This percentage represents the percent of native load that is served by power that KCPL did not generate ("true purchased power"). This calculation is based on the output from Staff's fuel model that was used to develop the revenue requirement found in Staff's *COS Report* for this case. The calculation is appropriate because it is consistent with the method used to calculate the pass-through percentage of SPP transmission costs for KCPL's and GMO's current FAC.

Staff Expert/Witness: David C. Roos

[31] Staff's calculation of the Base Factor is included in Appendix 2, Highly Confidential Schedule CCOS-3.

D. Revised FAC Voltage Adjustment Factors

As provided in Staff's *COS Report*, filed in this case, Staff witness Alan J. Bax used the information in KCPL's line loss study in developing the following transmission, primary, and secondary voltage level adjustment factors:[32]

Voltage Level	Voltage Adjustment Factor
Transmission	1.0195
Primary	1.0451
Secondary	1.0707

These voltage adjustment factors adjust for the energy losses experienced in the delivery of electricity from the generator to customers being served at the transmission, primary, and secondary voltage levels. These factors will be utilized in Staff's determination of a Fuel Adjustment Rate ("FAR"), for each voltage service classification.

Staff Expert/Witness: David C. Roos

Appendices

Appendix 1: Staff Credentials

Appendix 2: Other Staff Schedules

[32] Staff *COS Report* page 89.

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-2016-0285

AFFIDAVIT OF JAMES A. BUSCH

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW JAMES A. BUSCH and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Rate Design - Class Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

JAMES A. BUSCH

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 14th day of December, 2016.

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

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-2016-0285

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 Staff Report - Rate Design - Class Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah L. Kliet

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 14th day of December, 2016.

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

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-2016-0285

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW DAVID C. ROOS and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing Staff Report - Rate Design - Class Cost of Service; and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

David C. Roos

DAVID C. ROOS

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 14th day of December, 2016.

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

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-2016-0285

AFFIDAVIT OF ASHLEY SARVER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ASHLEY SARVER and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing Staff Report - Rate Design - Class Cost of Service; and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Ashley Sarver
ASHLEY SARVER

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 14th day of December, 2016.

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