MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

CLASS COST OF SERVICE

KANSAS CITY POWER & LIGHT COMPANY
CASE NO. ER-2018-0145

KCP&L GREATER MISSOURI OPERATIONS COMPANY
CASE NO. ER-2018-0146

Jefferson City, Missouri
July 6, 2018

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I. Executive Summary

In Staff's *Cost of Service Report* ("COS Report") filed June 19, 2018, Staff recommended a revenue requirement for Kansas City Power & Light Company ("KCPL") at its recommended return on equity of 9.85%, based on KCPL's actual costs through December 31, 2017, net of other revenue of $858,943,665, a decrease of $19,076,752 from its current retail rate revenues of approximately $878,020,417, a decrease of approximately 2.17%. For KCP&L Greater Missouri Operations Company ("GMO") Staff recommended a revenue requirement, at its recommended return on equity of 9.85%, based on GMO's actual costs through December 31, 2017, of $713,905,213, a decrease of $34,812,142 from its current retail rate revenues of approximately $748,717,355, a decrease of approximately 4.6%.

Staff's class cost-of-service ("CCOS") study is designed to determine what rate of return is produced by each customer class on that class's currently tariffed rates, for recovery of any calculated revenue requirement amount. 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. 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 cost of-service study.[1]

As part of GMO's last rate case, Case No. ER-2016-0156, GMO comprehensively modified its rate structures and designs applicable to all customer classes, which resulted in

[1] Staff studied the following KCPL Service Classifications: Residential ("Res."), Small General Service ("SGS"), Medium General Service ("MGS"), Large General Service ("LGS"), Large Power Service ("LPS"), and Total Lighting ("Ltg."). Although not studied in this direct filing, GMO's Service Classifications are Residential ("Res."), Small General Service ("SGS"), Large General Service ("LGS"), Large Power Service ("LPS"), and Total Lighting ("Ltg.").

rate switching and changes in relevant billing determinants due to the reconfiguration of its customer classes.[2] Class-level hourly load information is necessary to produce class-level coincident and non-coincident peak information, among other things. In its *Report on Rate Design* ("CCOS Report") filed in Case No. ER-2016-0156, Staff stated that GMO's requested rate structure and rate designs for the non-residential rate classifications were not what Staff would have proposed, but that GMO's non-residential rate design was not unreasonable for use until GMO is able to file a rate design case as soon as necessary data is available. Because GMO is unable to provide 12 months of data for the customer classes as established under its reconfigured classes and rate structures, Staff has determined that the information needed to produce a reasonably reliable class cost of service study for GMO, for purposes of recommending interclass revenue requirement shifts, is not available in this case.[3]

A. <u>Interclass Cost Responsibility Recommendations</u>

In the absence of the information necessary to conduct a reliable class cost of service study, Staff does not recommend any deliberate interclass revenue-neutral shifts to revenue responsibility for GMO.

For KCPL, Staff found that all classes are contributing revenues at or near their cost of service, and contributing to the company's overall return. While the Large General Service, Large Power Service, and Lighting Classes contribute to overall returns at a level below system average, the variance is within the expected precision of a CCOS study.

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[2] Billing determinants are the quantity of each charge type to be billed to collect an allowed revenue requirement. Every charge type that appears in a company's rate structure must have an associated billing determinant. Energy-related billing determinants are developed from the normalized and annualized usages and revenues Staff developed as part of its Cost of Service filing. Additional billing determinants are developed from actual billing demands during the test period, and from annualized customer counts.

The normalized and annualized usages and revenues developed by Staff serve three purposes in each rate case. The first purpose is to determine the normalized and annualized level of revenue that is generated by existing tariffs. The second purpose is for the development of Net System Input for the calculation of variable fuel and purchased power expenses. Finally, normalized and annualized usage is also used with the ordered revenue requirement resulting from a case to determine the appropriate value for each energy-related rate element to be included in the compliance tariff sheets. This latter usage is commonly referred to as billing determinants.

[3] Staff has performed a preliminary GMO CCOS Study for purposes of developing a residential customer charge recommendation. While not reasonably reliable for purposes of determining the reasonableness of revenue recovery related to class-allocated cost causation among the classes, this study is not unreliable for purposes of estimating the costs to be recovered through the residential customer charge. The cost elements allocated for calculating the costs related to the residential customer charge are generally not reliant on class-level hourly load data and non-residential rate configurations.

If an overall revenue decrease of approximately $19 million is ordered for KCPL, Staff recommends a revenue neutral shift in revenue responsibility from the Small General Service ("SGS") class in the amount of $7.5 million, and a shift from the Medium General Service ("MGS") class in the amount of $2 million, to be spread equally among the remaining classes.

If a decrease of less than $18 million but more than $10 million is ordered for KCPL, Staff recommends a revenue neutral shift in revenue responsibility from the SGS class of $6 million and from the MGS class of $1 million, to be spread equally among the remaining classes.

If a decrease of less than $10 million is ordered for KCPL, Staff recommends that the first $5 million of the decrease be applied to the SGS class, and any remaining decrease be applied as an equal percentage to the remaining classes.

If there is no change in revenue requirement or an increase in revenue requirement is ordered, Staff recommends that no revenue neutral shifts be made.

B. Rate Design Recommendation Summary

Staff recommends these cases be used as an opportunity to begin the process of implementing mandatory company-wide Time of Use ("ToU") rates. Because complete cost information is unavailable for GMO, and in the interest of using these introductory ToU rates to educate customers about ToU with minimal customer impact, Staff's recommended ToU design for both utilities is focused on minimizing customer impact.

Staff recommends implementation of mandatory ToU rates for the residential classes for both utilities for all customers with AMI meters. For KCPL, its residential general use, separately metered space heating, and all electric rate schedules would be consolidated into a single KCPL residential rate schedule. For GMO, its residential general use and separately metered space heating schedules would be consolidated into a single GMO residential rate schedule.[4] The estimated resulting rates, per kWh, are provided below:

	KCPL	GMO
Summer 8:00 AM to 9:59 PM	$ 0.141	$ 0.129
Summer 10:00 PM to 7:59 AM	$ 0.111	$ 0.092
Non-Summer 8:00 AM to 9:59 PM	$ 0.124	$ 0.105
Non-Summer 10:00 PM to 7:59 AM	$ 0.071	$ 0.064

[4] For both utilities, a simplified non-ToU rate schedule would be maintained for the few customers without AMI metering.

For KCPL's LPS class the declining blocked demand charges should be flattened on a revenue-neutral basis within the class, regardless of whether any increase or decrease in revenue requirement be ordered. Any decrease ordered should be applied as an equal percent reduction to the facilities charge, and the first and second blocks of the energy charge. For all other non-residential non-lighting classes for both utilities, Staff recommends that any class-level decrease be applied to the first and second block hour's use energy charges. If a class-level increase is ordered for any non-residential class for either KCPL or GMO, Staff recommends that such increase be applied as an additional charge to kWh sold between the hours of 8:00 am and 6:00 pm, on non-holiday weekdays. This will result, on average, in a relative shift of revenue recovery from customer NCP-emphasized energy charges in a manner consistent with cost-causation.

C. Other Tariff Recommendations

(1) Staff recommends revisions to KCPL's and GMO's Economic Development Rider tariff intended to clarify the requirements of the program to aid in the consistency of application of the discounts among customers.

(2) Staff recommends that KCPL and GMO offer, for each jurisdiction, a community solar program to provide increased renewable choices to customers.[5]

(3) Staff recommends that KCPL and GMO each offer independent green tariff programs to provide increased renewable choices to customers.

(4) Staff recommends incorporating a "make ready" EV charging modification to the line extension tariff provision consistent with prior commission orders.

(5) Staff recommends establishment of a ToU rate schedule to be applicable to separately-metered EV charging equipment. This rate would be mandatory for customers taking advantage of the "make ready" model, but opt-in for customers not receiving discounted line extensions.

(6) Staff recommends the modifications to the FAC tariff described in Section V.

(7) As proposed in Staff's Report on Distributed Energy Resources filed in EW-2017-0245, dated April 5, 2018, Staff recommends KCPL and GMO

[5] KCPL and GMO proposed a co-offered program, Staff's recommendation is that each utility offer a separate program.

maintain information related to distributed energy resources. To accomplish this, Staff recommends language to be added to the Net Metering Interconnection Agreement, Parallel Generation Contract Service (Cogeneration Purchase Schedule), and Standby Service Rider.

Staff Expert/Witnesses: Sarah L.K. Lange, Robin Kliethermes

II. Bundled Class Cost of Service Results and Interclass Revenue Responsibility

For KCPL, Staff performed the following class cost of service studies:

1. Detailed Base Intermediate and Peak ("DBIP") allocation of production costs as was relied upon by the Commission in recent cases,
2. An Average and Excess ("A&E") 4 NCP allocation of production costs for a comparison study, and
3. An A&E 4 NCP allocation of only dispatchable production costs for a comparison study.

A. Current Class Revenues and Cost to Serve (KCPL Only)

Staff bases its interclass and intraclass recommendations on Staff's DBIP production cost allocation study. These study results indicated that while the classes do not provide equal rates of return, no class is providing a negative return, and thus no economic subsidies exist in this case. 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.[6] The current revenue provided by each class, prior to any rate increase/decrease is the starting point for this analysis. 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.

[6] 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.

Table 1

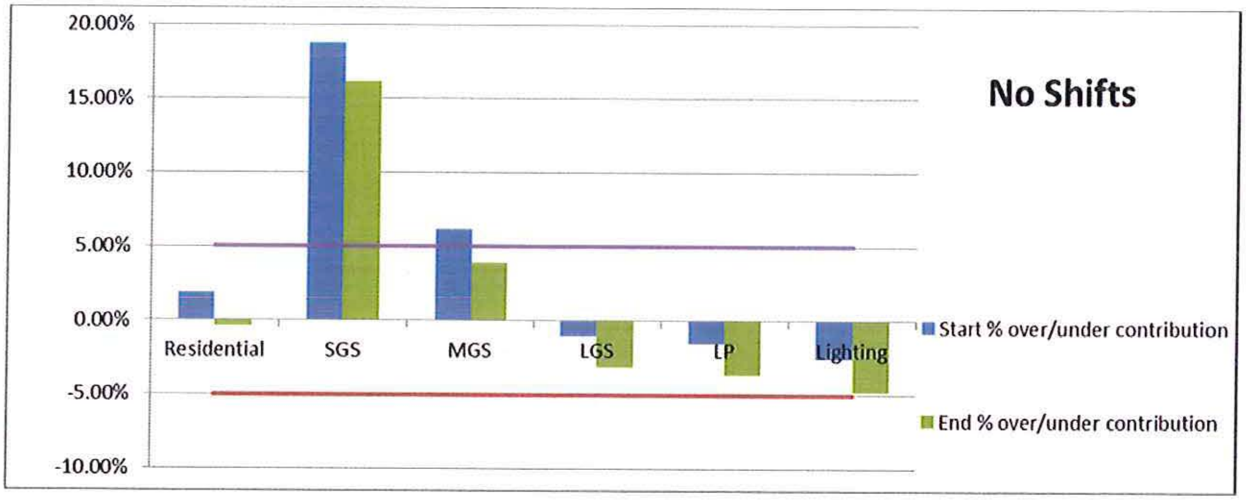
	Current Revenue *plus Allocated Other Revenue*	Revenue Change to Equalize Class Rates of Return	Start % over/under contribution	% Change to Class Revenue to Exactly Match Cost of Service	Start RoR
Residential	$ 360,765,542	-$6,068,463	1.85%	-1.82%	7.97%
Small General Service	$ 65,593,965	-$9,685,875	18.78%	-15.81%	13.97%
Medium General Service	$ 147,267,476	-$7,898,138	6.21%	-5.85%	9.42%
Large General Service	$ 213,093,973	$2,059,213	-1.06%	1.07%	7.01%
Large Power	$ 161,127,637	$2,240,456	-1.53%	1.56%	6.81%
Lighting	$ 11,449,825	$276,060	-2.54%	2.61%	6.37%

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 perfectly 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 ("ROR"). Therefore, to perfectly 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 it is properly known as a "subsidy." As indicated above, no class is being subsidized.

Typically, in the interest of mitigating customer impacts, and in recognition of the relative precision of a CCOS Study, Staff recommends adjustment to interclass revenue responsibility only when one or more classes over-contribute by more than 5% while one or more classes under-contribute by more than 5%. Because at the time of this filing, Staff has determined that KCPL's retail rates should be reduced by approximately 2.2%, there is significant flexibility in interclass revenues shifts from a customer impact mitigation perspective. For purposes of this section, Staff will provide discussion of the shifts it recommends only if KCPL's revenues are ordered to be reduced by $18-19 million or more. Staff does not recommend this magnitude of interclass revenue shifts if a smaller decrease, an increase, or no change in revenue requirement is ordered.

As Graph 2, Graph 3, and Table 4 indicate, Staff's recommended interclass shifts at a full $19 million reduction to rates will minimize certain classes' exceedance of a +/-5% threshold.

Graph 2



Graph 3

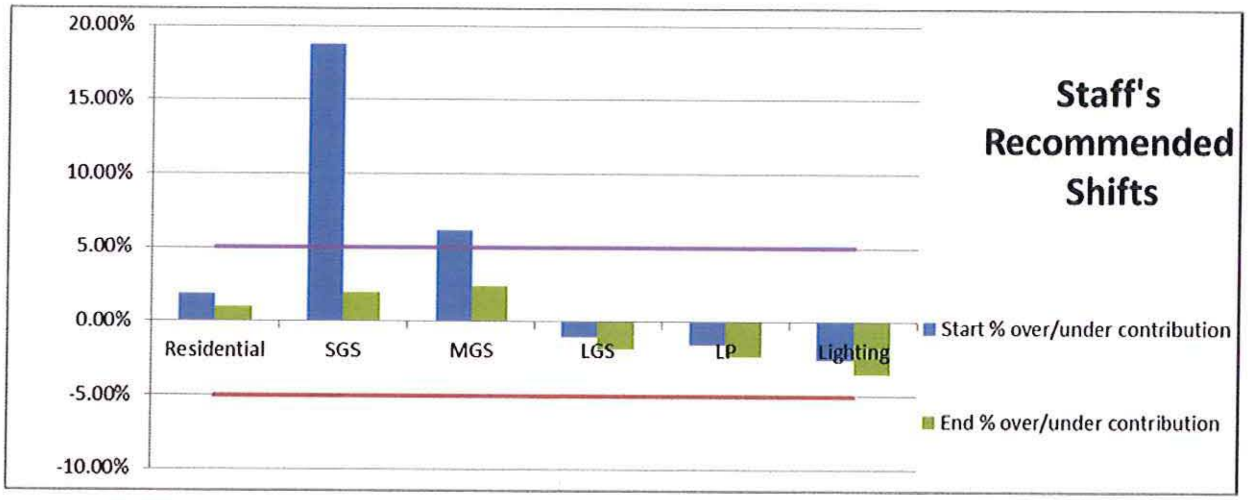


Table 4

	Start % over/under contribution	Current RoR	Revenue Shift	Retail Increase	% Increase to Retail Revenues	End RoR	End % over/under contribution
Residential	1.85%	7.97%	$ 4,655,818	$ (7,359,933)	-0.81%	7.70%	1.03%
Small General Service	18.78%	13.97%	$ (7,500,000)	$ (1,168,215)	-14.15%	8.05%	1.97%
Medium General Service	6.21%	9.42%	$ (2,000,000)	$ (2,890,905)	-3.62%	8.14%	2.36%
Large General Service	-1.06%	7.01%	$ 2,689,191	$ (4,251,082)	-0.81%	6.74%	-1.86%
Large Power	-1.53%	6.81%	$ 2,007,652	$ (3,173,703)	-0.81%	6.52%	-2.33%
Lighting	-2.54%	6.37%	$ 147,339	$ (232,914)	-0.81%	6.06%	-3.33%
Total / System Average:		8.11%	$ 0	$ (19,076,752)	-2.17%	7.36%	0.00%

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. 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.

B. Production Cost Allocation Detailed BIP Procedure

Staff's DBIP 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 DBIP 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 DBIP 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 DBIP study.

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 Southwest Power Pool ("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 DBIP 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 DBIP method also recognizes the fact that Base plants tend to be more expensive to install and own, but have a lower average cost of energy, while Peak plants tend to be less expensive to install and own, but have a high average cost of energy, and that Intermediate plants tend to be somewhere between the two.

The DBIP 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. Staff recommends using these DBIP allocation factors to reasonably allocate the return on production related plant investment and production related expenses to the retail classes because they reasonably allocate the investment and expenses of KCPL's generation fleet among the retail classes.

<u>KCPL's generation fleet characteristics</u>

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.[7] 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

[7] 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 purchased power agreements. Staff did allocate these expenses and costs to the classes using the DBIP allocators; however, Staff did not assign these expenses and costs in its allocator development.

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 $1,124,491/MW. However, Staff found that the average fuel cost for these plants was only $19.92/MWh. Taken together, KCPL's Base generation ran at a 66% 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.[8] Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Intermediate generation is approximately $355,087/MW, and the average fuel cost for these plants was $22.25/MWh. Taken together, KCPL's Intermediate generation ran at a 13% capacity factor in Staff's fuel model.

KCPL's "Peaking" generating plants include the simple cycle gas combustion turbines at West Gardner, Osawatomie, and Hawthorn 7 & 8.[9] Staff determined that the average capacity cost, net of depreciation reserve, for KCPL's Peaking generation is only approximately $223,559/MW. Based on information provided by KCPL, the average fuel price for these units is approximately $37.05/MWh. For Peaking generation that dispatched in Staff's fuel run, the experienced capacity factor was only 0.42%.

<u>Finding Class Demands</u>

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, known as the class 12 CP demand. That additional MW value over the base demand MW value

[8] 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.

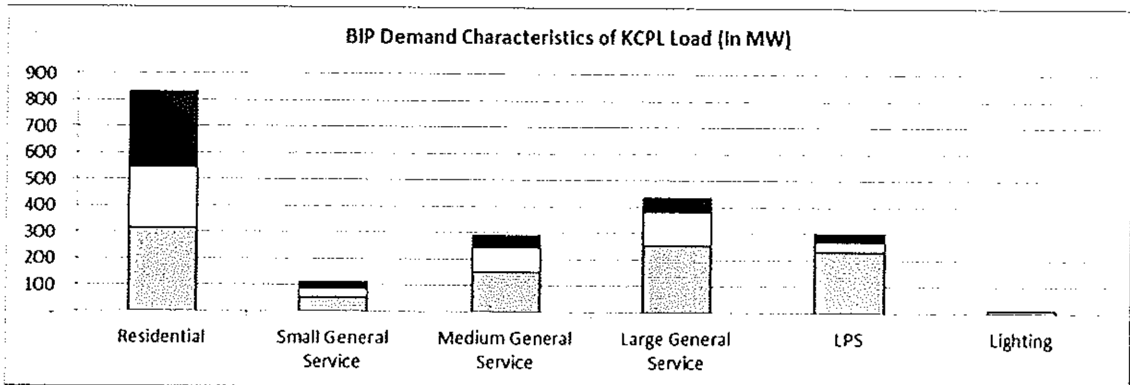
[9] Gas combustion turbines are quick ramping, and because they can be cold-dispatched quickly, they are ideal for meeting spiky changes in the level of load – for example – when air conditioners fire on as a heat wave moves into an area. Gas combustion turbines are capable of high capacity factors, 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.

is each class's intermediate demand. The difference between each class's base demand and its intermediate demand is its incremental intermediate demand.[10]

3. Staff found each class's demand in MW at the time of the two highest system peaks. Staff then averaged each class's demands at those two 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:

	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Demand	317	54	152	255	233	10
Intermediate Demand	544	87	243	382	267	2
Peak Demand	833	111	290	435	302	0



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.

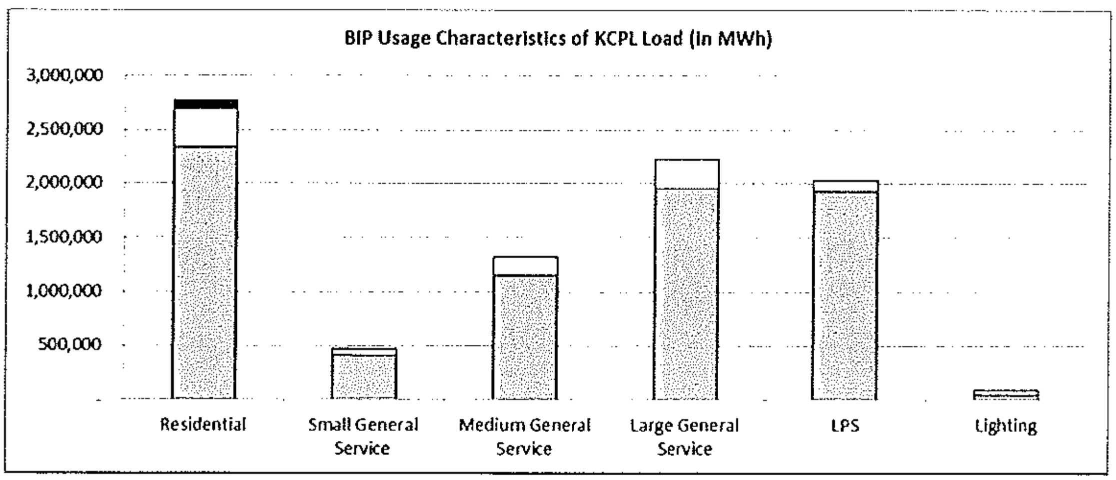
[10] Class coincident peak is the amount of energy a class was determined to have used per hourly data in the hour that the system experienced its peak level of demand for the reference period per hourly data. Class NCP is the highest level of energy estimated to have been used by a studied class in a given hour of the reference period.

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	2,336,012	409,617	1,154,411	1,957,669	1,929,143	42,822
Intermediate Energy	360,948	56,492	167,489	270,292	93,437	45,809
Peak Energy	78,027	4,199	10,333	8,769	15,168	-



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.[11]

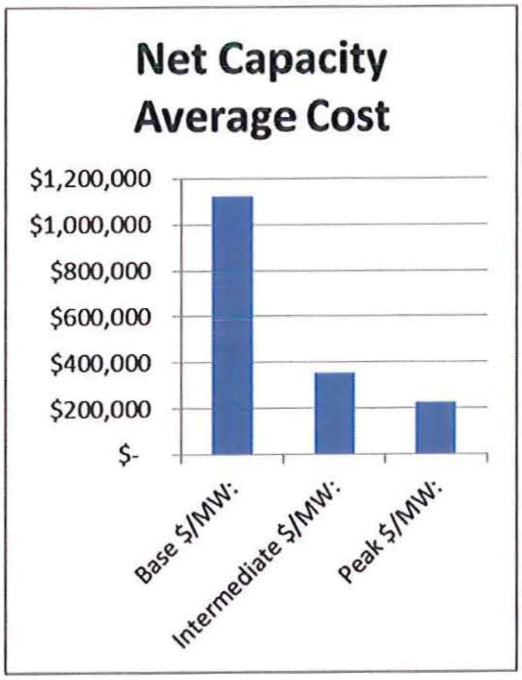
Staff relied on the energy characteristics of each customer class to appropriately assign: (1) the relatively inexpensive fuel costs of base generation on each class's base energy usage, (2) the relatively moderate fuel costs of intermediate generation on each class's intermediate energy usage, and (3) 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.

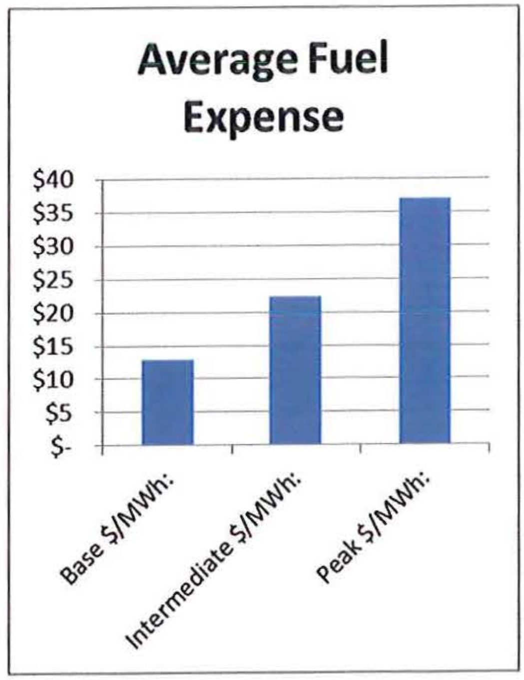
Staff also used the assignments of generating plant to BIP components to develop allocators for KCPL's production-related operating and maintenance expense, and fuel stored on site. This method expressly assigns the expenses of each plant to follow that plant. Each of the generating plants causes production 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 Operations and Maintenance ("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.

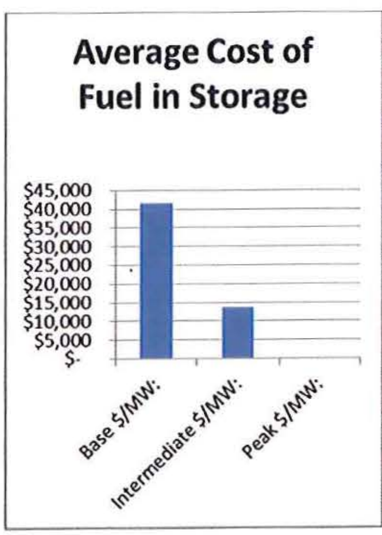
Staff's DBIP study reasonably balances the offsetting impacts of the relative costs of energy, capacity, O&M, and fuel-in-storage associated with meeting the demand and usage characteristics of KCPL's load. Thus, Staff's DBIP method is a reasonable method for allocating the production-related costs and 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.

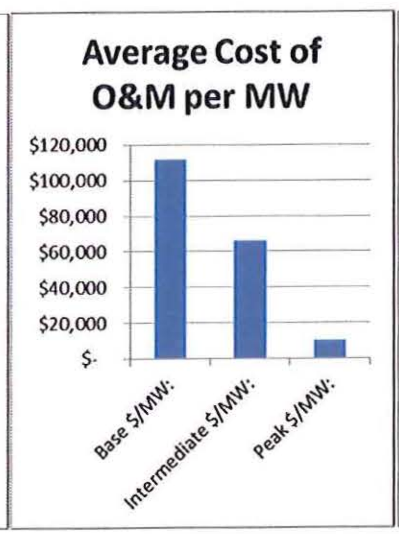
[11] A separate capacity-related allocator is used to allocate the return on investment associated with fuel stored at the various generation stations.

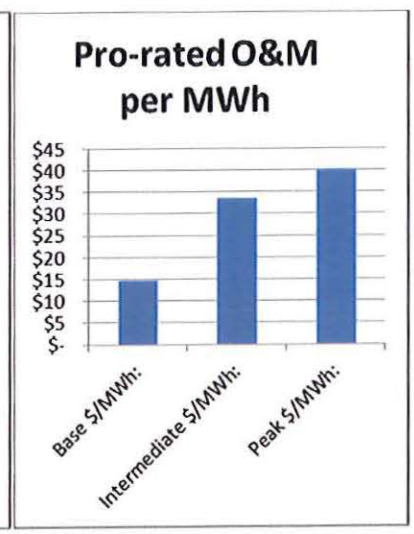
The allocators that result from applying these values to KCPL's BIP load characteristics are provided in the graphs and tables below.



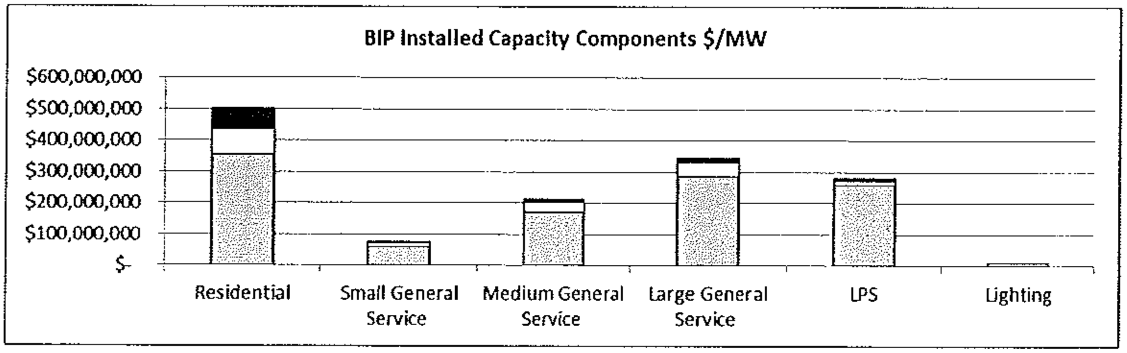




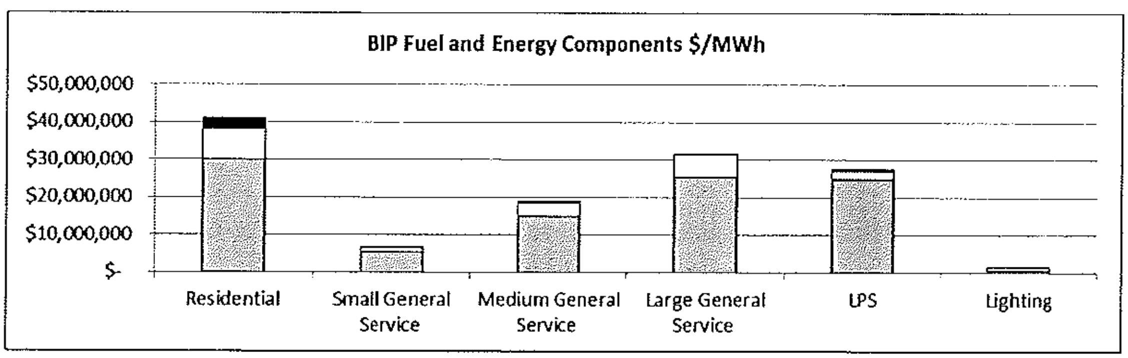




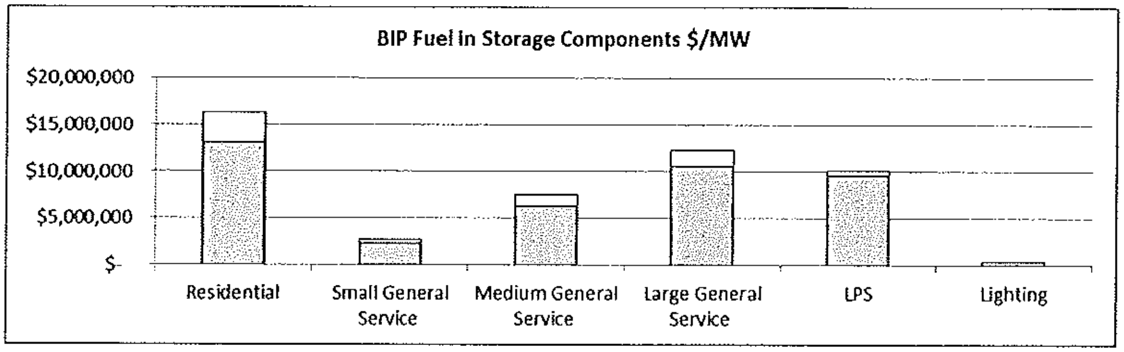
BIP Installed Capacity Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Capacity	$ 1,147,678,422	$ 356,215,370	$ 60,371,825	$ 171,014,118	$ 287,121,262	$ 261,578,662	$ 11,377,185
Incremental Intermediate Capacity	$ 181,991,563	$ 80,629,728	$ 12,001,175	$ 32,238,918	$ 44,856,190	$ 12,265,551	$ -
Incremental Peak Capacity	$ 100,197,218	$ 64,671,378	$ 5,272,027	$ 10,497,854	$ 12,026,016	$ 7,729,943	$ -
Totals:	$ 1,429,867,203	$501,516,477	$77,645,027	$213,750,889	$344,003,468	$281,574,156	$11,377,185
BIP Installed Capacity Allocator:		35.07%	5.43%	14.95%	24.06%	19.69%	0.80%



BIP Fuel and Energy Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Energy Usage	$ 101,175,107	$ 30,185,971	$ 5,293,077	$ 14,917,306	$ 25,297,013	$ 24,928,396	$ 553,343
Incremental Intermediate Usage	$ 22,127,706	$ 8,031,381	$ 1,256,999	$ 3,726,766	$ 6,014,221	$ 2,079,059	$ 1,019,281
Incremental Peak Usage	$ 4,316,012	$ 2,890,773	$ 155,556	$ 382,833	$ 324,886	$ 561,964	$ -
Totals:	$ 127,618,826	$41,108,124	$6,705,632	$19,026,905	$31,636,120	$27,569,419	$1,572,624
BIP Fuel and Energy Allocator:		32.21%	5.25%	14.91%	24.79%	21.60%	1.23%



BIP Fuel in Storage Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Capacity	$ 42,359,439	$ 13,147,484	$ 2,228,252	$ 6,311,927	$ 10,597,303	$ 9,654,556	$ 419,918
Incremental Intermediate Capacity	$ 7,081,468	$ 3,137,381	$ 466,977	$ 1,254,448	$ 1,745,398	$ 477,264	$ -
Incremental Peak Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Totals:	$ 49,440,907	$16,284,864	$2,695,229	$7,566,374	$12,342,700	$10,131,820	$419,918
BIP Fuel in Storage Allocator:		32.94%	5.45%	15.30%	24.96%	20.49%	0.85%



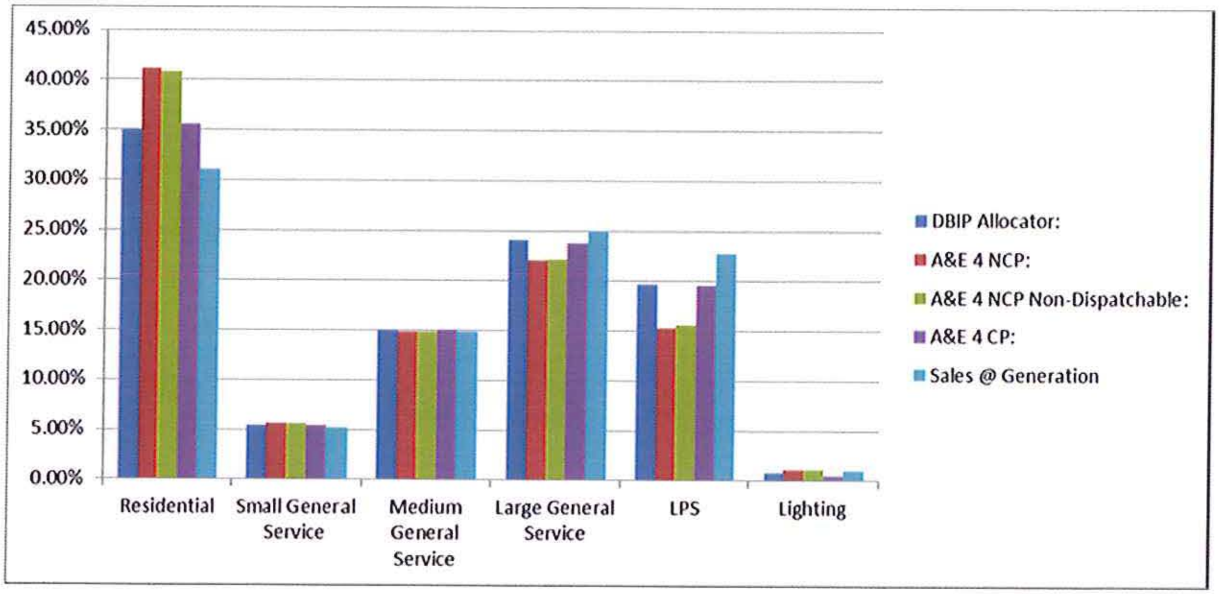
BIP O&M Allocator							
	Total	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
Base Usage	$ 114,050,378	$ 34,027,356	$ 5,966,660	$ 16,815,642	$ 28,516,243	$ 28,100,717	$ 623,760
Incremental Intermediate Usage	$ 33,338,979	$ 12,100,578	$ 1,893,872	$ 5,614,978	$ 9,061,400	$ 3,132,439	$ 1,535,712
Incremental Peak Usage	$ 4,689,275	$ 3,140,776	$ 169,009	$ 415,942	$ 352,983	$ 610,565	$ -
Totals:	$ 152,078,632	$49,268,709	$8,029,541	$22,846,562	$37,930,626	$31,843,721	$2,159,473
BIP O&M Allocator:		32.40%	5.28%	15.02%	24.94%	20.94%	1.42%

Staff Expert/Witness: Sarah L.K. Lange

C. Comparison Studies and Results

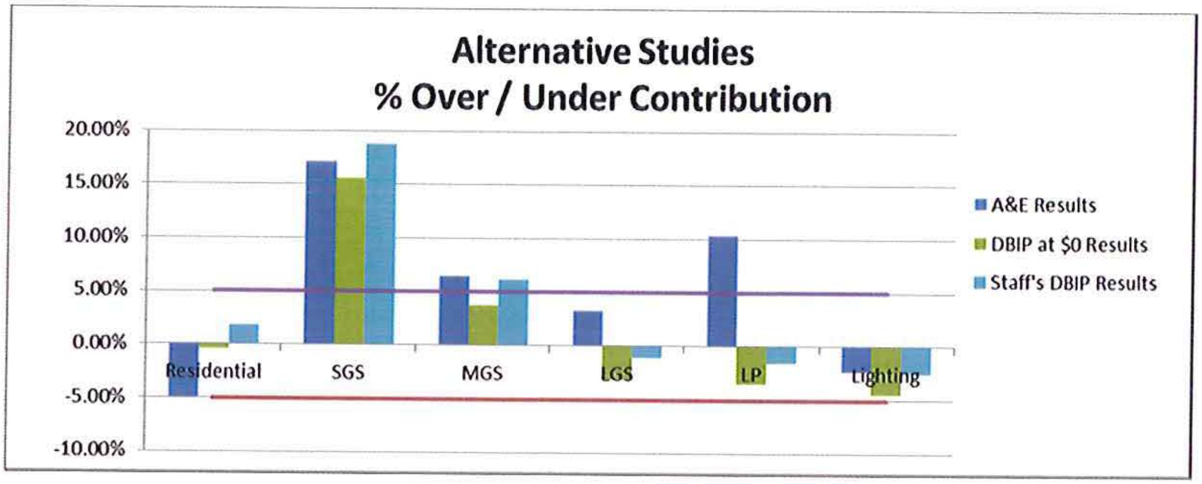
To review the reasonableness of its DBIP calculation, Staff reviewed alternative production capacity allocators: (1) an A&E 4 NCP, which is typically advocated by industrial intervenors, (2) an A&E 4 NCP, modified to reflect allocation of the capacity associated with resources with capacity costs but little-to-no energy costs owned by KCPL on an energy-only basis ("A&E 4 NCP Non-Dispatchable"), and (3) an A&E 4 CP study as submitted by KCPL. In the table and chart below, these allocators are provided with Staff's DBIP, and with the level of sales at the generation voltage level to each class:

	Residential	Small General Service	Medium General Service	Large General Service	LPS	Lighting
DBIP Allocator:	35.07%	5.43%	14.95%	24.06%	19.69%	0.80%
A&E 4 NCP:	41.15%	5.58%	14.88%	22.01%	15.29%	1.09%
A&E 4 NCP Non-Dispatchable:	40.77%	5.57%	14.88%	22.12%	15.57%	1.09%
A&E 4 CP:	35.60%	5.47%	15.06%	23.81%	19.55%	0.51%
Sales @ Generation	31.04%	5.26%	14.90%	25.02%	22.79%	0.99%



	Residential	SGS	MGS	LGS	LPS	Lighting
A&E Results	-4.96%	17.12%	6.52%	3.25%	10.30%	-2.35%
DBIP at Current Revenue Requirement Results	-0.36%	15.57%	3.76%	-3.11%	-3.53%	-4.47%
Staff's DBIP Results	1.85%	18.78%	6.21%	-1.06%	-1.53%	-2.54%

Staff performed comparison CCOS Studies using (1) the A&E 4 NCP allocator using Staff's direct-filed Cost of Service results, and (2) the DBIP allocator using a revenue requirement equal to current revenues, such that no change to total system cost of service would be indicated within the CCOS results. The results of these studies, with the DBIP results for reference, are provided in the table and graph below:



Staff Expert/Witnesses: Robin Kliethermes, Sarah L.K. Lange

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 and labor to operate and maintain these facilities. KCPL's transmission investment and transmission costs comprise approximately 6% 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"). 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.

E. Allocation of Distribution Costs

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 a 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 non-coincident peak (as measured at substation voltage) to allocate substation costs.

Staff allocated the costs of the primary distribution facilities on the basis of each customer class' annual non-coincident peak demand measured at primary voltage. 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 distribution secondary investment and line transformers on the basis of each class's annual-peak demand measured at secondary voltage. 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. Coincident-peak demand is the demand of each customer class and each customer at the hour when the overall system peak occurs. Class-peak demand is the maximum hourly demand of all customers within a specific class. Although not all customers 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. Therefore, class-peak demand will have less diversity than the class's load at the time of system peak.

Staff recommends allocating the costs of distribution secondary investment and line transformers on the basis of each class's non-coincident peak demand measured at secondary voltage. Only secondary customers served at the secondary voltage level were included in the calculation of the allocation factor, so that distribution secondary costs were allocated only to those customers that use these facilities.

Staff recommends allocating distribution costs for service lines to each class based on KCPL's study of service line investment per class. Staff has reviewed KCPL's study for meter investment per class and Staff recommends allocated distribution costs for meters based on KCPL's investment per class provided in KCPL's workpapers in Case No. ER-2016-0285.

F. Customer Service Cost Allocation

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 has reviewed KCPL's study of meter reading costs, uncollectible accounts, and customer deposits per class that directly assigns the costs of meter reading, uncollectible accounts, and customer deposits to each of the customer classes. Staff recommends allocating these costs on KCPL's directly assigned costs per class. Staff recommends allocating other customer-service related accounts on the number of customers per class.

Staff Expert/Witness: Robin Kliethermes

G. Interclass Cost Responsibility Recommendations

In the absence of the information necessary to conduct a reliable class cost of service study, Staff does not recommend any deliberate interclass revenue-neutral shifts to revenue responsibility for GMO.

For KCPL, Staff found that all classes are contributing revenues at or near their cost of service, and contributing to the company's overall return. While the Large General Service, Large Power Service, and Lighting Classes contribute to overall returns at a level below system average, the variance is within the expected precision of a CCOS study.

If an overall revenue decrease of approximately $19 million is ordered for KCPL, Staff recommends a revenue neutral shift in revenue responsibility from the Small General Service class in the amount of $7.5 million, and a shift from the Medium General Service class in the amount of $2 million, to be spread equally among the remaining classes.

If a decrease of less than $18 million but more than $10 million is ordered for KCPL, Staff recommends a revenue neutral shift in revenue responsibility from the SGS class of $6 million and from the MGS class of $1 million, to be spread equally among the remaining classes.

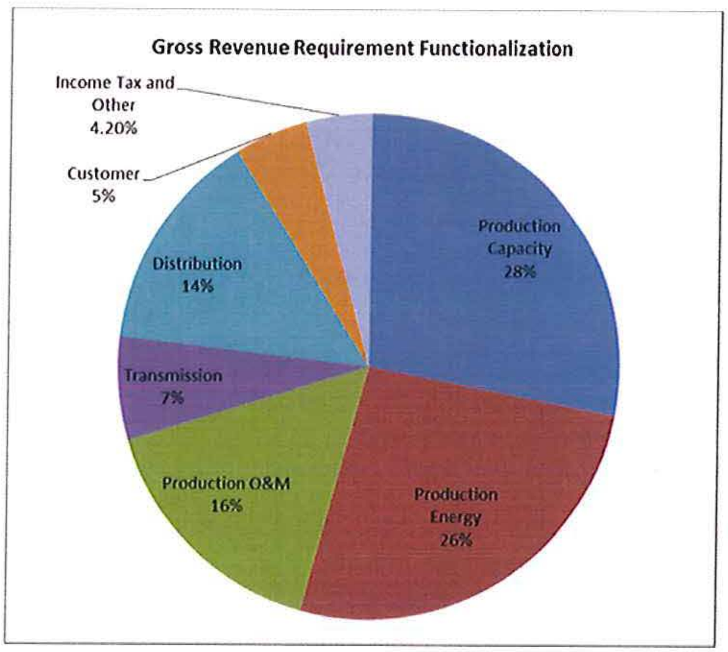
If a decrease of less than $10 million is ordered for KCPL, Staff recommends that the first $5 million of the decrease be applied to the SGS class, and any remaining decrease be applied as an equal percentage to the remaining classes.

If there is no change in revenue requirement or an increase in revenue requirement is ordered, Staff recommends that no revenue neutral shifts be made.

Staff Expert/Witnesses: Sarah L.K. Lange, Robin Kliethermes

H. <u>Functionalized CCOS Study Results (KCPL Only)</u>

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 6 and 7 and the accompanying graphs 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 6

	Residential	SGS	MGS	LGS	LPS	Lighting	Total
Production Capacity	$ 92,218,630	$ 14,295,483	$ 39,369,678	$ 63,377,507	$ 51,878,869	$ 2,097,298	$ 263,237,465
Production Energy	$ 78,596,912	$ 12,885,148	$ 36,552,810	$ 60,855,268	$ 53,355,052	$ 2,942,943	$ 245,188,133
Production O&M	$ 48,649,134	$ 7,928,566	$ 22,559,256	$ 37,453,631	$ 31,443,272	$ 2,132,316	$ 150,166,175
Transmission	$ 22,068,614	$ 3,555,116	$ 9,851,567	$ 15,492,857	$ 10,810,173	$ 93,102	$ 61,871,429
Distribution	$ 67,037,191	$ 8,473,381	$ 22,495,702	$ 29,919,283	$ 4,499,141	$ 1,499,713	$ 133,924,411
Customer	$ 35,158,619	$ 5,367,091	$ 2,960,039	$ 162,378	$ 68,969	$ 209,030	$ 43,926,126
Income Tax and Other	$ 15,080,233	$ 3,923,654	$ 6,921,545	$ 7,861,359	$ 5,294,095	$ 338,962	$ 39,419,848
Lighting	$ -	$ -	$ -	$ -	$ -	$ 2,488,079	$ 2,488,079

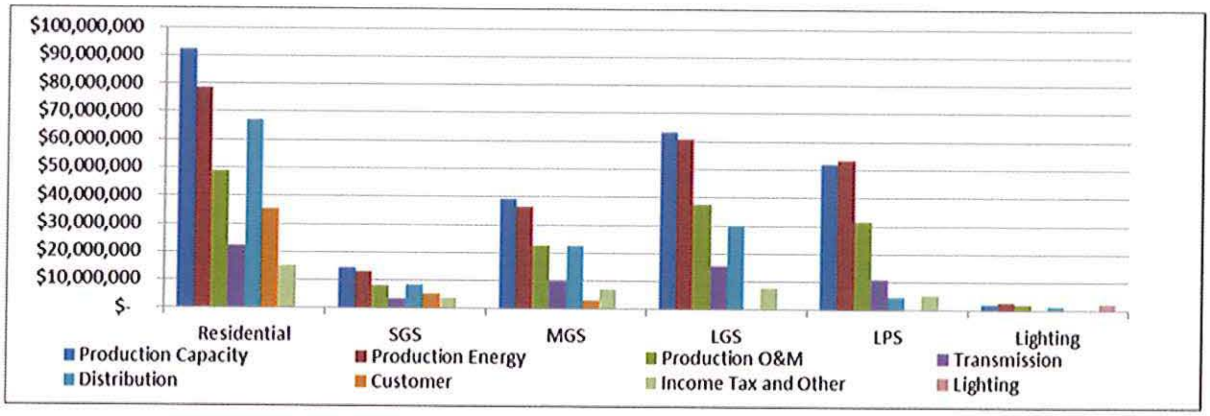


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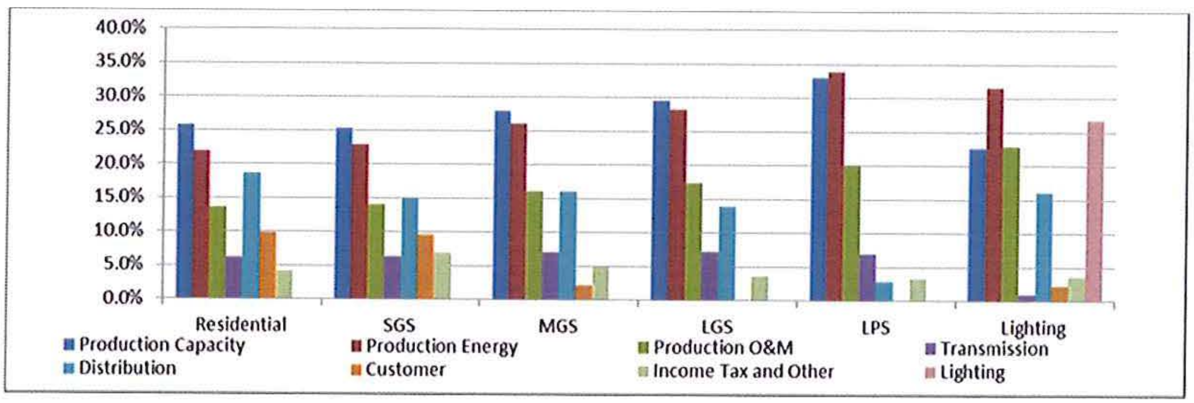
Table 7

	Residential	SGS	MGS	LGS	LPS	Lighting
Production Capacity	25.7%	25.3%	28.0%	29.5%	33.0%	22.5%
Production Energy	21.9%	22.8%	26.0%	28.3%	33.9%	31.6%
Production O&M	13.6%	14.1%	16.0%	17.4%	20.0%	22.9%
Transmission	6.2%	6.3%	7.0%	7.2%	6.9%	1.0%
Distribution	18.7%	15.0%	16.0%	13.9%	2.9%	16.1%
Customer	9.8%	9.5%	2.1%	0.1%	0.0%	2.2%
Income Tax and Other	4.2%	7.0%	4.9%	3.7%	3.4%	3.6%
Lighting	0.0%	0.0%	0.0%	0.0%	0.0%	26.7%



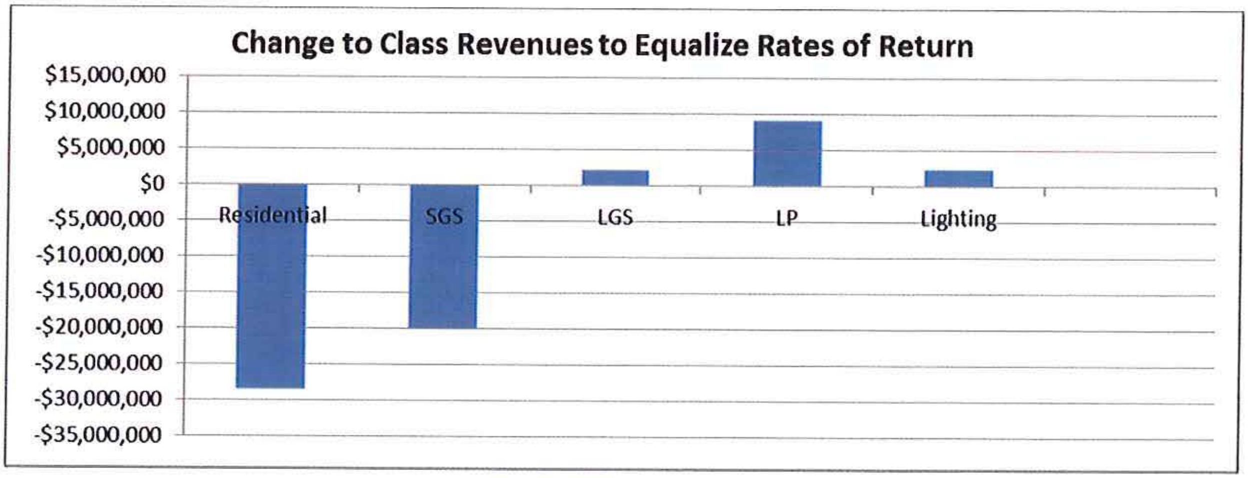
As indicated most clearly in the graph version of Table 7, the portion of a class's revenue requirement related to that class's consumption of energy varies greatly across classes.

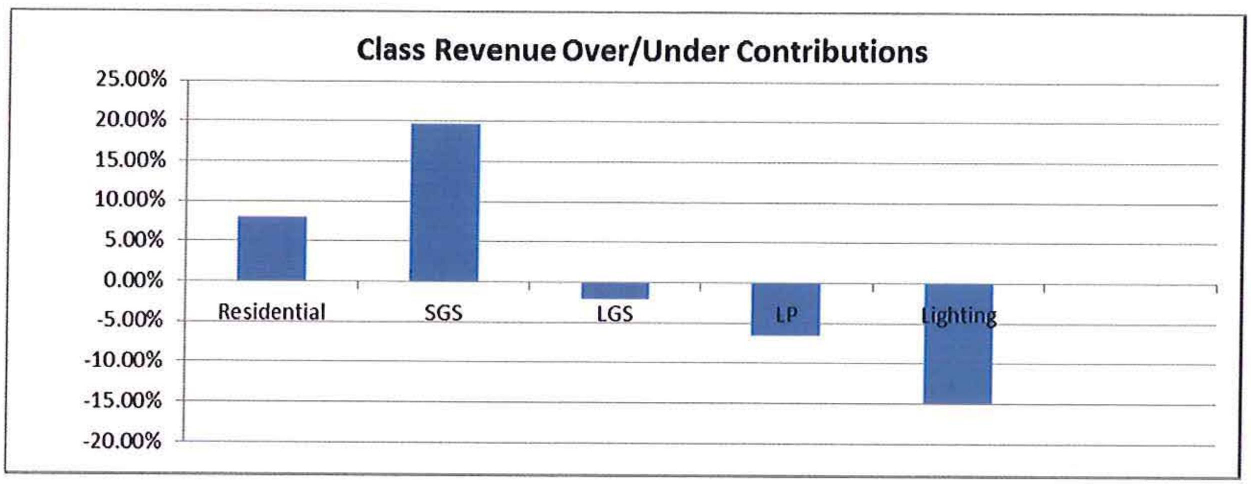
Staff Expert/Witnesses: Sarah L.K. Lange, Robin Kliethermes

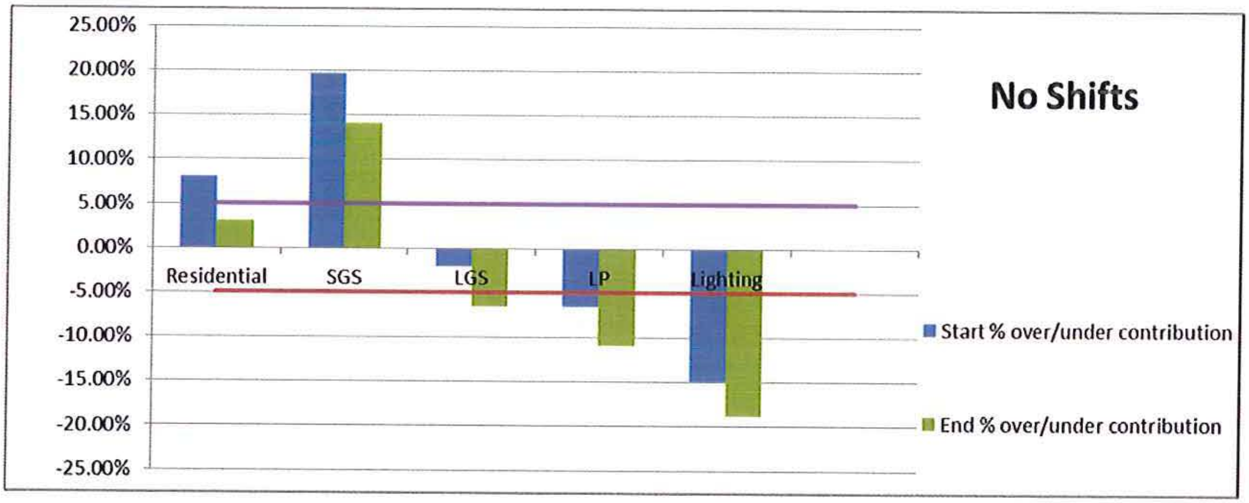
I. <u>Preliminary GMO CCOS Study Results</u>

To facilitate a residential customer charge recommendation, Staff performed a preliminary DBIP CCOS for GMO using Staff's direct-filed revenues and hourly class loads for net system input. While not reliable for purposes of interclass allocations, the results of that study 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
Residential	$ 389,744,708	-$28,471,947	8.07%	-7.47%	10.37%
Small General Service	$ 123,590,111	-$19,887,851	19.71%	-16.47%	15.07%
Large General Service	$ 105,804,048	$2,106,827	-2.01%	2.05%	6.64%
Large Power	$ 135,243,091	$9,088,408	-6.51%	6.96%	4.83%
Lighting	$ 13,672,682	$2,352,418	-14.87%	17.47%	1.64%







Staff Expert/Witnesses: Sarah L.K. Lange, Robin Kliethermes

III. Rate Design

A. Residential Time of Use

Considerations in defining reasonable bounds for a ToU rate design include: (1) the cost of energy across time; (2) the cost of system transmission and distribution capacity, and identification of the times driving those costs; (3) the cost of production or RTO capacity, and identification of the times driving those costs; (4) understandability of rates to all impacted customers; and (5) for purposes of this initial case implementing ToU mandatory rates, mitigation of rate impacts to all impacted customers in recognition of the intent of these rates as customer education. In the interest of understandability, impact mitigation, and in recognition of the unfamiliarity of customers with ToU rates, Staff selected a relatively long on-peak period as the basis for its recommended ToU rates. This enables consistency of the on-peak definition across the year and across classes, and lays the groundwork for future implementation of seasonally-appropriate super-peak rates and super-off-peak discounts.

The ToU rates designed and studied below are based on KCPL's and GMO's residential revenue recovery embedded in current rates, including the current residential customer charges. Any changes to class revenue responsibility and customer charges would necessarily be incorporated in the rates resulting from this case. Decreases to class revenue responsibility and increases to customer charges would tend to decrease the rate impact of a switch to ToU rates.

Staff anticipates working with the utility and other stakeholders to refine the ToU design during the rate case process, and to facilitate customer education on this fundamental change to the residential rate structure prior to tariff effective dates implementing the rates resulting from this case.

B. <u>Energy cost considerations</u>

For KCPL, for the 12 months ending October 31, 2017, the hourly simple average cost of day-ahead wholesale energy, by 30 day period, at the KCPL Hub is provided below. Hours in which the average hourly price is at least 85% of that 30 day's hourly peak price are indicated in red:

KCPL Hourly Energy Prices Relative to Monthly Peak:

Start	10/31/2017	10/31/2017	9/30/2017	8/30/2017	7/30/2017	6/29/2017	5/29/2017	4/28/2017	3/28/2017	2/25/2017	1/25/2017	12/25/2016	11/24/2016
End	10/25/2016	10/1/2017	8/31/2017	7/31/2017	6/30/2017	5/30/2017	4/29/2017	3/29/2017	2/26/2017	1/26/2017	12/26/2016	11/25/2016	10/25/2016
1:00:00 AM	12.12	2.45	11.33	16.19	17.23	13.80	9.84	9.02	6.85	10.05	14.91	18.26	15.55
2:00:00 AM	11.14	0.35	10.22	15.54	16.03	12.38	8.11	8.12	6.07	9.76	14.44	17.74	14.96
3:00:00 AM	10.93	(0.18)	9.76	15.33	15.72	11.69	7.49	7.91	6.98	9.90	14.32	17.51	14.68
4:00:00 AM	10.99	0.50	9.62	15.15	15.56	11.57	7.05	7.80	7.42	9.73	14.84	17.75	14.87
5:00:00 AM	12.04	2.07	10.52	15.47	15.85	11.97	8.17	8.99	9.05	11.19	15.95	19.14	16.09
6:00:00 AM	14.76	7.35	12.87	16.24	16.70	13.29	11.12	12.73	12.16	14.12	19.08	22.85	18.57
7:00:00 AM	19.97	14.98	16.26	17.43	17.33	14.58	15.71	20.18	20.60	21.53	25.93	31.28	23.80
8:00:00 AM	21.28	17.10	17.12	18.53	19.36	17.65	18.78	21.02	19.91	21.52	28.14	31.99	24.26
9:00:00 AM	22.25	17.57	18.46	20.36	22.55	21.01	21.67	22.52	20.68	20.85	25.92	30.75	24.61
10:00:00 AM	23.58	19.37	20.11	22.38	24.80	22.41	23.19	23.33	21.78	22.51	26.66	30.17	26.26
11:00:00 AM	24.09	19.42	21.67	24.58	28.40	24.78	23.58	23.56	20.82	21.59	25.84	28.09	26.72
12:00:00 PM	24.41	18.27	24.13	27.14	32.36	26.72	23.38	24.05	20.16	20.18	24.52	25.58	26.47
1:00:00 PM	24.66	18.15	26.18	29.28	35.45	28.70	24.50	24.24	18.70	18.16	22.61	23.67	26.33
2:00:00 PM	25.21	19.01	28.27	31.64	37.60	31.32	25.21	23.62	18.07	17.40	21.51	22.31	26.52
3:00:00 PM	25.32	18.75	29.04	32.20	40.24	32.83	25.21	23.12	17.42	16.62	20.52	21.54	26.31
4:00:00 PM	26.27	19.17	31.44	35.55	43.66	34.92	25.23	22.56	17.24	16.57	20.41	21.73	26.73
5:00:00 PM	27.42	19.53	32.37	35.04	44.61	36.63	26.39	23.61	17.99	17.99	22.17	25.02	27.73
6:00:00 PM	28.71	20.02	30.49	32.00	40.49	33.54	26.32	23.53	19.21	21.56	31.05	36.20	30.11
7:00:00 PM	27.51	22.10	27.38	30.01	36.63	31.20	24.77	23.42	21.76	24.29	28.09	31.40	29.02
8:00:00 PM	25.59	22.17	25.44	27.66	33.88	27.46	24.13	24.89	21.95	19.70	24.32	29.06	26.47
9:00:00 PM	23.60	16.72	23.03	25.99	29.83	24.43	26.98	28.81	18.27	16.76	22.29	27.18	22.94
10:00:00 PM	19.31	11.38	17.97	23.19	26.07	22.26	21.38	20.81	12.66	13.41	18.91	23.95	19.73
11:00:00 PM	15.78	7.85	14.45	19.51	21.89	17.90	16.04	15.82	9.42	11.59	17.02	20.66	17.24
12:00:00 AM	12.70	3.91	11.76	16.85	18.44	14.41	11.62	11.08	6.81	9.55	14.51	17.87	15.64

The same information at the GMO load node is provided below:

continued on next page

GMO Hourly Energy Prices Relative to Monthly Peak:

Start	10/31/2017	10/31/2017	9/30/2017	8/30/2017	7/30/2017	6/29/2017	5/29/2017	4/28/2017	3/28/2017	2/25/2017	1/25/2017	12/25/2016	11/24/2016
End	10/25/2016	10/1/2017	8/31/2017	7/31/2017	6/30/2017	5/30/2017	4/29/2017	3/29/2017	2/26/2017	1/26/2017	12/26/2016	11/25/2016	10/25/2016
1:00:00 AM	14.02	5.50	12.81	16.88	18.22	15.19	11.50	11.76	9.50	12.38	16.67	20.81	17.02
2:00:00 AM	13.00	3.72	11.68	16.18	16.93	13.75	9.81	10.66	8.66	12.03	16.18	20.13	16.26
3:00:00 AM	12.75	3.32	11.11	15.89	16.49	12.99	9.19	10.54	9.53	12.15	16.03	19.81	15.92
4:00:00 AM	12.71	3.51	10.88	15.66	16.24	12.71	8.63	10.30	9.94	12.04	16.56	19.99	16.10
5:00:00 AM	13.71	4.91	11.67	15.94	16.48	13.00	9.68	11.51	11.44	13.47	17.72	21.41	17.31
6:00:00 AM	16.45	9.74	13.96	16.72	17.29	14.25	12.54	15.16	14.56	16.58	20.96	25.70	19.88
7:00:00 AM	21.77	17.08	17.14	17.93	17.88	15.41	16.93	22.48	22.67	24.00	27.88	35.16	26.70
8:00:00 AM	23.23	18.97	17.94	19.02	19.98	18.51	19.95	23.50	22.05	23.90	30.37	36.91	27.71
9:00:00 AM	24.30	19.42	19.28	20.87	23.21	21.77	23.02	25.15	22.70	23.74	28.11	37.14	27.23
10:00:00 AM	25.55	21.24	21.07	22.91	25.60	23.15	24.27	26.05	24.02	24.93	28.84	35.72	28.80
11:00:00 AM	26.00	21.50	22.86	25.15	29.46	25.75	24.89	26.29	22.95	23.61	27.83	32.59	29.15
12:00:00 PM	26.44	20.83	25.72	27.77	33.72	28.27	24.85	26.67	22.17	21.71	26.36	30.27	28.96
1:00:00 PM	26.76	20.90	28.71	30.02	37.04	30.83	26.14	26.97	20.80	20.01	24.06	26.71	28.91
2:00:00 PM	27.29	21.91	31.20	32.51	39.37	33.95	26.80	26.25	20.20	18.79	22.74	24.74	29.06
3:00:00 PM	27.60	21.78	32.86	33.32	42.45	36.23	27.01	25.63	19.70	17.97	21.66	23.62	28.98
4:00:00 PM	28.74	22.26	35.85	36.79	46.35	38.88	27.37	25.16	19.28	18.12	21.55	23.83	29.40
5:00:00 PM	29.85	22.49	36.38	36.23	47.48	40.85	28.63	25.95	19.94	19.18	23.43	27.30	30.28
6:00:00 PM	31.06	22.54	33.75	33.10	42.95	37.56	28.22	25.88	20.60	22.74	33.07	39.85	32.49
7:00:00 PM	29.75	24.54	29.94	31.04	38.76	34.92	26.38	25.69	23.31	25.76	30.11	34.82	31.68
8:00:00 PM	27.86	25.08	28.08	28.63	36.01	30.80	25.60	27.20	23.84	21.29	26.20	32.50	29.11
9:00:00 PM	25.92	19.56	25.74	26.97	32.03	27.74	28.74	31.50	20.44	18.57	24.16	30.41	25.22
10:00:00 PM	21.40	13.92	20.00	24.08	27.84	24.94	23.16	23.50	15.06	15.45	20.70	26.50	21.68
11:00:00 PM	17.78	10.64	15.93	20.29	23.44	19.96	17.80	18.57	11.77	13.70	18.75	23.49	18.96
12:00:00 AM	14.51	6.77	13.02	17.48	19.66	16.01	13.30	13.58	9.10	11.65	16.20	20.04	17.29

Staff reviewed for each utility the hours of the hourly simple average cost of day-ahead wholesale energy, by 30 day period, in which the hourly cost was at least 55% of the annual system peak. Those hours, and percentages, are provided below for KCPL and for GMO:

KCPL Hourly Energy Prices by Month Relative to Annual Peak:

Start	10/31/2017	10/31/2017	9/30/2017	8/30/2017	7/30/2017	6/29/2017	5/29/2017	4/28/2017	3/28/2017	2/25/2017	1/25/2017	12/25/2016	11/24/2016
End	10/25/2016	10/1/2017	8/31/2017	7/31/2017	6/30/2017	5/30/2017	4/29/2017	3/29/2017	2/26/2017	1/26/2017	12/26/2016	11/25/2016	10/25/2016
1:00:00 AM	27%	5%	25%	36%	39%	31%	22%	20%	15%	23%	33%	41%	35%
2:00:00 AM	25%	1%	23%	35%	36%	28%	18%	18%	14%	22%	32%	40%	34%
3:00:00 AM	24%	0%	22%	34%	35%	26%	17%	18%	16%	22%	32%	39%	33%
4:00:00 AM	25%	1%	22%	34%	35%	26%	16%	17%	17%	22%	33%	40%	33%
5:00:00 AM	27%	5%	24%	35%	36%	27%	18%	20%	20%	25%	36%	43%	36%
6:00:00 AM	33%	16%	29%	36%	37%	30%	25%	29%	27%	32%	43%	51%	42%
7:00:00 AM	45%	34%	36%	39%	39%	33%	35%	45%	46%	48%	58%	70%	53%
8:00:00 AM	48%	38%	38%	42%	43%	40%	42%	47%	45%	48%	63%	72%	54%
9:00:00 AM	50%	39%	41%	46%	51%	47%	49%	50%	46%	47%	58%	69%	55%
10:00:00 AM	53%	43%	45%	50%	56%	50%	52%	52%	49%	50%	60%	68%	59%
11:00:00 AM	54%	44%	49%	55%	64%	56%	53%	53%	47%	48%	58%	63%	60%
12:00:00 PM	55%	41%	54%	61%	73%	60%	52%	54%	45%	45%	55%	57%	59%
1:00:00 PM	55%	41%	59%	66%	79%	64%	55%	54%	42%	41%	51%	53%	59%
2:00:00 PM	57%	43%	63%	71%	84%	70%	57%	53%	41%	39%	48%	50%	59%
3:00:00 PM	57%	42%	65%	72%	90%	74%	57%	52%	39%	37%	46%	48%	59%
4:00:00 PM	59%	43%	70%	80%	98%	78%	57%	51%	39%	37%	46%	49%	60%
5:00:00 PM	61%	44%	73%	79%	100%	82%	59%	53%	40%	40%	50%	56%	62%
6:00:00 PM	64%	45%	68%	72%	91%	75%	59%	53%	43%	48%	70%	81%	67%
7:00:00 PM	62%	50%	61%	67%	82%	70%	56%	53%	49%	54%	63%	70%	65%
8:00:00 PM	57%	50%	57%	62%	76%	62%	54%	56%	49%	44%	55%	65%	59%
9:00:00 PM	53%	37%	52%	58%	67%	55%	60%	65%	41%	38%	50%	61%	51%
10:00:00 PM	43%	26%	40%	52%	58%	50%	48%	47%	28%	30%	42%	54%	44%
11:00:00 PM	35%	18%	32%	44%	49%	40%	36%	35%	21%	26%	38%	46%	39%
12:00:00 AM	28%	9%	26%	38%	41%	32%	26%	25%	15%	21%	33%	40%	35%

GMO Hourly Energy Prices by Month Relative to Annual Peak:

Start	10/31/2017	10/31/2017	9/30/2017	8/30/2017	7/30/2017	6/29/2017	5/29/2017	4/28/2017	3/28/2017	2/25/2017	1/25/2017	12/25/2016	11/24/2016
End	10/25/2016	10/1/2017	8/31/2017	7/31/2017	6/30/2017	5/30/2017	4/29/2017	3/29/2017	2/26/2017	1/26/2017	12/26/2016	11/25/2016	10/25/2016
1:00:00 AM	30%	12%	27%	36%	38%	32%	24%	25%	20%	26%	35%	44%	36%
2:00:00 AM	27%	8%	25%	34%	36%	29%	21%	22%	18%	25%	34%	42%	34%
3:00:00 AM	27%	7%	23%	33%	35%	27%	19%	22%	20%	26%	34%	42%	34%
4:00:00 AM	27%	7%	23%	33%	34%	27%	18%	22%	21%	25%	35%	42%	34%
5:00:00 AM	29%	10%	25%	34%	35%	27%	20%	24%	24%	28%	37%	45%	36%
6:00:00 AM	35%	21%	29%	35%	36%	30%	26%	32%	31%	35%	44%	54%	42%
7:00:00 AM	46%	36%	36%	38%	38%	32%	36%	47%	48%	51%	59%	74%	56%
8:00:00 AM	49%	40%	38%	40%	42%	39%	42%	50%	46%	50%	64%	78%	58%
9:00:00 AM	51%	41%	41%	44%	49%	46%	48%	53%	48%	50%	59%	78%	57%
10:00:00 AM	54%	45%	44%	48%	54%	49%	51%	55%	51%	53%	61%	75%	61%
11:00:00 AM	55%	45%	48%	53%	62%	54%	52%	55%	48%	50%	59%	69%	61%
12:00:00 PM	56%	44%	54%	58%	71%	60%	52%	56%	47%	46%	56%	64%	61%
1:00:00 PM	56%	44%	60%	63%	78%	65%	55%	57%	44%	42%	51%	56%	61%
2:00:00 PM	57%	46%	66%	68%	83%	72%	56%	55%	43%	40%	48%	52%	61%
3:00:00 PM	58%	46%	69%	70%	89%	76%	57%	54%	41%	38%	46%	50%	61%
4:00:00 PM	61%	47%	76%	77%	98%	82%	58%	53%	41%	38%	45%	50%	62%
5:00:00 PM	63%	47%	77%	76%	100%	86%	60%	55%	42%	40%	49%	57%	64%
6:00:00 PM	65%	47%	71%	70%	90%	79%	59%	54%	43%	48%	70%	84%	68%
7:00:00 PM	63%	52%	63%	65%	82%	74%	56%	54%	49%	54%	63%	73%	67%
8:00:00 PM	59%	53%	59%	60%	76%	65%	54%	57%	50%	45%	55%	68%	61%
9:00:00 PM	55%	41%	54%	57%	67%	58%	61%	66%	43%	39%	51%	64%	53%
10:00:00 PM	45%	29%	42%	51%	59%	53%	49%	49%	32%	33%	44%	56%	46%
11:00:00 PM	37%	22%	34%	43%	49%	42%	37%	39%	25%	29%	39%	49%	40%
12:00:00 AM	31%	14%	27%	37%	41%	34%	28%	29%	19%	25%	34%	42%	36%

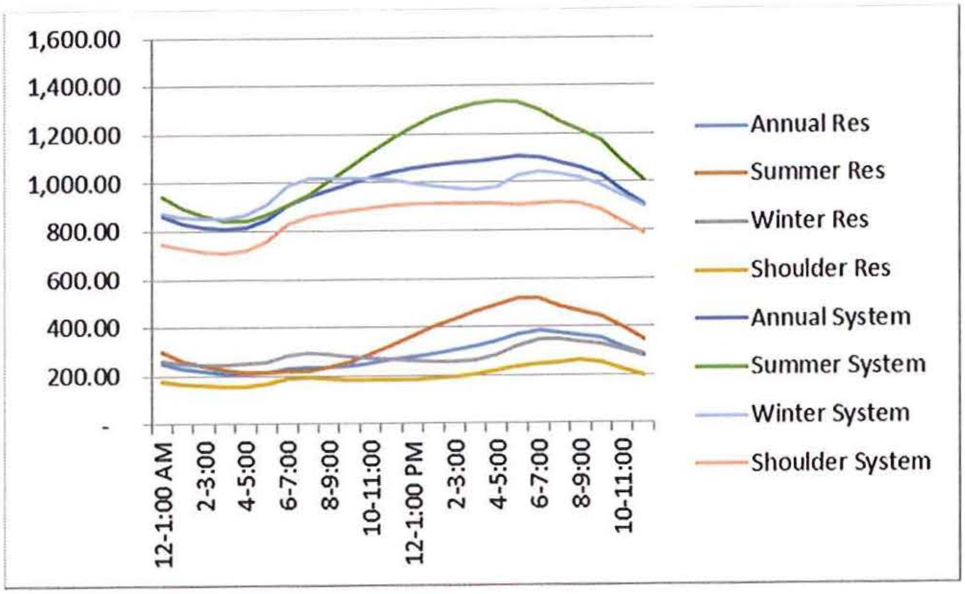
C. Distribution system cost considerations

Staff also reviewed system utilization across hours of the day, at both the residential class and system levels to determine hours of the day associated with fuller utilization of the distribution system and local elements of the transmission system. For this analysis, the system loading in each hour of the day was averaged across all days within the specified season. For example, in the KCPL chart provided below, the green line, "summer system," peaks at a value of 1,337 from 4:00 – 5:00 pm. This indicates that the average of each "summer" day's load during that hour is approximately 1,337 MW. However, the red line, "summer res" indicates that the KCPL residential class, on average, peaks during the hour of 6:00 – 7:00 pm, at approximately 519 MW.

KCPL's seasonal loads for total system and for the residential class are provided below:

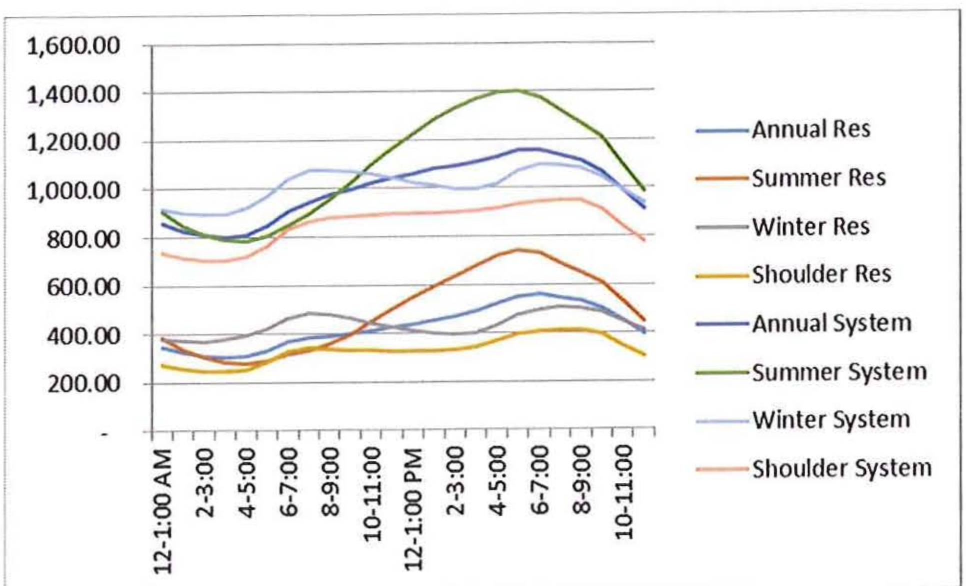
continued on next page

KCPL Hourly Loading by Season



GMO seasonal loads for total system and for the residential class are provided below:

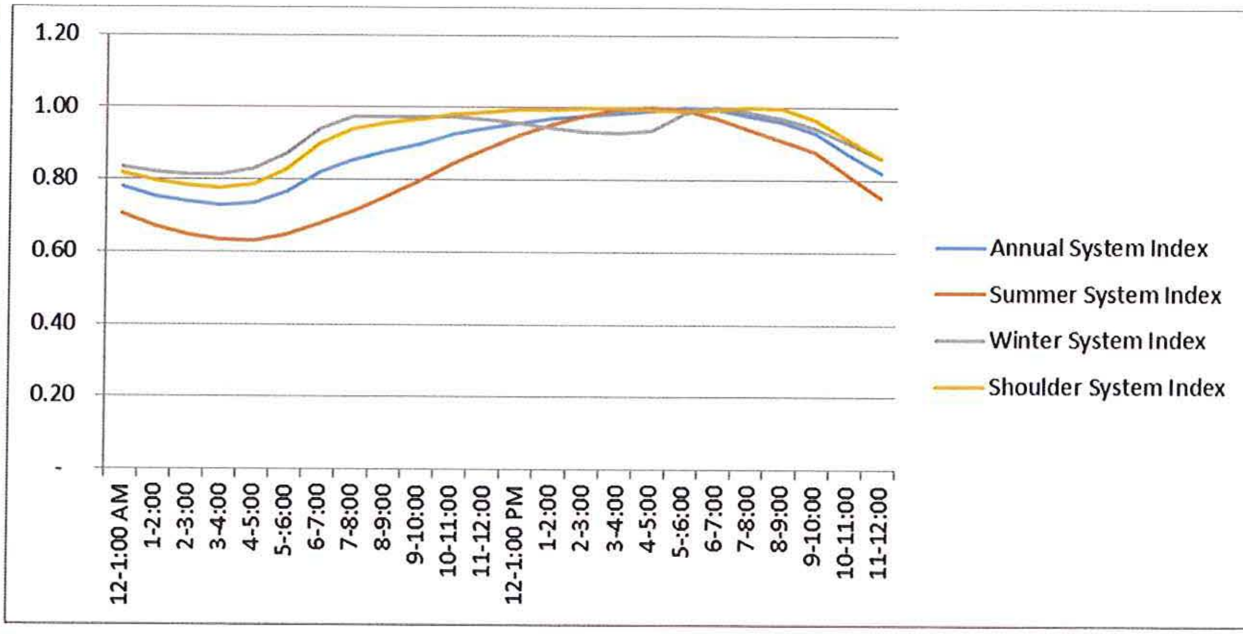
GMO Hourly Loading by Season



KCPL total system utilization, indexed to seasonal peak is provided below:[12]

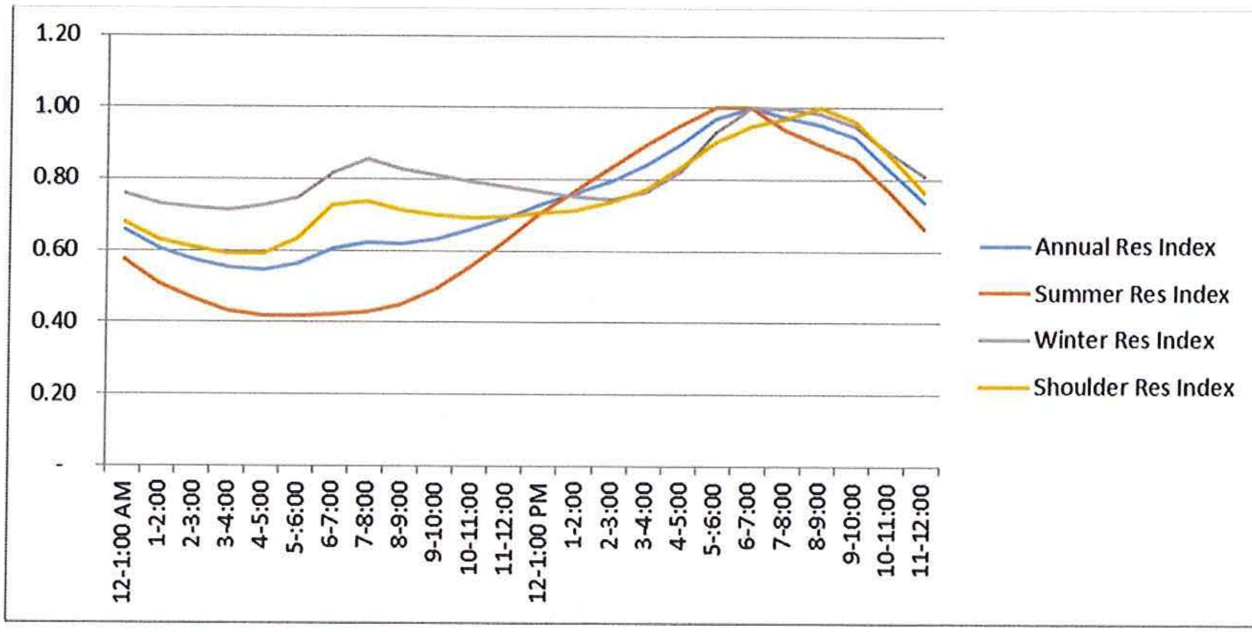
[12] "Index" refers to representing the applicable seasonal peak level of demand with the value of 1, and providing the other hours' demand relative to that value.

KCPL Total System Hourly Loading by Season (Indexed to Seasonal Peak)



KCPL residential class system utilization, indexed to seasonal peak, is provided below:

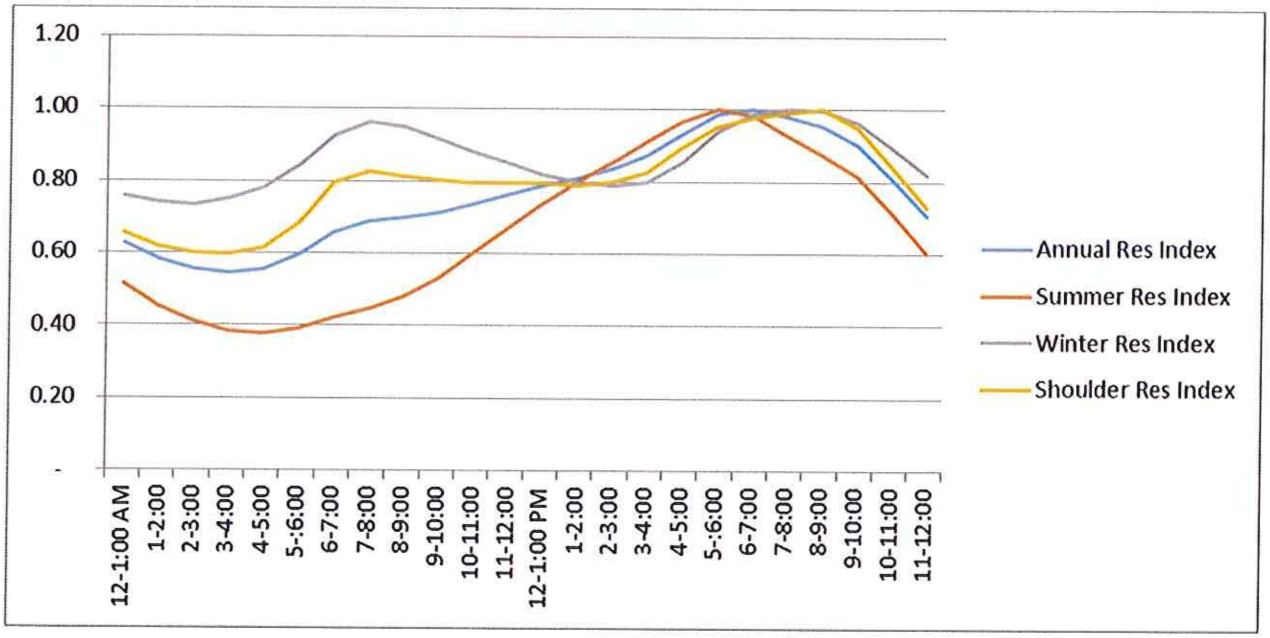
KCPL Residential Hourly Loading by Season (Indexed to Seasonal Peak)



In addition to the variance in utilization across classes, there is also variation in utilization across seasons. For example, the gray line in the GMO residential utilization graph below, "Winter Res Index," indicates a high level of residential system utilization from about

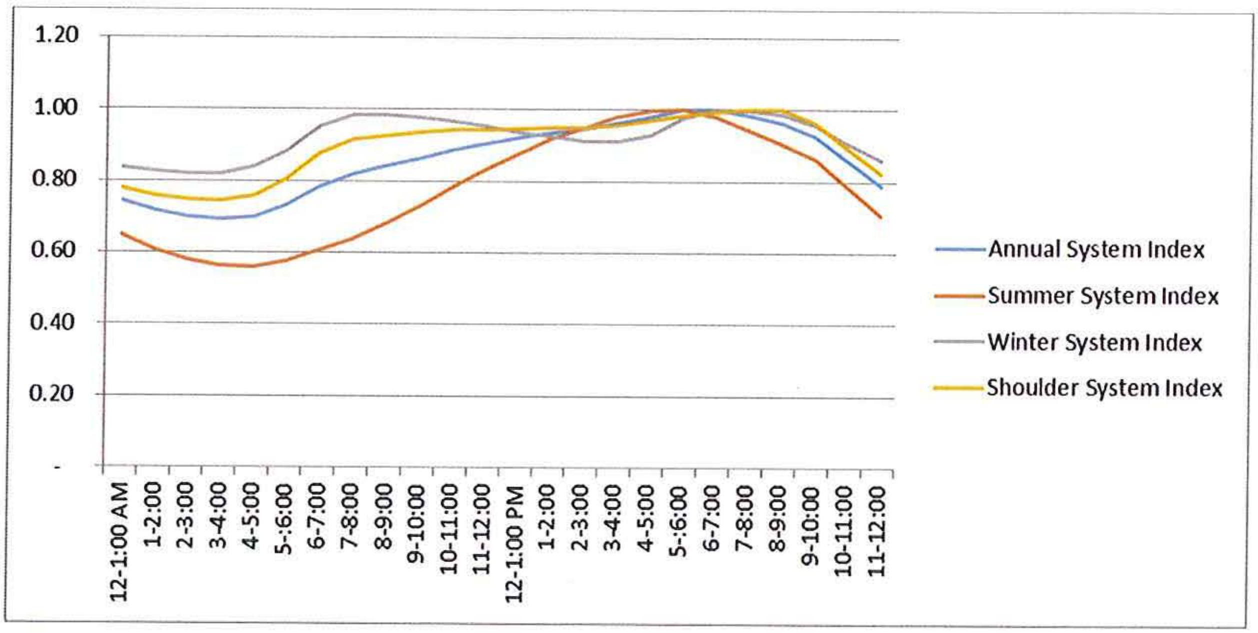
6:00 am until about 9:00 am during the winter months. However, this same time period during the summer months, as indicated by the red line, reflects relatively low system utilization. GMO total system utilization, indexed to seasonal peak, is provided below:

GMO Residential Hourly Loading by Season (Indexed to Seasonal Peak)



GMO total system utilization, indexed to seasonal peak, is provided below:

GMO Total System Hourly Loading by Season (Indexed to Seasonal Peak)



In selecting on peak and off peak periods for a time of use rate design, price signals should be sent that reflect that system costs are driven by times of high system utilization. Price signals should not be sent to increase use of the system during times of high system utilization. Selection of reasonable on-peak and off-peak time periods is complicated by two factors, (1) utilization patterns vary by season, and (2) the residential class itself has a different utilization pattern than the total system. In the interest of having one pricing period in place throughout the year, and in the interest of not incenting the residential class to consume additional energy during times when residential class utilization is not high, but total system utilization is high, it is most reasonable for this initial implementation of ToU rates to utilize a longer on-peak period that (1) encompasses the times of high system utilization across various seasons and (2) encompasses high levels of system utilization by both the residential class and the total system.

D. Understandability and Customer Impact Mitigation

At this time, based on rate impact mitigation and energy-cost drivers, Staff recommends the on-peak period be defined as beginning at 8:00 am and ending at 9:59 pm, in all months.

In the Staff Report on Distributed Energy Resources, filed April 5, 2018, in File No. EW-2017-0245, concerning residential and utility-wide rate design, Staff recommended the following:

> *Initial steps to be taken during or prior to applicable rate cases:*
>
> a. Residential Rate Design:
>
> i. Improve customer education regarding cost composition and energy cost differences over time of day and season.
>
> ii. Review rates on an unbundled basis, with potential to provide tariffed rates on an unbundled basis.
>
> iii. Implement a Low-differential TOU rate design related only to energy price difference or existing rate design blocks, with relatively long on-peak periods.
>
> iv. Study determinants for an on-peak demand charge.
>
> * * *
>
> c. Utility-wide
>
> i. Study bifurcating Fuel and Purchased Power costs into the TOU time periods for recovery of differences through bifurcated FACs.
>
> ii. Study distribution of DER on existing system.

iii. Identify locations on the distribution and transmission systems where DER may be an alternative to expansion or replacement of the system.
iv. Develop strategies to encourage strategic placement and deployment of DER to reduce overall system investment needs and operation expenses, including transmission congestion including study of locational rate designs and location-dependent compensation schemes.
v. Study located DER scenarios as part of Chapter 22 planning consistent with Staff's recommendations contained in *Section VII. Changes to IRP process or Chapter 22.*
vi. Study energy cost distribution and system utilization to find opportunities for efficient utilization and pricing – for example, some utilities experience significant winter night and evening usage – to refine time periods applicable to time of use rates and develop super on-peak or super off-peak rates.

<u>Phase 2 (approximately 2025 time frame, will vary by utility and rate case timing):</u>
a. Residential:
i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.
ii. Increase TOU differential to recover some generation capacity costs on-peak.
iii. Incorporate super on-peak and super off-peak TOU elements, which may vary by season.
iv. Implement a 12 month demand charge for recovery associated with local distribution facilities.

* * *

c. Utility-wide
i. Study distribution locational pricing determinants for locational rate designs; study location-dependent compensation schemes.
ii. Revenue Decoupling.
iii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

<u>Anticipated goals (approximately 2030 time frame, will vary by utility and rate case timing):</u>
a. Residential:
i. Continued and increased customer education regarding cost composition and energy cost differences over time of day and season.
ii. Implement on-peak demand charge to nearly fully recover generation capacity costs on peak, not already included in on-peak and super on-peak elements.
iii. Consider and implement, if appropriate, distribution locational rates or rate elements.

* * *

c. Utility-wide

i. Study distribution locational pricing determinants.

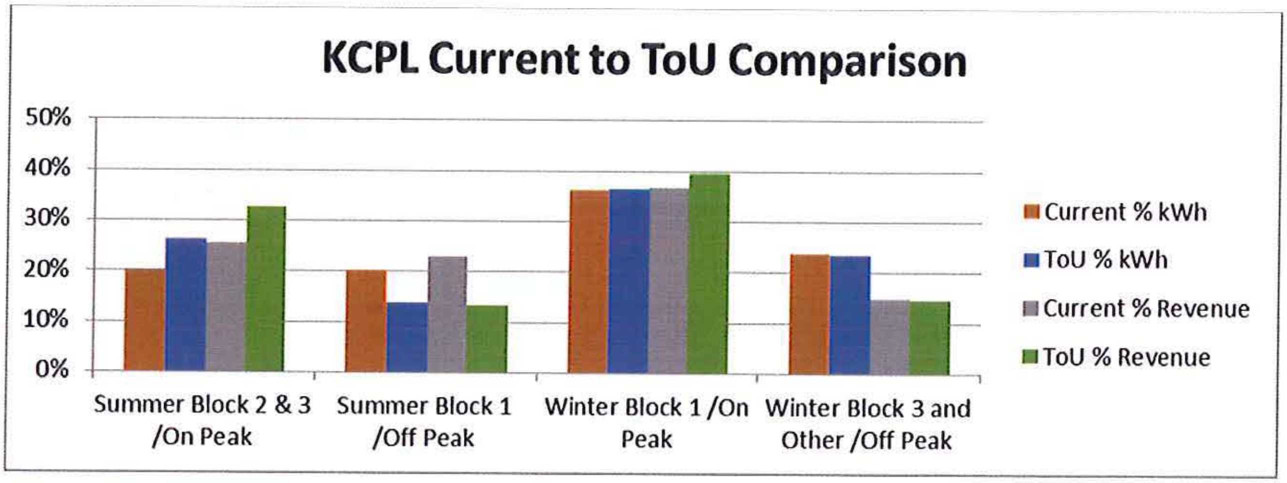
ii. Based on outcomes of studies of beneficial DER location, locate DER or incent the location of DER using reasonably designed compensation designs.

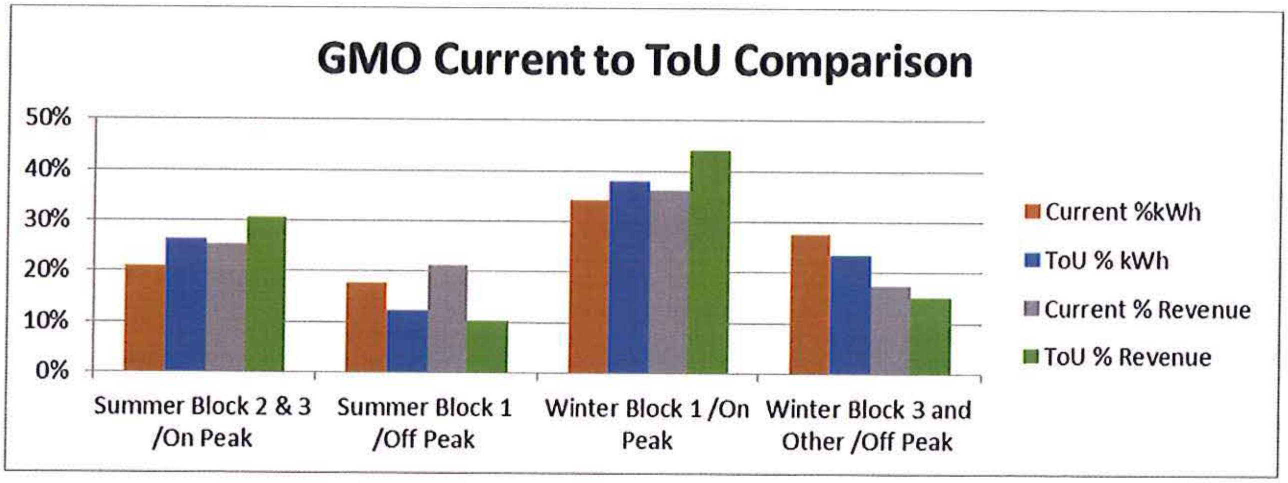
A low-impact, low-differential, long time period time-of-use rate design is an excellent customer education opportunity. As provided below, Staff's rate design recommendation is intended to produce little to no bill variation in a statistically average residential customer. However, this rate design will impart to customers the concept that, in general, energy used during the daytime is more cost-intensive, and energy used during the night time is less cost-intensive. Staff's proposed rate designs, on a revenue neutral basis, reflecting current customer charges, and a slight shift in revenue recovery from summer billing months to non-summer billing months,[13] are provided below:

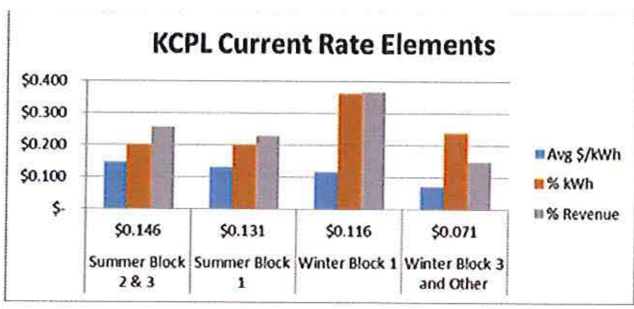
	KCPL	GMO
Summer 8:00 AM to 9:59 PM	$ 0.141	$ 0.129
Summer 10:00 PM to 7:59 AM	$ 0.111	$ 0.092
Non-Summer 8:00 AM to 9:59 PM	$ 0.124	$ 0.105
Non-Summer 10:00 PM to 7:59 AM	$ 0.071	$ 0.064

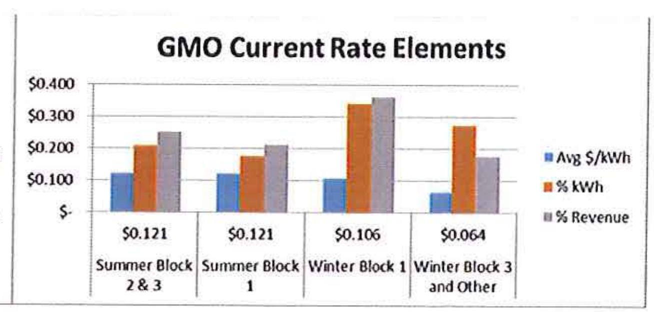
These rates will be subject to change based on the overall revenue to be collected from each utility's residential classes, and subject to any change in either utility's residential customer charge. These rates are designed so that, on average, a customer will pay approximately the same rate for Non-Summer off-peak usage that customers currently pay for Non-Summer usage in the third energy block. Customers will, on average, pay a very similar rate for Summer on-peak usage as to what customers currently pay for Summer usage in the second and third energy blocks. Comparisons of the current revenue recovery and kWh per current block to the proposed revenue recovery and kWh per ToU block are provided below.

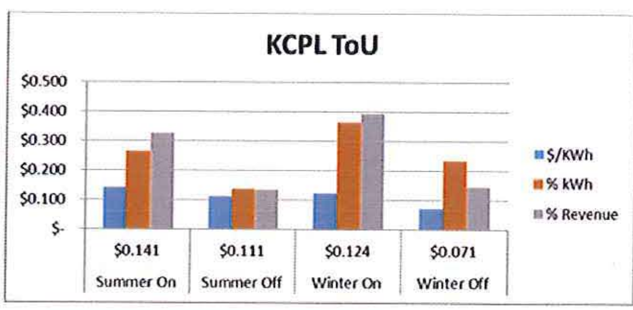
[13] This design is based on a 5% shift in KCPL seasonal energy revenue recovery, and a 10% shift in GMO seasonal energy revenue recovery.

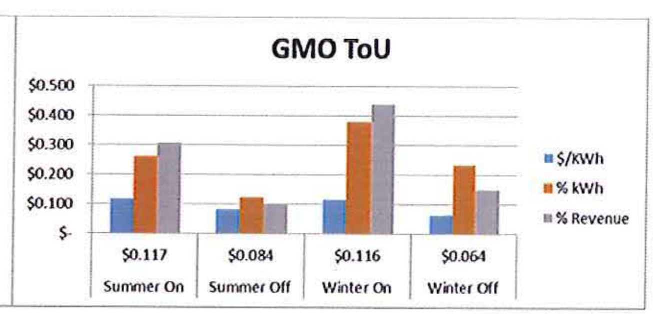

KCPL Current to ToU Comparison
50%
40%
30%
20%
10%
0%
Summer Block 2 & 3 /On Peak
Summer Block 1 /Off Peak
Winter Block 1 /On Peak
Winter Block 3 and Other /Off Peak
Current % kWh
ToU % kWh
Current % Revenue
ToU % Revenue


GMO Current to ToU Comparison
50%
40%
30%
20%
10%
0%
Summer Block 2 & 3 /On Peak
Summer Block 1 /Off Peak
Winter Block 1 /On Peak
Winter Block 3 and Other /Off Peak
Current %kWh
ToU % kWh
Current % Revenue
ToU % Revenue


KCPL Current Rate Elements
$0.400
$0.300
$0.200
$0.100
$-
$0.146
$0.131
$0.116
$0.071
Summer Block 2 & 3
Summer Block 1
Winter Block 1
Winter Block 3 and Other
Avg $/kWh
% kWh
% Revenue


GMO Current Rate Elements
$0.400
$0.300
$0.200
$0.100
$-
$0.121
$0.121
$0.106
$0.064
Summer Block 2 & 3
Summer Block 1
Winter Block 1
Winter Block 3 and Other
Avg $/kWh
% kWh
% Revenue


KCPL ToU
$0.500
$0.400
$0.300
$0.200
$0.100
$-
$0.141
$0.111
$0.124
$0.071
Summer On
Summer Off
Winter On
Winter Off
$/KWh
% kWh
% Revenue


GMO ToU
$0.500
$0.400
$0.300
$0.200
$0.100
$-
$0.117
$0.084
$0.116
$0.064
Summer On
Summer Off
Winter On
Winter Off
$/KWh
% kWh
% Revenue

Any increase in customer charge would tend to decrease these energy rates in a manner that is generally consistent with mitigating customer impact to above-average use customers. The estimated impact of Staff's recommended changes to residential customer charges are provided below:

	KCPL Current Cust. Charge	KCPL Staff Cust. Charge	GMO Current Cust. Charge	GMO Staff Cust. Charge
Summer 8:00 AM to 9:59 PM	$ 0.141	$ 0.141	$ 0.129	$ 0.117
Summer 10:00 PM to 7:59 AM	$ 0.111	$ 0.111	$ 0.092	$ 0.084
Non-Summer 8:00 AM to 9:59 PM	$ 0.124	$ 0.124	$ 0.105	$ 0.116
Non-Summer 10:00 PM to 7:59 AM	$ 0.071	$ 0.071	$ 0.064	$ 0.064

The intent of this design is consistent with the price signal the Commission pursued in KCPL's last rate case when it established a summer inclining block rate design. The intent of this ToU design is to establish a "Time of Use Training Wheel" framework that is consistent across the year, but upon which more complex elements that will vary by season can be established. For example, in future cases, it is likely that Staff will recommend implementation of (1) an additional summer on-peak charge priced consistent with pricing signals associated with RTO capacity costs or production capacity costs, for example, an additional approximate $0.02-5 / kWh during summer afternoon hours of approximately 2:00 pm – 6:00 pm; and (2) an additional spring/fall (and possibly summer) super-off-peak charge associated with times of very low energy prices and capacity costs, for example, a discount of approximately $0.02-5 / kWh during shoulder months during approximately the hours of 11:00 pm – 5:00 am. Rate elements to encourage pre-cooling thermal storage during the summer mornings, or system-coincident demand charges to recover capacity costs associated with summer afternoons are also possibilities that, while ideal from a pure cost-recovery perspective, cannot be expected to be understandable to customers at this time.[14]

E. Customer Impacts and Complications to Customer Impact Mitigation

Currently, both KCPL and GMO residential classes include General Use rate classifications and Space Heating / All Electric rate classifications.[15] Due to these separate rate

[14] In the case of certain rate elements, particularly coincident demand, billing determinants are not available at this time.

[15] For convenience, residential rate tariffs for each utility, with a summary of current rates, billing determinants, and revenues by charge type, are attached as Appendix 2, Schedule SLKL-d1.

classifications, a residential customer with a particular usage pattern would pay a different bill if they were billed as a "General Use" customer than if they were billed as a "Space Heating" customer. For KCPL, General Use Summer rates are an inclining block rate design, while Space Heating and All Electric Customer Summer rates are flat. For GMO, summer rates are the same for all residential customers, but winter rates for space heating customers usage over 1000 kWh are 36% less than the rate applied to the same General Use customer usage. KCPL's space heating and all electric winter rate disparities from the General Use rate are less severe than the GMO seasonal rate disparity, but the design of the KCPL winter declining block is a steeper slope. These existing rate disparities are poorly, if at all, reflective of underlying differences in the cost of providing service to these customers. However, the existence of these rate disparities implicates customer impacts in moving customers currently charged different rates onto a single rate schedule.[16]

Because of the multiple similar, but ultimately different, rates that comprise the various rate classifications of KCPL's and GMO's current residential rates, Staff used kWh-weighted averages to calculate the average $/kWh for each utility for a relatively higher cost per kWh for both Summer and Winter, and a relatively lower cost per kWh for both Summer and Winter, for each utility. Those values, along with the number of kWh associated with each average charge, and the revenue collected through the indicated charges, are provided below, by utility.

KCPL Current Rate Elements	Avg $/kWh	kWh	Revenue	% kWh	% Revenue
Summer Block 2 & 3	$ 0.146	517,557,912	$ 75,700,131	20%	26%
Summer Block 1	$ 0.131	519,356,150	$ 67,784,135	20%	23%
Winter Block 1	$ 0.116	933,529,003	$ 108,751,058	36%	37%
Winter Block 3 and Other	$ 0.071	614,202,395	$ 43,648,750	24%	15%

GMO Current Rate Elements	Avg $/kWh	kWh	Revenue	% kWh	% Revenue
Summer Block 2 & 3	$ 0.121	721,386,201	$ 87,035,478	21%	25%
Summer Block 1	$ 0.121	606,766,154	$ 73,115,322	18%	21%
Winter Block 1	$ 0.106	1,177,048,225	$ 125,105,074	34%	36%
Winter Block 3 and Other	$ 0.064	950,531,901	$ 60,481,520	28%	17%

[16] In hourly load data KCPL's residential class is provided with all residential sub-classifications consolidated into a single hourly value, and GMO's residential class is provided with all residential sub-classifications consolidated into a single hourly value. Staff relied on these hourly loads to develop the Time of Use billing determinants. Without knowing the hourly loads for General Use Customers separate from the hourly loads for Space Heating customers, Staff is unable to develop separate Time of Use rates for these customers.

While these are the average rates, KCPL customers on Space Heating rates tend to pay lower than average rates in the winter relative to General Use Customers, as indicated below:

KCPL		Revenue	kWh		$/kWh
General Use Average $/kWh Summer	$	108,560,410	784,004,578	$	0.138
General Use Average $/kWh Winter	$	108,689,191	1,040,724,248	$	0.104
Space Heat Average $/kWh Summer	$	34,869,371	252,566,793	$	0.138
Space Heat Average $/kWh Winter	$	43,642,635	506,426,603	$	0.086

GMO	Revenue	kWh		$/kWh
All Residential Average $/kWh Summer	$ 159,569,771	1,324,230,464	$	0.121
Space Heat Average $/kWh Summer	$ 100,333,223	1,040,255,640	$	0.096
Space Heat Average $/kWh Winter	$ 84,250,341	1,078,295,497	$	0.078

To estimate a range of possible customer impacts, Staff priced out the existing KCPL General Use and Space Heating rates for a sampled set of customers on each rate schedule, using existing rates including customer charges. Staff then computed what those customers' bills would be under the proposed ToU rates, designed to recover the same level of revenue from the KCPL residential class as a whole, and not necessarily from these specific customers, using existing customer charges. These samples are based on the customer for whom KCPL had a year or more of hourly meter data, and are not representative of a random mix of KCPL customers.

The results on a seasonal average dollar per kWh basis per individual customers of the customer impacts studied are attached as Appendix 2, Schedule SLKL-d2. Provided below in graphic form is a summary of that information.

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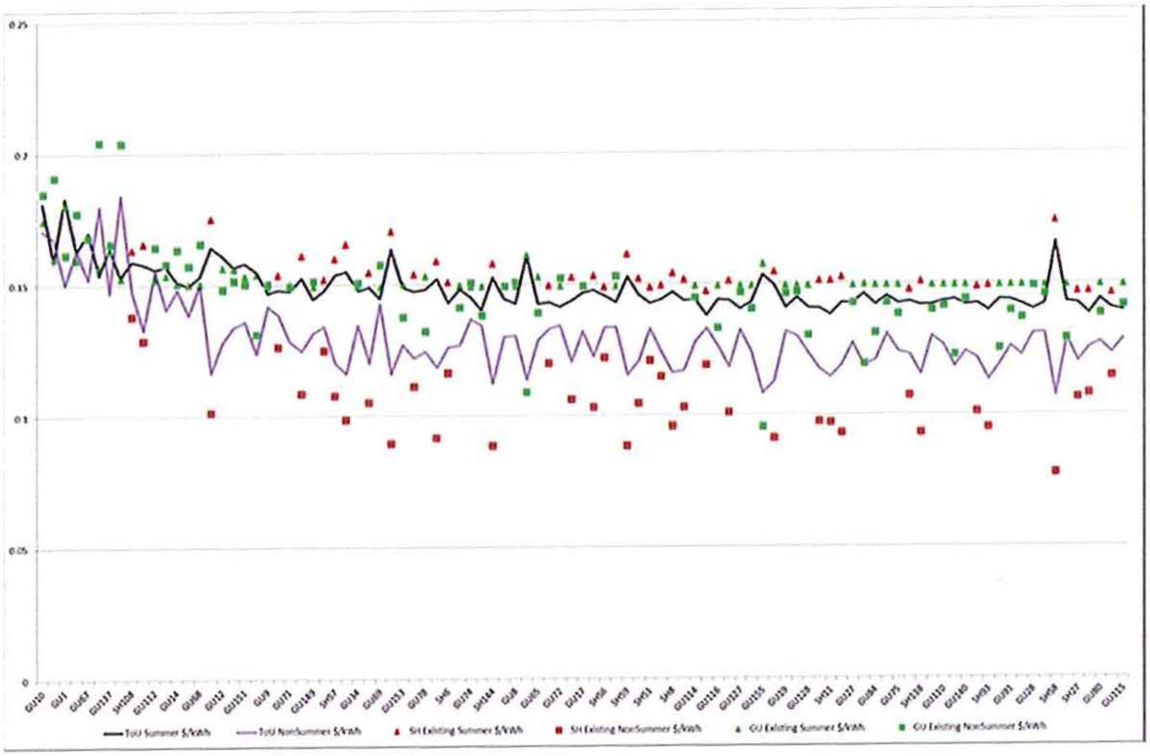

The above graph, condensed to provide information for only every fifth customer to facilitate readability, is provided below:

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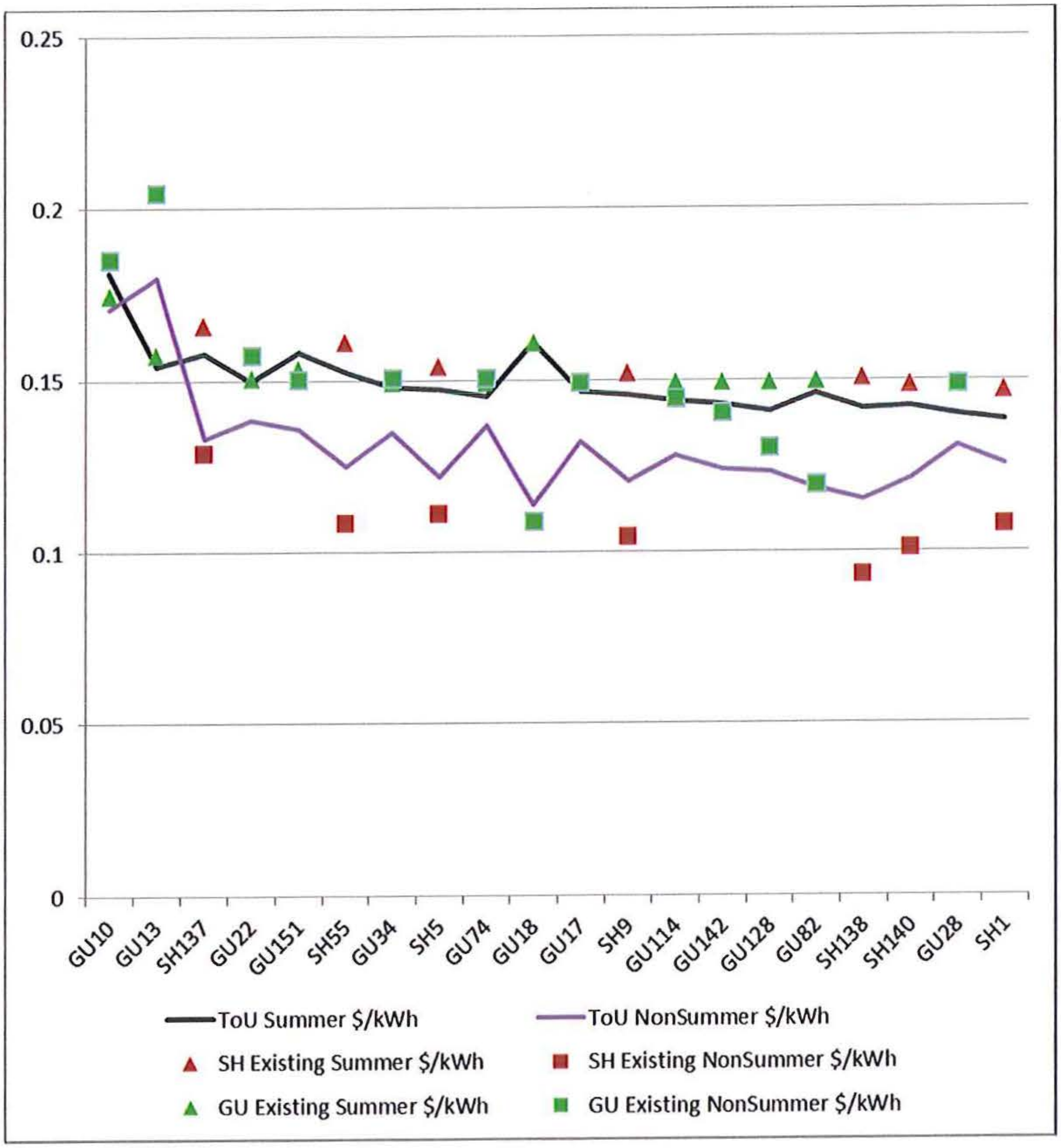
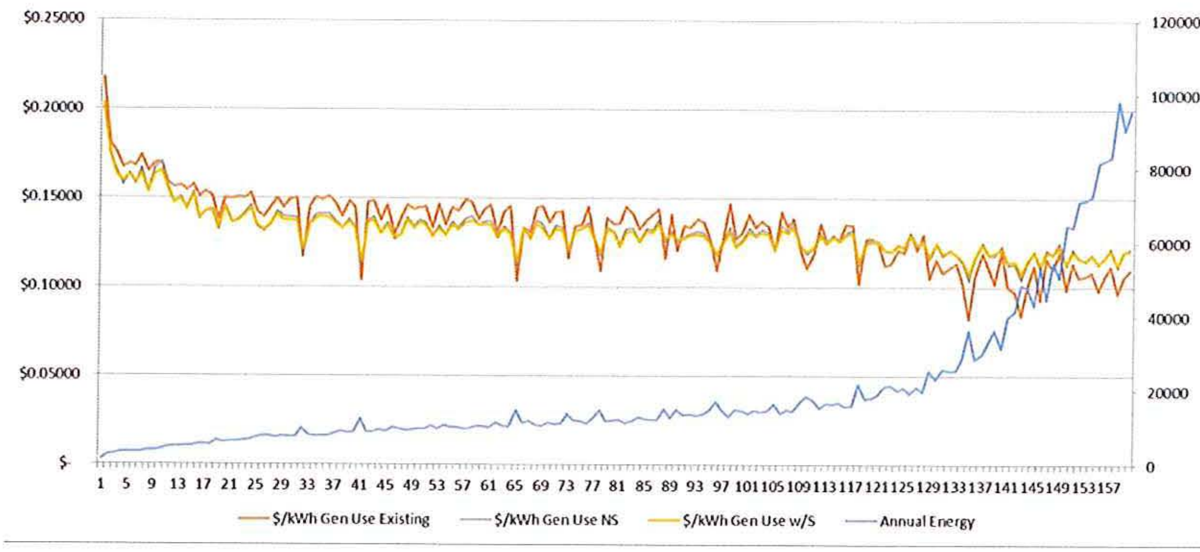


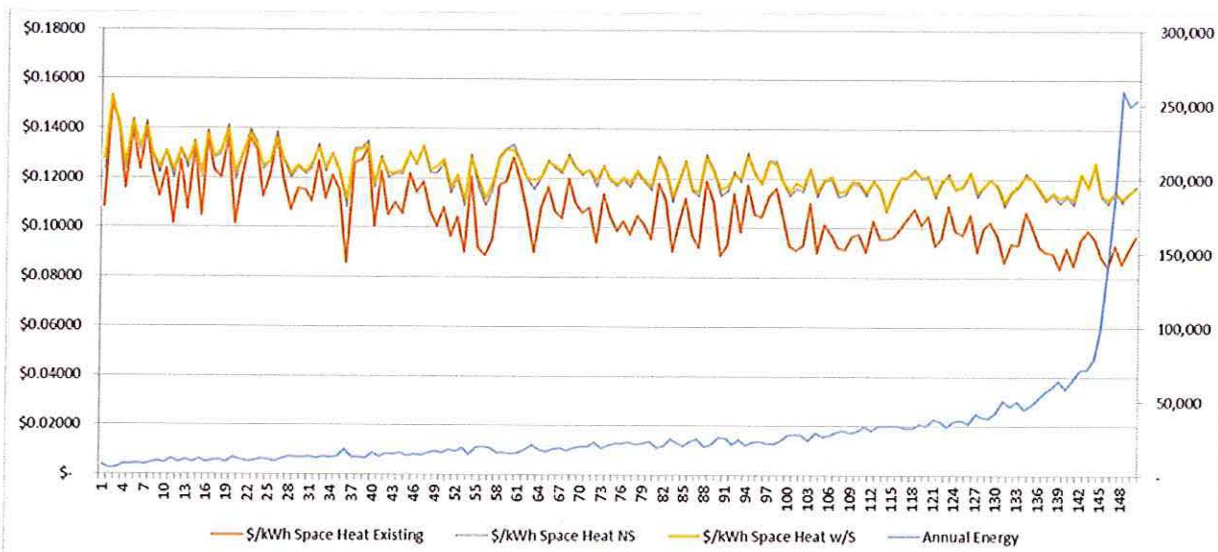
While it is important to consider seasonal rate impacts, annual impacts do provide additional convergence in average cost per kWh for most customers.

Provided below is a comparison on each studied customer of average $/kWh under (1) current bills, (2) ToU bills without a revenue shift ("NS"), and (3) ToU bills with a shift of revenue recovery from the General Use subclass to the Space Heating subclass ("w/S"):

General Use Subclass Estimated Annual Impact



Space Heating Subclass Estimated Annual Impact



Staff Expert/Witness: Sarah L.K. Lange

F. <u>Residential Customer Charge</u>

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

Based on Staff's CCOS for KCPL, Staff's residential customer charge calculation resulted in a residential customer charge of $12.82. KCPL's current residential customer charge is $12.62.

Based on Staff's preliminary CCOS for GMO, Staff's residential customer charge calculation resulted in a residential customer charge of $12.38 for GMO. GMO's current residential customer charge is $10.43.

Although Staff's overall revenue requirement recommendation results in a decrease in rates for KCPL and GMO, Staff recommends movement to the full CCOS calculated residential customer charges for both KCPL and GMO in keeping with recent Commission orders. Increases to customer charges will further mitigate the impact of the shift to residential ToU rates.

Staff Expert/Witness: Robin Kliethermes

G. Residential Rate Schedule Consolidations

Staff recommends additional changes to the Residential rate schedules of both utilities for the small number of customers without AMI metering. If the Commission does not order mandatory ToU rates at this time, these changes would be applicable to all residential customers.

Staff recommends the Commission order (1) correction of minor discrepancies in the existing Residential General Use and Space Heating rate schedules of KCPL, (2) elimination of the Frozen All Electric Rate Schedule and consolidation into the Space Heating rate schedule for KCPL, and (3) intraclass shifts in revenue responsibility to bring the rates of the Space Heating rate schedule closer to those of the General Use rate schedule for both utilities. These changes are provided in Appendix 2, Schedule SLKL-d3.

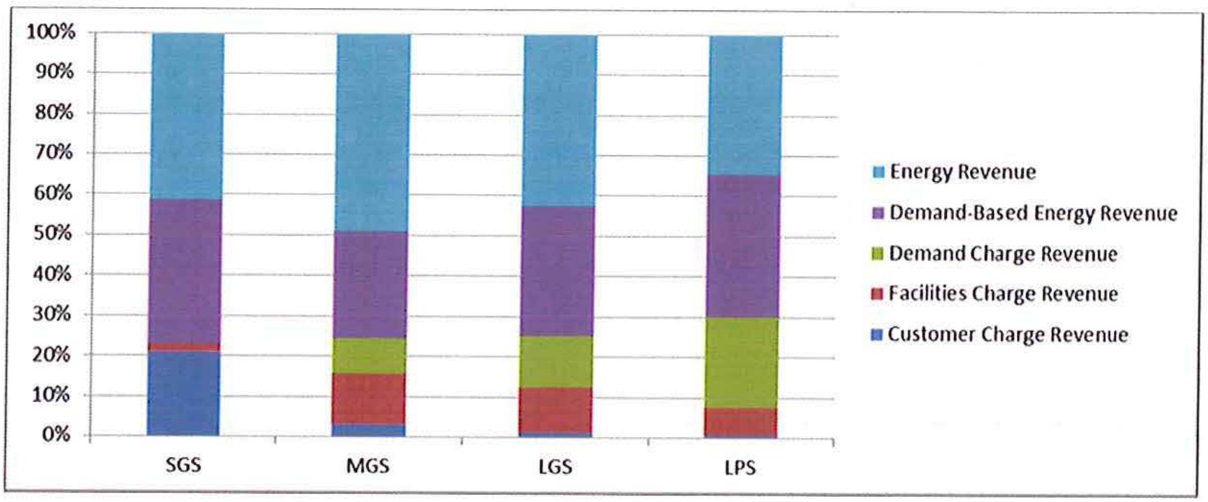
Staff Expert/Witness: Sarah L.K. Lange

H. <u>Non Residential Rate Design</u>

<u>Revenue Recovery through Billing Determinants (KCPL Only)</u>

Staff reviewed the revenue recovery of KCPL's nonresidential classes, by source of rate element type, Customer charges, Facilities Charges, NCP Demand Charges, and Energy Charges. Due to KCPL's hours-use rate design, it is necessary to further disaggregate energy charges that vary with customer NCP demand. To remove the demand-related component from the energy charge revenue, Staff priced out all kWh sold at a given voltage level as though it were sold at the seasonally-applicable tail block rate. The revenue sources, by class, are provided in the table below as total revenue dollars by charge type, and in the chart below as each charge type's percent of class revenues:

	SGS		MGS		LGS		LPS	
Customer Charge Revenue	$	14,170,585	$	3,622,234	$	2,516,898	$	855,027
Facilities Charge Revenue	$	1,391,718	$	14,735,973	$	21,716,914	$	10,093,005
Demand Charge Revenue	$	-	$	10,304,141	$	24,970,325	$	32,488,103
Demand-Based Energy Revenue	$	24,344,445	$	31,146,021	$	62,304,363	$	50,911,756
Energy Revenue	$	28,001,950	$	57,799,395	$	82,928,702	$	50,378,525
Total Revenue Collected	$	67,908,698	$	117,607,764	$	194,437,203	$	144,726,416

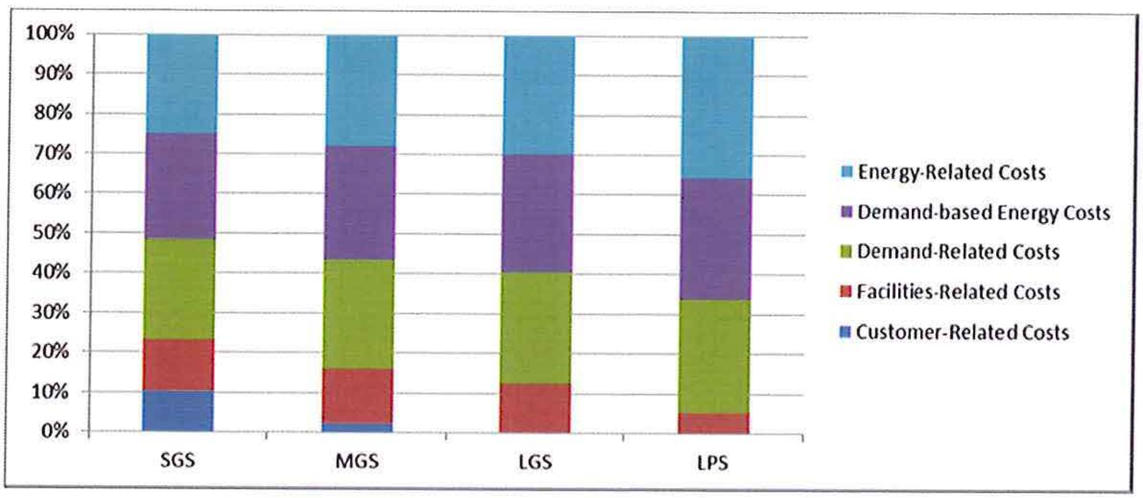


Staff unbundled the functionalized CCOS results to review relevant charge types using the allocations provided below. While there is significant discretion in establishing these relationships, and while if Staff were to start from scratch it is unlikely that Staff would recommend recreation of KCPL's existing rate structures, these allocations are reasonable for purposes of reviewing the reasonableness of KCPL's existing rate design.

	Customer	Facilities	Demand	Demand in Energy	Energy
Capacity			*System Load Factor*	*System Load Factor*	
Energy					100%
Transmission		50%	25%	25%	
Secondary		75%	15%	10%	
Customer	100%				

The cost type sources, by class, are provided in the table below as dollars by cost type, and in the chart below as each cost type's percent of class cost of service:

	SGS	MGS	LGS	LPS
Customer-Related Costs	5,768,171	3,113,176	168,537	71,370
Facilities-Related Costs	7,313,645	19,218,611	26,465,711	8,355,712
Demand-Related Costs	14,269,964	38,646,468	60,473,475	44,859,780
Demand-based Energy Costs	14,926,466	40,458,411	63,514,782	47,756,369
Energy-Related Costs	14,150,193	39,273,931	64,499,778	56,306,340
Allocated Cost of Service	56,428,439	140,710,597	215,122,283	157,349,571
Revenue Collected minus Cost of Service	11,480,259	(23,102,833)	(20,685,080)	(12,623,155)



To recognize the differences in rate structures among classes and the presence and absence of certain charge types among classes, in the first table below Staff combined (1) Customer and

Facilities charges, and (2) all energy-derived charges; and in the second table below Staff combined (1) Customer and Facilities charges, and (2) all demand-related charges:

	SGS Revenue	SGS Costs	MGS Revenue	MGS Costs	LGS Revenue	LGS Costs	LPS Revenue	LPS Costs
Customer & Facilities	$ 15,562,303	$ 13,081,816	$ 18,358,207	$ 22,331,787	$ 24,233,813	$ 26,634,248	$ 10,948,032	$ 8,427,082
Demand	$ -	$ 14,269,964	$ 10,304,141	$ 38,646,468	$ 24,970,325	$ 60,473,475	$ 32,488,103	$ 44,859,780
All Energy	$ 52,346,395	$ 29,076,659	$ 88,945,416	$ 79,732,342	$ 145,233,065	$ 128,014,560	$ 101,290,281	$ 104,062,709

	SGS Revenue	SGS Costs	MGS Revenue	MGS Costs	LGS Revenue	LGS Costs	LPS Revenue	LPS Costs
Customer & Facilities	$ 15,562,303	$ 13,081,816	$ 18,358,207	$ 22,331,787	$ 24,233,813	$ 26,634,248	$ 10,948,032	$ 8,427,082
Demand and Demand in	$ 24,344,445	$ 29,196,430	$ 41,450,162	$ 79,104,879	$ 87,274,688	$ 123,988,257	$ 83,399,859	$ 92,616,149
Non-Demand Energy	$ 28,001,950	$ 14,150,193	$ 57,799,395	$ 39,273,931	$ 82,928,702	$ 64,499,778	$ 50,378,525	$ 56,306,340

The highlighted cells indicate where the revenue derived from the charge type does not cover the allocated cost with which it is associated. In general, these results indicate that, in all classes, too much revenue is being recovered through combined customer and facilities charges, and that for the LPS class, too little revenue is being recovered through the non-demand (tail block) energy charge.

For comparison across classes, the unbundled costs and revenues by charge type are provided below, on a $/kWh average basis:

	SGS Revenue	SGS Costs	MGS Revenue	MGS Costs	LGS Revenue	LGS Costs	LPS Revenue	LPS Costs
Customer	$ 0.0301	$ 0.0123	$ 0.0027	$ 0.0023	$ 0.0011	$ 0.0001	$ 0.0004	$ 0.0000
Facilities	$ 0.0030	$ 0.0087	$ 0.0111	$ 0.0080	$ 0.0097	$ 0.0066	$ 0.0050	$ 0.0022
Demand	$ -	$ 0.0361	$ 0.0077	$ 0.0344	$ 0.0112	$ 0.0315	$ 0.0159	$ 0.0238
Demand in Energy	$ 0.0518	$ 0.0328	$ 0.0234	$ 0.0314	$ 0.0279	$ 0.0292	$ 0.0250	$ 0.0236
Energy	$ 0.0595	$ 0.0301	$ 0.0434	$ 0.0295	$ 0.0371	$ 0.0288	$ 0.0247	$ 0.0276

This comparison, in conjunction with the additional discussion of unbundled cost of service provided above, indicates the following:

(1) SGS revenues are over-recovered in general, but the revenue recovery generally aligns with cost-causation. (SGS does not have an NCP demand charge, and Staff's class cost of service indicates that SGS as a class over-contributes to revenues by approximately 18%);

(2) MGS and LGS rates are over-dependent on recovery through the non-demand component of energy charges;

(3) LPS revenues are under-recovered through the non-demand component of energy charges and through the demand charges. LPS revenues are over-recovered through the demand-components of energy charges, and through the facilities charge.

Non Residential Rate Design

Ultimately, Staff recommends KCPL and GMO adopt time of use rates for its non-residential non-lighting classes. Staff further recommends movement towards a continuous non-residential non-lighting rate design, as generally outlined in Staff's DER Report in the EW-2017-0245 Docket. Specifically, Staff recommends KCPL and GMO begin to take steps to move towards a rate design generally consisting of the following:

1. On Peak Energy $/kWh
    a. Recovers the market energy costs
    b. Recovers 60% or more of net generation-related costs (generation capacity, fuel, and purchased power, net of sales of energy into the market)
    c. Recovers approximately 30% to 40% of Transmission costs
2. Off Peak Energy $/kWh
    a. Recovers the market energy costs
    b. Recovers approximately 10% of net generation-related costs (generation capacity, fuel, and purchased power, net of sales of energy into the market)
    c. Recovers approximately 10%-15% of Transmission costs
3. Customer $/month (varies by size of service drop and on-site facilities)
    a. Includes metering costs, customer service costs, billing expenses, etc.
4. Monthly NCP $/kW – the highest 15 minutes of demand during the month
    a. Recovers approximately 50% of the costs of secondary distribution facilities
5. Designated Monthly CP $/kW – the highest 15 minutes of demand occurring during a specified time period in that month, for example, weekday afternoons between 1 -6pm.
    a. Recovers approximately 50% of the costs of primary distribution facilities and 25% of the costs of transmission facilities
6. Annual NCP $/kW – the highest monthly NCP during the last 12 months
    a. Recovers approximately 50% of the costs of secondary distribution facilities
7. Designated Annual CP $/kW – the highest CP occurring in a month defined as a peak month, within the prior 12 months

a. Recovers approximately 10% - 20% of net generation-related costs (generation capacity, fuel, and purchased power, net of sales of energy into the market)

b. Recovers approximately 25% of transmission costs

c. Recovers approximately 50% of primary distribution costs

To implement the changes to revenue requirement ultimately ordered in this case, on an intraclass basis Staff recommends the following:

(1) For KCPL's LPS class the declining blocked demand charges should first be flattened on a revenue-neutral basis within the class, regardless of whether any increase or decrease in revenue requirement be ordered. Any decrease ordered should be applied as an equal percent reduction to the facilities charge and the first and second blocks of the energy charge.

(2) For all other non-residential non-lighting classes for both utilities, Staff recommends that any class-level decrease be applied to the first and second block hour's use energy charges.

(3) If a class-level increase is ordered for any non-residential class for either KCPL or GMO, Staff recommends that such increase be applied as an additional charge to kWh sold between the hours of 8:00 am and 6:00 pm, on non-holiday weekdays. This will result, on average, in a relative shift of revenue recovery back from the energy charge variation based on customer NCP in a manner consistent with cost-causation.

While at this time the sizing of the ToU non-residential rider will be guided primarily by mitigation of customer impacts with a primary goal of customer education, over time this charge can be refined to more reasonably reflect the cost of capacity and other demand-related elements as allocated to classes and customers within a class, and is consistent with the development of a continuous non-residential rate structure and design.

Staff recommends that GMO's rate designs be fully reviewed and redesigned, as necessary, in GMO's next rate design or rate case, when a full year of usage and billing information for the classes as currently configured is available.

I. Wholesale Energy Prices

The day ahead market energy costs experienced by KCPL, at transmission voltage, during the test period are provided below, by month:

Start	10/31/2017	10/31/2017	9/30/2017	8/30/2017	7/30/2017	6/29/2017	5/29/2017	4/28/2017	3/28/2017	2/25/2017	1/25/2017	12/25/2016	11/24/2016
End	10/25/2016	10/1/2017	8/31/2017	7/31/2017	6/30/2017	5/30/2017	4/29/2017	3/29/2017	2/26/2017	1/26/2017	12/26/2016	11/25/2016	10/25/2016
Min	$ (28.01)	$ (28 01)	$ (3.52)	$ (2.61)	$ 12 04	$ (4.70)	$ (11.98)	$ (7.30)	$ (10 49)	$ (5.14)	$ 0 03	$ 2.19	$ (0 79)
Average	$ 20.39	$ 13.24	$ 19 98	$ 23.46	$ 27 10	$ 22.38	$ 18.98	$ 18.94	$ 15.50	$ 16.51	$ 21 41	$ 24 64	$ 22 56
Max	$ 64 24	$ 39 50	$ 49.40	$ 44.78	$ 59.12	$ 49.69	$ 52.83	$ 49 86	$ 39.55	$ 38 05	$ 51 07	$ 64.24	$ 46 95

The day ahead market energy costs experienced by GMO, at transmission voltage, during the test period are provided below, by month:

Start	10/31/2017	10/31/2017	9/30/2017	8/30/2017	7/30/2017	6/29/2017	5/29/2017	4/28/2017	3/28/2017	2/25/2017	1/25/2017	12/25/2016	11/24/2016
End	10/25/2016	10/1/2017	8/31/2017	7/31/2017	6/30/2017	5/30/2017	4/29/2017	3/29/2017	2/26/2017	1/26/2017	12/26/2016	11/25/2016	10/25/2016
Min	$ (17.49)	$ (17 49)	$ (0 11)	$ 0.27	$ 13 38	$ (3.24)	$ (9.47)	$ (0.77)	$ (5.31)	$ (1.39)	$ 2.60	$ 6.09	$ 4 61
Average	$ 22 43	$ 15.91	$ 21 97	$ 24 21	$ 28 52	$ 24 46	$ 20 59	$ 21 49	$ 17 68	$ 18.48	$ 23.16	$ 27 88	$ 24 74
Max	$ 69.67	$ 41.64	$ 56.73	$ 46.49	$ 62.69	$ 57.62	$ 54.72	$ 51.57	$ 41.13	$ 45.93	$ 57.37	$ 69.67	$ 50.20

These amounts do not reflect the losses experienced between transmission and retail voltages, and do not account for costs of participation in the real time market, ancillary services market, or acquisition of capacity resources.

J. Recommended Studies

(1) Staff recommends that prior to the next rate design or general rate case, KCPL and GMO each study the seasonal nature of demands on the transmission and distribution systems, as well as the seasonal nature of the costs of capacity and energy to serve load. Specifically, Staff recommends the utilities consider dividing the current "winter" season, which consists of all non-summer months, into winter and shoulder seasons.

(2) Staff recommends KCPL and GMO consider aligning the summer seasons of the two utilities, which currently vary by approximately 15 days.

(3) Staff recommends that KCPL and GMO begin to study and/or retain determinants associated with the creation of a coincident peak demand charge for all classes. For example, the highest 15 minute level of usage at any time between 12:01 pm and 6:00 pm on weekdays during the months of June – September.

(4) Staff recommends that KCPL and GMO develop the record necessary to assign facility extensions to the classes in which customers take service.

Staff Expert/Witnesses: Robin Kliethermes, Sarah L.K. Lange

IV. Other Tariff Issues

A. Economic Development Rider Revisions

Staff recommends revisions to KCPL's and GMO's Economic Development Rider tariff, intended to clarify the requirements of the program and to aid in the consistency of application of the discounts among customers. Staff's recommended tariff provisions are attached as Appendix 2, Schedule SLKL-d4.

Staff Expert/Witness: Sarah L.K. Lange

B. Electric Vehicle Make Ready Model

In its Report and Order in Case No. ER-2016-0285, concerning KCPL's request to include EV chargers in its Missouri jurisdictional regulated rate base, in addition to distribution infrastructure incidental to electric vehicle ("EV") charging, the Commission stated as follows:

> KCPL may include in rate base any equipment, such as distribution lines, transformers, and meters, necessary to provide electric service to an owner of an EV charging station, whether or not that owner is affiliated with KCPL. Also, the Commission orders KCPL to accumulate data regarding the appropriate electric rate to charge owners of EV charging stations and provide that data during its next general rate case. Finally, KCPL shall file an amended tariff to revise the existing prohibition on the resale of electricity in order to clarify that EV charging stations are not reselling electricity.

KCPL tariff sheets 1.30 et seq. set out the rules and regulations pertaining to the extension of electric facilities, including the calculation of a construction allowance to determine any construction charges to be borne by an applicant for service.[17] To more fully effectuate the quoted provisions of the Commission's Report and Order in No. ER-2016-0285, sometimes referred to as the "make ready" model for installation of EV charging equipment, Staff recommends incorporating additional provisions generally consistent with the following language into KCPL's existing line extension tariff provisions:[18]

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[17] The Commission has not issued similar language concerning GMO. GMO's line extension tariff provisions are similar in structure and content to KCPL's line extension tariff provisions.

[18] Values and terms provided are intended as a starting point for discussion, and should be modified to reasonably reflect the needs and characteristics of the utility service area prior to implementation.

9.02(D) 3. Make Ready EV Extension: A request by Applicant for a Distribution Extension to provide electric service to a customer-owned electric vehicle charging station meeting one or more of the provisions of 9.03(I). The cost of Distribution Extensions as specified in 9.03(I) shall be assumed to be fully offset by the Estimated Margin for Distribution Extension requests made prior to (1) December 31, 2023, and (2) installation of the number of specified installation of the facility types contained in 9.03(I). Distribution Extension costs in excess of those identified in 9.03(I) shall be borne by the Applicant as Construction Charges.

9.03(I) Make Ready EV Definitions and Terms of Service:

1. Summer Day Time: shall refer to the hours of 10:00 am through 6:00 pm on week days in summer billing months, except for holidays.
2. Non-Winter Nighttime: shall refer to the hours of 10:00 pm through 6:00 am in months other than the calendar months of December, January, and February.
3. Ordinary Time means all hours except those specified as Summer Day Time or Non-Winter Nighttime.
4. Publicly available means parking areas available to the general public with the indicated number of minimum parking spaces available, without permit, for example, parking areas at Parks, Commuter Parking Lots, Public Transportation parking areas, Public Parking Lots and Garages, Shopping Centers, and Retail facilities.
5. Employee parking and residential parking may qualify if parking spots are not assigned, and the indicated minimum parking spaces available requirements are met.
6. Where indicated, the Applicant shall ensure that sufficient measures are in place to reasonably cause EVs to vacate the charging location to enable other EVs to access the charging location.
7. Within 30 days of the promulgation of this tariff sheet the utility shall file an additional tariff sheet bearing 30 days' effective date designating no fewer than 50 locations as suitable for publicly-available capable of charging no fewer than five (5) ports at a capacity of 40-50 kW on the basis of distribution system capacity, that are accessible within .25 miles of two or more roads carrying an average of not less than 10,000 cars per day.
8. EV charging under this program shall be separately metered from any other customer uses on the premises. Customers receiving Distribution Extensions for EV Charging under these provisions shall be served under the EV ToU Rate Schedule.
9. The ports shall be configured and throttled so that the applicable demand specified is not exceeded, but that the capacity allotted to each vehicle seeking to charge not be limited beyond the safe operating parameters of the equipment.
10. The length of extension assumed to be offset for each configuration is provided below:

Length of Extension (in feet)	Summer Day Time Max Demand (kW)	Ordinary Max Demand (kW)	Non-Winter Nighttime Max Demand (kW)	Minimum # of Level 2 Ports	Minimum # of Level 3 Ports	Public Accessibility Minimum Size	Alternative Employee/Residential Minimum Size	Overstay Requirement	Designated Charging Corridor Required?	Available Extensions
1000	7	20	24.5	3		75	100	4 Hours		50
50	7	20	24.5	1		15	30	4 Hours		50
1000	34	92	124	5		100	150	2 Hours		25
1000	69	185	249	10		200	300	2 Hours		25
1000	139	219	294	5	5	NA	NA	30 minutes	Yes	15

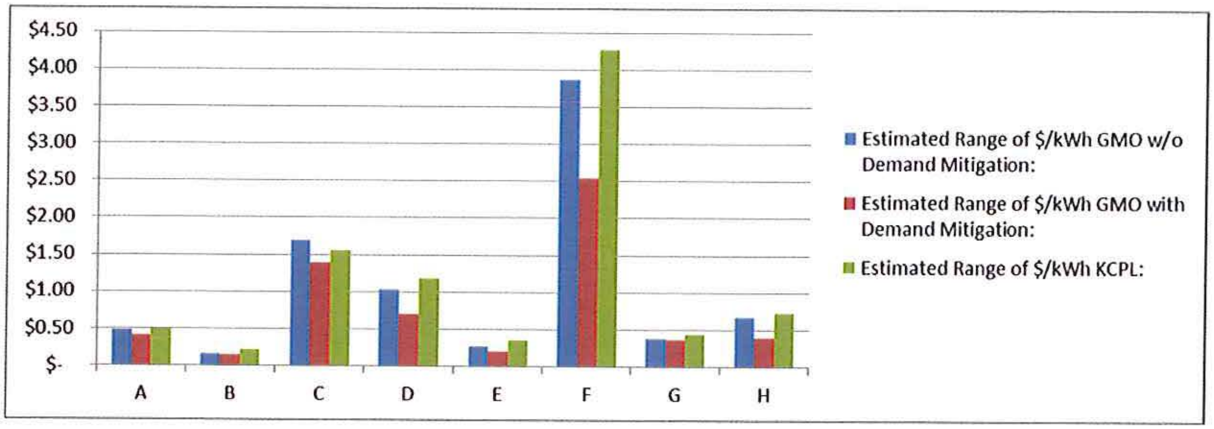
Staff Expert/Witness: Sarah L.K. Lange

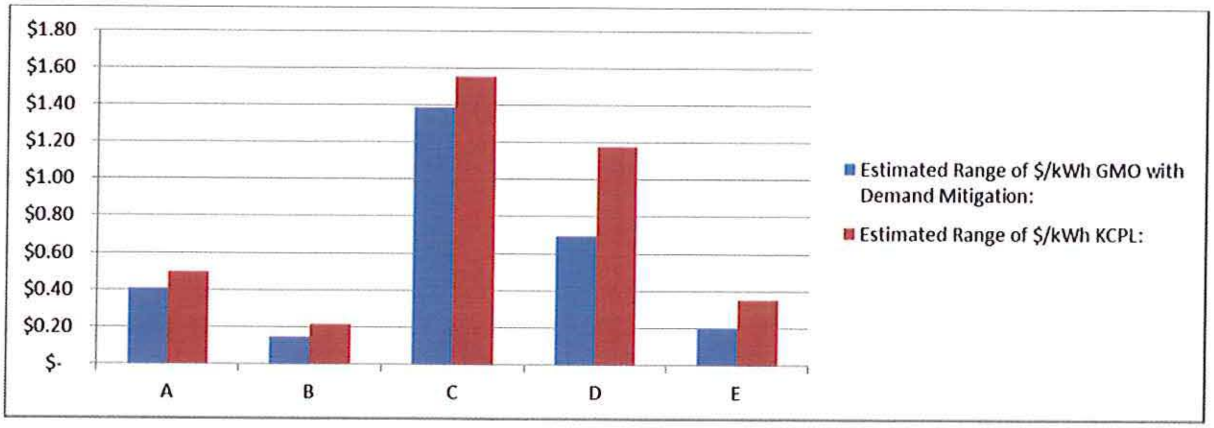
C. Separately Metered Electric Vehicle Charging Rate Schedule

GMO's SGS rate structure includes (1) a customer charge that is a set price per customer per month regardless of that customer's demand, (2) a facilities charge, based on that customer's annual non-coincident peak demand, (3) a demand charge, based on that customer's monthly non-coincident peak demand, and (4) energy charges. The energy charges are both seasonally differentiated and priced out in declining hours-use blocks, which charge a higher average price per kWh to customers with a lower load factor than to customers with a higher load factor. These elements, particularly the demand-related charges and the declining hours-use design of the energy charge, can result in relatively high average $/kWh prices for customers operating separately-metered EV charging equipment. The otherwise applicable bill is somewhat mitigated if the monthly demand charge (item 3 in the SGS rate structure) is based on the customer's peak coincident with the system peak. Such mitigation of demand charges could be appropriate if offered in conjunction with an approach similar to that recommended by Staff under the "make ready" EV line extension tariff provisions, which requires throttling be implemented to mitigate the impact of separately-metered EV charging on the system's generation, transmission, and distribution capacity requirements.

KCPL's SGS rate structure includes (1) a customer charge that varies by customer based on that customer's demand, (2) a facilities charge, based on that customer's annual non-coincident peak demand, and (3) energy charges. The energy charges are both seasonally differentiated and priced out in declining hours-use blocks, which charge a higher average price per kWh to customers with a lower load factor than to customers with a higher load factor. Staff considered a variety of charging utilization scenarios associated with the build-out scenarios contemplated in the "make ready" EV line extension tariff provisions. The resulting $ per kWh resulting from estimated bills under current SGS Secondary rates for GMO, demand mitigated rates for GMO, and SGS Secondary rates for KCPL are provided in the chart and graphs below:

Charging Scenario:	A	B	C	D	E	F	G	H
Estimated Range of $/kWh GMO w/o Demand Mitigation:	$ 0.48	$ 0.16	$ 1.70	$ 1.03	$ 0.27	$ 3.87	$ 0.38	$ 0.67
Estimated Range of $/kWh GMO with Demand Mitigation:	$ 0.41	$ 0.15	$ 1.39	$ 0.70	$ 0.20	$ 2.54	$ 0.36	$ 0.40
Estimated Range of $/kWh KCPL:	$ 0.50	$ 0.22	$ 1.55	$ 1.18	$ 0.35	$ 4.27	$ 0.43	$ 0.73





Given the overall range of the average $/kWh to be recovered under existing KCPL rates and Demand-Mitigated GMO rates, Staff recommends creation of a separately-metered EV charging rate schedule. Participation in this schedule should be (1) required of customers receiving Distribution Extensions for EV Charging under Staff's recommended Make Ready provisions and (2) made available to any customer with separately-metered EV charging where the demand limitations are in place:

1. Summer Day Time: shall refer to the hours of 10:00 am through 6:00 pm on week days in summer billing months, except for holidays. Maximum Demand of 14 kWh.
2. Non-Winter Nighttime: shall refer to the hours of 10:00 pm through 6:00 am in months other than the calendar months of December, January, and February. Maximum Demand of 24.5 kWh.
3. Ordinary Time means all hours except those specified as Summer Day Time or Non-Winter Nighttime. Maximum Demand of 49.5 kWh.

On a revenue neutral basis, Staff recommends the following rates for separately-metered EV Charging at secondary voltage:

	GMO	KCPL	
Base Customer Charge:	10.00	10.00	$/Month
Facilities Charge:	0.5564	0.3632	$/kW
On-Peak (as defined in Residential Tariff):	$ 0.41	$ 0.50	$/kWh
Off-Peak (as defined in Residential Tariff):	$ 0.15	$ 0.22	$/kWh

Staff Expert/Witness: Sarah L.K. Lange

D. Solar Subscriber Program

Customers who are interested in solar generation may not have the ability to own their own systems for a variety of reasons, such as, lacking a suitable site (due to space, shading, roof pitch), being renters or apartment dwellers, or having near-term plans to move. Shared solar programs, or community solar programs, provide customers with an option for solar generation by allowing a single facility to serve multiple dispersed customers. A key driver for differences in solar access among income groups is home ownership;[19] community solar programs can be designed to expand solar access to low to moderate income customers.

[19] Barbose, G., N. Darghouth, B. Hoen, and R. Wiser. 2018. *Income Trends of Residential PV Adopters: An analysis of household-level income estimates.* Berkeley, CA: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/income-trends-residential-pv-adopters.

Key principles to a quality, utility-offered, shared solar program include:

- Expanding solar energy access equitably to various customers, including low to moderate income customers, and customer classes;
- Balancing the economic benefits to subscribers with the risk to non-subscribers; and
- Reasonably accommodate a range of consumer preferences[20] with consideration of administrative ease.

Shared solar programs vary greatly dependent on program design. Typical program attributes, corresponding design options, and the key principles which are impacted are presented in the table[21] below:

Program Attribute	**Description**	**Design Options**	**Principles impacted**
Participation Mechanism	How the subscriber pays for participation in the program.	Options include a rate (may be designed as a replacement of certain charges), upfront payment (entire project or per panel), or a combination of both.	Subscriber benefit/Non-subscriber risk
Economic value	The value subscribers receive in participating.	Options include fixed rate for the lifetime of the asset or bill credits (may be based on net energy metering rate or retail rate or other valuation).	Subscriber benefit/Non-subscriber risk
Size Increments	A set increment in which a subscriber can increase or decrease its share.	Size of solar blocks vary (in kW or kWh) or based on percentage of total system size.	Consumer Preferences/ Program Administration
Subscription Fee	Used to guarantee a participant's subscription prior to the community solar project.	If included, this fee is typically fairly low. May be treated as a deposit.	Program Administration
Treatment of Renewable Energy Credits	Determination on which party retains the RECs generated by the project.	Utility, subscribers, or retired on behalf of program.	Consumer Preferences/ Program Administration

[20] Including whether or not the program is additive to existing renewable programs and policies.

[21] Program attributes, descriptions, and design options based on review of the following: Solar Electric Power Association. *Community Solar Handbook*. 2013, Interstate Renewable Energy Council. *Shared Renewable Energy State Policy Catalog*. 2017; Response to Staff Data Request No. 0230, and Staff research of various programs.

Program Attribute	Description	Design Options	Principles impacted
Availability	Customer classes which are allowed to participate.	Programs may be limited to target specific customer classes or split so that various classes have the option to participate.	Equitable solar energy access
Participation limitations	Limitation on an individual's share ensures multiple subscribers can participate.	Based on a percentage of average usage or capacity (number of panels or kW).	Equitable solar energy access
Subscription Transfers	Whether subscriptions can be transferred to others or follow the individual.	May include fee, re-evaluation of participation limitations, or limitation on the number of transfer occurrences.	Consumer Preferences/ Program Administration
Cancelation Fees and Minimum Subscription Term	Used to discourage subscribers from leaving the program or to ensure a subscriber will participate for a certain amount of time.	Fees vary but tend to be $100 or more; terms vary 1 year-10 years	Non-subscriber risk; Consumer Preferences/ Program Administration
Unsubscribed energy	How unsubscribed energy is treated.	May be covered by all ratepayers, marketed for another use, or by sponsoring utility outside of typical ratemaking.	Non-subscriber risk

Staff recommends that KCPL and GMO offer, for each jurisdiction, a community solar program to provide increased renewable choices to customers.[22]

Staff Expert/Witness: Claire M. Eubanks, P.E.

E. <u>Renewable Energy Rider</u>

Renewable energy resources and green initiatives have become popular with organizations wanting to spark social change or market themselves as forward thinking. There is a growing list of cities and businesses that have gone, or have plans to go, "100% renewable" in the near future. Typically, obtaining a large enough resource to accomplish this is cost

[22] KCPL and GMO proposed a co-offered program, Staff's recommendation is that each utility offer a separate program.

prohibitive for all but the largest of organizations, and many lack the expertise to manage said assets. To serve this market, providers of renewable energy have offered the option to purchase energy for a contracted price under purchased power agreements ("PPAs"). These allow for access to renewable energy without the need to construct it. Large businesses can enter into these contracts to manage their energy needs outside of a utility.

To some extent, keeping large energy users as customers provides benefits to utilities and ratepayers. Therefore, a utility may offer access to renewable energy resources for said large users to entice them to remain customers and eliminate the need for a large user to purchase energy via a PPA. Such programs are often referred to as green tariff programs. There are many designs for a green tariff program. These programs have much in common with the solar programs discussed in testimony by Staff witness Claire M. Eubanks. Typical program attributes, corresponding design options, and the key principles impacted are presented in the table below.

Program Attribute	Description	Design Options	Principles impacted
Participation Mechanism	How the subscriber pays for participation in the program.	Options include a rate (may be designed as a replacement of certain charges), upfront payment (entire project or per resource unit), or a combination of both.	Subscriber benefit/Non-subscriber risk
Economic value	The value subscribers receive in participating.	Options include fixed rate for the subscription term or life of the asset, or bill credits (may be based on net energy metering rate or retail rate or other valuation).	Subscriber benefit/Non-subscriber risk
Size Increments	A set increment in which a subscriber can increase or decrease its share.	Size of subscription blocks vary (in kW or kWh) or based on percentage of total system size.	Consumer Preferences/ Administration

Program Attribute	Description	Design Options	Principles impacted
Subscription Fee	Used to guarantee a participant's subscription prior to the renewable energy project.	If included, this fee is typically fairly low. May be treated as a deposit.	Administration
Treatment of Renewable Energy Credits	Determination on which party retains the RECs generated by the project.	Utility, subscribers, or retired on behalf of program.	Consumer Preferences/ Administration
Availability	Customer classes which are allowed to participate.	Programs may be limited to target specific customer classes or split so that various classes have the option to participate. Programs may offer specific terms for individual customers.	Equitable renewable energy access
Participation limitations	Limitation on an individual's share ensures multiple subscribers can participate.	Based on a percentage of average usage or capacity (output from specific units or kW).	Equitable renewable energy access
Subscription Transfers	Whether subscriptions can be transferred to others or follow the individual.	May include fee, re-evaluation of participation limitations, or limitation on the number of transfer occurrences.	Consumer Preferences/ Administration
Cancelation Fees and Minimum Subscription Term	Used to discourage subscribers from leaving the program or to ensure a subscriber will participate for a certain amount of time.	Fees vary but tend to be $100 or more and are designed to cover the costs of the formerly subscribed portion for the remainder of the contract; terms vary but typically are 5 years-20 years.	Non-subscriber risk; Consumer Preferences/ Administration
Unsubscribed energy	How unsubscribed energy is treated.	May be covered by all ratepayers, marketed for another use, or covered by sponsoring utility outside of typical ratemaking.	Non-subscriber risk

Staff recommends that KCPL and GMO each offer independent green tariff programs to provide increased renewable choices to customers.

Staff Expert/Witness: Cedric E. Cunigan

F. Distributed Energy Resources Considerations

As proposed in Staff's Report on Distributed Energy Resources filed in EW-2017-0245, dated April 5, 2018, Staff recommends KCPL and GMO maintain information related to distributed energy resources. To accomplish this, Staff recommends the following language be added to KCPL's and GMO's Net Metering Interconnection Agreement:

> The Company shall maintain and aggregate the following information related to customer generator systems:
>
> 1. Characterization of the distribution circuits where the systems are connected,
>
> 2. Aggregate capacity of the systems for each feeder or load, and
>
> 3. Relevant interconnection standard requirement that specify the performance of the system.

For larger distributed energy resources, Staff recommends the following language be included in KCPL's and GMO's Parallel Generation Contract Service (Cogeneration Purchase Schedule) and Standby Service Rider:

> The Company shall maintain the following information related to customer generator systems which are greater than 100 kW:
>
> 1. Type of generating resource,
>
> 2. Distribution bus nominal voltage where the system is connected,
>
> 3. Feeder characteristics for connecting the system to distribution bus, if applicable,
>
> 4. Capacity of each resource,
>
> 5. Relevant interconnection standard requirements, and
>
> 6. Actual plant control modes in operation.

To support the evaluation of the Standby Service Rider, and to enable adjustment of rate design or rate structure, as applicable, Staff recommends that KCPL and GMO retain hourly load data, or 15-minute interval data, where available, for each customer served under the Standby Service Rider.

Staff Expert/Witness: Claire M. Eubanks, P.E.

V. FAC Tariff Issues

A. <u>Loss Study As Applied to the Fuel and Purchases Power Adjustment Clause</u>

KCPL and GMO are both seeking authorization to continue using their respective Fuel Adjustment Clauses ("FAC") in the current rate cases pursuant to Commission Rule 4 CSR 240-20.090. In order to continue their FACs, KCPL and GMO must design rates that reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes. To ensure this, 4 CSR 240-20.090(9) requires an electric utility to conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial FAC, and again no less often than every four (4) years thereafter. KCPL and GMO supplied Staff with a Loss Study in a supplemental Response to Staff Data Request No. 0388 on June 12, 2018. This loss study is said to be an analysis based on data collected on KCPL's and GMO's respective systems during calendar year 2016. Staff is presently evaluating this loss study. At this time, while Staff may later consider using data contained in this loss study in a determination of voltage adjustment factors, Staff will continue to utilize the voltage adjustment factors that are currently included in the respective KCPL and GMO FAC tariffs:

KCPL:
- Transmission – 1.0195
- Primary – 1.0451
- Secondary – 1.0707

GMO:
- Primary – 1.0419
- Secondary – 1.0709

These voltage adjustment factors account for the energy losses experienced in the delivery of electricity from the generation level to the retail customer (secondary level). These factors will be utilized in Staff's determination of Fuel Adjustment Rates ("FAR"), applicable to the individual voltage service classification of a particular customer in the corresponding FAC tariff, if the Commission authorizes KCPL and/or GMO to continue their respective FAC tariffs.

Staff Expert/Witness: Alan J. Bax

B. <u>Fuel and Purchased Power Adjustment Clause Tariff Sheet Recommendations</u>

Staff provides its recommendations for the following issues that have an impact on KCPL's and GMO's respective fuel adjustment clauses ("FAC") and FAC tariff sheets:

1. Continue KCPL's FAC and GMO's FAC with the modifications discussed below:

    a. Include a new Base Factor for KCPL and a new Base Factor for GMO in the FAC tariff sheets calculated from the Net Base Energy Cost[23] that the Commission includes in the revenue requirement upon which it sets KCPL's and GMO's general rates in this case;

    b. Continue suspension of financial fuel hedging activities for KCPL and financial hedging activities (cross hedging and fuel hedging) for GMO;

    c. Clarify that the only transmission costs that are included in KCPL's FAC and GMO's FAC are those that KCPL and GMO incur for purchased power[24] and off-system sales ("OSS"); excluding any and all transmission costs related to GMO's Crossroads Generating plant;

    d. Order KCPL and GMO to continue to provide the additional information as part of its monthly reports[25] as KCPL was ordered to do in Case No. ER-2016-0285 and as GMO was ordered to do in Case No. ER-2016-0156;

    e. Add subaccounts 555035, purchased power associated with WAPA contract, and 447035, revenue associated with the WAPA contract, and their descriptions to the GMO compliance tariff sheets filed in this case;

[23] Net Base Energy Cost is defined in KCPL's Second Revised Sheet No. 50.7 and defined in GMO's 4th Revised Sheet No. 127.10 as Net base energy costs ordered by the Commission in the last general rate case for KCPL and GMO and consistent with the costs and revenues included in the calculation of the FPA.

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

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

C. Fuel Adjustment Clause Tariff Sheets Modifications

Staff reviewed the current KCPL FAC tariff sheets that were approved by the Commission in Case No. ER-2016-0285 and became effective July 27, 2017, and GMO's FAC tariff sheets that were approved by the Commission in Case No. ER-2016-0156 and became effective February 22, 2017. The current FAC tariff sheets reflect KCPL's and GMO's participation in the Southwest Power Pool's ("SPP") Integrated Marketplace ("IM") and account for transmission costs in a manner consistent with the way transmission costs are treated in Ameren Missouri's and Empire's current FACs.

In summary, Staff proposes the following modifications to the KCPL and GMO FACs:

1. Replace the current Base Factor with the revised Base Factor of $0.01657 per kWh for KCPL and $0.02186 per kWh for GMO 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 27.5% for KCPL and 47.5% for GMO as Staff calculated for this case, as described in the Revised Transmission Percentage section of this report;
3. Add subaccounts 555035, purchased power associated with WAPA contract, and 447035, revenues associated with the WAPA contract, and their descriptions to the GMO compliance tariff sheets when they are filed in this case;

Staff Expert/Witnesses: Brooke Richer, Catherine F. Lucia

During Staff's review of the Base Factor calculation for GMO's FAC, Staff determined that accounts 555035, purchased power associated with the WAPA contract, and 447035, revenues associated with the WAPA contract, should be included in the Base Factor calculation and should be included on GMO's tariff sheets. Staff understands these accounts to be in the nature of purchased power contracts and therefore should be included in the Base Factor calculation for GMO's tariff sheets. Staff is recommending GMO include these accounts on its compliance FAC tariff sheets.

Staff Expert/Witness: Brooke Richter

D. 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:

KCPL Base Factor: $0.01657 per kWh

GMO Base Factor: $0.02186 per kWh

Staff Expert/Witnesses: Brooke Richter, Catherine F. Lucia

E. Revised Transmission Percentage

As provided in Staff witness Shawn E. Lange's workpapers,[26] Staff calculated the pass-through percentage of SPP transmission costs[27] in the FAC as 27.5% for KCPL. As provided in Staff witness Charles T. Poston's workpapers,[28] Staff calculated the pass-through percentage of SPP transmission costs[29] in the FAC as 47.5% for GMO. This calculation is based on the output from Staff's fuel models that were used to develop the revenue requirements found in Staff's COS report for this case. The calculations are appropriate because they are 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/Witnesses: Brooke Richter, Catherine F. Lucia

F. FAC Voltage Adjustment Factors

Staff is currently reviewing a line loss study which was received in June 2018. At this time, Staff witness Alan J. Bax continues to use the voltage adjustment factors presently included

[26] Workpaper titled "KCPL Summary 6-13-18 final" tab "FAC%".

[27] The pass-through percentage of SPP transmission costs are a representation of transmission expenses that are associated with energy purchases from the SPP IM in excess of energy generation by KCPL's and GMO's respective generation units.

[28] Workpaper titled "GMO Summary 06-13-18 – Direct" tab "FAC%".

[29] The pass-through percentage of SPP transmission costs are a representation of transmission expenses that are associated with energy purchases from the SPP IM in excess of energy generation by KCPL's and GMO's respective generation units.

in the FAC tariff sheets for the most recent general rate cases of KCPL and GMO in the current general rate case as provided in the following table.[30]

	KCPL	GMO
Voltage Level	**Voltage Adjustment Factor**	
Transmission	1.0195	N/A
Primary	1.0451	1.0419
Secondary	1.0707	1.0709

These voltage adjustment factors adjust for the energy losses experienced in the delivery of electricity from the generator to customers with 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. The voltage adjustment factors may change based on Staff's recommendation after the review of the line loss study is completed.

Staff Expert/Witnesses: Brooke Richter, Catherine F. Lucia

VI. Appendices

Appendix 1 - Staff Credentials

Appendix 2 – Other Staff Schedules

[30] KCPL rate case ER-2016-0285 and GMO rate case ER-2016-0156.

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-2018-0145
		and
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ALAN J. BAX and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Class Cost of Service Report* and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Alan J Bax
ALAN J. BAX

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 2nd day of July, 2018.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Dianna L. Vaught
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-2018-0145
		and
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF CEDRIC E. CUNIGAN

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CEDRIC E. CUNIGAN and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Staff Class Cost of Service Report* and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Cedric E. Cunigan

CEDRIC E. CUNIGAN

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 5th day of July, 2018.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Dianna L. Vaught

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-2018-0145
		and
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF CLAIRE M. EUBANKS, P.E.

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CLAIRE M. EUBANKS, P.E., and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Class Cost of Service Report* and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Claire M Eubanks
CLAIRE M. EUBANKS, P.E.

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 3rd day of July, 2018.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Dianna L. Vaught
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-2018-0145
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In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF ROBIN KLIETHERMES

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW ROBIN KLIETHERMES, and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Class Cost of Service Report* and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

ROBIN 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 3rd day of July, 2018.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Dianna L. Vaught
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-2018-0145
		and
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF SARAH L. K. LANGE

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW SARAH L. K. LANGE and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Class Cost of Service Report* and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Sarah LK Lange
SARAH L. K. LANGE

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 3rd day of July, 2018.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Dianna L. Vaught
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-2018-0145
		and
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF CATHERINE F. LUCIA

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW CATHERINE F. LUCIA and on her oath declares that she is of sound mind and lawful age; that she contributed to the foregoing *Staff Class Cost of Service Report* and that the same is true and correct according to her best knowledge and belief.

Further the Affiant sayeth not.

Catherine F. Lucia

CATHERINE F. LUCIA

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 2nd day of July, 2018.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Dianna L. Vaught

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-2018-0145
		and
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	Case No. ER-2018-0146

AFFIDAVIT OF BROOKE RICHTER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

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

Further the Affiant sayeth not.

Brooke Richter

BROOKE RICHTER

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 3rd day of July, 2018.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: June 28, 2019
Commission Number: 15207377

Dianna L. Vaught
Notary Public