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MISSOURI PUBLIC SERVICE COMMISSION

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

KCP&L GREATER MISSOURI OPERATIONS COMPANY

CASE NO. ER-2012-0175

Jefferson City, Missouri
August 21, 2012

Staff Exhibit No. 267
Date 10/17/12 Reporter MM
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Staff Exhibit - 267

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RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

I. Executive Summary

As Staff described in the corrected Revenue Requirement Cost of Service Report ("COS Report") it filed August 13, 2012, in this case, KCP&L Greater Missouri Operations Company ("GMO") has two rate districts–L&P (in and about St. Joseph, Missouri) and MPS (the remainder of GMO's service area). Staff determined operating revenues and class cost of service for each rate district based on assigning generating capacity based on whether St. Joseph Light & Power Company owned it and Commission orders, except that Staff shifted the assignment of the 71 MW Ralph Green combustion turbine from MPS to L&P.

Although Staff treated each rate district separately in this case for class cost of service and rate design, because typical residential customer bills now are close between the two districts, GMO needs more capacity to serve its L&P district than the traditional assignments based on what St. Joseph Power & Light Company had when Aquila acquired it and GMO has the capacity it needs to serve both L&P and MPS, Staff is recommending the Commission order GMO to perform comprehensive studies of the customer impacts of eliminating its rate districts and the differences in its costs to serve its customers in its L&P and MPS rate districts, if any. In particular, Staff recommends:

- That the Commission order GMO to prepare and file in its next general rate increase a comprehensive study of the impacts on its retail customers of eliminating the MPS and L&P rate districts and implementing company-wide uniform rate classes, and rates and rate elements for each rate class; and
- That the Commission order GMO to perform a comprehensive class cost-of-service study to determine the differences in its cost of serving each class of MPS and L&P customers.

Based on the results of its Class Cost-of-Service ("CCOS") studies in this case, Staff's rate design recommendations are that the Commission order GMO to implement the following rate designs:

For its MPS rate district

- Apply any overall change in revenue requirement ordered by the Commission on an equal percentage basis to all classes.

For its L&P rate district

- Apply any overall change in revenue requirement ordered by the Commission on an equal percentage basis to all classes, then
- Impose an additional 6% increase for the two winter energy block rates of the MO 920 rate schedule (residential service with space heating). This adjustment will bring the winter season rates closer to the class cost of service for that class in the winter season.
- Impose an additional 6% increase for the winter energy rate of the MO 922 Frozen rate schedule (residential space heating / water heating – separate meter). The MO 922 rate schedule is not available for new installations as of June 15, 1995. This adjustment will bring the winter season rates closer to the class costs of service for these classes in the winter season.
- Impose an additional 6% increase for winter energy rate of the MO 941 Frozen rate schedule (non-residential space heating/water heating – separate meter). The MO 941 rate schedule is not available for new installations as of June 15, 1995. This adjustment will bring the winter season rate closer to the class cost of service for this class in the winter season.

Staff's objectives in this Report are:

1. To present an overview of Staff's CCOS study results for MPS and L&P. Staff's CCOS study is based upon the test year of October 1, 2010 through September 30, 2011, updated through March 31, 2012. It is to be trued-up through August 31, 2012;
2. To provide the Commission with rate design recommendations that are based on each customer class's relative cost-of-service responsibility;
3. To provide methods to implement in rates any Commission-ordered overall changes in customer revenue responsibility;
4. To retain, to the extent practical, existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock; and
5. To modify GMO's fuel adjustment clause ("FAC") tariff sheets to be consistent with Staff recommendations in the corrected Staff COS Report that was filed August 13, 2012, and to simplify and clarify current GMO FAC language.

Staff's CCOS Report is organized into the following main sections. They are:

- Executive Summary
- Class Cost-of-Service and Rate Design Overview
- Staff Class Cost-of-Service Study - MPS and L&P
- Rate Design – MPS and L&P
- FAC Voltage Adjustment Factors
- Fuel adjustment clause – MPS and L&P

The results of Staff's CCOS study for MPS are summarized in Table 1 and its results for L&P are summarized in Table 2 below.

Table 1
Summary Results of Staff's CCOS Study – MPS

Customer Class	Revenue Deficiency	CCOS % Increase	System Average	Revenue Neutral Increase
Residential				
Regular and Other Use	$8,459,937	4.73%	-2.18%	2.54%
Space Heating	$3,581,646	2.99%	-2.18%	0.81%
Small General Service				
Primary	$1,220	4.42%	-2.18%	2.24%
Secondary	($927,654)	-1.35%	-2.18%	-3.53%
No Demand & Short Term without Demand	($722,382)	-7.80%	-2.18%	-9.98%
Large General Service				
Primary & Secondary	$464,560	0.65%	-2.18%	-1.54%
Large Power Service				
Primary	($465,416)	-1.10%	-2.18%	-3.28%
Secondary	$523,040	1.17%	-2.18%	-1.01%
Lighting				
Lighting – Combined	$977,613	10.37%	-2.18%	8.19%
Total	$11,892,564	2.18%	-2.18%	0.00%

Table 2
Summary Results of Staff's CCOS Study - L&P

Customer Class	Revenue Deficiency	CCOS % Increase	System Average	Revenue Neutral Increase
Residential				
Regular and Other Use	$383,424	0.92%	-2.73%	-1.81%
Space Heating	$6,256,379	20.06%	-2.73%	17.33%
General Service				
General Use	($845,468)	-10.08%	-2.73%	-12.81%
Limited Demand & Short Term	($767,039)	-17.25%	-2.73%	-19.98%
Separate Meter SH/WH	$36,835	27.98%	-2.73%	25.25%
Large General Service				
Primary, Secondary, & Substation	($328,028)	-1.12%	-2.73%	-3.85%
Large Power Service				
Primary	$54,709	0.63%	-2.73%	-2.10%
Secondary	$572,857	1.64%	-2.73%	-1.09%
Substation	($142,991)	-3.79%	-2.73%	-6.52%
Transmission	($364,580)	-9.11%	-2.73%	-11.85%
Lighting				
Lighting - Combined	($200,539)	-5.06%	-2.73%	-7.79%
Total	$4,655,560	2.73%	-2.73%	0.00%

Table 1 and Table 2 each show the rate revenue shifts necessary for the current rate revenues from each customer class to exactly match with Staff's determination of GMO's cost of serving that class. Staff developed its analysis of the cost of serving each class using inputs taken from the Staff's COS Report and Accounting Schedules. Staff's customer classes correspond to GMO's current rate schedules, except that MPS primary[1] and secondary large general service customers were combined into one class ("Primary & Secondary"), MPS non-

[1] MPS only has twenty two large general service customers that are served at primary.

demand and short-term[2] were combined into one class ("No Demand & Short Term without Demand"), L&P Limited Demand and Short Term general service customers were combined ("Limited Demand & Short Term")[3] into one class, all MPS lighting rate schedules were combined into one class, and all L&P lighting rate schedules were combined into one class.

The results of a CCOS study can be presented either in terms of (1) the rate of return a utility realizes for providing service to each class or (2) in terms of the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize the utility's rate of return from each class. The results of Staff's analysis are presented in terms of the shifts in revenue that produce an equal rate of return for GMO from each customer class.

A negative amount or percentage indicates revenue from the customer class exceeds the cost of providing service to that class; therefore, to equalize revenues and cost of service, rate revenues should be reduced, i.e., the class has overpaid. A positive amount or percentage indicates revenue from the class is less than the cost of providing service to that class; therefore, to equalize revenues and cost of service, rate revenues should be increased, i.e., the class has underpaid.

Staff's recommended customer class revenue adjustments are intended to bring the winter season rates with electric space heating (residential and non-residential) closer to GMO's cost to serve that class in the winter season, while maintaining rate continuity, maintaining revenue stability, and minimizing rate shock to any customer class.

Staff recommends the Commission make changes to GMO's FAC tariff sheets to implement the changes Staff identified in its COS Report and to update the expansion factors

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[2] Short term average monthly usage is 321 kWh.
[3] L&P only has sixty-six short term customers.

Staff used in preparing that report. Staff is also recommending changes to GMO's FAC tariff sheets to simplify and clarify the current FAC language.

II. Class Cost-of-Service and Rate Design Overview

The purpose of a CCOS study is to determine whether each class of customers is providing the utility with a level of revenue reasonably necessary to cover (1) the utility's investments required to provide service to that class of customers and (2) the utility's ongoing expenses to provide electric service to that class of customers. A CCOS study provides a basis for allocating and/or assigning to the customer classes the utility's total jurisdictional cost of providing electric service to all the customer classes in a manner which best reflects cost causation. Since those jurisdictional costs equate to the utility's jurisdictional revenue requirement, the results of a CCOS study determine class revenue requirements based on the cost responsibility of each customer class for its equitable share of the utility's total annual cost of providing electric service within a given jurisdiction -- Missouri retail in this case.

Schedule MSS-6 provides fundamental concepts, terminology, and definitions used in CCOS studies and rate design. It addresses functionalization, classification, and allocation as used in CCOS studies. It lists generation allocation methods outlined in the National Association of Utility Commissioners ("NARUC") Manual and provides Staff's descriptions of the strengths and weaknesses of some of the more common allocation methods used in CCOS studies.

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

The results of Staff's CCOS studies appear in Table 1 (MPS) and Table 2 (L&P) above and in attached Schedules MSS-1 and MSS-2. They show the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with GMO's cost to serve that class. The results are also presented, on a revenue neutral basis, as the revenue shifts (expressed as negative or positive dollar amounts or percentages) that are required to equalize GMO's rate of return from each customer class.

Revenue neutral means that the revenue shifts among classes do not change the utility's total system revenues. Staff finds the revenue neutral format aids in comparing revenue deficiencies between customer classes and makes it easier to discuss revenue neutral shifts between classes, if appropriate. Staff calculated the revenue neutral percent increase to a class's rate revenue by subtracting the overall system average increases of 2.18% for MPS and 2.73% for L&P, which the Staff determined and reported in its COS Report, from each customer class's required percentage increase to rate revenue to match the revenues GMO should receive from that class to match GMO's cost to serve that class.

For example, based on Table 1, on a revenue neutral basis, the Residential - Regular customer class is providing 2.54% fewer revenues to GMO than GMO's cost to serve that MPS class. Also, the Small General Service Secondary class is providing 3.53% more revenues to GMO than GMO's cost to serve that MPS class.

Because a CCOS study is not precise and the results can vary according to the allocation methodologies chosen, it should be used only as a guide for designing rates. In addition, bill impacts need to be considered. While reducing over-collection from customer classes with negative revenue shift percentages (revenues greater than cost to serve) is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered. Based on its CCOS study results and judgment, Staff recommends no revenue neutral adjustments between any MPS or L&P customer classes.

However, Staff does recommend intra-class revenue adjustments for space heating customers in GMO's L&P rate district and an intra-class revenue adjustment for general service space heating customers in GMO's L&P rate district. These intra-class revenue shifts are intended to bring the winter season rates closer to GMO's costs to serve these classes in the winter season. As a result, Staff's recommended increase to the summer rates for the residential class in the L&P rate district is less than the system average.

Staff's CCOS study used costs and revenues from Staff's accounting information and from the other sources that are identified below.

A. Data Sources

Staff's CCOS study is based on the data on its revenue requirements for MPS and L&P that it reported in its corrected COS Report filed on August 13, 2012. This data includes:

- Adjusted jurisdictional investment and cost data by FERC account;
- Annualized, normalized rate revenues;
- Fuel and purchased power costs;
- Other operating and maintenance expenses;
- Depreciation and amortizations; and
- Taxes.

In addition, Staff reviewed GMO witness Paul M. Normand's direct testimony and workpapers from this case on meters, meter reading, uncollectible accounts, customer premise installations, and customer deposits.

B. Classes and Rate Schedules

GMO currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service. They are listed in Table 1 (MPS) and Table 2 (L&P) above. The non-residential customer groups are differentiated by voltage level and/or whether they have demand meters (e.g., no demand or short term service without demand).

C. Functions

The major functional cost categories Staff used in its CCOS study are Production, Transmission, Distribution, and Customer. Within the Production Function, Staff distinguished between "Production-Capacity" and "Production-Energy." Production-Capacity is allocated by designated usage—base usage, intermediate usage, and peaking usage. The designated usage for each group (base, intermediate, and peak) is allocated to each customer class based on the usage characteristics of the customers in that class.

Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs. The charts below show the percentage of total costs associated within each major function for MPS (Chart 1) and L&P (Chart 2).

Chart 1

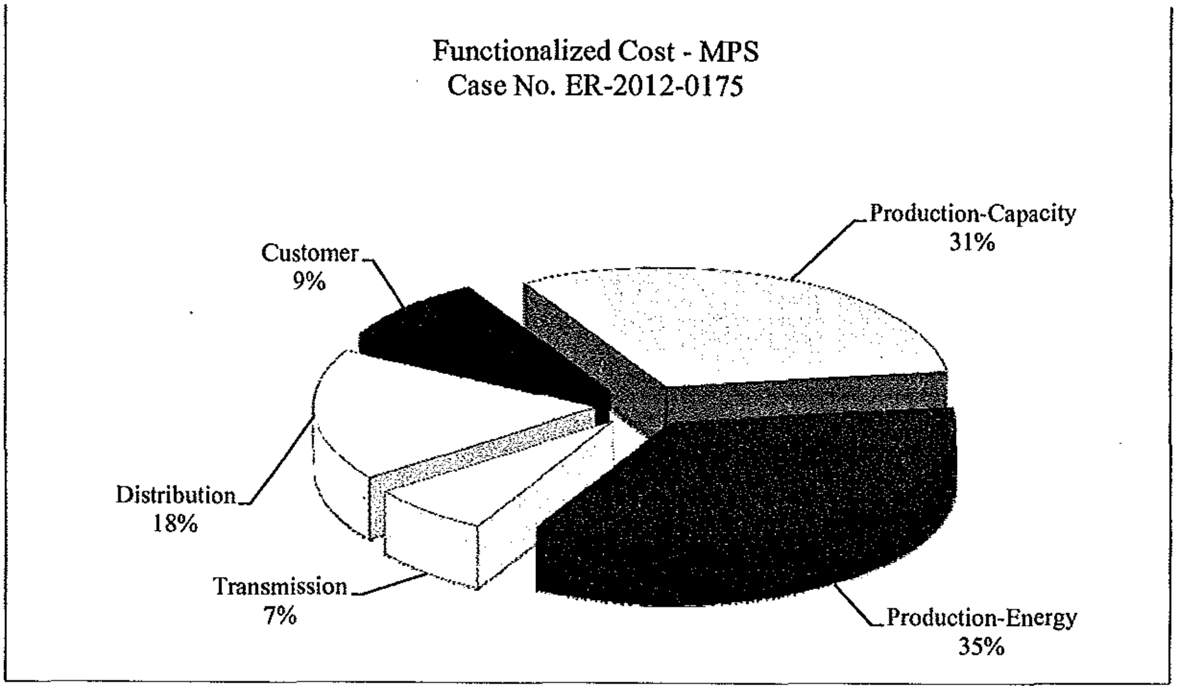
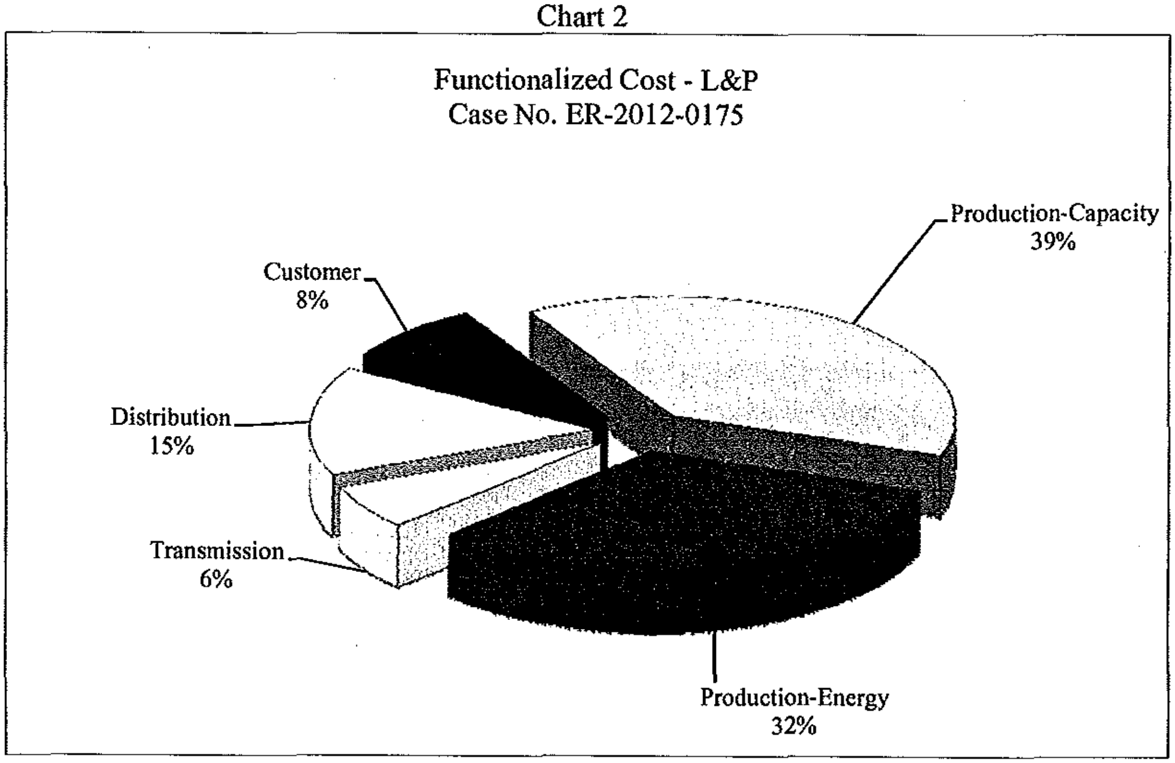


Chart 2



The Production Function (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 66% of GMO's total cost to serve its MPS district and 71% of GMO's total cost to serve its L&P rate district. The Distribution Function—18% of GMO's total cost to serve its MPS rate district and 15% of GMO's total cost to serve its L&P rate district, is the second largest contributor to GMO's total cost to serve its retail customers, and includes substations, overhead and underground lines, and line transformers, as well as the costs to operate and maintain this equipment. Customer Services at 9% for MPS and 8% for L&P, and Transmission at 7% for MPS and 6% for L&P round out the total cost. Schedule MSS-3 provides a detailed description of each external allocation factor Staff used to allocate these costs in its CCOS studies.

D. Allocation of Production Costs

Allocators are used to distribute the functionalized costs to the customer classes. The Production investment and costs comprise approximately 66% (MPS) and 71% (L&P) of the functionalized investment and cost. Both the demand and energy characteristics of GMO's load in its two rate districts are important determinants of production investment and costs, since production must produce output to satisfy periods of normal use and intermittent peak use throughout the year. These functionalized costs are 1) Production–Capacity and 2) Production–Energy.

Staff allocated Production–Capacity costs and Production-Energy fuel costs based on a Base-Intermediate-Peak ("BIP") method. The BIP method is based on recognition that both capacity and energy requirements are an important determinant of production–capacity investment and costs. With the BIP method the utility company's required investments and the ongoing expense of providing service are allocated based on:

1. A base component consisting of the annual energy attributable to a given customer class;
2. An intermediate component consisting of the average 12 NCP[4] of demand for electricity for a given class minus the base component previously allocated; and
3. A peaking component consisting of the average 4 NCP[5] component of demand for electricity less the base and intermediate components previously allocated.

The BIP method is described in the January 1992[6] NARUC Electric Utility Cost Allocation Manual ("NARUC Manual"). Schedule MSS-4 details the BIP method as described in the NARUC Manual. The NARUC Manual describes the BIP method as a time-differentiated method that assigns production costs to three rating periods (1) peak usage, (2) secondary usage and (3) base loading usage. Generally, base load units have high capital costs, generally take five to ten years to build and have low, constant running costs. Because of this, these units run almost continuously, except for when they need maintenance. Because base load units operate regardless of peak requirements, they are appropriately classified as energy-related.[7] Intermediate units, those with capital costs and operating characteristics between those of base load units and peaking units, serve a dual purpose in that they are partially energy-related and partially-demand related.[8] Older coal units sometimes are in this category. Gas–fired combined cycle units are also generally considered intermediate units. Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months—but are costly to run. It is most cost effective to only run these units for the

[4] 12 NCP is each month's maximum peak demand of each customer class at any time during the months of January through December.
[5] 4 NCP is each month's maximum peak demand of each customer class during June, July, August, and September.
[6] The BIP method is outlined in the NARUC Manual in Part IV C Section 2.
[7] **Energy-related:** Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, a portion of production plant maintenance expenses and the energy portion of net interchange power costs.
[8] **Demand-related:** Demand–related costs are rate base investment and related operating and maintenance expenses associated with facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption.

few hours of the year when the system load is the highest. Peaking units are used to follow the energy requirements of the system on a real-time basis.

GMO operates and maintains generating units that are required to provide both capacity and energy for its customers throughout the year. Prudency requires that GMO operate and maintain these units in a manner that minimizes the overall cost for it to produce safe and reliable electricity for its customers through a mix of generating units that best fits the load on GMO's system, both instantaneously and over time.

The BIP method Staff used to allocate production-capacity costs is based on a recognition that generation is built to meet both peak demands and energy usage. For GMO, the basic components of the BIP method are:

1. The base portion of the total production-capacity costs is allocated to each customer class based upon that class's contribution to annual energy.
2. The intermediate portion of the total costs allocated to each class based upon each class's contribution to the 12 NCP demands. Because for each class the portion allocated to it includes the base portion allocated to it, the base portion allocated to the class is subtracted.
3. A peak portion of the total costs allocated to each class based upon each class's contribution to the 4 NCP demands. Because for each class the portion allocated to it includes both the base portion and the intermediate portion allocated to it, the base and intermediate portions allocated to the class is subtracted.

The first step of the BIP method is to evaluate the system monthly loads of the test period. A listing of monthly peak loads for the MPS and L&P rate districts is shown in Table 3 below. The listing helps to define the twelve months in terms of a peak season and a non-peak season.

Table 3

Month	MPS CP Demands	L&P CP Demands
January	1,128,763	420,359
February	1,136,559	466,551
March	963,260	365,395
April	960,413	362,731
May	1,227,527	386,900
June	1,416,929	424,167
July	1,443,424	435,311
August	1,487,286	448,829
September	1,523,232	454,377
October	1,012,892	340,187
November	1,030,033	403,504
December	1,162,022	452,280

Peak
Next 3 highest

GMO, and the MPS rate district, is summer peaking with the system four highest monthly coincident peaks occurring in the summer season (June through September). Separately, the L&P rate district is a combination of winter and summer peaking (see Table 3) with the system four highest monthly CP peaks occurring in two winter months (December, February) and two summer months (August, September).

In the BIP method, the base allocator ("B" portion of BIP method) is calculated on each class's annual kWh usage at generation in the test year and weighted by the system load factor. The intermediate portion ("I" in BIP) involves using the average of the twelve non-coincident peaks ("NCP") for the intermediate piece. The final step is to determine the peak portion ("P" portion of BIP method) for allocation to the various classes. The peak portion is allocated to the various classes based on each class' share of the summer months less the base and intermediate portion already allocated to the various classes. Staff used the four highest peaks during the test year for calculating the production–capacity cost allocator, since the four highest peaks are in excess of the winter load requirements for GMO (MPS and L&P combined).

Staff uses a balancing methodology to allocate fuel and purchased power costs between MPS and L&P. Staff developed this methodology in Case No. ER-2009-0090 and used it in GMO's most recent past electric case, Case No. ER-2010-0356. For further explanation, see the corrected Staff Revenue Requirement Cost of Service Report filed on August 13, 2012, at pages 120 – 128.

Demand refers to the rate at which electric energy is delivered to match the energy requirements of an electric utility's customers, either at an instant in time or averaged over a designated interval of time. To develop a fully comprehensive cost of service analysis to identify revenue requirements for the MPS and L&P rate districts, all of the costs for plant investment and the production costs appearing on the respective income statements for MPS and L&P, must be appropriately allocated by a production-capacity (fixed) and a production-energy (variable) component. Generation facilities, used to produce electricity to retail customers in Missouri, are predominantly considered fixed assets. The costs of and investments in these assets are apportioned to the rate classes on the basis of the production-capacity allocator. Staff used the same allocation factors to allocate GMO's investment in fixed production plant and depreciation reserve accounts for MPS and L&P. The approach of using the same allocators for allocating investments and costs to each class of customer is referred to as "expenses follow plant." Production plant expenses are associated with maintaining and operating the production plant; therefore, it is appropriate to use the same allocator for allocating both plant investment and plant expense.

E. Allocation of Transmission Costs

The Transmission investment and costs comprise approximately 7% (MPS) and 6% (L&P) of the functionalized investment and costs to the classes. GMO's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines that transport power to other transmission or distribution voltages. Staff allocated transmission costs to the MPS and L&P customer classes on a twelve coincident peak ("12 CP") basis[9]. The 12 CP allocation methodology is used as it includes periods of normal use and intermittent peak use throughout all 12 months of the year.

F. Allocation of Distribution Costs

Voltage level is a factor that Staff considered when allocating distribution costs to the classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level requirement of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, substation, or transmission level voltages.

Staff allocated the costs of distribution substations on the basis of each class's annual peak demand measured at substation voltage. Only those customer classes served at substation voltage or below (i.e., all substation, primary and secondary customers) were included in the calculation of the allocation factor, so that distribution substation costs were allocated only to those customers that used these facilities. Staff used the annual class peak of customer classes served at substation voltage or below to allocate substation costs because it represents the appropriate level of diversity at the distribution substation.

[9] The average of the percent of each class' load at time of system peak for 12 months of October 2010 through September 2011

Staff allocated the costs of distribution primary on the basis of each class's annual peak demand measured at primary voltage. Only those customers served at primary voltage or below (i.e., primary and secondary customers) were included in the calculation of the allocation factor, so that distribution primary costs were allocated only to those customers that used these facilities. Staff used the annual class peak to allocate primary costs because it represents the appropriate level of diversity at the distribution primary voltage.

Load diversity is a condition that exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time reflects the diversity of the class load, and should be used to allocate facilities that are shared by groups of customers. Load diversity is important in allocating demand-related distribution costs because the greater the 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 its customers' needs. Therefore, when allocating demand-related distribution costs, it is important to choose a measure of demand that corresponds to the proper level of diversity. The following table summarizes the type of demands Staff used in the allocation of the demand-related portions of the various distribution function categories.

Table 4
Allocation of Demand Related Distribution Facilities

Functional Category	Demand Measure	Amount of Diversity
N/A	Coincident Peak	High
Substations	Class Peak	Moderate to High
Primary	Class Peak	Moderate to High
OH/UG[10] Conduits/Conductors	Diversified Demand	Low to Moderate
Line Transformers	Diversified Demand	Low to Moderate

[10] Overhead (OH)/Underground (UG)

Coincident peak demand is the demand of each class and each customer at the hour when the overall system peak occurs. Coincident peak demand reflects the maximum diversity, because most classes are not at their individual class peaks at the time of the coincident peak. Class peak demand is the maximum hourly demand of all customers within a specific class. It often does not occur at the same hour as the coincident peak (i.e., system peak). Although, not all customers peak at the same time (diversity), a significant percentage of the customers in the class will be at or near their peak at the class peak. Therefore, class peak demand will have less diversity than the class coincident peak.

Diversified demand is the weighted average of the class' customer maximum demand and its annual maximum class peak demand. As constructed, diversified demand has less diversity than the class peak, but more diversity than the customer maximum demand. Customer maximum demand has no diversity. It is defined as the sum of the annual peak demands of each customer, whenever it occurs. If there is no sharing of equipment, there is no diversity.

Staff allocated the costs of distribution secondary and line transformers on the basis of diversity factors which include each class's annual peak demand and customer maximum demands. Only secondary customers (i.e., no primary, substation, or transmission voltage 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 used these facilities.

Staff reviewed GMO-conducted special studies that split the cost of poles, towers, fixtures; and overhead ("OH") and underground ("UG") distribution lines between the portions that are primary and secondary related. Rather than independently conducting its own studies, Staff reviewed GMO's studies, found them appropriate, and chose to rely on them.

Staff allocated meter costs using the same allocator that GMO's used to allocate meter costs. This allocator is based on a GMO study that weights the meter investment by class and by the cost of the meter used to serve that class.

G. Allocation of Customer Service Costs

Customer costs include labor expense 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 reviewed how GMO developed its allocators for allocating meter reading costs, uncollectible accounts, and customer deposits to the customer classes. The allocators are the fraction of total costs of meter reading, uncollectible accounts and customer deposits assigned to each class, respectively. Staff used these allocators and recommends the Commission rely on them as well.

H. Revenues

Operating revenues consists of (1) the revenue that the utility collects from the sale of electricity to Missouri retail customers ("rate revenues"), and (2) the revenue the utility receives for providing other services ("other revenues"). Rate Revenues are also used in developing Staff's rate design proposal and will be used to develop the rate schedules required to implement the Commission's ordered revenue requirement and rate design for GMO in this case. GMO's Missouri rate schedules are designated as residential, small general service (MPS only), general service (L&P only), large general service, large power service, and lighting. However, for some of the classes named the same for MPS and L&P, the criteria differ. The normalized and annualized class rate revenues can be found in Staff's corrected COS Report filed August 13, 2012.

I. Allocation of Taxes

Taxes consist of real estate and property taxes, payroll tax expenses and income taxes. Real estate and property tax expenses are directly related to GMO's original cost investment in plant, so these expenses are allocated to customer classes on the basis of the sum of the previously allocated production, transmission, distribution and general plant investment.

Payroll tax expenses are directly related to GMO's payroll expenses, so these expenses are allocated to customer classes on the basis of previously allocated payroll expenses.

Staff calculated income taxes separately for each customer class, which recognizes the appropriate income tax deductions for each class and calculates the income tax obligation of each customer class as a function of its taxable income. This has the effect of allocating income taxes based on class earnings.

J. Allocation of Energy Efficiency Costs

On December 22, 2011, GMO filed in File No. EO-2012-0009 its *Application for Approval of Demand-Side Programs and for Authority to Establish A Demand-Side Programs Investment Mechanism* in which the Company requested Commission approval of a 3-year program plan for the majority of its existing demand-side management ("DSM") programs and five new DSM programs as Missouri Energy Efficiency Investment Act ("MEEIA") programs. At this time, GMO's general rate application in this case includes no revenue requirement increase as a result of its MEEIA application in File No. EO-2012-0009. However, as established in prior rate cases, Case Nos. ER-2009-0090 and ER-2010-0356, all

DSM programs' costs will be placed in a regulatory asset account and amortized over time. This rate base treatment is reflected in Staff CCOS study.

Staff Expert: Michael S. Scheperle

IV. Rate Design

Staff's rate design objectives in this case are:

- Provide the Commission with a rate design recommendation that is based on each customer class's relative cost-of-service responsibility.
- Provide methods to implement in rates any Commission-ordered overall changes in customer revenue responsibility.
- Retain, to the extent practical, existing rate schedules, rate structures, and important features of the current rate design that reduce the number of customers that switch rates looking for the lowest bill, and mitigate the potential for rate shock.

Staff's rate design recommendations are that the Commission order GMO to implement the following rate designs:

For its MPS rate district

- Apply any overall change in revenue requirement ordered by the Commission on an equal percentage basis to all classes.

For its L&P rate district

- Apply any overall change in revenue requirement ordered by the Commission on an equal percentage basis to all classes, then
- Impose an additional 6% increase for the two winter energy block rates of the MO 920 rate schedule (residential service with space heating). This adjustment will bring the winter season rates closer to the class cost of service for that class in the winter season.
- Impose an additional 6% increase for the winter energy rate of the MO 922 Frozen rate schedule (residential space heating / water heating – separate meter). The MO 922 rate schedule is not available for new installations as of June 15, 1995. This adjustment will bring the winter season rates closer to the class costs of service for these classes in the winter season.
- Impose an additional 6% increase for winter energy rate of the MO 941 Frozen rate schedule (non-residential space heating/water heating – separate meter). The MO 941

rate schedule is not available for new installations as of June 15, 1995. This adjustment will bring the winter season rate closer to the class cost of service for this class in the winter season.

Staff's Rate Design General Recommendations

Staff's more general rate design recommendations are that GMO:

1. Retain all existing rate schedules;
2. Retain all existing rate structures; and
3. Retain the existing rate design of the current rate schedules.

Retain the Current Rate Schedules, Rate Structures, and Rate Design for MPS

The residential rate General Use and Separate Space Heating schedules, rate structures, and rate design consist of the following elements for MPS:

- General Use rate schedule and Separate Space Heating rate schedule
  - Customer Charge
  - Winter Energy Charge
  - Summer Energy Charge
- Residential Other Use rate schedule
  - Customer Charge
  - Winter Energy Charge
  - Summer Energy Charge
- Residential Time of Day rate schedule

The non-residential, non-lighting rate schedules consist of the following rate groups, rate schedules, and rate design elements for MPS:

- Small General Service (SGS) rate schedules (secondary, primary-frozen)
  - Customer Charge
  - Demand Charge
  - Energy Charge
- Small General Service (SGS) rate schedules(non-demand, short term without demand)
  - Customer Charge
  - Energy Charge
- Large General Service (LGS) rate schedules (secondary, primary)
  - Customer Charge
  - Demand Charge
  - Energy Charge
- Large Power Service (LPS) rate schedules (secondary, primary)
  - Customer Charge
  - Demand Charge

    - Energy Charge
    - Reactive Charge
- Thermal Energy Storage Pilot Program (frozen)[11]
- Real Time Pricing

The customers who belong to the residential and the lighting classes are well defined. The remaining customers generally belong to one of four main rate classes based upon their load and cost characteristics. Staff's intent is to define customer classes that are homogeneous in the statistical sense; namely, the variation in load and cost characteristics among the individuals within the class is smaller than the variation between the classes. The typical customer in each of the main MPS classes can be described as follows:

- Small General Service: very small (under 30 kW – non-demand, short term without demand) (over 30 kW – secondary or primary) commercial or industrial customers with low load factor12; almost always served at secondary voltage.

- Large General Service: large size (100 kW – 500 kW) commercial or industrial customer with higher load factor; customers must have, or be willing to assume, a 100 kW minimum demand.

- Large Power Service: very large size (500 kW or greater) commercial or industrial customer with very high load factor, customer must have, or be willing to assume, a 500 kW minimum demand.

Within each rate schedule, demand and energy charges should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining charges (e.g., customer and reactive) should be constant year-round.

The rate schedules should continue to reflect any cost difference associated with service at different voltage levels (i.e., losses and facilities ownership by customers).

Retain the Current Rate Schedules, Rate Structures, and Rate Design for L&P

The residential rate schedules, rate structures, and rate design consist of the following elements for L&P:

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[11] There is only one customer on the Thermal Energy Storage Pilot Program rate schedule
[12] Load factor is the average demand divided by peak demand

- General Use and Separate Space Heating rate schedules
    - Service Charge
    - Winter Energy Charge
    - Summer Energy Charge
- Separate Meter – Space Heating/Water heating (frozen) and Residential Other Use
    - Customer Charge
    - Winter Energy Charge
    - Summer Energy Charge
- Residential Time of Day rate schedule

The non-residential, non-lighting rate schedules, rate structures, and rate design consist of the following rate groups and rate elements for L&P:

- General Service (GS) rate schedules (limited demand, separate meter space heating/water heating-frozen, short term)
    - Service Charge
    - Energy Charge
- General Service (GS) rate schedules (general use)
    - Facilities kW charge
    - Energy Charge
- Large General Service (LGS) rate schedules (secondary, primary)
    - Facilities kW charge
    - Demand Charge
    - Energy Charge
- Large Power Service (LPS) rate schedules (secondary Time of Use ("TOU"), primary TOU, substation TOU, Transmission TOU)
    - Facilities Charge
    - Demand Charge
    - Energy Charge for "on-peak" and "off-peak" hours by season

The L&P customers who belong to the residential and lighting classes are well defined. The remaining customers generally belong to one of four main rate classes based upon their load and cost characteristics. Staff's intent is to define customer classes that are homogeneous in the statistical sense; namely, the variation in load and cost characteristics among the individuals within the class is smaller than the variation between the classes. The typical customer in each of the main classes can be described as follows:

- General Service: very small (less than 40 kW – limited demand, short term) (over 40 kW – general use) commercial or industrial customers with low load factor (average demand divided by peak demand); almost always served at secondary voltage.

- Large General Service: large size (40 kW – 500 kW) commercial or industrial customer with higher load factor; customers must have, or be willing to assume, a 40 kW minimum demand.

- Large Power Service: very large size (500 kW or greater) commercial or industrial customer with very high load factor, customer must have, or be willing to assume, a 500 kW minimum demand.

Within each rate schedule, demand and energy charges should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining charges (e.g., customer or service charge, facilities) should be constant year-round.

The rate schedules should continue to reflect any cost difference associated with service at different voltage levels (i.e., losses and facilities ownership by customers).

Staff Expert: Michael S. Scheperle

<u>Staff Recommendations for Comprehensive Studies</u>

- Staff recommends that the Commission order GMO to prepare and file in its next general rate increase a comprehensive study on the impacts to its retail customers of eliminating the MPS and L&P rate districts and implementing company-wide uniform rate classes, and rates and rate elements for each rate class.

- Additionally, Staff recommends that the Commission order GMO to do a comprehensive class cost-of-service study to determine the differences in its cost of serving each of the classes of MPS and L&P customers.

These recommendations are discussed and detailed in Staff's August 9, 2012 COS Report on pages 120 – 128. The Staff's COS Reports address the following topics:

1. Capacity Allocation Between Rate Districts
2. Resource Assignment Background
3. Impact of Resource Assignments in Case No. ER-2010-0356
4. Impact of Fuel Cost Assignments to MPS and L&P Rates
5. Fuel and Purchased Power Cost Allocation Between Rate Districts

It is time to start the process of eliminating GMO's rate districts and implementing company-wide uniform classes through a CCOS study. Comprehensive studies using rate districts, CCOS classes and GMO company specific information is necessary before the

Commission can make such a determination. In addition to CCOS studies of the two rate districts and one for the combined rate district, comprehensive studies on the impacts of eliminating rate districts and implementing company-wide uniform classes need to be completed *before* implementing company-wide uniform classes because of the differences in the current MPS and L&P classes. Table 5 below outlines the current rate classes.

TABLE 5

Retail Rate Schedules - MPS	**Retail Rate Schedules - L&P**
Residential - Regular	Residential - Regular
Residential - Space Heating	Residential - Space Heating
Residential – Other	Residential - Other
SGS – Primary	GS - General Use
SGS - Secondary	GS - Limited Demand
SGS - ND (non demand)	GS - Sep. Meter SH/WH
SGS - Short Term without Demand	GS - Short Term
LGS – Primary	LGS - Primary
LGS - Secondary	LGS - Secondary
Large Power Service - Primary	Large Power Service - TOU Primary
Large Power Service - Secondary	Large Power Service - TOU Secondary
	Large Power Service - TOU Substation
	Large Power Service - TOU Transmission
Lighting	Lighting - Metered
	Lighting - Non-Metered

Table 5 shows that some rate classes are similarly named, but that there are differences between the rate districts (MPS and L&P) in rates, rate structures and rate elements that need to be addressed. For example, the Large General Rate for L&P is available for customers with a minimum demand of 40 kilowatts (kW), it contains two hours-use block rates, it has a facilities charge and it has no customer charge. In contrast, the Large General Service Rate for MPS is available for customers with a minimum demand of 100 kW, it has three hours-use block rates, it has no facilities charge and it has a customer charge.

The rate structures of Kansas City Power and Light Company ("KCPL") also need to be considered if Great Plains' objective is to have similar rate structures for KCPL and GMO in the future. Schedule MSS-5 is a comparison of rate structures for KCPL and GMO rate districts of MPS and L&P.

Schedule MSS-7 are requirements that Staff recommends for the Missouri class cost of service study to be provided with GMO's next rate case filing for a (1) comprehensive study on the impacts on its retail customers of eliminating the MPS and L&P rate districts and implementing company-wide uniform rate classes, and rates and rate elements for each rate class; and (2) to determine the differences in its cost of serving classes of MPS and L&P customers.

Staff Expert: Michael S. Scheperle

V. FAC Voltage Adjustment Factors

Rule 4 CSR 240-20.090(9) requires an electric utility that wants to continue to utilize its Rate Adjustment Mechanism ("RAM") to conduct a jurisdictional system loss study on the losses incurred from the delivery of electricity. Because it is to perform such a study at least every four years after it initially gets a FAC, this study is to be completed within four years prior to the rate case in which the utility has requested to continue its FAC.[13] The KCPL Loss Study R154-09 Revision 1 is the most current loss study for the KCPL and GMO systems.

[13] 4 CSR 240-20.090(9) Rate Design of the RAM. The design of the RAM rates shall reflect differences in losses incurred in the delivery of electricity at different voltage levels for the electric utility's different rate classes. Therefore, the electric utility shall conduct a Missouri jurisdictional system loss study within twenty-four (24) months prior to the general rate proceeding in which it requests its initial RAM. The electric utility shall conduct a Missouri jurisdictional loss study no less often than every four (4) years thereafter, on a schedule that permits the study to be used in the general rate proceeding necessary for the electric utility to continue to utilize a RAM.

The study is dated October 8, 2009, and contains system loss data from the calendar year 2008. Staff used the information in this loss study to develop its FAC voltage adjustment factors below.

Based on the results from the KCPL Loss Study R154-09 Revision 1, Staff updated the system losses for the MPS and L&P districts. These system losses are the basis for calculating the FAC voltage adjustment factors. The adjustment factors account for the energy losses incurred in the transmission and distribution of energy from the generator to the customer. These factors are used in the FAC calculations to adjust the fuel adjustment rates in the Company's FAC to the fuel adjustment rates applicable to the individual voltage service classification. In general, the new adjustment factors represent a slight decrease for metered primary voltage and above, and a slight increase for metered secondary voltage, when compared to the factors in the current FAC tariff sheets. Tables 1 and 2 provide Staff's proposed new FAC voltage adjustment factors.

Table 1: L&P		
Voltage Adjustment Factors	Voltage Level	
	Primary	Secondary
Current Tariff	1.0444	1.0700
Proposed	**1.0421**	**1.0701**
Change	(0.0023)	0.0001

Table 2: MPS		
Voltage Adjustment Factors	Voltage Level	
	Primary	Secondary
Current Tariff	1.0444	1.0679
Proposed	**1.0419**	**1.0712**
Change	(0.0025)	0.0033

Staff Expert/Witness: David Roos

VI. Fuel Adjustment Clause Tariff Sheet Changes

In its COS Report in this case, Staff provided its analysis of and recommendations for the following issues which have an impact on GMO's FAC tariff sheets:

1. Change the sharing mechanism from 95% returned/recovered from the customers and 5% kept/absorbed by GMO to 85% returned/recovered from the customers and 15% kept/absorbed by GMO to provide GMO with a more appropriate incentive to keep its fuel and purchased power costs down;
2. Include any revenues from the sale of excess Renewable Energy Certificates in the FAC;
3. Specifically limit fuel hedging costs in the FAC to hedging costs for natural gas burned as fuel in GMO's generating units;
4. Standardize the terminology in GMO's FAC tariff sheets to be consistent with the changes Staff is recommending, when appropriate, to the FACs of the three investor-owned electric utilities with FACs; and
5. Clarify that the only transmission costs that are included in GMO's FAC are those that GMO incurs for purchased power and off-system sales ("OSS"), excluding the transmission costs related to GMO's Crossroads Generating plant.

Staff recommends the Commission approve FAC tariff sheets that are consistent with Staff's FAC recommendations. Schedule MJB-2 contains exemplar tariff sheets with language consistent with these recommendations.

Staff recommends the Commission change the base energy cost per kWh rates for the MPS and L&P rate districts to the below rates based upon the following information in Staff's COS Report in this case: 1) base energy cost (fuel and purchased power costs less off-system sales revenue) and Staff's adjustments to test year; 2) updated voltage expansion factors, e. g., loss factors; and 3) normalized net system inputs:

- $0.02446 per kWh for MPS
- $0.02177 per kWh for L&P

Staff will update these base energy cost per kWh before voltage adjustment rates for the MPS and L&P rate districts as part of the test year true-up in this case.

Clarification Regarding Hedging Gains and Losses

Staff recommends that the Commission clarify that only hedging gains and losses associated with fuel actually burned in GMO's generating units are allowed to flow through its FAC. The current FAC tariff sheet No. 127.8 includes in its definition of the natural gas generation costs in FERC Account Number 547 the following:

> The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, *hedging costs*, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees in Account 547. (Emphasis added)

Staff recommends the language be "for fuel burned in the Company's generating units" inserted after the words "hedging costs" and before the comma preceding the words "fuel additives" so that it will now read:

> The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, *hedging costs for fuel burned in the Company's generating units*, fuel additives, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees in Account 547. (Emphasis added)

Changes to FAC Tariff Sheet Terminology

The Commission, Staff, the electric utilities and other parties have been refining FACs, and the tariff sheets that implement them, since the Commission first authorized Aquila, Inc., n/k/a KCP&L Greater Missouri Operations Company ("GMO"), to use a FAC in Case No. ER-2007-0004. While each utility's FAC operates in a similar fashion, and the FAC tariff sheets are similar, each utility has a unique FAC and unique FAC tariff sheets with unique acronyms and definitions. Different nomenclatures for the same thing are used across the utilities, and sometimes even within a single utility's FAC tariff sheets. On Page 279, Line 16 through Line 21, in the COS Report filed August 9, 2012, Staff provided an example of the various terms that the Missouri electric utilities use for the dollar amount of the adjustment. Another example is the terms used to identify the FAC dollar per kWh charge before voltage adjustment rate. Union Electric Company d/b/a Ameren Missouri refers to it as "FPA rate," "FPA_c rate" or just "FPA_c." GMO refers to it as a "Cost Adjustment Factor" or "CAF," "Current annual CAF," "Annual CAF," and "Fourth Interim Total." The Empire District Electric Company refers to it as a "Cost Adjustment Factor" or "CAF." It is Staff's proposal that the FAC dollar per kWh charge before voltage adjustment rate be called the "Fuel Adjustment Rate" or "FAR" consistently in the FAC tariff sheets of all the electric utilities.

Schedule MJB-1 contains a table that lists the terminology and definitions that Staff is proposing be made consistent across the three electric utilities' FAC tariff sheets. Staff has been working with all of the electric utilities, including GMO, on these proposals to reach a consensus with them on the terminology to be used within the electric utility industry in Missouri. It is not Staff's desire to change the intent or the meaning of different concepts in each utility's FAC tariff sheets with these changes, but to help avoid and minimize confusion when discussing the FACs of electric utilities in Missouri. Staff witness Lena M. Mantle made this same recommendation in the current Ameren Missouri rate case, Case No. ER-2012-0166, and Staff plans to make the same recommendation again in the pending Empire general electric rate case, Case No. ER-2012-0345.

The attached exemplar FAC tariff sheets also include some "clean up" suggestions along with other changes Staff has identified and is recommending. Staff also recommends instead of adding more FAC tariff sheets as GMO has, the proposed tariff sheets replace the first set of FAC tariff sheets in GMO's tariff.

Schedule MJB-2 contains exemplar tariff sheets with Staff's proposed changes for GMO's proposed FAC tariff sheets. Schedule MJB-3 is a redline/strikeout comparison of these exemplar tariff sheets with GMO's currently effective FAC tariff sheets.

Clarification Regarding Transmission Costs

Staff recommends that GMO's FAC continue to only include the transmission costs GMO incurs that are necessary for it to serve the load requirements of its customers and those that are necessary for it to make OSS, but excluding the transmission costs related to GMO's Crossroads Energy Station. The current FAC Tariff Sheet No. 127.8 includes in its definition of the transmission costs in FERC Account Number 565 the following:

> Transmission costs for Off System Sales included in FERC Account Number 565 except for costs for the Crossroads facility.

Staff recommends the following language replace the current definition of the transmission costs in FERC Account Number 565:

> Transmission costs that are necessary to receive purchased power to serve native load and costs that are necessary to make Off System Sales included in FERC Account Number 565 except for costs related to the Crossroads Generating plant.

No other transmission costs should flow through GMO's FAC without GMO first proposing that they do so in a general rate proceeding where all parties have an opportunity to make recommendations to the Commission on the appropriateness of doing so. Staff recommends that the Commission clarify that only the transmission costs GMO incurs that are necessary to receive purchased power to serve the load requirements of its customers and those that are necessary for it to make OSS are flowed through GMO's FAC by specifically stating that only these transmission costs are allowed to flow through GMO's FAC, excluding the transmission costs related to GMO's Crossroads Generating plant. Doing so will avoid potential confusion in future prudence audits.

Staff Expert: Matthew J. Barnes

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF MICHAEL S. SCHEPERLE

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

Michael S. Scheperle, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Staff Report on pages 1-27, and the facts therein are true and correct to the best of his knowledge and belief.

Michael S. Scheperle
Michael S. Scheperle

Subscribed and sworn to before me this 21st day of August, 2012.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

David C. Roos, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Staff Report on pages 27-28, and the facts therein are true and correct to the best of his knowledge and belief.

David C. Roos

Subscribed and sworn to before me this 21st day of August, 2012.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer
Notary Public

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement General Rate Increase for Electric Service	))))	Case No. ER-2012-0175

AFFIDAVIT OF MATTHEW J. BARNES

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Matthew J. Barnes, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Staff Report on pages 29-32, and the facts therein are true and correct to the best of his knowledge and belief.

Matthew J. Barnes

Matthew J. Barnes

Subscribed and sworn to before me this 21st day of August, 2012.

SUSAN L. SUNDERMEYER
Notary Public - Notary Seal
State of Missouri
Commissioned for Callaway County
My Commission Expires: October 03, 2014
Commission Number: 10942086

Susan L. Sundermeyer

Notary Public

David C. Roos

Present Position: I am a Regulatory Economist III in the Energy Resource Analysis Section, Energy Unit, Tariff, Safety Economic and Engineering Analysis Department, of the Regulatory Review Division, of the Missouri Public Service Commission.

Educational Background and Work Experience:

In May 1983, I graduated from the University of Notre Dame, Notre Dame, Indiana, with a Bachelor of Science Degree in Chemical Engineering. I also graduated from the University of Missouri in December 2005, with a Master of Arts in Economics. I have been employed at the Missouri Public Service Commission as a Regulatory Economist III since March 2006. I began my employment with the Commission in the Economics Analysis section where my responsibilities included class cost of service and rate design. In 2008, I moved to the Energy Resource Analysis section where my testimony and responsibility topics include energy efficiency, resource analysis, and fuel adjustment clauses. Prior to joining the Public Service Commission I taught introductory economics and conducted research as a graduate teaching assistant and graduate research assistant at the University of Missouri. Prior to the University of Missouri, I was employed by several private firms where I provided consulting, design, and construction oversight of environmental projects for private and public sector clients.

Previous Cases

Company	Case No.
Empire District Electric Company	ER-2006-0315
AmerenUE	ER-2007-0002
Aquila Inc.	ER-2007-0004

Kansas City Power and Light	ER-2007-0291
AmerenUE	EO-2007-0409
Empire District Electric Company	ER-2008-0093
Kansas City Power and Light	ER-2008-0034
Greater Missouri Operations	HR-2008-0340
Greater Missouri Operations	ER-2009-0091
Greater Missouri Operations	EO-2009-0115
Greater Missouri Operations	EE-2009-0237
Greater Missouri Operations	EO-2009-0431
Empire District Electric Company	ER-2010-0105
Greater Missouri Operations	EO-2010-0002
AmerenUE	ER-2010-0036
AmerenUE	ER-2010-0044
Empire District Electric Company	EO-2010-0084
Empire District Electric Company	ER-2010-0105
AmerenUE	ER-2010-0165
Greater Missouri Operations	EO-2010-0167
AmerenUE	EO-2010-0255
Greater Missouri Operations (Aquila)	EO-2008-0216
Ameren Missouri	ER-2011-0028
Empire District Electric Company	EO-2011-0066
Empire District Electric Company	EO-2011-0285
Ameren Missouri	EO-2012-0074
Greater Missouri Operations	EO-2012-0009
Ameren Missouri	EO-2012-0142
Ameren Missouri	ER-2012-0166

Missouri Public Service Commission
Case No. ER-2012-0175 - MPS
Based on Staff CCOS at High Range

Functional Category	RES RESA Regular	RES RESB All Electric	RES RES C Other	SGS Primary	SGS Secondary	SGS No Demand	SGS Short Term	LGS Primary
Production - Capacity	$56,357,444	$31,846,559	$53,522	$9,151	$18,443,996	$1,777,156	$30,968	$769,133
Production - Energy	$45,217,016	$35,939,566	$63,322	$10,309	$20,857,394	$2,118,307	$39,363	$669,644
Transmission	$10,302,588	$7,972,039	$13,883	$2,125	$4,282,349	$431,278	$7,763	$119,733
Distribution - Demand	$35,957,326	$23,672,558	$47,422	$3,679	$10,790,452	$1,019,546	$26,750	$366,448
Distribution - Services	$3,423,434	$2,145,808	$4,465	$0	$861,706	$82,194	$2,291	$0
Distribution - Meters	$2,649,828	$1,420,479	$13,469	$62	$406,059	$174,286	$7,182	$31,237
Distribution - Customer Inst.	$0	$0	$0	$0	$0	$0	$0	$0
Distribution - Lighting	$0	$0	$0	$0	$0	$0	$0	$0
Customer Deposit	($73,932)	($39,632)	($376)	($11)	($70,199)	($30,131)	($1,242)	($51)
Customer Meter Reading	$1,238,138	$663,721	$6,293	$27	$175,139	$75,170	$3,098	$187
Other Customer Billing	$7,195,895	$3,857,463	$36,578	$168	$1,102,696	$473,294	$19,504	$84,828
Uncollectible Accounts	$2,044,266	$1,095,855	$10,390	$27	$182,422	$78,298	$3,227	$0
Customer Services and Inf.	$1,482,004	$752,593	$5,617	$341	$2,258,073	$915,961	$58,132	$10,501
Sales Expenses	$158,404	$80,441	$601	$5	$31,142	$12,633	$802	$618
Energy Efficiency	$466,749	$370,984	$654	$58	$117,562	$11,940	$222	$3,774
Income Taxes	$12,873,316	$8,825,793	$70,080	$1,830	$5,733,154	$840,336	$1,192	($158,469)
Total CCOS Including Additional Tax	$179,292,477	$118,604,225	$325,919	$27,770	$65,171,944	$7,980,267	$199,252	$1,897,584
Rate Revenue	$178,525,112	$119,816,471	$458,090	$27,576	$68,701,600	$9,074,108	$186,685	$1,142,217
Other Operating Revenue	($7,809,280)	($4,793,891)	($15,462)	($1,026)	($2,602,002)	($349,171)	($9,720)	($74,113)
Total Revenue	$170,715,831	$115,022,579	$442,629	$26,550	$66,099,598	$8,724,936	$176,965	$1,068,105
Revenue Deficiency	$8,576,646	$3,581,646	($116,709)	$1,220	($927,654)	($744,669)	$22,287	$829,479
Percent Change	4.80%	2.99%	-25.48%	4.42%	-1.35%	-8.21%	11.94%	72.62%

Functional Category	LGS Secondary	LPS Primary	LPS Secondary	Lighting Lighting	TOTAL
Production - Capacity	$19,806,990	$11,545,277	$11,983,813	$1,156,031	$153,780,040
Production - Energy	$26,994,748	$20,292,535	$19,921,976	$1,350,047	$173,474,227
Transmission	$4,818,883	$2,975,908	$2,922,104	$368,408	$34,217,061
Distribution - Demand	$8,730,318	$2,378,367	$4,931,798	$173,903	$88,098,567
Distribution - Services	$0	$0	$0	$0	$6,519,897
Distribution - Meters	$326,107	$72,854	$205,273	$0	$5,306,836
Distribution - Customer Inst.	$0	$0	$0	$0	$0
Distribution - Lighting	$0	$0	$0	$6,211,512	$6,211,512
Customer Deposit	($3,365)	($63)	($213)	$0	($219,214)
Customer Meter Reading	$12,524	$365	$1,228	$0	$2,175,889
Other Customer Billing	$885,578	$197,844	$557,440	$0	$14,411,288
Uncollectible Accounts	$0	$0	$0	$0	$3,414,486
Customer Services and Inf.	$656,085	$32,521	$112,692	$0	$6,284,519
Sales Expenses	$38,601	$9,083	$31,474	$9	$363,812
Energy Efficiency	$152,154	$114,378	$112,289	$0	$1,350,764
Income Taxes	$5,466,013	$2,918,276	$2,961,335	$662,760	$40,195,616
Total CCOS Including Additional Tax	$67,884,635	$40,537,344	$43,741,211	$9,922,671	$535,585,300
Rate Revenue	$70,702,913	$42,283,215	$44,702,895	$9,429,671	$545,050,554
Other Operating Revenue	($2,453,360)	($1,280,456)	($1,484,725)	($484,613)	($21,357,818)
Total Revenue	$68,249,553	$41,002,760	$43,218,171	$8,945,058	$523,692,736
Revenue Deficiency	($364,918)	($465,416)	$523,040	$977,613	$11,892,564
Percent Change	-0.52%	-1.10%	1.17%	10.37%	2.18%

Missouri Public Service Commission
Case No. ER-2012-0175 - L&P
Based on Staff CCOS at High Range

Functional Category	RES Regular	RES Other	RES Space heating	GS Gen use	GS Limited demand	GS Sep Mtr SH/WH	GS Short Term	LGS Primary
Production - Capacity	$14,895,684	$209,368	$13,500,287	$2,732,436	$1,076,363	$60,211	$19,669	$262,501
Production - Energy	$9,478,884	$156,878	$9,600,887	$1,863,197	$755,797	$41,967	$13,842	$190,324
Transmission	$2,135,591	$34,763	$2,106,674	$421,171	$170,121	$9,301	$3,116	$36,986
Distribution - Demand	$6,422,908	$155,640	$8,421,435	$1,178,956	$508,981	$38,751	$9,850	$1,722,876
Distribution - Services	$866,296	$25,039	$809,250	$135,164	$51,720	$3,895	$1,064	$0
Distribution - Meters	$785,600	$43,047	$431,096	$54,328	$88,343	$3,185	$1,570	$11,991
Distribution - Customer Inst.	$0	$0	$0	$0	$0	$0	$0	$0
Distribution - Lighting	$0	$0	$0	$0	$0	$0	$0	$0
Customer Deposit	($29,596)	($1,622)	($16,198)	($15,748)	($25,607)	($463)	($455)	($8)
Customer Meter Reading	$1,005,183	$55,075	$551,589	$64,170	$104,339	$3,761	$1,853	$196
Other Customer Billing	$1,539,285	$84,346	$844,679	$106,449	$173,097	$6,240	$3,077	$23,496
Uncollectible Accounts	$539,739	$29,575	$295,405	$26,991	$43,889	$793	$781	$0
Customer Services and Information	$711,571	$38,991	$389,451	$85,315	$138,731	$2,507	$2,466	$530
Sales Expenses	$57,378	$3,145	$31,403	$3,662	$5,953	$108	$106	$11
Energy Efficiency	$66,174	$1,095	$67,026	$7,179	$2,912	$162	$53	$733
Income Taxes	$3,499,436	$116,400	$1,072,437	$1,039,962	$596,373	$922	$12,027	($285,981)
Total CCOS Including Additional Income Tax	$41,974,133	$951,741	$38,105,420	$7,703,232	$3,691,011	$171,340	$69,021	$1,963,654
Rate Revenue	$40,687,344	$1,047,258	$31,181,937	$8,388,275	$4,364,201	$131,651	$83,581	$562,304
Other Operating Revenue	$789,822	$18,025	$667,104	$160,426	$77,816	$2,854	$1,474	$12,485
Total Revenue	$41,477,166	$1,065,283	$31,849,041	$8,548,700	$4,442,017	$134,505	$85,055	$574,788
Revenue Deficiency	$496,967	($113,543)	$6,256,379	($845,468)	($751,005)	$36,835	($16,034)	$1,388,866
Percent Change	1.22%	-10.84%	20.06%	-10.08%	-17.21%	27.98%	-19.18%	247.00%

Functional Category	**LGS** Secondary	**LGS** Substation	**LPS** Primary	**LPS** Secondary	**LPS** Substation	**LPS** Transmission	**Lighting** Lighting	TOTAL
Production - Capacity	$10,833,098	$21,189	$3,289,077	$13,135,157	$1,385,578	$1,452,105	$775,968	$63,648,689
Production - Energy	$9,158,278	$13,639	$3,640,713	$14,355,157	$1,630,451	$1,593,632	$557,861	$53,051,509
Transmission	$1,777,086	$2,633	$538,240	$2,121,749	$240,952	$235,420	$152,679	$9,986,481
Distribution - Demand	$1,797,333	$1,895	$704,594	$3,711,403	$115,014	$0	$73,181	$24,862,816
Distribution - Services	$0	$0	$0	$0	$0	$0	$0	$1,892,427
Distribution - Meters	$310,429	$1,713	$14,325	$101,070	$6,139	$10,232	$3,466	$1,866,536
Distribution - Customer Inst.	$0	$0	$0	$0	$0	$0	$0	$0
Distribution - Lighting	$0	$0	$0	$0	$0	$0	$1,824,911	$1,824,911
Customer Deposit	($1,412)	($1)	($11)	($92)	($5)	($8)	$0	($91,225)
Customer Meter Reading	$32,646	$28	$196	$1,656	$84	$140	$4,435	$1,825,352
Other Customer Billing	$608,247	$3,357	$28,068	$198,034	$12,029	$20,048	$6,792	$3,657,244
Uncollectible Accounts	$0	$0	$0	$0	$0	$0	$0	$937,171
Customer Services and Information	$91,345	$78	$16	$137	$7	$11	$0	$1,461,156
Sales Expenses	$1,857	$2	$11	$95	$6	$8	$0	$103,745
Energy Efficiency	$35,285	$53	$14,027	$55,308	$6,282	$6,140	$0	$262,428
Income Taxes	$2,942,123	$2,907	$668,460	$2,649,646	$327,167	$413,047	$433,495	$13,488,422
Total CCOS Including Additional Income Tax	$27,586,314	$47,492	$8,897,717	$36,329,320	$3,723,704	$3,730,776	$3,832,788	$178,777,663
Rate Revenue	$28,683,423	$44,041	$8,632,331	$34,914,154	$3,773,569	$4,000,201	$3,966,022	$170,460,291
Other Operating Revenue	$622,292	$944	$210,676	$842,309	$93,126	$95,154	$67,305	$3,661,812
Total Revenue	$29,305,715	$44,986	$8,843,007	$35,756,463	$3,866,695	$4,095,356	$4,033,327	$174,122,103
Revenue Deficiency	($1,719,400)	$2,506	$54,709	$572,857	($142,991)	($364,580)	($200,539)	$4,655,560
Percent Change	-5.99%	5.69%	0.63%	1.64%	-3.79%	-9.11%	-5.06%	2.73%

Missouri Public Service Commission
Case No. ER-2012-0175
Summary of Functions and Allocation Methods in CCOS Study

Function	**Allocation to Rate classes**
Production Plant and Reserve	
Base	Annual kWh usage @ generation
Intermediate	12 NCP Average less Base
Peak	4 NCP remaining less Base and Intermediate

Transmission Plant and Reserve	12 CP Average

Distribution Plant and Reserve	
Substations	NCP
Primary	NCP
Secondary	NCP and customer maximum demands
Line Transformers	NCP and customer maximum demands
Services	GMO assignment
Meters	GMO assignment
General & Intangible Plant & Reserve	Functional separation of Production, Transmission and Distribution Plant

Expenses	
Production	
Fuel	Annual kWh usage @ generation
Other	Fixed - expenses follow plant
Maintenance	Fixed - expenses follow plant
Transmission	12 CP Average
Distribution	NCP, customer maximums, Distribution plant, and company studies
Customer Billing, Services and Sales	Number of customers and company studies
Depreciation & Amortization Expenses	
Production	Base, Intermediate, and Peak component based on Production Plant
Transmission	12 CP Average
Distribution	Distribution plant
General and Intangible	Functional separation of Production, Transmission and Distribution Plant
A&G expenses	Labor, plant, revenues
Taxes, other than income taxes	Plant, labor
Taxes, other than income taxes	Earnings of each class
Energy Efficiency	Program Costs

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

Schedule MSS-4-2

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

TABLE 4-18

SUMMARY OF PRODUCTION PLANT
COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 369,461,692	34.84	$ 340,287,579	32.09	$ 388,925,712	36.67	$ 340,747,311	32.13	$ 386,682,685	36.46
LSMP	394,976,787	37.25	407,533,507	38.43	376,433,254	35.50	384,043,376	36.21	369,289,317	34.82
LP	261,159,089	24.63	283,283,130	26.71	266,582,600	25.14	299,737,319	28.26	254,184,071	23.97
AG&P	34,878,432	3.29	25,700,311	2.42	23,555,089	2.22	28,970,743	2.73	41,218,363	3.89
SL	0	0.00	3,671,473	0.35	4,978,544	0.47	6,977,251	0.66	9,101,564	0.86
Total	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.0

	EQUIVALENT PEAKER COST METHOD		BASE AND PEAK METHOD		1 CP AND AVERAGE DEMAND METHOD		12 CP AND 1/13th AVERAGE DEMAND METHOD		PRODUCTION STACKING METHOD	
Rate Class	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 340,657,471	32.12	$ 3350,522,360	33.05	$ 354,381,313	33.42	$ 339,370,900	32.00	$ 334,590,738	31.55
LSMP	362,698,678	34.20	382,505,016	36.07	381,842,722	36.01	403,814,709	38.08	360,965,510	34.04
LP	317,863,510	29.97	293,007,874	27.63	286,764,179	27.04	286,948,099	27.06	324,315,213	30.58
AG&P	32,021,813	3.02	27,868,280	2.63	34,623,156	3.36	26,352,815	2.48	33,089,034	3.12
SL	7,232,529	0.68	6,572,470	0.62	2,864,631	0.27	3,989,478	0.38	7,515,505	0.71
Total	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00

Missouri Public Service Commission
Case Nos. ER-2012-0174 & ER-2012-0175
Comparison of Rate Structures

Description	KCPL	MPS	L&P
Residential			
Customer Charge	Yes	Yes	Yes
Summer/Winter Rate Schedules	Yes	Yes	Yes
Summer Energy Charges (Flat rate per kWh	Yes	No	Yes
Summer Energy Charges (Inclining rate per kWh	No	Yes	No
Winter Energy Charges (Declining rate per kWh	Yes	Yes	Yes
Separate All Electric Rate Schedule	Yes	Yes	Yes
Residential General Use and Space heat - 2 meters	Yes	No	Yes (frozen)
Time of Day Tariffs	Yes	Yes	Yes
Summer Period	May 16 - Sep. 15	June 1 - Sep. 30	June 1 - Sep. 30
Winter Period	Sep. 16 - May 15	Oct 1 - May 31	Oct 1 - May 31

	KCPL	MPS (Non-Demand) (Short Term)	L&P (Limited Demand) (Short Term) Both General Service
Small General Service			
Customer Charge	Yes	Yes	Yes
Summer/Winter Rate Schedules	Yes	Yes	Yes
Separate rate schedules by voltage	Yes	No	No
Demand Charge	No	No	No
Facilities Charge	Yes	No	No
Reactive charges	No	No	No
Energy Charges (Hours of Use)	Yes	Yes	No
All Electric Rate schedules by voltage (Frozen	Yes	No	No
Minimum Billing Demand	No	No	No

Missouri Public Service Commission
Case Nos. ER-2012-0174 & ER-2012-0175
Comparison of Rate Structures

Description	**KCPL**	**MPS**	**L&P**
Separately Metered Space Heat - Frozen	Yes	No	Yes
Time of Day Tariffs	Yes	Yes	Yes
Summer Period	May 16 - Sep. 15	June 1 - Sep. 30	June 1 - Sep. 30
Winter Period	Sep. 16 - May 15	Oct 1 - May 31	Oct 1 - May 31

	KCPL	**MPS**	**L&P (General Use) General Service**
Medium General Service		SGS - Regular	
Customer Charge	Yes	Yes	No
Summer/Winter Rate Schedules	Yes	Yes	Yes
Separate rate schedules by voltage	Yes	Yes	No
Demand Charge	Yes	Yes	No
Facilities Charge	Yes	No	Yes
Reactive charges	Yes	No	No
Energy Charges (Hours of Use)	Yes	Yes	Yes
All Electric Rate schedules by voltage (Frozen	Yes	No	No
Minimum Billing Demand	Yes (1)	Yes	Yes (thru facilities Charge)
Separately Metered Space Heat - Frozen	Yes	No	Yes
Time of Day Tariffs	Yes	Yes	Yes
Summer Period	May 16 - Sep. 15	June 1 - Sep. 30	June 1 - Sep. 30
Winter Period	Sep. 16 - May 15	Oct 1 - May 31	Oct 1 - May 31

	KCPL	**MPS**	**L&P**
Large General Service			
Customer Charge	Yes	Yes	No
Summer/Winter Rate Schedules	Yes	Yes	Yes
Separate rate schedules by voltage	Yes	Yes	No (discount)

Missouri Public Service Commission
Case Nos. ER-2012-0174 & ER-2012-0175
Comparison of Rate Structures

Description	KCPL	MPS	L&P
Demand Charge	Yes	Yes	Yes
Facilities Charge	Yes	No	Yes
Reactive charges	Yes	No	No
Energy Charges (Hours of Use)	Yes	Yes	Yes
All Electric Rate schedules by voltage (Frozen	Yes	No	No
Minimum Billing Demand	Yes (2)	Yes (criteria)	Yes (3)
Separately Metered Space Heat - Frozen	Yes	No	No
Time of Day Tariffs	Yes	Yes	Yes
Summer Period	May 16 - Sep. 15	June 1 - Sep. 30	June 1 - Sep. 30
Winter Period	Sep. 16 - May 15	Oct 1 - May 31	Oct 1 - May 31

	KCPL	MPS	L&P
Large Power Service			
Customer Charge	Yes	Yes	No
Summer/Winter Rate Schedules	Yes	Yes	Yes
Separate rate schedules by voltage	Yes	Yes	No (Discount)
Demand Charge	Yes	Yes	Yes
Facilities Charge	Yes	No	Yes
Reactive charges	Yes	No	No
Energy Charges (Hours of Use)	Yes	Yes	No
Energy Charges (On-peak, Off-peak)	No	No	Yes
All Electric Rate schedules by voltage (Frozen	No	No	No
Minimum Billing Demand	Yes	Yes	Yes (4)
Separately Metered Space Heat - Frozen	No	No	No
Time of Day Tariffs	Yes	No	No (energy on-peak; Off-peak

(1) Minimum billing demand - 25 kW at secondary voltage

Description	**KCPL**	**MPS**	**L&P**
(2) Minimum billing demand - 200 kW at secondary voltag			
(3) Minimum Facilities - criteria			
(4) Minimum Facilities - criteria			

	KCPL	**MPS**	**L&P**
Small General Service (Minimum Billing Demand	None	None	None
Medium General Service (Minimum Billing Demand)	25 kW	Criteria (5)	Thru facilities charge
Large General Service (Minimum Billing Demand	200 kW	100 kW	40 kW
Large Power Service (Minimum Billing Demand	980 kW	500 kW	500 kW

(5) General service - Lessor of: 100% of customer's billing demand in May; (2) 100% of customer's billing demand in October; or (3) 65% of maximum billing demand established during the preceding four summer month billing periods.

STAFF RATE DESIGN AND CLASS COST-OF-SERVICE REPORT

Class Cost-of-Service and Rate Design Overview

A Class Cost of Service (CCOS) study is a detailed analysis where the costs incurred to provide utility service to a particular jurisdiction (e.g., Missouri retail) are assigned to customers, or customer classes, based on the manner in which the costs are incurred. An electric utility's power system is designed, constructed, and operated in order to meet the ongoing energy and load requirements of vast numbers of diverse customers. How and when customers utilize energy has a great bearing on the fixed and variable costs of service. Customer classes are groups of customers with similar electrical service characteristics. For proper cost assignment, the composite load of the system must be differentiated by the various customer classes in order to determine the proportional responsibilities of each customer class. In other words, the customers' load contributions to the total demand are a major cost driver. Staff's CCOS study generally follows the procedures described in Chapter 2 of the NARUC Manual. Staff produces an embedded cost study using historical information developed from data collected over the test year updated through the true-up date set in the case.

Definitions and Fundamental Concepts of Electric CCOS and Rate Design

Cost-of-Service: All the costs that a utility prudently incurs to provide utility service to all of its customers in a particular jurisdiction.

Cost-of-Service Study: A study of total company costs, adjusted in accordance with regulatory principles (annualizations and normalizations), allocated to the relevant jurisdiction, and then compared to the revenues the utility is generating from its retail rates, off-system sales and other sources. The results of a cost-of-service study are typically presented in terms of the additional revenue required for the utility to recover its cost-of-service or the amount of revenue over what is required for the utility to recover its cost-of-service.

Class Cost-of-Service (CCOS) Study: **A** Class Cost-of-Service study is where a utility's revenue requirement is allocated among the various rate classes of that utility. It is a quantitative analysis of the costs the utility incurs to serve each of its various customer classes. When Staff performs a CCOS study it performs each of the following steps: a) categorize or functionalize costs based upon the specific role the cost plays in the operations of the utility's integrated electrical system; b) classify costs by whether they are demand-related, energy-related, or customer-related; and c) allocate the functionalized/classified costs to the utility's customer classes. The sum of all the costs allocated to a customer class is the cost to serve[1] that class.

Relationship between Cost-of-Service and Class Cost-of-Service: The sum of all *class* cost-of-service in a jurisdiction is the cost-of-service of that jurisdiction. The purpose of a Cost-of-Service study is to determine what portion of a utility's costs are attributable to a particular jurisdiction. The purpose of a Class-Cost-of-Service study is to allocate the cost-of-service study costs to the customer classes in that jurisdiction.

Cost allocation: A procedure by which costs incurred to serve multiple customers or customer classes are apportioned among those customers or classes of customers.

Cost Functionalization: The grouping of rate base and expense accounts according to the specific function they play in the operations of an integrated electrical system. The most aggregated functional categories are production, transmission, distribution and

[1] The cost to serve a particular class is sometimes referred to as the cost-of-service for that class.

customer-related costs, but numerous sub-categories within each functional category are commonly used.

Customer Class: A group of customers with similar characteristics (such as usage patterns, conditions of service, usage levels, etc.) that are identified for the purpose of setting rates for electric service.[2]

Rate Design: (1) A process used to determine the rates for an electric utility once cost-of-service and CCOS is known; (2) Characteristics such as rate structure, rate values, and availability that define a rate schedule and provide the instructions necessary to calculate a customer's electric bill. Rates are designed to collect revenue to recover the cost to serve the class.

Rate Design Study: While a CCOS study focuses on customer class revenue responsibility, a rate design study focuses on how service is priced and billed to the individual customers within each class and to sending appropriate price signals to customers. The rate design process attempts to recover costs in each time period (such as summer/winter seasonal pricing, or peak/off-peak time-of-day pricing) from each rate component for each customer in a way that best approximates the cost of providing service and send appropriate price signals, e.g., costs are higher in the summer so rates are higher in the summer..

Rate Schedule: One or more tariff sheets that describe the availability requirements, prices, and terms applicable to a particular type of retail electric service. A customer class used in a class cost-of-service study may consist of one or more rate schedules.

[2] A customer class used in a class cost-of-service study may consist of one or more rate schedules.

Rate Structure: Rate structure is the composition of the various charges for the utility's products. These charges include

1) customer charge: a fixed dollar amount per month irrespective of the amount of usage;
2) usage (energy) charges: a price per unit charged on the total units of the usage during the month; and
3) peak (demand) usage charge: a price per unit charge on the maximum units of the product taken over a short period of time (for electricity, usually 15 minutes or 30 minutes), which may or may not have occurred within the particular billing month.

More elaborate variations such as seasonal differentials (different charges for different seasons of the year), time-of-day differentials (different charges for different times during the day), declining block rates (lowest per-unit charges for higher usage), hours-use rates (rates which decline as the customer's hours of use – the ratio of monthly usage to maximum hourly usage – increases) are also possible. Different variations are used to send price signals to the customer.

Rate Values (Rates): The per-unit prices the utility charges for each element of its rate structure. Rate values are expressed as dollars per unit of demand (kilowatt), cents per unit of energy (kWh), etc.

Tariff: A document filed by a regulated entity with either a federal or state commission. It describes both the rate values (prices) the regulated entity will charge to provide service to its customers as well as the terms and conditions under which those rate values are applicable.

Class Cost-of-Service Overview on Functionalization, Classification and Allocation

The cost allocation process consists of three major parts: functionalization, classification and allocation.

1. Functionalization

The first step of a CCOS study is functionalization. Functionalization of costs involves categorizing plant investment and operation cost accounts by the type of function with which an account is associated. A utility's equipment investment and operations can be organized along the lines of the function (purpose) that each piece of equipment or task provides in delivering electricity to customers. The result of functionalization is the assignment of plant investment and expenses to the principal utility functions, which include:

1. Production
2. Transmission
3. Distribution
4. Customer Accounts
5. Customer Assistance
6. Customer Sales

Attachment 1 is a diagram of a typical vertically integrated electrical system, and illustrates the concept of functionalization. Electric power is produced at the generation station, transmitted some distance through high voltage lines, stepped down to secondary voltage and distributed to secondary voltage customers. Other customers (high voltage and primary voltage) are served from various points along the system.

In practice, each major Federal Energy Regulatory Commission (FERC) account is assigned to the functional area that causes the cost. This assignment process is called functionalization. Some costs cannot be directly attributed to a single functional area, and are shared between functions -- these costs are refunctionalized to more than one functional area, with the distribution of costs between functions based upon some relating factor.[3] As an example, it is reasonable to assume that social security taxes are directly related to payroll costs so that these taxes can be assigned to functions in the same manner as payroll costs. In

[3] The costs in the FERC account are distributed based on a relationship of the distributed cost to a function rather than all the costs in that account being associated to a particular function.

this case, the ratio of labor costs assigned to the various functional categories becomes the factor for distributing social security taxes between functional groups.

Yet other costs can be clearly attributed to providing service to a particular class of customers, and these costs can be directly assigned to that customer class. Special studies are undertaken by the utility to determine the assignment of costs to customer classes. An example of a direct assignment is the assignment of the cost of transmission equipment used only by a large customer on a particular rate schedule to the rate class associated with that rate schedule.

Functionalized costs are then subdivided into measurable, cost-defining service components. Measurable means that data is available to appropriately divide costs between service components. Cost-defining means that a cost-causing relationship exists between the service component and the cost to be allocated. Functionalized costs are often divided into customer-related costs and demand-related costs. In addition, some functionalized costs can be classified on the basis of the voltage level at which the customer receives electric service.

2. Classification

The second step of a CCOS study is to separate the functionalized costs into classifications based on the components of utility service being provided. Classification is a means to divide the functionalized, cost-defining components into a: 1) customer component, 2) demand component, 3) and an energy component for rate design considerations. The January 1992 edition of the NARUC Manual references customer-related, demand-related, and energy-related cost components for all distribution plant and operating expense accounts, other than for substations and street lighting.

Customer-related costs are the costs to connect the customer to the electrical system and to maintain that connection. Examples of such costs include meter reading expense, billing expense, postage expense, customer accounting expense, customer service expense, and various distribution costs (plant, reserve, and operating and maintenance expenses). The customer components of the distribution system are those costs necessary to make service available to a customer.

Demand-related costs are rate base investment and related operating and maintenance expenses associated with the facilities necessary to supply a customer's service requirements during periods of maximum, or peak, levels of power consumption each month. The major portion of demand-related costs consists of generation and transmission plant and the non-customer-related portion of distribution plant. Demand-related costs are based on the maximum rate of use (maximum demand) of electricity by the customer. In addition, some demand-related investment and costs can be classified on the basis of voltage level at which the customer receives electric service.

Energy-related costs are those costs related directly to the customer's consumption of electrical energy (kilowatt-hours) and consist primarily of fuel, fuel handling, a portion of production plant maintenance expenses and the energy portion of net interchange power costs.

The purpose of classification is to make the third step, allocation, more accurate. For example, assume a special study shows that overhead lines for distribution can be classified into a demand component directly related to a customer's maximum rate of energy usage, and a customer component that is directly related to the fact that a customer exists and requires service. The demand-related portion of overhead distribution line costs can be allocated on the basis of customer maximum demands and the customer-related portion can be allocated on the basis of the number of customers in each class. Typically, the information allowing classification is obtained through special studies of the distribution system. These studies often include statistical analysis of equipment and labor costs, and line losses.

3. Allocation

The third step of performing a CCOS study is called allocation. After the costs have been functionalized and classified, the next step in a CCOS study is to allocate costs to the customer classes. This process involves applying the allocation factors developed for each class to each component of rate base investment and each of the elements of expense specified in the jurisdictional cost of service study. The allocation factors or allocators determine the results of this process. The aggregation of such cost allocations indicates the total annual revenue requirement associated with serving a particular customer class. Allocation factors are chosen that will reasonably distribute a portion of the functionalized costs to each customer class on the basis of cost causation. Allocation factors are typically ratios that represent the fraction of total units (e.g., total number of customers; total annual energy consumption) that are attributable to a certain customer class. These ratios are then used to calculate the fraction of various cost categories for which a class is responsible.

Calculation of Class Net Income and Rate of Return

The operating revenues of each customer class minus its total operating expenses determined through the functionalization, classification and allocation process provide the resulting net income to the utility of each class. The net operating income divided by the allocated rate base of each class will indicate the percentage rate of return being earned by the utility from a particular customer class.

Generation Allocation Methods Listed in NARUC Manual

Utilities design and build generation facilities to meet the energy and demand requirements of their customers on a collective basis. It is impossible to determine which customer classes are being served by which facilities. As such, generation facilities are joint costs used by all customers and allocated to customer classes. Utilities experience periods of high demand during certain times of the year and during various hours of the day (summer hours). All customer classes do not contribute in equal proportions to the varying demands placed on the utility system. Utilities design their mix of generation facilities to minimize the total costs of energy and capacity, while making certain that there is enough available capacity to meet demands for every hour of the year. For example, base load nuclear and coal units require high capital expenditures resulting in large investments per kW, whereas smaller units like gas and oil require less investment per kW but higher variable production costs. It is most cost-effective to build base load units to meet the continuous load of the year and depend on small units to meet the few peak hours of the year. Therefore, production costs vary each hour of the year.

Different parties use different methodologies to allocate generation related plant and expenses. For example, the National Association of Regulatory Commissioners (NARUC) outlined thirteen (13) generation allocation methods in its 1992 Electric Utility Cost Allocation Manual (Manual). The thirteen generation allocation methods are:

1. Single Coincident Peak Method (1-CP)
2. Summer and Winter Peak Method (S/W)
3. Twelve Monthly Coincident Peak (12CP)
4. Multiple Coincident Peak Method
5. All Peak Hours Approach
6. Average and Excess Method (A&E)
7. Equivalent Peaker Methods (EP)
8. Base and Peak Method (B&P)

9. Peak and Average Demand (P&A)
10. Production Stacking Methods
11. Base-Intermediate-Peak (BIP)
12. Loss of Load Probability (LOLP)
13. Probability of Dispatch Method (POD)

A brief description of some of the cost methodologies used most often along with the assumptions and implications are as follows:

Single Coincident Peak Method (1-CP) – The NARUC Manual describes the objective of the 1-CP is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load. The calculation translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements. The basic premise of the 1-CP method is that an electric utility must have enough capacity available to meet its customers' peak coincident demand. Strengths of this methodology are that the concepts are easy to understand and the data to conduct the CCOS are relatively simple and easy to obtain. The weaknesses are that the sole criteria is based on load during a single hour of the year; the results of the 1-CP method can be unstable from year to year, i.e., if peak occurs on a weekend or holiday, the class contributions to the peak load will be significantly different if the peak occurred during a weekday. Also, when using this methodology there can be free ride allocation. In this context, free ridership is when service rendered completely off-peak is not assigned any responsibility for capacity costs. An example of the free ride allocation may occur for street lighting. Street lights are not on during the day and would be allocated no capacity costs at all if the peak occurred during daylight hours.

The system peak typically occurs on days with extreme weather. Therefore this allocation methodology will allocate more costs to weather sensitive classes and less costs to non-weather sensitive classes than other methodologies.

Summer and Winter Coincident Peak (S/W Peak) – The NARUC Manual describes the objective of S/W Peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. This approach may be used if the summer and winter peaks are close in value. The S/W Peak method was developed because some utilities annual peak load occurs in the summer for certain years and in the winter during other years. This method has essentially the same strengths and weaknesses as the 1-CP method except that two hours are used to define the class allocations for generating facilities.

Twelve Monthly Coincident Peak (12-CP) - The NARUC Manual describes this method as an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range for all twelve months. Most electric utilities have distinct seasonal load patterns such as high peaks in the summer months and lower peaks during the winter, spring and autumn months. However, depending on types of heating options available, winter months may be equal or exceed summer month peaks. This method may be appropriate for some electric utilities where the winter heating season is within a narrow band with the summer cooling season.

The 12-CP method assigns class responsibilities based on their respective contributions throughout the year more closely matching the fact that utilities use all of their resources during the highest peaks, and only use their most efficient plants during lower peak periods than the 1-CP and S/W Peak methods. Weaknesses of this method are that the utility must accurately track load data for all twelve months and customer classes who have major off-peak usage may not receive its fair share of generation facilities. A strength of this method is that a utility can allocate its proportion of cost using twelve months of data information and this method takes into account some class diversity in allocations. The percent allocated to weather sensitive classes is not as great as with the 1-CP and S/W Peak methods.

Average and Excess Method (A&E) – The NARUC Manual describes the A&E method as a method that allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands. All production plant costs are usually classified as demand related. The A&E method consists of two parts. The first component of each class's allocation factor is its proportion of the class' total average demand (based on energy consumption) times the system load factor. The second component of each class's allocation factor is called the "excess" demand factor. This component is multiplied by the remaining proportion of production plant (1 minus system load factor). The first and second components (Average and Excess components) are then added to obtain the total allocator. A weakness of this method is that the allocation favors high load factor customers, e.g., classes with industrial customers, and disfavors customer classes with lower load factor customers, e.g., residential and small commercial classes, because the "excess" portion of the allocator uses non-coincidental peak information. Some of the non-coincidental peaks for classes may not occur in peaking seasons. Strengths are that no class of customers will receive a free-ride under this method, e.g., street lighting, and recognition is given to average consumption as well as to additional costs imposed by certain classes for not maintaining a perfectly constant load.

Equivalent Peaker (EP) – The NARUC Manual describes EP as a method based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. The EP method often relies on planning information in order to classify individual generating units as energy or demand-related and considers the need for a mix of base load, intermediate load, and peaking load generation resources. The EP method has some appeal because base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units that are seldom used are allocated based on peak demands to those classes contributing to the system peak load. With the EP method, only the combustion turbines and the combustion turbines equivalent capacity cost portion of all other units are treated as demand related. The remainder of the total plant investment is thus treated as energy related. A strength of the EP method is that base load units that operate with high capacity factors are allocated largely on the basis of energy consumption with costs shared by all classes based on their usage, while peaking units used sparingly and only called upon during peak periods are allocated based on peak demands to those classes contributing to the system peak load. One weakness of this method is that it requires a significant amount of data.

Peak and Average (P&A) – The NARUC Manual describes the impetus for this method as some regulatory commissions recognizing that energy loads are an important determinant of production plant costs, requiring the incorporation of judgmentally-established energy weightings into cost studies. The allocator is effectively the average of adding together each class's contribution to the system peak demand and its average demand. This methodology premise is that a utility's actual generation facilities are placed into service to meet peak load and to serve customers demands throughout the entire year. This method assigns capacity cost partially on the basis of contributions to peak load and partially on the basis of consumption throughout the year or peak period. Strengths of this methodology are an attempt to recognize the capacity/energy allocation in the assignment of fixed capacity costs and that data requirements are minimal. Weaknesses are that the capacity/energy allocation method may have the perception that double-counting occurs in the capacity/energy allocation.

Base-Intermediate-Peak (BIP) – The NARUC Manual describes the BIP method as a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate hours), and (3) base loading hours. The BIP method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load (base, intermediate, and peak). The BIP method is an accepted allocation method that attempts to recognize the capacity/energy trade-off that exists within a utility's generation asset portfolio. A utility's base load units tend to operate during all periods of the year (less outages or maintenance) to satisfy energy requirements in the most efficient manner possible during minimum periods. Because base load units operate regardless of peak requirements, they are appropriately classified as energy related. Intermediate plants serve a dual purpose in that they are partially energy-related and partially-demand related. Peaking plants operate with high variable cost and are only utilized to help meet peak period demands. As such, peaker generating facilities plants are classified as peak demand-related. The BIP method considers the differences in the capacity/energy trade off that exist across a company's generation mix. Strengths of the BIP method are that there are three different components being allocated to the various rate classes. There is a base component (based on energy), an intermediate component based on demands less base portion, and a peaking component based on demands less the base and intermediate components already allocated to the classes. The BIP method is one of several methods that allow for a complete recognition of the dual nature of generating resources and provides a structured and precise way to model the costs and develop appropriate class allocators for production plant. Another strength is that each generating unit may be classified as a base, intermediate, or peak generating facility based on fuel costs, heat rates, and operating hours in its classification or the method may allocate investment in production plant and facilities as a whole and does not require an analysis of individual generating units. An additional strength is it eliminates free ridership by customer classes with a substantial off-peak usage. A general weakness is that the BIP method may not be appropriate for utilities that purchase the majority of their energy needs or for utilities with an inefficient mix of generating resources.

Time of Use (TOU) – A production allocation method that assigns production costs to each hour of the year that the specific production occurs. The TOU method apportions production plant accounts for both demand and energy characteristics as each much satisfy both periods of normal use throughout the year and intermittent peak use. The TOU is used for analyzing cost of service by time periods. This method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. Previous Staff employee Mike Proctor refined this process with the Commission adopting the TOU methodology in previous cases in Case No. EO-78-161, Case No. EO-85-17, and Case No. ER-85-60. Strengths of the method is that all 8,760 hours are analyzed and assigned to rate groups. Also, each class of customers is assigned their share of costs for the entire test year period. Weaknesses are that a lot of data is needed to analyze and the data needs to be weather normalized for each hour. The Commission rejected this method in a previous case noting that the TOU is unreliable because it considers every hour in the year to be a demand peak.

Requirements of the Missouri Class Cost of Service
Study to Be Provided With GMO's Next Rate Case Filing

I. Rate Classes to be Used in Missouri Class Cost of Service Study

Residential
Small General Service
Large General Service
Large Power Service
Lighting & other customers to which known costs are assigned and other costs are allocated

II. Work Products

1. Functionalized Costs

GMO will provide a summary of actual costs by functional category and FERC account* for the test year. Each functional category is defined by the allocation factor that is applied to the costs in that category; thus, there is a one-to-one correspondence between the functional cost categories and the allocation factors used in a class cost-of-service study.

*This includes all plant accounts, depreciation expense, depreciation reserve, all expenses, and revenues.

2. Hourly Class Load Data

GMO will provide hourly rate class load data for the test year.

3. Monthly Rate Class Load Characteristics

GMO will provide each of the following work-products in three versions
Version #I: 12 months of test year; Version #2: weather-normalized (at meter voltage); and Version #3: weather-normalized (at each voltage level from meter to generator):

a) coincident peak demands
b) non-coincident (class peak) demands by delivery voltage*
c) customer maximum demands by delivery voltage*, also the annual customer maximum demand
d) monthly kWh sales by billing month and by delivery voltage level*

*delivery voltage relates to ownership of facilities (e. g., "secondary" refers to GMO ownership of the transformation equipment required to transform electricity from a primary voltage to a secondary voltage ; "primary" refers to customer ownership of said transformation equipment)

4. Revenue and Billing Units

GMO will provide each of the following work products in two versions:

Version #1: 12 months of test year; Version #2: weather-normalized (at meter voltage):

a) billing units by billing month and by the voltage groupings shown on GMO's current rate schedules

b) rate revenues by rate class

5. Allocation Factors

GMO will provide the allocation factors based on 12 months of test year, and the derivation of such factors that correspond to each of the functional cost categories used in a class cost-of-service study.

6. Special Cost Studies

GMO will provide the following special studies:

a) Primary/secondary split of distribution investment contained in FERC accounts #364 - #367

b) Demand split of distribution investment contained in FERC accounts #364 - #368

c) Meter cost study (typical installed meter and associated replacement cost)

d) Service Line cost study (typical installed service line and associated replacement cost)

e) Meter reading

f) Billing

g) Losses (load and no-load)

7. Individual Customer Billing Data

GMO will provide all monthly billing data for individual accounts that were served under either the Large Power or Special Contract rate schedules at any time during the 12 months of test year.

8. Work Papers

GMO will provide Staff and OPC complete copies of the work papers relating to all of the above items. GMO will also make copies of any or all of these work papers available upon request to other parties to this agreement. Work papers should include both the input data and the computations in sufficient detail that the Company's results are replicable by technical experts from the signatory parties. The work papers should be in an electronic, preferably EXCEL spreadsheet, format with all formulas intact.

FAC Tariff Sheet Comparison

	Ameren Missouri	GMO	Empire
Accumulation period definition	The historical calendar months during which fuel and purchased power costs, including transportation, net of OSSR for all kWh of energy supplied to Missouri retail customers are determined	None	The six calendar months during which the actual costs subject to this rider will be accumulated for purposes of determining the CAF
Proposal	The four calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR)	The six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR)	
Recovery Period definition	The billing months as set forth in the above table during which the difference between the Actual Net Fuel Costs during an Accumulation Period and NBFC are applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.	the billing months during which the Cost Adjustment Factor (CAF) for each of the respective accumulation periods are applied to retail customer billings on a per kilowatt-hour (kWh) basis	The billing months during which CAF is applied to retail customer billings on a per kilowatt-hour (kWh) basis
Proposal	The billing months during which FAR is applied to retail customer usage on a per kilowatt-hour (kWh) basis adjusted for service voltage		
Filing date	By set date	By set date	set date
Proposal	60 days prior to the first billing cycle read date for the first billing month in the recovery period	By set date	By set date
Adjustment Amount ($) name	Third Subtotal	Fuel Adjustment Clause (FAC), Fuel and Purchased Power Adjustment, FPA, FAC Costs, FAC	FAC, Fuel Adjustment Clause

FAC Tariff Sheet Comparison

	Ameren Missouri	GMO	Empire
Proposal	Fuel and Purchase Power Adjustment (FPA)		
\$/kWh charge before voltage adj	FPA rate, FPA_c rate, FPA_c	Cost Adjustment Factor (CAF) CAF, Current annual CAF Annual CAF, Forth Interim Total	Cost Adjustment Factor (CAF) and CAF
Proposal	Fuel Adjustment Rate (FAR)		
\$/kWh charge for recovery period for that just ended	$FPA_{(RP)}$	Current period CAF Single Accumulation Period CAF	Cost Adjustment Factor (CAF) and CAF
Proposal	FAR_{RP}	FAR_{RP}	FAR
\$/kWh charge for prior period	$FPA_{(RP-1)}$ and $FPA_{(RP-2)}$	Previous period CAF Single Accumulation Period CAF	N/A
Proposal	FAR_{RP-1}	FAR_{RP-1}	N/A
Adjustment for losses	Voltage level adjustment factors	Expanded for losses Expansion factors, XF XF_{Sec} and XF_{Pri}	Expansion factors
Proposal	Voltage Adjustment Factors (VAF), VAF_{SEC}, VAF_{PRI}, and VAF_{TRAN}		
Voltage adjusted \$/kWh charge	FPA rate, FPAc (with voltage level adjustment)	Annual CAF, FPA CAF	
Proposal	FAR_{SEC} FAR_{PRI}, and FAR_{TRAN}		

FAC Tariff Sheet Comparison

	Ameren Missouri	GMO	Empire
Base definition	net output calculation in the fuel run used in part to determine Net Base Fuel Costs, as included in the Company's retail rates	Base energy costs are costs as defined in the description of TEC (Total Energy Cost).	are calculated using the costs included in the revenue requirement upon which Empire's general rates are set for fuel including the costs associated with the Company's fuel hedging program; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, Air Quality Control consumables, such as anhydrous ammonia, limestone, and powder activated carbon, and emission allowance costs, but not purchased power demand costs as off-set by off-system sales revenue, any emission allowances revenues and renewable energy credit revenues in the accumulation period. Base energy cost per kWh: cost per kWh at the generator, established in the most recent base rate case
Proposal	Base energy costs are ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the FPA		
Base acronym $	Net Base Fuel Costs (factor NBFC), NBFC and First Subtotal	B and Base energy cost	B and Base Energy Cost
Proposal	Net Base Energy Costs (B)		

FAC Tariff Sheet Comparison

	Ameren Missouri	GMO	Empire
Base energy $/kWh name	NBFC rate, Net Base Fuel Costs and NBFC	Applicable Base Energy Cost, base energy cost	Base energy cost per kWh
Proposal	Base Factor (BF)		
Name of filing to change rate	Fuel and Purchased Power Adjustment (FPA) filing, FPA filing	None	Cost Adjustment Factor (CAF) filing
Proposal	Fuel Adjustment Rate filing		
Fuel Costs	Included in CF	FC	F
Proposal	Set out separately as FC		
Cost of Purchased Power	CPP	PP	P
Proposal	PP		
Off-System Sales Revenues	OSSR	OSSR	O
Proposal	OSSR		
Interest calculation	Monthly based on the weighted average interest rate paid on the Company's short-term debt	As applied to deferred electric energy costs: at a rate equal to the weighted average interest paid on short-term debt No explanation for true-up interest calculation	The Company's short-term interest rate
Proposal	Monthly based on the weighted average interest rate paid on the Company's short-term debt.		Monthly based on the interest rate paid on the Company's short-term debt.
Under/over recovery amount	R – includes interest	C – includes accumulated interest	C - doesn't mention interest
Proposal	T. Interest would be in a separate term (I)		
Accumulation Period kWh	S_{AP}	NSI and total system kWh, net system input	NSI kWh and NSI
Proposal	S_{AP}		
Recovery Period kWh	S_{RP}	RNSI	S

Schedule MJB-1-4

FAC Tariff Sheet Comparison

	Ameren Missouri	GMO	Empire
Proposal	S_{RP}		
True-up filing timing	In conjunction with an adjustment to its FAC	At the end of each recovery period	Upon completion of each recovery period
Proposal	In conjunction with an adjustment to its Fuel Adjustment Rate (FAR)		
Actual Energy Cost name	CF also called Actual Net Fuel Costs	TEC – consists of FC, EC, PP, TC and OSSR	None
Proposal	Actual Net Energy Costs (ANEC)		
Emissions Cost	Included in CF	EC – net emissions costs	E – Actual total system net emission allowance cost and revenue
Proposal	Explicit in equation as "E"		
Transmission costs	Not mentioned	TC – for off-system sales	Included in description of base energy cost, not mentioned elsewhere
Proposal	Include in purchase power costs. Explicitly mention in tariff as portion of purchased power costs		
Jurisdictional factor acronym	N/A	J and Energy retail ratio	J and Missouri Energy Ratio
Proposal	N/A	Missouri Retail Energy Ratio (J)	
Prudence disallowances included in under/ over recovery	Modifications as a result of prudence reviews	Modifications due to prudence reviews	This factor will reflect any modifications due to prudence reviews
Proposal	Modifications as ordered by the Commission as a result of prudence reviews		
Other changes allowed in under/over recovery	Other disallowances and reconciliations		
Proposal	Other disallowances and reconciliations as ordered by Commission, if any		
Interest included in under/over recovery	Yes	Yes	No
Proposal	Should be included in tariff language		
REC revenues included	No	No	Yes – factor R

FAC Tariff Sheet Comparison

	Ameren Missouri	GMO	Empire
Proposal	If included in FAC designate as REC		
Prudence amount return	Shall be returned to customers with interest at a rate equal to the weighted average interest rate paid on the Company's short-term debt.	Adjustments, if any, necessary by Commission order pursuant to any prudence review shall also be placed in the FAC for collection unless a separate refund is ordered by the Commission	In C → This factor will reflect any modifications made due to prudence reviews
Proposal	Adjustments by Commission order pursuant to any prudence review shall also be placed in the FPA for collection unless a separate refund is ordered by the Commission		
Prudence amount designation	None	None	None
Proposal	P		
Emission type allowed	SO_2 and NO_x emissions allowances	Costs in Acct 509 or any other Acct FERC may designate for emission expenses in the future	Emission allowance costs in Acct 509 and 254.103
Proposal	Type of emission allowance (e.g., SO_2, NO_x) as ordered by Commission with appropriate FERC account		

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR). The two six-month accumulation periods each year through Month Day, Year, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	**Filing Dates**	**Recovery Periods**
June – November	By January 1	March – February
December – May	By July 1	September – August

A recovery period consists of the billing months during which the Fuel Adjustment Rate (FAR) is applied to retail customer billings on a per kilowatt-hour (kWh) basis.

COSTS AND REVENUES:

Costs eligible for the Fuel and Purchased Power Adjustment (FPA) will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, including the costs described below associated with the Company's fuel hedging programs; purchased power energy charges, and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues, applicable net SPP revenues, any revenue from the sale of Renewable Energy Certificates and any emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the FPA mechanism and approval by the Missouri Public Service Commission.

The FAR is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (S_{RP}) during the recovery period, expanded for Voltage Adjustment Factors (VAF), rounded to the nearest $0.0001, and aggregating over two accumulation periods. The amount charged on a separate line on retail customers' bills is equal to the current annual FAR times kWh's billed.

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = 85% * ((ANEC – B) * J) +T + I + P

FAR = FPA/S_{AP}

Single Accumulation Period Secondary Voltage FAR_{Sec} = FAR * VAF_{Sec}

Single Accumulation Period Primary Voltage FAR_{Prim} = FAR * VAF_{Prim}

Annual Secondary Voltage FAR_{Sec} =
Aggregation of the Single Accumulation Period Secondary Voltage FARs still to be recovered

Annual Primary Voltage FAR_{Prim} =
Aggregation of the Single Accumulation Period Primary Voltage FARs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

FAR = Fuel Adjustment Rate

85% = Customer responsibility for fuel variance from base level.

ANEC = Actual Net Energy Costs = (FC + E + PP + TC – OSSR-R):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost for fuel burned in the Company's generating units, , fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, ash disposal revenues and expenses, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

- The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs for fuel burned in the Company's generating units, fuel additives, settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees in Account 547.

  Hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost for natural gas burned as fuel in the Company's generating units, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps

E = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs offset by revenues from the sale of emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555, excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

TC = Transmission Costs:

Transmission costs that are necessary to receive purchased power to serve native load and transmission costs that are necessary to make Off System Sales included in FERC Account Number 565, except for costs related to the Crossroads Generating plant.

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales shall exclude full and partial requirements sales to Missouri municipalities that are associated with GMO.

R = Renewable Energy Credit Revenue

- Revenues reflected in FERC Account 509 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard before they expire

B = Net base energy costs ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the FPA. Base Energy costs will be calculated as shown below:

L&P S_{AP} x Base Factor (BF)
MPS S_{AP} x Base Factor (BF)

S_{AP} = Net system input (kWh) for the accumulation period

J = Missouri Retail Energy Ratio = Retail kWh sales/S_{AP}
Where: total system kWh equals retail and full and partial requirements sales associated with GMO.

T = True-up amount as defined below.

I = Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P= Prudence disallowance amount, if any, as defined below.

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1 ______ Original Sheet No. 126.2
Canceling P.S.C. MO. No. ______ ______ Sheet No.__
KCP&L Greater Missouri Operations Company For Territory Served as L&P and MPS
KANSAS CITY, MO

FUEL AND PURCHASE POWER ADJUSTMENT
ELECTRIC (continued) (Applicable to Service Provided March 28, 2012 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

S_{RP}= Forecasted recovery period net system input in kWh, at the generator

VAF = Expansion factor by voltage level
VAF_{Sec} = Expansion factor for lower than primary voltage customers
VAF_{Prim} = Expansion factor for primary and higher voltage customers

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant FAR's will be applied to customers in the respective rate districts and voltage levels.

BASE FACTOR (BF)

Company base factor costs per kWh:
$0.02177 for L&P
$0.02446 for MPS

TRUE-UPS

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in "T" above. Interest on the true-up adjustment will be included in item I above. The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

PRUDENCE REVIEWS

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in item "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in item "I" above.

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION

P.S.C. MO. No.	1	5th	Revised Sheet No. 127
Canceling P.S.C. MO. No.	1	4th	Revised Sheet No. 127

KCP&L Greater Missouri Operations Company For Territory Served as L&P and MPS

KANSAS CITY, MO

	Accumulation Period Ending:		Month, Day, Year MPS	L&P
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)			
2	Net Base Energy Cost (B)	-		
	2.1 Base Factor (BF)			
	2.2 Accumulation Period Sales (S_{AP})			
3	(ANEC-B)			
4	Jurisdictional Factor (J)	*	%	%
5	(ANEC-B)*J			
6	Customer Responsibility	*	85%	85%
7	85% *((ANEC-B)*J)			
8	True-Up Amount (T)	+		
9	Prudence Adjustment Amount (P)	+		
10	Interest (I)	+		
11	Fuel and Purchased Power Adjustment (FPA)	=		
12	Estimated Recovery Period Sales (S_{RP})	÷		
13	Current Period Fuel Adjustment Rate (FAR)	=		
14	Current Period FAR_{Pri} = FAR x VAR_{Pri}			
15	Prior Period FAR_{Pri}	+		
16	Current Annual FAR_{Pri}			
17	Current Period FAR_{Sec} = FAR x VAR_{Sec}			
18	Prior Period FAR_{Sec}	+		
19	Current Annual FAR_{Sec}			

MPS VAR_{Prim} = 1.0419
MPS VAR_{Sec} = 1.0712
L&P VAR_{Prim} = 1.0421
L&P VAR_{Sec} = 1.0701

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1 2nd ~~Original~~ Revised Sheet No. ~~127.11~~124
Canceling P.S.C. MO. No. 1 1st Revised Sheet No. 124
KCP&L Greater Missouri Operations Company For Territory Served as L&P and MPS
KANSAS CITY, MO

~~FUEL ADJUSTMENT CLAUSE~~FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC For the L&P and MPS Rate Districts(Applicable to Service Provided ~~March 28, 2012~~Month Day, Year and Thereafter)

DEFINITIONS

ACCUMULATION PERIODS, FILING DATES AND RECOVERY PERIODS:

An accumulation period is the six calendar months during which the actual costs and revenues subject to this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR). The two six-month accumulation periods each year through ~~March 27, 2016~~Month Day, Year, the two corresponding twelve-month recovery periods and the filing dates will be as shown below. Each filing shall include detailed work papers in electronic format to support the filing.

Accumulation Periods	**Filing Dates**	**Recovery Periods**
June – November	By January 1	March – February
December – May	By July 1	September – August

A recovery period consists of the billing months during which the ~~Cost Adjustment Factor~~Fuel Adjustment Rate (~~CAF~~FAR) is applied to retail customer billings on a per kilowatt-hour (kWh) basis. ~~for each of the respective accumulation periods are applied to retail customer billings on a per kilowatt-hour (kWh) basis.~~

COSTS AND REVENUES:

Costs eligible for the ~~Fuel Adjustment Clause~~ Fuel and Purchased Power Adjustment (FPA~~AC~~) will be the Company's allocated Jurisdictional costs for the fuel component of the Company's generating units, including the costs ~~as~~ described below associated with the Company's fuel hedging programs; purchased power energy charges, and emission allowance costs - all as incurred during the accumulation period. These costs will be offset by off-system sales revenues, applicable net SPP revenues, any revenue from the sale of Renewable Energy Certificates and any emission allowance revenues collected during the accumulation period. Eligible costs do not include the purchased power demand costs associated with purchased power contracts in excess of one year.

APPLICABILITY

The price per kWh of electricity sold to retail customers will be adjusted (up or down) periodically subject to application of the ~~FAC~~FPA mechanism and approval by the Missouri Public Service Commission.

The ~~CAF~~FAR is the result of dividing the Fuel and Purchased Power Adjustment (FPA) by forecasted retail net system input (~~RNSI~~S_{RP}) during the recovery period, expanded for ~~losses~~Voltage Adjustment Factors (VAF), rounded to the nearest \$0.00001, and aggregating over two accumulation periods. ~~A CAFFAR will appear on a separate line on retail customers' bills and represents the rate charged to customers to recover the FPA.~~ The amount charged on a separate line on retail customers' bills is equal to the current annual FAR times kWh's billed.

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1 — 2nd ~~Original~~ Revised Sheet No. ~~127.11~~125~~-~~
Canceling P.S.C. MO. No. 1 — 1st Revised Sheet No. 125
KCP&L Greater Missouri Operations Company For Territory Served as L&P and MPS
KANSAS CITY, MO

~~FUEL ADJUSTMENT CLAUSE~~FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC (continued) (Applicable to Service Provided ~~March 28, 2012~~(Month, Day, Year) ~~-~~and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS

FPA = ~~9~~85% * ((~~T~~ANEC – B) * J) ~~+~~-~~TC~~ + I + P

~~CAF~~FAR = FPA/~~RNS~~S_{AP}

Single Accumulation Period Secondary Voltage ~~CAF~~FAR_{Sec} = ~~CAF~~FAR * ~~XF~~VAF_{Sec}

Single Accumulation Period Primary Voltage ~~CAF~~FAR_{Prim} = ~~CAF~~FAR * ~~XF~~VAF_{Prim}

Annual Secondary Voltage ~~CAF~~FAR_{Sec} =
Aggregation of the Single Accumulation Period Secondary Voltage ~~CAF~~FARs still to be recovered

Annual Primary Voltage ~~CAF~~FAR_{Prim} =
Aggregation of the Single Accumulation Period Primary Voltage ~~CAF~~FARs still to be recovered

Where:

FPA = Fuel and Purchased Power Adjustment

~~CAF~~FAR = ~~Cost Adjustment Factor~~Fuel Adjustment Rate

~~9~~85% = Customer responsibility for fuel variance from base level. ~~TEC~~ ANEC = ~~Total~~

Actual Net Energy Costs = (FC + E~~C~~ + PP + TC ~~-~~– OSSR~~-~~R):

FC = Fuel Costs Incurred to Support Sales:

- The following costs reflected in Federal Energy Regulatory Commission (FERC) Account Numbers 501 & 502: coal commodity and railroad transportation, switching and demurrage charges, applicable taxes, natural gas costs, alternative fuel (i.e. tires and bio-fuel), fuel additives, quality adjustments assessed by coal suppliers, fuel hedging cost for fuel burned in the Company's generating units, ~~(hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps)~~, fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, propane costs, ash disposal revenues and expenses, and settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses in Account 501.

~~FUEL ADJUSTMENT CLAUSE~~FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC (continued) (Applicable to Service Provided March 28, 2012 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

- The following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, fuel losses, hedging costs for fuel burned in the Company's generating units, fuel additives, ~~and~~ settlement proceeds, insurance recoveries, subrogation recoveries for increased fuel expenses, broker commissions and fees in Account 547.

Hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel, including but not limited to, the Company's use of futures, options and over-the-counter derivatives including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps

E~~C~~ = Net Emissions Costs:

- The following costs reflected in FERC Account Number 509 or any other account FERC may designate for emissions expenses in the future: Emission allowances costs offset by revenues from the sale of emission allowances.

PP = Purchased Power Costs:

- Purchased power costs reflected in FERC Account Numbers 555: Purchased power costs, settlement proceeds, insurance recoveries, and subrogation recoveries for increased purchased power expenses in Account 555, excluding capacity charges for purchased power contracts with terms in excess of one (1) year.

TC = Transmission Costs:

Transmission costs that are necessary to receive purchased power to serve native load and transmission costs that are necessary to make Off System Sales included in FERC Account Number 565, except for costs related to the Crossroads ~~Generating plant~~Energy Center. ~~Transmission costs for Off System Sales included in FERC Account Number 565 except for costs for the Crossroads facility.~~

OSSR = Revenues from Off-System Sales:

- Revenues from Off-system Sales shall exclude full and partial requirements sales to Missouri municipalities that are associated with GMO.

R = Renewable Energy Credit Revenue

- Revenues reflected in FERC Account 509 from the sale of Renewable Energy Credits that are not needed to meet the Renewable Energy Standard before they expire.

B = Net base energy costs ~~are~~ ordered by the Commission in the last rate case consistent with the costs and revenues included in the calculation of the FPA. ~~Base energy costs are costs as defined in the description of TEC (Total Energy Cost).~~ Base Energy costs will be calculated as shown below:

L&P ~~NSI~~ S_{AP} x ~~Applicable Base Energy Cost~~Base Factor (BF)
MPS ~~NSI~~ S_{AP} x ~~Applicable Base Energy Cost~~Base Factor (BF)

S_{AP} = Net system input (kWh) for the accumulation period

J = ~~Energy retail ratio~~Missouri Retail Energy Ratio = Retail kWh sales/~~total system kWh~~S_{AP}
Where: total system kWh equals retail and full and partial requirements sales associated with GMO.

~~C~~ T = ~~Under / Over recovery determined in the true-up of prior recovery period cost, including accumulated interest, and modifications as ordered by the Commission as a result of due to prudence reviews.~~ True-up amount as defined below.

I = ~~Interest on deferred electric energy costs calculated at a rate equal to the weighted average interest paid on short-term debt applied to the month-end balance of deferred electric energy costs.~~ Interest applicable to (i) the difference between ANEC and B for all kWh of energy supplied during an AP until those costs have been recovered; (ii) refunds due to prudence reviews ("P"), if any; and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the true-up filings ("T") provided for herein. Interest shall be calculated monthly at a rate equal to the weighted average interest paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

P= Prudence disallowance amount, if any, as defined below.

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION
P.S.C. MO. No. 1
Canceling P.S.C. MO. No.
KCP&L Greater Missouri Operations Company
KANSAS CITY, MO

Original Sheet No.
~~127.11~~126.2-
Sheet No.
For Territory Served as L&P and MPS

~~FUEL ADJUSTMENT CLAUSE~~FUEL AND PURCHASE POWER ADJUSTMENT ELECTRIC (continued) (Applicable to Service Provided March 28, 2012 and Thereafter)

FORMULAS AND DEFINITIONS OF COMPONENTS (continued)

~~RNSI~~ S_{RP}= Forecasted recovery period net system input in kWh, at the generator

~~XF~~VAF = Expansion factor by voltage level

~~XF~~VAF_{Sec} = Expansion factor for lower than primary voltage customers

~~XF~~VAF_{Prim} = Expansion factor for primary and higher voltage customers

~~NSI = Net system input (kWh) for the accumulation period~~

The FPA will be calculated separately for L&P and MPS, and by voltage level, and the resultant ~~CAF~~FAR's will be applied to customers in the respective ~~divisions~~ rate districts

and voltag~~e~~e ~~-~~levels.

~~APPLICABLE BASE ENERGY COST~~BASE FACTOR (BF)

Company base ~~energy~~ factor costs per kWh:

$0.021772~~121~~ for L&P

$0.024464~~34~~ for MPS

TRUE-UPS

After completion of each RP, the Company shall make a true-up filing on the same day as its FAR filing. Any true-up adjustments shall be reflected in "T" above. Interest on the true-up adjustment will be included in item I above.

The true-up adjustments shall be the difference between the revenues billed and the revenues authorized for collection during the RP.

~~AND~~ PRUDENCE REVIEWS

Prudence reviews of the costs subject to this FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the Commission to have been imprudently incurred or incurred in violation of the terms of this rider shall be returned to customers. Adjustments by Commission order, if any, pursuant to any prudence review shall be included in the FAR calculation in item "P" above unless a separate refund is ordered by the Commission. Interest on the prudence adjustment will be included in item "I" above.

~~There shall be prudence reviews of costs and the true-up of revenues billed with costs intended for collection. FACFPA costs billed in rates will be refundable based on true-up results and findings in regard to prudence. Adjustments, if any, necessary by Commission order pursuant to any prudence review shall also be placed in the FACFPA for billing, unless a separate refund or credit is ordered by the Commission. True-ups occur in conjunction with an adjustment to its FARat the end of each recovery period. Prudence reviews shall occur no less frequently than at 18- month intervals.~~

STATE OF MISSOURI, PUBLIC SERVICE COMMISSION ~~Original~~ Revised Sheet No.

P.S.C. MO. No.	1	5th	~~127.11~~127-
Canceling P.S.C. MO. No.	1	4th	Revised Sheet No. 127

KCP&L Greater Missouri Operations Company For Territory Served as L&P and MPS

KANSAS CITY, MO

Accumulation Period Ending:

			Month, Day, Year	
			MPS	L&P
1	Actual Net Energy Cost (ANEC) = (FC+E+PP+TC-OSSR-R)			
2	Net Base Energy Cost (B)	-		
	2.1 Base Factor (BF)			
	2.2 Accumulation Period Sales (S_{AP})			
3	(ANEC-B)			
4	Jurisdictional Factor (J)	*	%	%
5	(ANEC-B)*J			
6	Customer Responsibility	*	85%	85%
7	85% *((ANEC-B)*J)			
8	True-Up Amount (T)	±		
9	Prudence Adjustment Amount (P)	±		
10	Interest (I)	±		
11	Fuel and Purchased Power Adjustment (FPA)	=		
12	Estimated Recovery Period Sales (S_{RP})	÷		
13	Current Period Fuel Adjustment Rate (FAR)	=		
14	Current Period FAR_{Pri} = FAR x VAR_{Pri}			
15	Prior Period FAR_{Pri}	±		
16	Current Annual FAR_{Pri}			
17	Current Period FAR_{Sec} = FAR x VAR_{Sec}			
18	Prior Period FAR_{Sec}	±		
19	Current Annual FAR_{Sec}			

MPS VAR_{Prim} = 1.0419

MPS VAR_{Sec} = 1.0712

L&P VAR_{Prim} = 1.0421

L&P VAR_{Sec} = 1.0701