MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

RATE DESIGN

AND

CLASS COST-OF-SERVICE

REPORT

UNION ELECTRIC COMPANY dba AMEREN MISSOURI

CASE NO. ER-2012-0166

Jefferson City, Missouri
July 19, 2012

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CLASS COST-OF-SERVICE

REPORT

I. Executive Summary

Staff's Class Cost-of-Service ("CCOS") and Rate Design recommendation in this case is that the Commission order Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri") to implement the following rate design:

1. Based on CCOS results, Staff recommends adjustments be made first on a revenue-neutral basis to all classes of customers. The Ameren Missouri residential class should receive a positive 1% adjustment, the lighting class should receive a positive 3% adjustment, and the remaining classes of customers (Small General Service, Large General Service, Small Primary Service, Large Primary Service, and the Large Transmission Service) receive a negative adjustment of approximately 1.0%.

2. After having made the recommended revenue-neutral adjustments above, any overall change in revenues ordered by the Commission should be applied on an equal percentage basis to all classes. Staff further recommends that as class revenues move towards class cost-of-service, that no class receive an overall reduction in its rate revenues while another receives an overall increase in its rate revenues.

3. That Ameren Missouri's rate schedules be uniform for certain interrelationships among non-residential rate schedules that are integral to Ameren Missouri's rate design. These include uniformity for customer charges, Rider B voltage credits, Reactive charge, and Time-of-Day customer charges.

4. Eliminate the pole and span charges in the 5(M) lighting classification with the resulting revenue reduction collected from the entire 5(M) classification within the lighting class.

5. Increase the residential customer charge to $9.00.

6. Require Ameren Missouri to combine its two tariffs and file them as a single tariff, bearing the designation "P.S.C. Mo. No. 6."

7. Adopt Fuel Adjustment Clause ("FAC") tariff sheets consistent with Schedule LMM-2.

Staff's CCOS and Rate Design objectives in this report are:

1. To present an overview of Staff's CCOS study and the study results based upon the test year of October 1, 2010, through September 30, 2011, updated and trued-up through July 31, 2012.

2. Provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility.

3. Provide methods to implement any Commission-ordered overall change in customer revenue responsibility in rates.

4. Retain, to the extent possible, existing rate schedules, rate structures, and important features of the current rate design and mitigate the potential for rate shock.

5. Provide the Commission with a recommendation for consolidating the current tariff provisions into one tariff.

Staff's Class Cost-of-Service and Rate Design Report (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
- Rate Design
- Loss Study
- Ameren Missouri to file its entire tariff as a single document
- Fuel Adjustment Clause Recommendations

<u>Current Class Revenues and Cost to Serve</u>

Table 1 shows the rate revenue shifts necessary for the current rate revenues from each customer class to exactly match Staff's determination of Ameren Missouri's cost of serving that class. Additionally, Table 1 shows all classes are below their cost-to-serve based on Staff's revenue deficiency recommendation of $210,300,136.

Table 1
Summary Results of Staff's CCOS Study - Ameren Missouri

Customer Class	Revenue Deficiency	CCOS % Increase
Residential	$175,961,181	14.94%
Small General Service	$11,349,188	3.93%
Large General Service/Small Primary Service	$6,384,821	0.85%
Large Primary Service	$4,552,708	2.41%
Large Transmission Service	$5,496,827	3.70%
Lighting	$6,555,411	18.80%
Total	$210,300,136	8.13%

Staff developed its analysis of the cost of serving each class using inputs taken from Staff's Revenue Requirement Cost of Service Report ("COS Report") and the Staff Accounting Schedules filed in this case on July 6, 2012. Staff's recommended revenue requirement for Ameren Missouri is $152,480,937 to $210,300,136, based on a return on equity (ROE) range of 8.00% to 9.00%. Staff supports the high end of its ROE recommendation of 9.00%. Staff's revenue requirement as presented in its Accounting Schedules includes expected changes for a true-up ending July 31, 2012, based on current information. For example, the plant and depreciation reserve balances have been adjusted to reflect the anticipated additions through the July 31, 2012, true-up period.

The results of a CCOS study can be presented either (1) in terms of the rate of return realized 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. Staff prefers to present its results in the latter format, i.e., negative or positive dollar amounts or percentages. The results of Staff's analysis are presented in terms of the shifts in revenue that produce an equal rate of return for Ameren Missouri 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.

The customer classes used in Staff's study correspond to Ameren Missouri's current rate schedules, except Staff combined all lighting rate schedules into one customer class for its study. Aside from lighting rate schedules, Ameren Missouri has six rate schedules: Residential ("Res"), Small General Service ("SGS"), Large General Service ("LGS"), Small Primary Service ("SPS"), Large Primary Service ("LPS"), and Large Transmission Service ("LTS").

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 the level of revenue 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 cost of providing electric service to all the customer classes in a manner which best reflects cost causation. Staff's CCOS study is a continuation and refinement of Staff's cost of service revenue requirement study, resulting in a determination of the costs incurred in providing electric service to each of Ameren Missouri's customer classes. Since those costs equate to the utility's 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.

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 Regulatory Utility Commissioners ("NARUC") Manual and provides 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 study appear in Table 1 above and are outlined in Table 2 below.

Table 2

Summary Results of Staff's CCOS Study

Customer Class	CCOS % Increase	Less: System Average	Revenue Neutral % Increase
Residential	14.94%	-8.13%	6.81%
Small General Service	3.93%	-8.13%	-4.20%
Large General Service/Small Primary Service	0.85%	-8.13%	-7.28%
Large Primary Service	2.41%	-8.13%	-5.73%
Large Transmission Service	3.70%	-8.13%	-4.43%
Lighting	18.80%	-8.13%	10.67%
Total	8.13%	-8.13%	0.00%

Both tables show the changes to the current rate revenues of each customer class required to exactly match that customer class's rate revenues with Ameren Missouri'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 the utility's rate of return from each class.

"Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. The revenue neutral format aids in comparing revenue deficiencies between customer classes and makes it easier to discuss revenue neutral shifts between classes, if appropriate. Staff calculated the revenue neutral percent increase to a class's rate revenue by subtracting the overall system average increase of 8.13% from each customer class's required-percentage increase to rate revenue to match the revenues Ameren

Missouri should receive from that class to match Ameren Missouri's cost to serve that class shown in Table 2.

For example, based on Table 2, on a revenue-neutral basis, the Residential customer class is providing 6.81% less revenue to Ameren Missouri than Ameren Missouri's cost to serve that class. Also, the Large General Service/Small Primary Service customer class is providing 7.28% more revenue to Ameren Missouri than Ameren Missouri's cost to serve that class. Staff's CCOS study results for all of the customer classes Staff used for Ameren Missouri are presented in Table 2.

Because a CCOS study is not precise, 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) for Ameren Missouri customer classes on the SGS, LGS/SPS, LPS, and LTS rate schedules all the way to zero is appealing, the bill impact on the customer classes with positive revenue shift percentages must be considered. For Ameren Missouri, these are the Res and Lighting rate classes. Staff's recommendations for shifts in the class-revenue requirements are based on its study results, Staff's review of Ameren Missouri's revenue-neutral adjustments in its last two general rate increase cases (ER-2011-0028 and ER-2010-0036), and Staff's judgment regarding the impact of revenue shifts on all classes. The Res rate class received a positive 2% revenue-neutral adjustment in Case No. ER-2011-0028 and a positive 1.5% revenue-neutral adjustment in Case No. ER-2010-0036. The Lighting class received a positive 4% revenue-neutral adjustment in Case No. ER-2011-0028, and received no increase (revenue neutral or rate increase) in Case No. ER-2010-0036, as the Report and Order exempted the Lighting class from the rate increase because no specific cost study addressed the lighting rates. The Commission decision noted that the deficiency should be corrected by the completion of a CCOS study for the development of lighting rates in Ameren Missouri's next rate case (which was Case No. ER-2011-0028). Staff's CCOS study indicates that a positive revenue-neutral adjustment of 10.67% is warranted for the Lighting class (Table 2).

Staff's CCOS study used costs and revenues from Staff's accounting information and other sources as outlined below:

A. Data Sources

Staff's CCOS study utilized the Staff's revenue-requirement position as filed on July 6, 2012, through Staff's direct revenue requirement cost of service recommendation for Ameren Missouri's retail cost of service. This data includes:

- Adjusted Missouri investment and cost data by FERC account;
- Annualized, normalized rate revenues;
- Fuel and purchased power costs;
- Other operating and maintenance expenses;
- Depreciation and amortizations;
- Taxes;
- Missouri Energy Efficiency Investment Act ("MEEIA") per Stipulation and Agreement filed July 5, 2012, in Case No. EO-2012-0142;
- For each class, Staff's weather-adjusted customer-coincidental peaks, customer-non-coincidental peaks, customer-maximum peaks, and Annual Energy ; and
- Off-system sales revenues.

In addition, data was also obtained from Ameren Missouri witness William Warwick's direct testimony and workpapers from this case, which includes allocation factors for specific customer allocations. These allocation factors relate to information on meters, meter reading, uncollectible accounts, customer premise installations, and customer deposits.

B. Classes and Rate Schedules

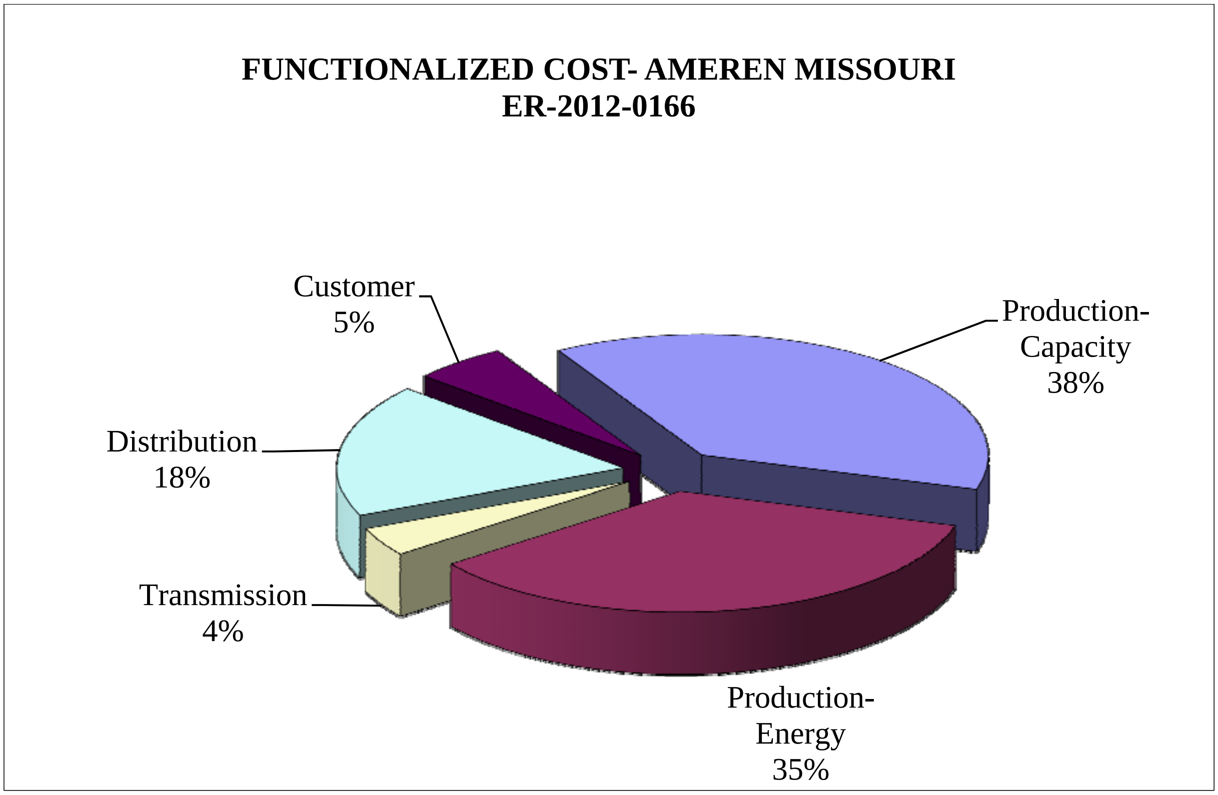
Ameren Missouri currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service and are listed in Table 1 above. The non-residential customer groups are differentiated by voltage level and/or by kilowatt (“kW”) demands.

C. Functions

The major functional-cost categories Staff used in its CCOS study are Production, Transmission, Distribution, and Customer. Within the Production Function, a distinction was made between Production-Capacity and Production-Energy. "Production-Capacity" costs are those costs directly related to the capital cost of generation. They are allocated by designated base usage, intermediate usage, and peak 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 the class.

"Production-Energy" costs are those costs related directly to the customer’s consumption of electrical energy (i.e., kilowatt-hours) and consist primarily of fuel, fuel handling, and the energy portion of net interchange power costs. The other functions that costs are classified by are distribution, transmission and customer costs. The chart below shows the percentage of total costs associated with each major function for all of Ameren Missouri’s classes, as consolidated.

TABLE 3



The “Production Function” (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 73% of the total cost. The “Distribution Function,” at 18% of the total cost, is the second largest contributor to total cost, and includes substations, overhead and underground lines, and line transformers, as well as the costs to operate and maintain this equipment. “Customer Services” at 5%, and “Transmission” at 4%, round out the total cost. Schedule MSS-1 provides Staff’s functionalized CCOS with each class’s revenue deficiency required to exactly match that customer class’s rate revenues with Ameren Missouri’s cost to serve that class. Schedule MSS-2 provides a detailed description of each external allocation factor Staff used to allocate each function in its CCOS study.

D. Allocation of Production Costs

"Production demand" refers to the rate at which electric energy is delivered to the system to match the energy requirements of its customers, either at an instant in time or averaged over a designated interval of time. In order to develop a fully comprehensive cost-of-service analysis to identify the revenue requirements for Ameren Missouri, all of Ameren Missouri's costs for plant investment and the production costs appearing on its income statement must be appropriately allocated by a production-capacity (fixed) or a production-energy (variable) component. Ameren Missouri's generation facilities, used to produce electricity for Ameren Missouri's retail customers in Missouri, are predominantly considered fixed assets. The costs and investments of these assets are apportioned to the rate classes on the basis of the production-capacity allocator. Both the demand and energy characteristics of Ameren Missouri's load are important determinants of production investment and costs, since Ameren Missouri must produce sufficient output to meet both periods of normal use and occasional peak use throughout the year. The costs of generation facilities are directly related to a utility's generation capacity, which is determined through the utility's system planning, where many factors including load factor and peak demand are considered, and thus are classified as capacity related.

Staff allocated Production-Energy fuel costs based on annualized kWh usage at generation. Fuel expenses and purchased power costs are directly related to the amount of electricity sold, and are thus classified as energy related.

Staff allocated Production–Capacity costs based on a Base-Intermediate-Peak ("BIP") method. The BIP method is based on recognition that capacity 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 Non-Coincident Peaks ("NCP[1]") of demand for electricity for a given class minus the base component previously allocated; and

3. A peaking component consisting of the average 3 NCP[2] component of demand for electricity less the base and intermediate components previously allocated.

The BIP method is described in the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual").[3] The NARUC Manual[4] in Part IV, C, Section 2, describes the BIP method as a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak, or intermediate hours, and (3) base-loading hours. Generally, base-load units have high capital costs, take five-to-ten years to build, and have low, constant running costs. Consequently, these units run almost continuously, except during periods of maintenance. Because base-load units operate regardless of peak requirements, they are appropriately classified as energy-related.[5] 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-

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[1] "12 NCP" is each month's maximum peak demand of each customer class at any time during the months of January through December.

[2] "3 NCP" is each month's maximum peak demand of each customer class during June, July, and August.

[3] Published January 1992.

[4] Schedule MSS-4 details the BIP method as described in the NARUC Manual.

[5] "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.

related.[6] Peaking units have low capital costs, are relatively quick to build—typically twelve to eighteen months—but are more costly to run. It is typically most cost-effective to only run these units for the few hours of the year when the system load is the highest. The output of peaking units is used to follow the energy requirements of the system on a real-time basis.

Ameren Missouri operates and maintains generating units that are required to provide both capacity and energy for its customers throughout the year. Prudence requires that Ameren Missouri 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 Ameren Missouri's system, both instantaneously and over time.

The BIP method Staff used to allocate Production-Capacity costs recognizes that generation is built to meet both peak demands and energy usage. The basic components of the BIP method are:

> 1) A portion of the total Production-Capacity costs is allocated to each customer class based upon that class's contribution to annual energy. This portion is classified as the base-peak portion;
>
> 2) A portion of the total Production-Capacity costs is allocated to each customer class based upon that class's contribution to intermediate peak demand. Because for each class the portion allocated to it includes the base portion allocated to the class, the base portion allocated to the class is subtracted; and
>
> 3) A portion of the total costs is allocated to each class based upon each class's contribution to the peak demand. Because for each class the portion allocated to it includes both the base portion and the intermediate portion, the base and intermediate portions allocated to the class is subtracted.

In the BIP method, the base allocator (the "B" portion in BIP) is calculated on each class's annual kWh usage at generation in the test year. The intermediate piece (the "I" in BIP) involves using the average of the 12 Non-Coincident Peaks ("NCP") for the intermediate

[6] "Demand-related" costs are rate-base investment and related operating and maintenance expenses associated with facilities necessary to supply a customer's service requirements (kW) during periods of maximum, or peak, levels of power consumption.

piece. The NCP demand is defined as the maximum monthly peak demand of each customer class at any time during the study period, and it may or may not fall on the same hour as the system peak for that month. The intermediate portion is determined by the intermediate peak less the base portion already allocated to the various classes. The final step is to determine the peak portion (the "P" in BIP) for allocation to the various classes. A listing of monthly peak loads, Table 4 below, helps to define the twelve months in terms of a peak season and a non-peak season. Ameren Missouri is a summer-peaking utility (see Table 4) with the system's three highest monthly peaks occurring in the summer season (June through August).

Table 4

System Peak @ Generation (kW)		
Month	**kW Peak**	**% of Peak**
Oct-10	4,975,922	61.0%
Nov-10	5,979,785	73.3%
Dec-10	6,519,559	79.9%
Jan-11	6,960,533	85.3%
Feb-11	6,467,330	79.2%
Mar-11	5,476,511	67.1%
Apr-11	5,094,488	62.4%
May-11	5,472,176	67.0%
Jun-11	7,037,051	86.2%
Jul-11	7,795,111	95.5%
Aug-11	8,163,084	100.0%
Sep-11	6,807,299	83.4%

The peak portion is allocated to the various classes based on each class's share of the summer peak based on the monthly peaks of June, July, and August, less the base and intermediate portions already allocated to the various classes. Staff used the three summer months during the test year for calculating the Production–Capacity cost allocator, since the three highest peaks are within approximately 86% of the system peak.

The BIP method takes into consideration the differences in the capacity/energy cost trade-off that exists across a company's generation mix. The BIP methodology gives weight to both considerations. It does so by considering energy in the base component through the allocation of base usage to all classes and by considering capacity in the allocation of intermediate and peak components. For these reasons, Staff recommends using the BIP method for production investment and for production costs for Ameren Missouri. Staff explains the BIP method further, and addresses other production allocation methods from the NARUC Manual, beginning on page 12 in the Schedule MSS-6.

Staff used the class BIP allocation factors to allocate Ameren Missouri's investment in fixed production plant and depreciation reserve accounts. 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 system moves electricity, at a very high voltage, from generating plants over long distances to local service areas. Transmission costs consist of costs for high voltage lines and transmission substations, and labor to operate and maintain these facilities. Ameren Missouri's transmission investment and transmission costs comprise approximately 4% of the functionalized investment and costs Staff allocated to the customer classes. Ameren Missouri's transmission system consists of highly-integrated bulk power supply facilities, high voltage power lines, and substations that transport power to other transmission or distribution voltages. Staff allocated transmission investment and costs to the customer classes based on the class loads at the time of the twelve monthly coincident peaks ("12 CP"). Staff recommends the 12 CP allocation method for this purpose because, by including periods of normal use and intermittent peak use throughout all twelve months of the year, it takes into account the need for a transmission system that is designed both to transmit electricity during peak loads and to transmit electricity throughout the year.

F. Allocation of Distribution Costs

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

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

Load diversity is important in allocating demand-related distribution costs because the greater the amount of diversity among customers within a class or among classes, the smaller the total capacity (and total cost) of the equipment required for the utility company to meet those customers' needs. Load diversity exists when the peak demands of customers do not occur at the same time. The spread of individual customer peaks over time within a customer class reflects the diversity of the class load. Therefore, when allocating demand-related distribution costs that are shared by groups of customers, it is important to choose a measure of demand that corresponds to the proper level of diversity. The following table summarizes the types of demand Staff used for allocating the demand-related portions of the various distribution function categories.

Table 5
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 Conduits/Conductors	Diversified Peak	Low to Moderate
Line Transformers	Diversified Peak	Low to Moderate

Coincident-peak demand is "the demand of each customer class and each customer at the hour when the overall system peak occurs." Coincident-peak demand reflects the maximum amount of diversity because most customer classes are not at their individual class peaks at the time of the coincident peak. Class-peak demand, which is "the maximum hourly demand of all customers within a specific class," often does not occur at the same hour, i.e., does not coincide with, the system peak. Although not all customers peak at the same time, due to intra-class diversity, to achieve the class peak a significant percentage of the customers in the class will be at or near their peak. Therefore, class-peak demand will have less diversity than the class' load at time of system peak.

"Diversified demand" is the weighted average of the class's 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 demand of each customer, whenever it occurs. If there is no sharing of equipment, there is no diversity.

Staff recommends allocating the costs of distribution secondary conduits/conductors and line transformers on the basis of each class's annual-peak demand and on customer maximum demands. Only secondary customers served at the secondary voltage level were included in the calculation of the allocation factor, so that distribution secondary costs were allocated only to those customers that use these facilities.

Staff recommends allocating meter costs using the same allocator that Ameren Missouri's used to allocate meter costs. This allocator is based on an Ameren Missouri study that weights the meter investment by class, and by the cost of the meter used to serve that class.

<u>G. Allocation of Customer Service Costs</u>

Customer costs include labor expenses incurred for billing and customer services. Customer-related costs are costs necessary to make electric service available to the customer, regardless of the electric service utilized. Examples of such costs include meter reading, billing, postage, customer accounting, and customer service expenses.

Staff recommends using the same allocators that Ameren Missouri used for allocating meter reading costs, uncollectible accounts, and for allocating customer deposits. These three allocators are derived using Ameren Missouri's studies that directly assign the costs of meter reading, 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 allocated other customer service accounts on customer counts or according to Ameren Missouri's CCOS study.

H. Revenues

Operating revenues consist of: (1) the revenue that the utility collects from the sale of electricity to Missouri retail customers ("rate revenue"), and (2) the revenue the utility receives for providing other services ("other revenue"). 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 Ameren Missouri in this case. The normalized and annualized class rate revenues in Staff's Cost of Service Revenue Requirement Report filed July 6, 2012, totaling $2,586.3 million, were used in Staff's CCOS Study.

Other Electric Revenues of $407.1 million were also allocated to the rate classes using Staff's production-energy and other cost allocators. The majority of other electric revenues pertain to off-system sales ("OSS"). OSS are those sales of electricity made after Ameren Missouri has met all obligations to serve its native load customers (retail and full requirements wholesale customers). This excess energy is then available to sell to other utilities. By engaging in such sales, Ameren Missouri generates revenue margins, which represent revenues-less-associated generation or purchased power cost. OSS represents an efficient utilization of the electric facilities/system that has been put in place to meet the electricity needs of Ameren Missouri's customers. Staff allocates off-system sales to customer classes on the basis of energy usage by the customer class at the generation level.

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 Ameren Missouri'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 Ameren Missouri'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. Each calculation 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 January 20, 2012, Ameren Missouri filed its Missouri Energy Efficiency Investment Act ("MEEIA") plan which is also reflected in Staff's cost of service and accounting schedules. The Stipulation and Agreement (File No. EO-2012-0142) filed on July 5, 2012, for Commission approval consists of three categories of costs: 1) Program costs,

2) Throughput Disincentive costs, and 3) Performance Mechanism costs. The Stipulation and Agreement defines how each category of costs is assigned or allocated to each customer class. Staff allocated energy efficiency to each customer class as defined in the Stipulation and Agreement.

Energy efficiency programs before 2013 are classified as pre-MEEIA programs and allocated on the basis of direct costs associated with each customer class less opt-out customers. These historical costs are included in rate base and amortized.

Staff Expert: Michael S. Scheperle

IV. Rate Design

Staff's rate design objectives in this case are to:

- Provide the Commission with a rate design recommendation based on each customer class's relative cost-of-service responsibility.
- Provide methods to implement in rates any Commission-ordered overall change in customer revenue responsibility.
- Retain, to the extent possible, 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 in this case are:

1. That Ameren Missouri's rate schedules should be uniform for certain interrelationships among the non-residential rate schedules that are integral to Ameren Missouri's rate design. The following features are uniform and should remain uniform:
    - The value of the customer charge should be uniform across rate schedules, with the customer charge on the SPS, LPS, and LTS rate schedules being the same.
    - The rates for Rider B voltage credits should be the same under all applicable rate schedules.

- The rate for the Reactive Charge should be the same for all applicable rate schedules.
- The rate associated with Time-of-Day meter charge should be the same for all applicable non-residential rate schedules (LGS, SPS, LPS, and LTS).

2. Based on CCOS results, Staff recommends adjustments be made on a revenue-neutral basis to all classes of customers. These adjustments consist of the residential class receiving an additional 1% adjustment, the lighting class receiving an additional 3% adjustment, and the remaining classes (SGS, LGS/SPS, LPS, and LTS) receiving a negative adjustment of approximately 1.0%. This is detailed in Schedule MSS-5.
3. After having made the recommended revenue-neutral adjustments above, any overall change in revenues allowed to Ameren Missouri can then be applied on an equal percentage, to all classes. Staff further recommends that an additional constraint (revenue requirement after true-up) be imposed limiting the extent to which class revenues are moved towards class cost-of-service to ensure that no class receives an overall reduction in its rate revenues while customer classes receive an overall increase in its rate revenues.
4. That the Residential customer charge be increased from $8.00 to $9.00 per month, excluding low-income assistance charge.
5. That the energy charges for the residential class be increased uniformly, after making the adjustments described in 2, 3, and 4 above.
6. That the charges for the SGS class be increased uniformly, after making the adjustments described in 2 and 3 above.
7. That the demand and energy charges for the LGS/SPS class be increased uniformly after making the adjustments described in 1, 2 and 3 above.

8. That the demand and energy charges for the LPS class be increased uniformly after making the adjustments described in 1, 2 and 3 above.
9. That the demand and energy charges for the LTS class be increased uniformly after making the adjustments described in 1, 2 and 3 above.
10. That the pole and span charges in the 5(M) Lighting classification be eliminated with the resulting revenue deficiency being collected from the entire 5(M) classification within the Lighting class.
11. That the Lighting charges be increased uniformly after making the adjustments described in 2, 3, and 10 above.

Ameren Missouri has three active lighting service classifications: 1) Street and Outdoor Area Lighting – Company owned 5(M); 2) Street and Outdoor Lighting – Customer owned 6(M); and 3) Municipal Street Lighting – Incandescent 7(M). Staff combined these three lighting service classifications in its CCOS study. The 5(M) classification is the largest, providing approximately 90% of Ameren Missouri's total revenue from the Lighting class. In Ameren Missouri's last rate case (Case No. ER-2011-0028), Ameren Missouri proposed to eliminate the rental charges on pole and span charges in the 5(M) category. For Ameren Missouri–owned lighting facilities, such as poles and spans, installed before September 1988, the municipality is billed a monthly amount. After September 1988, Ameren Missouri changed its billing policy and charged a one-time, up-front fee to the municipality when it installed the new pole and span, thus the municipality paid no pole or span monthly charge. In the Commission's decision in Case No. ER-2011-0028, the Commission found that the pole and span charges should be eliminated. However, to avoid rate shock that would result from the complete elimination of the charge, the Commission directed Ameren Missouri to initially reduce the monthly pole and span charges by half (50%). In this case, Ameren Missouri proposes to eliminate these charges with the resulting revenue reduction being collected from the entire 5(M) classification within the Lighting class. This appears to be reasonable for this case. Staff supports Ameren Missouri's recommendation.

Schedule MSS-3 shows that Ameren Missouri's residential customer charge is the lowest of the five electric utility tariffs in the state. The results of Staff's CCOS study calculate that customer costs approximate the $9.00 customer charge. Staff recommends increasing Ameren Missouri's residential customer charge by $1.00, from $8.00 to $9.00 after considering and taking into account the (1) potential for rate shock, and (2) Staff's revenue-neutral rate increase recommendation for the residential class.

Current Rate Schedules

The residential rate schedule 1(M) consists of the following elements:

- Regular Service Rates
- Optional Time of Day rates
- Customer Charge – per month
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

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

The Small General Service Rate schedule 2(M) consists of the following elements:

- Small General Service Rates

- Optional Time of Day Rates
- Customer Charge (Single or Three Phase Service) – per month
- Low-Income Pilot Program Charge – per month per season
- Summer Energy Charge – per kWh
- Winter Energy Charge – Base Energy Charge and Seasonal Energy Charge per kWh
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Large General Service Rate schedule 3(M) consists of the following elements:

- Large General Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Summer Energy Charge – Hours of use per kW of billing demand - per kWh per season
- Winter Energy Charge – Base Energy Charge – Hours of Use per kW of base demand and seasonal energy energy charge per kWh
- Demand Charge – per kW of total billing demand per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Small Primary Service Rate schedule 4(M) consists of the following elements:

- Small Primary Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season

- Energy Charge – Hours of use per kW of billing demand - per kWh per season
- Demand Charge – per kW of total billing demand per season
- Reactive Charge – per kVar per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Large Primary Service Rate schedule 11(M) consists of the following elements:

- Large Primary Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Demand Charge – per kW of billing demand per season
- Reactive Charge – per kVar per season
- Fuel and Purchased Power Adjustment – per kWh
- Energy Efficiency Program Charge – per kWh per season

The Large Transmission Service Rate schedule 12(M) consists of the following elements:

- Large Transmission Service Rates
- Optional Time of Day Rates
- Customer Charge – per month per season
- Low-Income Pilot Program Charge – per month per season
- Energy Charge – per kWh per season
- Demand Charge – per kW of billing demand per season

- Reactive Charge – per kVar per season
- Energy Line Loss Rate – per kWh
- Fuel and Purchased Power Adjustment – per kWh

The Lighting rate schedules are:

- Street and Outdoor Area Lighting 5(M) – Company owned
- Street and Outdoor Area Lighting 6(M) – Customer owned
- Municipal Street Lighting 7(M)
- Unmetered service
- Metered service
- Discounted rates for municipalities with franchise agreements
- Existing revenue - $34.8 million
- Fuel and Purchased Power Adjustment – per kWh

Important Rate Design Features

Ameren Missouri's charges are determined by each customer's usage and the (per unit) rates that are applied to that usage. Within each rate schedule, demand and energy rates should continue to be seasonally differentiated (i.e., summer rates are higher than winter rates). The remaining rates (customer, facilities, reactive) should be constant year-round. Ameren's rate schedules should be uniform for certain interrelationships among the non-residential rate schedules that are integral to Ameren Missouri's rate design. Staff recommends that the following features maintain their existing uniformity:

- The amount of the customer charge be uniform across rate schedules, with the customer charges on the SPS, LPS, and LTS rate schedules being the same.
- The rates for Rider B voltage credits be the same under all applicable rate schedules.

- The rate for the Reactive Charge be the same for all applicable rate schedules.
- The value of the customer charge for Time-of-Day be uniform across rate schedules, with the customer charges on the LGS, SPS, LPS, and LTS rate schedules being the same.

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).

The customers who belong to the residential class and the lighting class are well defined. The remaining customers generally belong to one of five main rate groups based upon their load and cost characteristics. A typical customer in each of the rate groups can be described as follows:

- Small General Service: Applicable to secondary service. Summer demand does not exceed 100 kW.
- Large General Service: Applicable to secondary service. Summer demand exceeds 100 kW.
- Small Primary Service: Applicable to Primary service. Summer demand exceeds 100 kW.
- Large Primary Service: Applicable to primary service. Billing demand no less than 5000 kW.
- Large Transmission Service: Applicable to transmission service. Billing demand no less than 5000 kW.

For its CCOS study, Staff broke the above rate groups into the four separate rate classes with the LGS and SPS classes combined into one rate class for purposes of the study. Staff combined the LGS and SPS rate classes for purposes of its CCOS study for the following reasons. First, both rate schedules serve non-residential customers with billing demands of at least 100 kW. Within this group, a customer may choose to take service at secondary voltage level under the LGS 3(M) rate schedule or at a primary voltage level under the SPS 4(M) rate schedule. Second, the rate structures are identical, except that the rate levels on the SPS rate schedule have been adjusted for the loss differential between primary and secondary voltages and to account for customer provision of voltage transformation equipment. The Staff's CCOS study provided the investment and costs associated for Ameren Missouri to provide service to the Lighting class.

Staff Expert: Michael S. Scheperle

V. Loss Study

Energy Loss Multipliers

Staff developed a set of energy loss multipliers for adjusting metered sales to different system voltage levels. Energy losses are accounted for in metered sales by multiplying metered sales by the appropriate energy multiplier. These energy loss multipliers were used by Staff witness Mike S. Scheperle to adjust metered sales in Staff's calculation of system energy peaks, and are listed in the following table:

Energy Multipliers For Changes In System Voltage Level

Starting Voltage Level	Ending Voltage Level					
	GEN	GSU	Transmission	HV Dist	LV Dist	Secondary
Generator (GEN)	1.0000	0.9965	0.9866	0.9720	0.9527	0.9239
Generation (GSU)	1.0035	1.0000	0.9901	0.9754	0.9561	0.9271
Transmission	1.0135	1.0100	1.0000	0.9851	0.9656	0.9364
HV Distribution	1.0288	1.0253	1.0151	1.0000	0.9802	0.9505
LV Distribution	1.0478	1.0460	1.0338	1.0202	1.0000	0.9697
Secondary Dist	1.0807	1.0786	1.0663	1.0520	1.0312	1.0000

Staff Expert: David C. Roos

VI. Ameren Missouri to file its entire tariff as a single document

New Electric Rate Schedule

Ameren Missouri has two electric rate tariffs: P.S.C. Mo. Schedule 1 that contains the cogeneration and net-metering tariff sheets and P.S.C. Mo. Schedule 5 that contains all other tariff sheets. In Ameren Missouri's last rate case (Case No. ER-2011-0028), Staff and Ameren Missouri agreed to perform a collaborative and comprehensive review of Ameren Missouri's electric rate schedule tariff to combine the two tariffs into a single electric tariff to be designated as P.S.C. Mo. Schedule 6. As part of the agreement, Ameren Missouri agreed to provide Staff with a new single electric tariff within one hundred-twenty (120) days of the effective date of the new tariffs filed in ER-2011-0028. Staff agreed to perform a comprehensive review of that proposal and offer suggestions as needed. Ameren Missouri agreed to file the new electric tariff within one hundred-eighty (180) days from the effective date of rates set in Case No. ER-2011-0028. Company and Staff spent a substantial amount of time and resources in this endeavor and completed much of the work. As the one hundred-eighty (180) day filing deadline neared, Ameren Missouri informed Staff it would not be filing the new tariff as agreed to in Case No. ER-2011-0028 due to the filing of a new rate case, this case, Case No. ER-2012-0166.

Staff recommends the Commission require Ameren Missouri to file a new electric rate schedule as agreed to in the last case, Case No. ER-2011-0028, within thirty (30) days of the effective date of rates in the current rate case (Case No. ER-2012-0166). This is a realistic deadline for filing the new tariff since most of the work regarding the cleanup and combining of the two current tariffs has been completed.

Staff Expert: Thomas M. Imhoff

VII. Fuel Adjustment Clause Tariff Sheet Changes

Changes to FAC Tariff Sheet Terminology

The Commission, Staff and the electric utilities have been refining fuel adjustment clauses ("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 the same fashion and the tariffs are fundamentally the same, each utility has unique FAC tariff sheets with unique acronyms and definitions. Different nomenclature for the same thing is used across the utilities and sometimes even within a single utility's tariff sheets. The COS Report provided examples of the various terms that the Missouri electric utilities use for the dollar amount of the adjustment. Another example would be the term used to identify the FAC dollar per kWh rate. 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." Empire refers to it as a "Cost Adjustment Factor or CAF." It is Staff's proposal that the FAC dollar per kWh rate be called the "Fuel Adjustment Rate" or "FAR."

Schedule LMM-1 contains a table that lists the terminology and definitions that Staff is proposing be made consistent across the three electric utilities' tariff sheets. Staff has been working with all of the electric utilities, including Ameren Missouri, on these proposals and hopes to reach a consensus on the terminology to be used within the electric utility industry in Missouri. It is not Staff's intent to change the intent or the meaning of different phrases 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 plans to make this same recommendation in the pending GMO rate case, Case No. ER-2012-0175, and Empire's rate case, Case No. ER-2012-0345.

In working with Ameren Missouri, some changes were suggested by Ameren Missouri to "clean up" the tariff sheets. The attached exemplar tariff sheets include these "clean up" suggestions along with other changes noticed by Staff as the tariffs were reviewed. These "clean up" changes include removing all references to "Missouri retail" since municipal contracts are now being treated as off-system sales contracts. Staff also recommends re-arranging the terms to correspond with the order in which they appear in the equations in the tariff sheets.

Schedule LMM-2 is exemplar tariff sheets with Staff's proposed changes for Ameren Missouri's proposed FAC tariff sheets. Schedule LMM-3 is a redline/strikeout comparison of these exemplar tariff sheets with the Ameren Missouri FAC tariff sheets currently in effect.

These exemplar tariff sheets also contain Ameren Missouri's proposed addition of limestone and urea cost in FERC Account 502. Staff agrees that these costs are variable and fluctuations in these costs should be accounted for in Ameren Missouri's FAC.

Clarification Regarding Transmission Costs

Staff recommends that the Commission clarify that the only transmission costs that are included in the FAC are the transmission costs that Ameren Missouri incurs for purchased power and off-system sales ("OSS"). Consistent with this recommendation, Staff recommends that the following sentence be added to the definition of the cost of purchased power ("PP") in the tariff sheets approved in this case:

> Only transmission costs incurred for the purchase or sale of electricity shall be included.

This sentence can be found on exemplar tariff on page 3 of Schedule LMM-2.

Clarification Regarding Hedging Gains and Losses

Staff recommends that the Commission clarify that only hedging gains and losses associated with mitigating volatility in its cost of fuel and SO_2 and NO_X allowances be included in Ameren Missouri's FAC. Currently, it is Staff's understanding that Ameren Missouri only includes hedging costs of its natural gas purchases used in the generation of electricity and its diesel fuel for over-the-road trucking used to transport coal in its FAC costs. The current FAC tariff sheet No. 98.16 includes in its definition of the fossil fuel costs in FERC account number 501 the following:

> … fuel hedging cost (*for purposes of factor CF, hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power, 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*), hedging costs associated with SO2 and fuel oil adjustments included in commodity and transportation costs, … (emphasis added)

Staff recommends the definition of hedging that is italicized above be removed from the list of items in FERC Account 501 and placed at the end of the definition of "FC" so that it applies to both the hedging costs in FERC Accounts 501 and 547 and the only reference to hedging in the definition of allowed costs recorded in 501 will be "fuel hedging costs including over-the-road diesel hedging."

In its definition of natural gas costs reflected in FERC Account 547, it simply states that "natural gas generation costs related to … hedging costs" are included in the FAC costs. Therefore, no change is necessary for FERC Account 547.

Staff has also recommended that SO_2 and NO_X hedging costs should be allowed because the current tariff language allows SO_2 hedging costs that are recorded in FERC

Account 501. SO_2 and NO_X gains and losses are recorded in FERC Accounts 411.8 and 411.9, not in the FERC Account 501 that the tariff lists them in. As a part of its effort to achieve consistency across the electric utility FAC sheets, Staff is proposing that the net emissions costs be separately identified. Therefore, Staff is recommending that the term "E" be defined in Ameren Missouri's FAC tariff as:

> Emission costs and revenues for SO_2 and NO_X emissions allowances in Accounts 411.8, 411.9, and 509

The "E" variable and its definition can be found on page 3 of Schedule LMM-2.

Clarification Regarding Off-System Sales

In the current tariff sheet no. 98.18, the process for dealing with the occurrence of a reduction in the usage of the Large Transmission Class of 40,000,000 kWh or greater, is found in both the section of the tariff sheet titled <u>Adjustment For Reduction of Service Classification 12(M) Billing Determinants</u> and in the definition of the "N" variable. Staff recommends that the <u>Adjustment For Reduction of Service Classification 12(M) Billing Determinants</u> section be modified from:

> Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2011-0028 an adjustment to OSSR shall be made in accordance with the following levels:
>
> a) A reduction of less than 40,000,000 kWh in a given month
> – No adjustment will be made to OSSR.
>
> b) A reduction of 40,000,000 kWh or greater in a given month
> – All Off-System Sales revenues derived from all kWh of energy sold off-system due to the entire reduction shall be excluded from OSSR.

to:

> Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. **ER-2012-0166,** an adjustment to OSSR shall be made in accordance with the following levels:
>
> a) A reduction of less than 40,000,000 kWh in a given month

- No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month

- **An adjustment excluding off-system sales revenue from OSSR will be made equal to the lesser of (1) all off-system sales revenues derived from all kWh of energy sold off-system due to the entire reduction, or (2) off-system sales revenues up to the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2012-0166**.

(Changes are in bold)

With this change, there is no need for the "N" variable. Therefore the "N" variable is removed from Staff's exemplar tariff sheets. This change can be found on page 4 of Schedule LMM-2.

Staff Experts: Lena M. Mantle and Michelle Bocklage

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2012-0166

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 accompany Staff Report on pages 1 — 29, 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 19th day of July, 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 Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2012-0166

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 accompany Staff Report on pages 29, and the facts therein are true and correct to the best of his knowledge and belief.

David C Roos

David C. Roos

Subscribed and sworn to before me this 19th day of July, 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 Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2012-0166

AFFIDAVIT OF THOMAS M. IMHOFF

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

Thomas M. Imhoff, 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 accompany Staff Report on pages 30, and the facts therein are true and correct to the best of his knowledge and belief.

Thomas M. Imhoff

Thomas M. Imhoff

Subscribed and sworn to before me this 19th day of July, 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 Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2012-0166

AFFIDAVIT OF LENA M. MANTLE

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

Lena M. Mantle, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that she has participated in the preparation of the accompany Staff Report on pages 31- 35, and the facts therein are true and correct to the best of her knowledge and belief.

Lena M Mantle
Lena M. Mantle

Subscribed and sworn to before me this 19th day of July, 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 Union Electric Company d/b/a Ameren Missouri's Tariffs to Increase Its Revenues for Electric Service	)))	Case No. ER-2012-0166

AFFIDAVIT OF MICHELLE BOCKLAGE

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

Michelle Bocklage, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that she has participated in the preparation of the accompany Staff Report on pages 31-35, and the facts therein are true and correct to the best of her knowledge and belief.

Michelle Bocklage
Michelle Bocklage

Subscribed and sworn to before me this 19th day of July, 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, Operations Department 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

Thomas M. Imhoff

Present Position:

I am Rate & Tariff Examination Supervisor in the Energy Unit, Operations Division of the Missouri Public Service Commission. My unit participates and makes recommendations on tariff filings, and cases filed at the Commission such as rate, complaint, applications, territorial agreements, sales, and merger cases. We also perform and provide technical support on the issues of rate design, class-cost-of-service studies and customer weather normalizations.

Educational Background and Experience:

I attended Southwest Missouri State University at Springfield, Missouri, from which I received a Bachelor of Science degree in Business Administration, with a major in Accounting, in May 1981. I began employment with the Commission in October, 1981. In May 1987, I successfully completed the Uniform Certified Public Accountant (CPA) examination and subsequently received the CPA certificate. I am currently licensed as a CPA in the State of Missouri.

Summary of Cases in which prepared testimony was presented by:
THOMAS M. IMHOFF

Company Name	Case No.
Terre-Du-Lac Utilities	SR-82-69
Terre-Du-Lac Utilities	WR-82-70
Bowling Green Gas Company	GR-82-104
Atlas Mobilfone Inc.	TR-82-123
Missouri Edison Company	GR-82-197
Missouri Edison Company	ER-82-198
Great River Gas Company	GR-82-235
Citizens Electric Company	ER-83-61
General Telephone Company of the Midwest	TR-83-164
Missouri Telephone Company	TR-83-334
Mobilpage Inc.	TR-83-350
Union Electric Company	ER-84-168
Missouri-American Water Company	WR-85-16
Great River Gas Company	GR-85-136
Grand River Mutual Telephone Company	TR-85-242
ALLTEL Missouri, Inc.	TR-86-14
Continental Telephone Company	TR-86-55
General Telephone Company of the Midwest	TC-87-57
St. Joseph Light & Power Company	GR-88-115
St. Joseph Light & Power Company	HR-88-116
Camelot Utilities, Inc.	WA-89-1
GTE North Incorporated	TR-89-182
The Empire District Electric Company	ER-90-138
Capital Utilities, Inc.	SA-90-224
St. Joseph Light & Power Company	EA-90-252
Kansas City Power & Light Company	EA-90-252
Sho-Me Power Corporation	ER-91-298
St. Joseph Light & Power Company	EC-92-214
St. Joseph Light & Power Company	ER-93-41
St. Joseph Light & Power Company	GR-93-42
Citizens Telephone Company	TR-93-268
The Empire District Electric Company	ER-94-174
Missouri-American Water Company	WR-95-205
Missouri-American Water Company	SR-95-206
Union Electric Company	EM-96-149
The Empire District Electric Company	ER-97-81
Missouri Gas Energy	GR-98-140
Laclede Gas Company	GR-98-374
Laclede Gas Company	GR-99-315
Atmos Energy Corporation	GM-2000-312
Ameren UE	GR-2000-512
Missouri Gas Energy	GR-2001-292

Laclede Gas Company	GT-2001-329
Laclede Gas Company	GR-2001-629
Missouri Gas Energy	GT-2003-0033
Aquila Networks – L&P	GT-2003-0038
Aquila Networks – MPS	GT-2003-0039
Southern Missouri Gas Company, L.P.	GT-2003-0031
Fidelity Natural Gas, Inc.	GT-2003-0036
Atmos Energy Corporation	GT-2003-0037
Laclede Gas Company	GT-2003-0032
Union Electric Company d/b/a Ameren UE	GT-2003-0034
Laclede Gas Company	GT-2003-0117
Aquila Nerworks MPS & L&P	GR-2004-0072
Missouri Gas Energy	GR-2004-0209
Missouri Pipeline Company & Missouri Gas Company	GC-2006-0491
Atmos Energy Corporation	GR-2006-0387
Laclede Gas Company	GR-2007-0208
Missouri Gas Utility Company	GR-2008-0060
TriGen-Kansas City Energy Group	HR-2008-0300
Laclede Gas Company	GT-2009-0056
Missouri Gas Energy	GR-2009-0355
Empire District Gas Company	GR-2009-0434
Atmos Energy Corporation	GR-2010-0192
Laclede Gas Company	GR-2010-0171
Union Electric Company d/b/a Ameren UE	GR-2010-0363
Veolia Energy Kansas City, Inc.	HR-2011-0241

Education and Work Experience Background for
Lena M. Mantle, P.E.

Energy Unit Manager
Tariff, Safety, Economic and Engineering Analysis Department
Regulatory Review Division

I received a Bachelor of Science Degree in Industrial Engineering from the University of Missouri, at Columbia, in May, 1983. I joined the Research and Planning Department of the Missouri Public Service Commission in August, 1983. I became the Supervisor of the Engineering Analysis Section of the Energy Department in August, 2001. In July, 2005, I was named the Manager of the Energy Department. The Energy Department was renamed the Energy Unit in August, 2011. I am a registered Professional Engineer in the State of Missouri.

In my work at the Commission from May 1983 through August 2001 I worked in many areas of electric utility regulation. Initially I worked on electric utility class cost-of- service analysis. As a member of the Research and Planning Department, I participated in the development of a leading-edge methodology for weather normalizing hourly class energy for rate design cases. I applied this methodology to weather normalize energy in numerous rate increase cases.

My responsibilities as the Supervisor of the Engineering Analysis section considerably broadened my work scope. This section of the Commission Staff is responsible for a wide variety of engineering analysis including electric utility fuel and purchased power expense estimation for rate cases, generation plant construction audits, review of territorial agreements, and resolution of customer complaints. As the Manager of the Energy Unit, I oversee the activities of the Engineering Analysis section, the electric and natural gas utility tariff filings, the Commission's natural gas safety staff, fuel adjustment clause filings, resource planning compliance review and the class cost-of-service and rate design for natural gas and electric utilities.

In my work at the Commission I have participated in the development or revision of the following Commission rules:

4 CSR 240-3.130	Filing Requirements and Schedule of Fees for Applications for Approval of Electric Service Territorial Agreements and Petitions for Designation of Electric Service Areas
4 CSR 240-3.135	Filing Requirements and Schedule of Fees Applicable to Applications for Post-Annexation Assignment of Exclusive Service Territories and Determination of Compensation
4 CSR 240-3.161	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.162	Electric Utility Environmental Cost Recovery Mechanisms Filing and Submission Requirements
4 CSR 240-3.190	Reporting Requirements for Electric Utilities and Rural Electric Cooperatives
4 CSR 240-14	Utility Promotional Practices
4 CSR 240-18	Safety Standards
4 CSR 240-20.015	Affiliate Transactions
4 CSR 240-20.090	Electric Utility Fuel and Purchased Power Cost Recovery Mechanisms
4 CSR 240-20.091	Electric Utility Environmental Cost Recovery Mechanisms
4 CSR 240-22	Electric Utility Resource Planning

I have testified before the Commission in the following cases:

CASE NUMBER	**TYPE OF FILING**	**ISSUE**
ER-84-105	Direct	Demand-Side Update
ER-85-128, et. al	Direct	Demand-Side Update
EO-90-101	Direct, Rebuttal & Surrebuttal	Weather Normalization of Sales; Normalization of Net System
ER-90-138	Direct	Normalization of Net System

EO-90-251	Rebuttal	Promotional Practice Variance
EO-91-74, et. al.	Direct	Weather Normalization of Class Sales; Normalization of Net System
ER-93-37	Direct	Weather Normalization of Class Sales; Normalization of Net System
ER-94-163	Direct	Normalization of Net System
ER-94-174	Direct	Weather Normalization of Class Sales; Normalization of Net System
EO-94-199	Direct	Normalization of Net System
ET-95-209	Rebuttal & Surrebuttal	New Construction Pilot Program
ER-95-279	Direct	Normalization of Net System
ER-97-81	Direct	Weather Normalization of Class Sales; Normalization of Net System; TES Tariff
EO-97-144	Direct	Weather Normalization of Class Sales; Normalization of Net System;
ER-97-394, et. al.	Direct, Rebuttal & Surrebuttal	Weather Normalization of Class Sales; Normalization of Net System; Energy Audit Tariff
EM-97-575	Direct	Normalization of Net System
EM-2000-292	Direct	Normalization of Net System; Load Research;
ER-2001-299	Direct	Weather Normalization of Class Sales; Normalization of Net System;
EM-2000-369	Direct	Load Research
ER-2001-672	Direct & Rebuttal	Weather Normalization of Class Sales; Normalization of Net System;
ER-2002-1	Direct & Rebuttal	Weather Normalization of Class Sales; Normalization of Net System;
ER-2002-424	Direct	Derivation of Normal Weather
EF-2003-465	Rebuttal	Resource Planning
ER-2004-0570	Direct	Reliability Indices

ER-2004-0570	Rebuttal & Surrebuttal	Energy Efficiency Programs and Wind Research Program
EO-2005-0263	Spontaneous	DSM Programs; Integrated Resource Planning
EO-2005-0329	Spontaneous	DSM Programs; Integrated Resource Planning
ER-2005-0436	Direct	Resource Planning
ER-2005-0436	Rebuttal	Low-Income Weatherization; Energy Efficiency Programs
ER-2005-0436	Surrebuttal	Low-Income Weatherization; Energy Efficiency Programs; Resource Planning
EA-2006-0309	Rebuttal, Surrebuttal	Resource Planning
EA-2006-0314	Rebuttal	Jurisdictional Allocation Factor
ER-2006-0315	Supplemental Direct	Energy Forecast
ER-2006-0315	Rebuttal	DSM; Low-Income Programs
ER-2007-0002	Direct	DSM Cost Recovery
GR-2007-0003	Direct	DSM Cost Recovery
ER-2007-0004	Direct	Resource Planning
ER-2008-0093	Rebuttal	Fuel Adjustment Clause, Low-Income Program
ER-2008-0318	Surrebuttal	Fuel Adjustment Clause
ER-2009-0090	Surrebuttal	Capacity Requirements
ER-2010-0036	Supplemental Direct, Surrebuttal	Fuel Adjustment Clause
EO-2010-0255	Direct/Rebuttal	Fuel Adjustment Clause Prudence
ER-2010-0356	Rebuttal, Surrebuttal	Resource Planning Issues
ER-2011-0028	Rebuttal, Surrebuttal	Fuel Adjustment Clause
EU-2011-0027	Rebuttal	Fuel Adjustment Clause
EO-2011-0390	Rebuttal	Resource Planning; Fuel Adjustment Clause Prudence
EO-2012-0074	Direct/Rebuttal	Fuel Adjustment Clause Prudence

Contributed to Staff Direct Testimony Report

ER-2007-0291	DSM Cost recovery
ER-2008-0093	Fuel Adjustment Clause, Experimental Low-Income Program
ER-2008-0318	Fuel Adjustment Clause
ER-2009-0090	Fuel Adjustment Clause, Capacity Requirements
HR-2009-0092	Fuel Adjustment Rider
ER-2010-0036	Environmental Cost Recovery Mechanism
ER-2010-0356	Resource Planning Issues
ER-2011-0028	Fuel Adjustment Clause
ER-2012-0166	Fuel Adjustment Clause

MICHELLE A. BOCKLAGE

Educational and Employment Background and Credentials

I have been employed by the Missouri Public Service Commission as a Rate & Tariff Examiner II since January 2011. I began my employment with the Commission as a Clerk IV in December 1997. In June 1999, I was promoted to Customer Services Specialist in the Consumer Services section where my responsibilities included investigating informal and formal consumer complaints for compliance with the rules and regulations of the Commission. In 2011, I was promoted to Rate & Tariff Examiner II in the Energy Resource Analysis section in the Energy Unit of the Regulatory Review Division. In this position, I am responsible for reviewing and making recommendations concerning tariff sheets related to Missouri Energy Efficiency Investment Act (MEEIA), Fuel Adjustment Clause (FAC), and promotional practices cases. I have filed testimony or Staff recommendations in numerous FAC and promotional practice tariff cases. Prior to joining the Commission, I was employed by the Missouri Department of Transportation.

In December 2010, I earned a Bachelor of Science degree in Business Administration with majors in Management and Human Resources Management from Columbia College. I am currently working to complete the necessary coursework to earn a Masters in Business Administration from Columbia College.

Michelle A. Bocklage
Staff Recommendations, Testimony and Reports
BEFORE THE MISSOURI PUBLIC SERVICE COMMISSION

File Number	Company/Organization	Issues
EO-2012-0175	KCP&L Greater Missouri Operations Company	FAC Tariff Issues
EO-2012-0166	Ameren Missouri	FAC Tariff Issues
ER-2012-0164	Ameren Missouri	FAC Tariff Issues
ER-2012-0142	Ameren Missouri	Missouri Energy Efficiency Investment Act Tariff Issues
ER-2012-0098	Empire District Electric Company	FAC Tariff Issues
ER-2012-0009	KCP&L Greater Missouri Operations Company	Missouri Energy Efficiency Investment Act Tariff Issues
ER-2011-0419	KCP&L Greater Missouri Operations Company	FAC Tariff Issues
ER-2011-0317	Ameren Missouri	FAC Tariff Issues
ER-2011-0320	Empire District Electric Company	FAC Tariff Issues
ET-2012-0156	Ameren Missouri	Business Energy Efficiency Tariff Issues
ET-2012-0011	Ameren Missouri	Residential Energy Efficiency Tariff Issues
GC-2007-0162	Missouri Gas Energy	Formal Complaint
HT-2012-0344	KCP&L Greater Missouri Operations Company	Quarterly Cost Adjustment Tariff Issues
HT-2011-0343	KCP&L Greater Missouri Operations Company	Quarterly Cost Adjustment Tariff Issues

MISSOURI PUBLIC SERVICE COMMISSION
Case No. ER-2012-0166
Based on Staff CCOS at High Point ROR Range

Functional Category	RES	SGS	LGS/SPS	LPS	LTS	Lighting	Total
Production - Capacity	$546,244,621	$123,430,965	$319,471,837	$85,302,058	$70,488,723	$8,088,430	$1,153,026,634
Production - Energy	$358,863,824	$92,960,136	$309,676,589	$97,944,354	$104,355,770	$5,971,413	$969,772,085
Transmission	$52,428,371	$12,090,557	$33,708,239	$9,235,145	$8,960,370	$343,430	$116,766,113
Distribution - Demand	$351,457,483	$63,205,006	$102,022,929	$18,423,766	$0	$9,848,558	$544,957,741
Distribution - Services	$25,720,851	$4,921,666	$6,568,515	$0	$0	$0	$37,211,032
Distribution - Meters	$21,811,054	$6,742,828	$4,393,690	$344,920	$23,845	$30,008	$33,346,345
Distribution - Customer Installations	$72,374	$0	($141,025)	($141,025)	$0	$0	($209,675)
Distribution - Lighting	$0	$0	$0	$0	$0	$18,562,391	$18,562,391
Customer Deposit	($728,822)	($319,589)	($243,775)	$0	($8,397)	($10,044)	($1,310,628)
Customer Meter Reading	$6,954,699	$962,283	$140,881	$17,036	$1,982	$9,419	$8,086,300
Other Customer Billing	$22,900,068	$2,400,299	$3,185,402	$44,987	$0	$194,462	$28,725,219
Uncollectible Accounts	$12,226,351	$1,275,941	$1,194,197	$99,557	$0	$68,598	$14,864,644
Customer Services and Information	$18,675,084	$1,578,561	$2,230,419	$47,486	$1,439	$161,166	$22,694,155
Sales Expenses	$309,287	$26,143	$36,939	$786	$24	$2,669	$375,849
Energy Efficiency	$53,438,042	$6,324,937	$30,121,557	$5,687,122	$0	$0	$95,571,658
Income Taxes	$47,405,266	$23,585,576	$65,275,328	$14,693,923	$9,473,296	$798,146	$161,231,536
Total CCOS Including Additional Income Tax	$1,517,778,554	$339,185,309	$877,641,724	$231,700,116	$193,297,052	$44,068,645	$3,203,671,398
Rate Revenue	$1,177,562,589	$288,728,307	$747,443,551	$189,277,099	$148,405,455	$34,870,218	$2,586,287,220
Other Operating Revenue	$164,254,783	$39,107,813	$123,813,351	$37,870,308	$39,394,770	$2,643,016	$407,084,042
Total Revenue	$1,341,817,373	$327,836,121	$871,256,902	$227,147,407	$187,800,225	$37,513,234	$2,993,371,262
Revenue Deficiency	$175,961,181	$11,349,188	$6,384,821	$4,552,708	$5,496,827	$6,555,411	$210,300,136
Percent Change	14.94%	3.93%	0.85%	2.41%	3.70%	18.80%	8.13%

Missouri Public Service Commission
Case No. ER-2012-0166
Summary of Functions and Allocation Methods in CCOS Study

Function	Allocation to Rate Schedules
Production Plant and Reserve	
Base	Annual kWh usage @ generation for each rate class
Intermediate	12 NCP Average less Base
Peak	3 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	Customer maximum demands
Meters	Ameren Missouri Allocation
General and Intangible Plant and Reserve	Functional separation of Production, Transmission and Distribution Plant
Other Rate Base	Revenues, Energy, Labor, Plant, O&M, and company studies
Expenses	
Production	
Fuel	Annual kWh usage @ generation for each rate class
Other	Fixed - expenses follow plant
Maintenance	Fixed - expenses follow plant
Transmission	12 CP Average
Distribution	NCP, customer maximum demands, Distribution Plant, and company studies
Customer Billing, Services and Sales	Number of customers and company studies
Depreciation and 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, and revenues
Taxes, other than Income Taxes	Plant, Labor
Taxes	Earnings of each class
Energy Efficiency	Program Costs, Throughput Disincentive, Performance Mechanism - all based on Stipulation and Agreement in MEEIA Case No. EO-2012-0142

Missouri Public Service Commission
Case No. ER-2012-0166
Customer Charges for Residential Class

Company	Current Residential Customer Charge
Ameren Missouri (1)	$8.00
Empire District Electric Company (2)	$12.52
Kansas City Power & Light Company (3)	$9.00
KCP&L Greater Missouri Operations Company - L&P (4)	$9.75
KCP&L Greater Missouri Operations Company - MPS (5)	$10.43

(1) Mo. P.S.C. Schedule No. 5 , Sheet No. 28 (Excludes Low-Income Pilot Program)

(2) P.S.C. Mo. No. 5, Section 1, Sheet No. 1

(3) P.S.C. Mo. No. 7, Sheet No. 5A

(4) P.S.C. Mo. No. 1, Sheet No. 18, Phase 1 of rate increase in Case No. ER-2012-0024

(5) P.S.C. Mo. No. 1, Sheet No. 51

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.

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 No. ER-2012-0166
Allocation of $210,300,136 Increase (Illustrative Purposes only)
Staff High Range

	Current Retail Revenues	Revenue Neutral Adjustment	Revenues with Revenue Neutral Adjustment	Percent Allocation	Increase @ Staff High Range	Total Increase	Total Revenues	Percent Increase
Residential	$1,177,562,589	$11,775,626	$1,189,338,215	45.9863%	$96,709,285	$108,484,911	$1,286,047,500	9.21%
Small General Service	$288,728,307	($2,694,607)	$286,033,700	11.0596%	$23,258,409	$20,563,803	$309,292,110	7.12%
Large General Service/Small Primary Service	$747,443,551	($6,975,645)	$740,467,906	28.6305%	$60,210,057	$53,234,412	$800,677,963	7.12%
Large Primary Service	$189,277,099	($1,766,461)	$187,510,638	7.2502%	$15,247,151	$13,480,690	$202,757,789	7.12%
Large Transmission Service	$148,405,455	($1,385,019)	$147,020,436	5.6846%	$11,954,750	$10,569,731	$158,975,186	7.12%
Lighting	$34,870,218	$1,046,107	$35,916,325	1.3887%	$2,920,483	$3,966,590	$38,836,808	11.38%
Total	$2,586,287,219	$0	$2,586,287,219	100.0000%	$210,300,136	$210,300,136	$2,796,587,355	8.13%

Staff High Point Recommendation	$210,300,136
Revenue Neutral Adj.	$0
Remaining	$210,300,136

Residential and Lighting Adj.	$12,821,732
SGS, LPS/SPS,LPS,LTS	$1,373,854,412
Percent Adjustment	0.009332672

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.

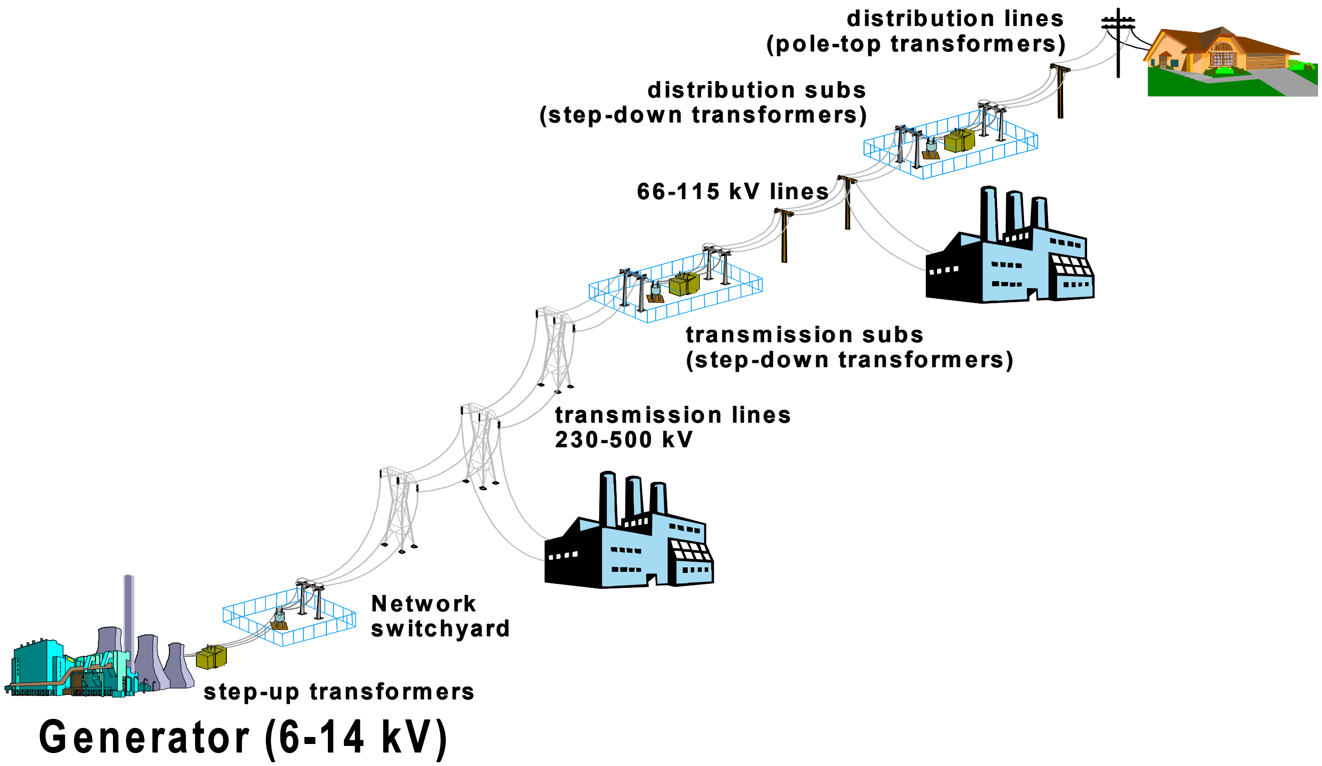
Equivalent Peaker (EP) – The NARUC Manual describes EP as a method based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. The EP 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.

Basic Components of Electricity Production and Delivery



FAC Tariff Sheet Comparison

	Ameren Mo	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 Mo	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 Mo	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 Mo	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

FAC Tariff Sheet Comparison

	Ameren Mo	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 Mo	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		

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation, plus emissions costs, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Energy Costs (ANEC)) and Net Base Energy Costs (B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	Recovery Period (RP)
February through May	October through May
June through September	February through September
October through January	June through January

AP means the four (4) 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).

RP means the billing months during which the FAR is applied to retail customer usage on a per kWh basis, as adjusted for service voltage.

The Company will make a FAR filing sixty (60) days prior to the first billing cycle read date of the applicable Recovery Period above. All FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FAR DETERMINATION

Eighty five percent (85%) of the difference between ANEC and B for each respective AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the customers' bills.

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 85\% + I + P + T]/S_{RP}$$

Where:

ANEC = FC + PP + E – OSSR

B = BF x S_{AP}

FC = Fuel costs associated with the Company's generating plants. These costs consist of the following:

a) For fossil fuel plants:

(i) the following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity, alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs including over the road diesel hedging, fuel oil adjustments included in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

(ii) the following costs reflected in FERC Account Number 502: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and power activated carbon; and

(iii) the following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation charges, fuel losses, hedging costs, broker commissions and fees associated with price hedges, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

b) Costs in FERC Account Number 518 (Nuclear Fuel Expense).

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

For purposes of factor FC, 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 futures contracts, puts, calls, caps, floors, collars, and swaps.

PP = Costs of purchased power reflected in FERC Account Numbers 555, 565, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one(1) year. Only transmission costs incurred for the purchase or sale of electricity shall be included. Also included in factor "PP" are insurance premiums in FERC Account Number 924 for replacement power insurance to the extent those premiums are not reflected in base rates. Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

E = Emission costs and revenues for SO_2 and NO_X emissions allowances in Accounts 411.8, 411.9, and 509;

OSSR = All revenues in FERC Account 447.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-2012-0166, an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month - No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month -An adjustment excluding off-system sales revenue from OSSR will be made equal to the lesser of (1) all off-system sales revenues derived from all kWh of energy sold off-system due to the entire reduction, or (2) off-system sales revenues up to the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2012-0166.

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 rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence.

S_{AP} = kWh during the AP that ended immediately prior to the FAR filing, as measured by taking the Company's load settled at its MISO CP node (AMMO.UE or successor node), plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above.

S_{RP} = Applicable RP estimated kWh representing the expected Company load settled at its MISO CP node (AMMO.UE or successor node).

**Indicates Change.

UNION ELECTRIC COMPANY ELECTRIC SERVICE

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

BF = $0.01586 per kWh determined by the Commission's order equal to the normalized test year value for the sum of allowable fuel costs (consistent with the term FC), plus cost of purchased power (consistent with the term PP), plus the cost of emissions (consistent with the term E), less revenues from Off-System Sales (consistent with the term OSSR) divided by corresponding test year retail kWh.

T = True-up amount as defined below.

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

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below, applicable starting with the following RP is calculated as:

$$FAR = FAR_{RP} + FAR_{RP-1}$$

where:

FAR = Fuel and Purchased Power Adjustment rate starting with the applicable Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1)}$ = FAR Recovery Period rate component from other prior FAR_{RP}.

To determine the FAR applicable to the individual Service Classifications, the FAR determined in accordance with the foregoing will be multiplied by the following Voltage Adjustment Factors (VAF):

Secondary Voltage Service (VAF_{SEC})	1.0575
Primary Voltage Service (VAF_{PRI})	1.0252
Large Transmission Voltage Service (VAF_{TRAN})	0.9917

The FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.00001 to be charged on a $/kWh basis for each applicable kWh billed.

**Indicates Change.

Schedule LMM-2-5

RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

TRUE-UP

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.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a Commission order implementing or continuing this FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this FAC, or any period for which charges hereunder must be fully refunded. In the event a court determines that this FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this FAC to file such a rate case.

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.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Calculation of Fuel Adjustment Rate for [month, day, year] through [month, day, year])**

*Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending: Month, Day, Year

1.	Actual Net Energy Cost (ANEC) (FC+PP+E-OSSR)		$
2.	Net Base Energy Cost (B)	-	$
	2.1 Base Factor (BF)($0.01586/kWh)	x	$0.00000
	2.2 Accumulation Period Sales (S_{AP}) XXXXXX kWh		
3.	Total Company Fuel & Purchased Power Difference	=	$
	3.1 Customer Responsibility	x	85%
4.	Fuel & Purchased Power Amount to be Recovered	=	
	4.1 Interest (I)	+	$
	4.2 True-Up Amount (T)	+	$
	4.3 Prudence Adjustment Amount (P)	-	
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$/kWh
9.	Fuel Adjustment Rate (FAR)	=	$/kWh
10	Secondary Adjustment Factor		1.0575
11.	Fuel Adjustment Rate for Secondary Customers (FAR_{SEC})		$/kWh
12.	Primary Adjustment Factor		1.0252
13.	Fuel Adjustment Rate for Primary Customers (FAR_{PRI})		$/kWh
14.	Transmission Adjustment Factor		0.9917
15.	Fuel Adjustment Rate for Transmission Customers (FAR_{TRAN})		$/kWh

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

APPLICABILITY

This rider is applicable to kilowatt-hours (kWh) of energy supplied to customers served by the Company under Service Classification Nos. 1(M), 2(M), 3(M), 4(M), 5(M), 6(M), 7(M), 11(M), and 12(M).

Costs passed through this Fuel and Purchased Power Adjustment Clause (FAC) reflect differences between actual fuel and purchased power costs, including transportation, plus emissions costs, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net ~~Fuel~~Energy Costs~~)~~ (ANEC)) and Net Base ~~Fuel~~Energy Costs (~~factor NBFC, as defined below~~B), calculated and recovered as provided for herein.

The Accumulation Periods and Recovery Periods are as set forth in the following table:

Accumulation Period (AP)	~~Filing Date~~	Recovery Period (RP)
February through May	~~By August 1~~	October through May
June through September	~~By December 1~~	February through September
October through January	~~By April 1~~	June through January

~~Accumulation Period (~~AP~~)~~ means the ~~historical~~four (4) calendar months during which ~~fuel and purchased power~~the actual costs~~, including transportation, net of OSSR for all kWh of energy supplied~~ and revenues subject to ~~Missouri retail customers are determined.~~this rider will be accumulated for the purposes of determining the Fuel Adjustment Rate (FAR).

~~Recovery Period (RP)~~RP means 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~~ FAR is applied to ~~and recovered through~~ retail customer ~~billings~~usage on a per kWh basis, as adjusted for service voltage ~~level~~.

The Company will make a ~~Fuel and Purchased Power Adjustment (FPA)~~FAR filing ~~by each Filing Date. The new FPA rates for which~~sixty (60) days prior to the ~~filing is made will be~~ first billing cycle read date of the applicable ~~starting with the~~ Recovery Period ~~that begins following the Filing Date.~~ above. All ~~FPA~~FAR filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

~~FPA~~FAR DETERMINATION

~~Ninety~~Eighty five percent (~~95~~85%) of the difference between ~~Actual Net Fuel Costs~~ANEC and ~~NBFC~~B for ~~all kWh of energy supplied to Missouri retail customers during the~~ each respective ~~Accumulation Periods shall be reflected as an FPA_C credit or debit,~~AP will be utilized to calculate the FAR under this rider pursuant to the following formula with the results stated as a separate line item on the ~~customer's bill and will be calculated according to the following formulas~~customers' bills.

~~For the FPA filing made by each Filing Date, the FPA~~$_{C}$ ~~rate, applicable starting with the Recovery Period following the applicable Filing Date, to recover fuel and purchased power costs, including transportation, net of OSSR, to the extent they vary from Net Base Fuel Costs (NBFC), as defined below, during the recently-completed Accumulation Period is calculated as:~~

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

~~$FPA_{(RP)} = [[(CF+CPP-OSSR-W) - (NBFC \times S_{AP})] \times 95\% + I + R - N]/S_{RP}$~~

~~The FPA rate, which will be multiplied by the voltage level adjustment factors set forth below, applicable starting with the following Recovery Period is calculated as:~~

~~$FPA_C = FPA_{(RP)} + FPA_{(RP-1)} + FPA_{(RP-2)}$~~

~~Effective with the Company's April 1, 2012 filing, FPA_C shall be revised to:~~

~~$FPA_C = FPA_{(RP)} + FPA_{(RP-1)}$~~

~~where:~~

~~FPA_C = Fuel and Purchased Power Adjustment rate applicable starting with the Recovery Period following the applicable Filing Date.~~

~~FPA_{RP} = FPA Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended prior to the applicable Filing Date.~~

~~$FPA_{(RP-1)}$ = FPA Recovery Period rate component from prior FPA_{RP} calculation, if any.~~

~~$FPA_{(RP-2)}$ = FPA Recovery Period rate component from FPA_{RP} calculation prior to $FPA_{(RP-1)}$, if any.~~

~~CF~~For each FAR filing made, the FAR_{RP} is calculated as:

$$FAR_{RP} = [(ANEC - B) \times 85\% + I + P + T]/S_{RP}$$

Where:

ANEC = FC + PP + E - OSSR

B = BF x S_{AP}

FC = Fuel costs ~~incurred to support sales to all retail customers and Off-System Sales allocated to Missouri retail electric operations, including transportation,~~ associated with the Company's generating plants. These costs consist of the following:

a) For fossil fuel ~~or hydroelectric~~ plants:

~~(i)~~ the following costs reflected in Federal Energy Regulatory Commission (FERC) Account Number 501: coal commodity, ~~applicable taxes, gas,~~ alternative fuels, fuel additives, Btu adjustments assessed by coal suppliers, quality adjustments related to the sulfur content of coal assessed by coal suppliers, railroad transportation, switching and demurrage charges, railcar repair and inspection costs, railcar depreciation, railcar lease costs, similar costs associated with other applicable modes of transportation, fuel hedging costs ~~(for purposes of factor CF, hedging is defined as realized losses and costs minus realized gains associated with mitigating~~

~~volatility in the Company's cost of fuel and purchased power,~~ including ~~but not limited to, the Company's use of futures, options and~~ over-_the-~~counter derivatives~~

~~**Indicates Change.~~
road diesel

~~RIDER FAC~~

~~FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)~~

~~**(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)~~

~~including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps),~~ hedging~~ costs associated with SO2 and,~~ fuel oil adjustments included

(i) in commodity and transportation costs, broker commissions and fees associated with price hedges, oil costs, ash disposal revenues and expenses, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; ~~and~~

~~(ii)~~

(ii) the following costs reflected in FERC Account Number 502: consumable costs related to Air Quality Control System (AQCS) operation, such as urea, limestone and power activated carbon; and

(iii) the following costs reflected in FERC Account Number 547: natural gas generation costs related to commodity, oil, transportation, storage, capacity reservation charges, fuel losses, hedging costs, broker commissions and fees associated with price hedges, and revenues and expenses resulting from fuel and transportation portfolio optimization activities; ~~and~~

~~(iii) costs and revenues for SO_2 and NO_x emission allowances;~~

b) Costs in FERC Account Number 518 (Nuclear Fuel Expense).

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

**(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)

~~CPP~~For purposes of factor FC, 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 futures contracts, puts, calls, caps, floors, collars, and swaps.

PP = Costs of purchased power reflected in FERC Account Numbers 555, 565, and 575, excluding MISO administrative fees arising under MISO Schedules 10, 16, 17, and 24, and excluding capacity charges for contracts with terms in excess of one (1) year~~, incurred to support sales to all Missouri retail customers and Off-System Sales allocated to Missouri retail electric operations.~~. Only transmission costs incurred for the purchase or sale of electricity shall be included. Also included in factor "~~CPP"~~ PP" are insurance premiums in FERC Account Number 924 for replacement power insurance to the extent those premiums are not reflected in base rates.~~Changes in replacement power insurance premiums from the level reflected in base rates shall increase or decrease purchased power costs.~~ Additionally, costs of purchased power will be reduced by expected replacement power insurance recoveries qualifying as assets under Generally Accepted Accounting Principles.

E = Emission costs and revenues for SO_2 and NO_X emissions allowances in Accounts 411.8, 411.9, and 509;

OSSR = All revenues in FERC Account 447.

**Indicates Change.

Schedule LMM-3-5

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

Adjustment For Reduction of Service Classification 12(M) Billing Determinants:

Should the level of monthly billing determinants under Service Classification 12(M) fall below the level of normalized 12(M) monthly billing determinants as established in Case No. ER-~~2011~~2012-~~0028~~0166, an adjustment to OSSR shall be made in accordance with the following levels:

a) A reduction of less than 40,000,000 kWh in a given month - No adjustment will be made to OSSR.

b) A reduction of 40,000,000 kWh or greater in a given month ~~- All Off-System Sales~~ -An adjustment excluding off-system sales revenue from OSSR will be made equal to the lesser of (1) all off-system sales revenues derived from all kWh of energy sold off-system due to the entire reduction ~~shall be excluded from OSSR.~~

~~W = $300,000 per month for the months, July 1, 2010 through, June 30, 2011. This factor "W" expires on June 30, 2011.~~

~~N = The positive amount by which, over the course of the Accumulation Period, (a)~~, or (2) off-system sales revenues ~~derived from the off-system sale of power made possible as a result of reductions in the level of 12(M) sales (as addressed in the definition of OSSR above) exceeds (b)~~up to the reduction of 12(M) revenues compared to normalized 12(M) revenues as determined in Case No. ER-2012-0166. ~~2011-0028.~~

I = Interest applicable to (i) the difference between ~~Actual Net Fuel Costs (adjusted for factor "W")~~ANEC and ~~NBFC~~B for all kWh of energy supplied ~~to Missouri retail customers~~ during an ~~Accumulation Period~~AP until those costs have been recovered; (ii) refunds due to prudence reviews ~~(a portion of factor R, below);~~("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 ~~(a portion of factor R, below).~~. Interest shall be calculated monthly at a rate equal to the weighted average interest rate paid on the Company's short-term debt, applied to the month-end balance of items (i) through (iii) in the preceding sentence. ~~(i) through (iii) in the preceding sentence.~~

~~**Indicates Change.~~

~~RIDER FAC~~

~~FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)~~

~~**(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)~~

~~R = Under/over recovery (if any) from currently active and prior Recovery Periods as determined for the FAC true-up adjustments, and modifications due to adjustments ordered by the Commission , as a result of required prudence reviews or other disallowances and reconciliations, with interest as defined in item I.~~

S_{AP} = kWh during the ~~Accumulation Period~~AP that ended immediately prior to the ~~applicable Filing Date~~FAR filing, as measured by taking ~~the retail component of~~ the Company's load settled at its MISO CP node (AMMO.UE or successor node), plus the kWh reductions up to the kWh of energy sold off-system associated with the 12(M) OSSR adjustment above.

S_{RP} = Applicable ~~Recovery Period~~ RP estimated kWh representing the expected ~~retail component of the Company's~~Company load settled at its MISO CP node (AMMO.UE or successor node~~), subject to the FPA~~$_{RP}$ ~~to be billed.~~).

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

~~NBFC = Net Base Fuel Costs are the net costs~~BF = $0.01586 per kWh determined by the Commission's order ~~as~~equal to the normalized test year value for the sum of allowable fuel costs (consistent with the term ~~C~~FFC), plus cost of purchased power (consistent with the term ~~C~~PPPP), plus the cost of emissions (consistent with the term E), less revenues from ~~off-system sales~~Off-System Sales (consistent with the term OSSR~~), less an adjustment (consistent with the term "W"), expressed in cents per kWh, based on the~~) divided by corresponding test year retail kWh~~from the net output calculation in the fuel run used in part to determine Net Base Fuel Costs~~.

T = True-up amount as defined below.

P = Prudence disallowance amount, if any, as ~~included in the Company's retail rates. The NBFC rate~~ defined below.

The FAR, which will be multiplied by the Voltage Adjustment Factors (VAF) set forth below, applicable ~~to June through September calendar months ("Summer NBFC Rate")~~starting with the following RP is calculated as:

$FAR = FAR_{RP} + FAR_{RP-1}$~~.319 cents per kWh. The NBFC rate~~

where:

FAR = Fuel and Purchased Power Adjustment rate starting with the applicable ~~to October through May calendar months ("Winter NBFC Rate") is~~ Recovery Period following the FAR filing.

FAR_{RP} = FAR Recovery Period rate component calculated to recover under/over collection during the Accumulation Period that ended immediately prior to the applicable filing.

$FAR_{(RP-1}$~~.213 cents per kWh.~~$_{)}$ = FAR Recovery Period rate component from other prior FAR_{RP}.

To determine the ~~FPA rates~~FAR applicable to the individual Service Classifications, the ~~FPA_C rate~~FAR determined in accordance with the foregoing will be multiplied by the following ~~voltage level adjustment factors:~~Voltage Adjustment Factors (VAF):

~~Secondary Voltage Service~~	~~1.0557~~
~~Primary Voltage Service~~	~~1.0234~~
~~Large Transmission Voltage Service~~	~~0.9906~~

Secondary Voltage Service (VAF_{SEC})	1.0575
Primary Voltage Service (VAF_{PRI})	1.0252
Large Transmission Voltage Service (VAF_{TRAN})	0.9917

Schedule LMM-3-8

The ~~FPA rates~~FAR applicable to the individual Service Classifications shall be rounded to the nearest $0.~~001 cents,~~00001 to be charged on a ~~cents/~~$/kWh basis for each applicable kWh billed.

**Indicates Change.

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Service Provided Between July 31, 2011 And The Day Before The Effective Date Of This Tariff)**

TRUE-UP~~ OF FAC~~

After completion of each ~~Recovery Period~~RP, the Company ~~will~~shall make a true-up filing ~~in conjunction with an adjustment to its FAC. The true-up filing shall be made~~ on the same day as ~~the~~its FAR filing~~ made to adjust its FAC~~. Any true-up adjustments ~~or refunds~~ shall be reflected in ~~item R~~"T" above~~, and shall include interest calculated as provided for~~. 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 ~~Recovery Period~~RP.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this ~~Fuel and Purchased Power Adjustment Clause~~FAC, in accordance with Section 386.266.4, RSMo. and applicable Missouri Public Service Commission Rules governing rate adjustment mechanisms established under Section 386.266, RSMo:

The Company shall file a general rate case with the effective date of new rates to be no later than four years after the effective date of a ~~Missouri Public Service~~ Commission order implementing or continuing this ~~Fuel and Purchased Power Adjustment Clause.~~ FAC. The four-year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this ~~Fuel and Purchased Power Adjustment Clause~~FAC, or any period for which charges hereunder must be fully refunded.

In the event a court determines that this ~~Fuel and Purchased Power Adjustment Clause~~FAC is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this ~~Fuel and Purchased Power Adjustment Clause~~FAC to file such a rate case.

Prudence reviews of the costs subject to this ~~Fuel and Purchased Power Adjustment Clause~~FAC shall occur no less frequently than every eighteen months, and any such costs which are determined by the ~~Missouri Public Service~~ Commission to have been imprudently incurred or incurred in violation of the terms of this rider 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 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.

**Indicates Change.

Schedule LMM-3-10

RIDER FAC

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)

****(Applicable To Calculation of Fuel Adjustment Rate for [month, day, year] through [month, day, year])**

*Calculation of Current Fuel Adjustment Rate (FAR):

Accumulation Period Ending: Month, Day, Year

1.	Actual Net Energy Cost (ANEC) (FC+PP+E-OSSR)		$
2.	Net Base Energy Cost (B)	-	$
2.1	Base Factor (BF)($0.01586/kWh)	x	$0.00000
2.2	Accumulation Period Sales (S_{AP}) XXXXXX kWh		
3.	Total Company Fuel & Purchased Power Difference	=	$
3.1	Customer Responsibility	x	85%
4.	Fuel & Purchased Power Amount to be Recovered	=	
4.1	Interest (I)	+	$
4.2	True-Up Amount (T)	+	$
4.3	Prudence Adjustment Amount (P)	-	
5.	Fuel and Purchased Power Adjustment (FPA)	=	$
6.	Estimated Recovery Period Sales (S_{RP})	÷	kWh
7.	Current Period Fuel Adjustment Rate (FAR_{RP})	=	$/kWh
8.	Prior Period Fuel Adjustment Rate (FAR_{RP-1})	+	$/kWh
9.	Fuel Adjustment Rate (FAR)	=	$/kWh
10	Secondary Adjustment Factor		1.0575
11.	Fuel Adjustment Rate for Secondary Customers (FAR_{SEC})		$/kWh
12.	Primary Adjustment Factor		1.0252
13.	Fuel Adjustment Rate for Primary Customers (FAR_{PRI})		$/kWh
14.	Transmission Adjustment Factor		0.9917
15.	Fuel Adjustment Rate for Transmission Customers (FAR_{TRAN})		$/kWh

Schedule LMM-3-11