MISSOURI PUBLIC SERVICE COMMISSION

STAFF'S

CLASS COST-OF-SERVICE

AND

RATE DESIGN REPORT

UNION ELECTRIC COMPANY
D/B/A AMERENUE

CASE NO. ER-2010-0036

Jefferson City, Missouri
January 6, 2010

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I. Executive Summary

Staff's Class Cost-of-Service (CCOS), Rate Design, Environmental Cost Recovery Mechanism (ECRM) Rate Design, and Fuel Adjustment Clause (FAC) objectives in this case are:

1. To present updated CCOS studies based upon the August 1, 2008 – July 31, 2009 twelve month period.
2. Provide the Commission with a rate design recommendation for determining each customer class's relative measure of class cost responsibility.
3. Provide a method to collect the Commission ordered overall increase in revenues.
4. Retain all of the existing rate schedules, rate structures and important features of the current rate design.
5. To present Staff's proposed ECRM rate design for an ECRM for AmerenUE, if the Commission approves one.
6. To present the Staff's proposed changes to AmerenUE's current FAC rider, including a proposed update of the FAC Net Base Fuel Cost (NBFC).

The results of Staff's CCOS studies (two studies) for AmerenUE are summarized in Table 1. Table 1 shows the rate revenue changes necessary for each customer class's current rate revenues to exactly match with AmerenUE's cost of serving that class as determined by Staff. Staff presented its determination of the cost of serving each class from cost of service accounting information as determined by Staff and presented in its Revenue Requirement study filed in this case on December 18, 2009.

Summary Results of CCOS Studies

Table 1

Summary Results of Staff's CCOS Study
Judgmental Energy Weightings 4 CP Method

	Residential	Small General Service	Large General Service (1)	Large Primary Service	Large Transmission Service	System Average
Revenue Deficiency	$186,394,064	$15,995,478	($4,666,440)	$16,947,820	$19,832,817	$234,503,739
Required % Increase	19.35%	6.44%	-0.72%	10.14%	14.25%	10.68%

(1) Large General Service and Small Primary Service classes combined

Summary Results of Staff's CCOS Study
Capacity Utilization Method

	Residential	Small General Service	Large General Service (1)	Large Primary Service	Large Transmission Service	System Average
Revenue Deficiency	$182,997,203	$15,904,206	($3,301,611)	$17,690,729	$21,213,212	$234,503,739
Required % Increase	19.00%	6.41%	-0.51%	10.58%	15.24%	10.68%

(1) Large General Service and Small Primary Service classes combined

Staff's CCOS studies show the need for a system average increase of 10.68 % to AmerenUE's rate revenues. Staff's CCOS studies show that the Residential (RES), Small General Service (SGS), Large Primary Service (LPS) and the Large Transmission Service (LTS) classes are each contributing less revenues to AmerenUE than AmerenUE's cost to serve them. The Large General Service (LGS) class, which consists of the combined large general service and small primary service customers, is paying more revenues to AmerenUE than AmerenUE's cost to serve it. Based on Staff's CCOS study results, Staff proposes minor shifts in the revenue responsibilities of the RES and LGS classes. Staff proposes to make revenue neutral adjustments based on Staff's CCOS study (4 CP Method) to increase RES class revenue responsibility by $3.0 million (0.3%) and decrease the revenue responsibility of the LGS class by $3.0 million (-0.5%).

Staff's rate design recommendations are:

- After the revenue neutral adjustments recommended above are made, any overall revenue increase should be implemented as an equal percentage increase to each customer class, including the lighting class;
- Return non-residential rate schedules to voltage level interrelationship uniformity;
- Increase the residential customer charge to $8.50;
- Increase small general service customer charges to $9.28 for single phase service and $18.56 for three phase service.

Staff's ECRM rate design recommendations are:

- The Commission adopt ECRM tariff sheets attached as Schedule MSS-9;
- To propose wording on customers bills of "Environmental Cost Recovery Adjustment" for the amount shown on the bill for the ECRM.

Staff's FAC rate design recommendations are:

- Refinement of the Fuel and Purchased Power Adjustment Clause true-up process to allow each true-up to occur after the completion of a full recovery period;
- Inclusion of the cost of quality adjustments related to the sulfur content of coal assessed by coal suppliers;
- Changes in the Taum Sauk factor to update the value of Taum Sauk; and
- Changes to voltage level adjustments consistent with updated system loss factors
- Rebase fuel and purchased power costs

II. Class Cost-of-Service

A. Results of Staff's CCOS Studies

The purpose of a CCOS study is to determine whether each class of customers are providing the utility with a reasonable level of revenue necessary to cover the investments and costs of providing electrical service to that class. A CCOS study provides a basis for allocating and/or assigning an electric utility's total jurisdictional cost of providing electric service to various customer classes in a manner which best reflects cost causation. The results of a CCOS study determine class revenue requirements/responsibility of each customer class for its equitable share of the utility's total annual cost of providing electric service within a given jurisdiction (Missouri retail in this case).

The results of a CCOS study can be presented either in terms of the rate of return realized for providing service to each class, or the results can be presented 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. A negative amount or percentage indicates revenue from the class exceeds the cost of providing service to that class and, therefore, 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 and, therefore, rate revenues should be increased, i.e., the class has underpaid. Staff prefers to present its results in the latter format (i.e., negative or positive dollar amounts or percentages), and the following results of the Staff's analysis are presented in terms of the shifts in revenue that produce an equal rate of return for AmerenUE from each class.

Staff used the following customer classes that correspond to AmerenUE's current rate schedules: RES; SGS; LGS, which includes both LGS and Small Primary Service (SPS); LPS; LTS; and Lighting (LTG). Both of Staff CCOS studies allocate costs to five customer classes that correspond to AmerenUE's current rate schedules. Staff used cost-of-service factors to refunctionalize the costs and revenue of the final AmerenUE customer class, LTG, to the other classes that were included in Staff's CCOS study.

In this case, Staff presents two different CCOS studies. The first uses a traditional method of allocating investment and costs based on Judgmental Energy Weightings (4 CP Method) as described in the National Association of Regulatory Utility Commissioners

(NARUC) ELECTRIC UTILITY COST ALLOCATION MANUAL, January 1992 (NARUC Manual). The second CCOS study involves the Capacity Utilization Method which Staff has used for many years.

The results of Staff's CCOS studies are outlined in Table 2 below which shows the changes to each class's current rate revenues required to exactly match each class's rate revenues with AmerenUE's cost to serve that class, as determined by Staff's CCOS studies. Staff's results are also presented as a revenue-neutral, percent increase to each class's rate revenues.

Table 2

Summary Results of Staff's Revenue Neutral CCOS Study
Judgmental Energy Weightings 4 CP Method

	Residential	Small General Service	Large General Service (1)	Large Primary Service	Large Transmission Service	System Average
Revenue Deficiency	$186,394,064	$15,995,478	($4,666,440)	$16,947,820	$19,832,817	$234,503,739
Required % Increase	19.35%	6.44%	-0.72%	10.14%	14.25%	10.68%
Less System Average	-10.68%	-10.68%	-10.68%	-10.68%	-10.68%	-10.68%
Revenue Neutral % Increase	8.67%	-4.24%	-11.40%	-0.55%	3.57%	0.00%

(1) Large General Service and Small Primary Service classes combined

Summary Results of Staff's Revenue Neutral CCOS Study
Capacity Utilization Method

	Residential	Small General Service	Large General Service (1)	Large Primary Service	Large Transmission Service	System Average
Revenue Deficiency	$182,997,203	$15,904,206	($3,301,611)	$17,690,729	$21,213,212	$234,503,739
Required % Increase	19.00%	6.41%	-0.51%	10.58%	15.24%	10.68%
Less System Average	-10.68%	-10.68%	-10.68%	-10.68%	-10.68%	-10.68%
Revenue Neutral % Increase	8.32%	-4.27%	-11.19%	-0.10%	4.56%	0.00%

(1) Large General Service and Small Primary Service classes combined

Revenue neutral means that the revenue shifts among classes do not change the utility's total system revenues. Staff finds the revenue neutral format aids in comparing revenue deficiencies between classes and makes it easier to propose revenue neutral shifts between classes, if appropriate. The revenue neutral percent increase to a class's rate revenue is calculated as follows: the overall system average increase of 10.68% is subtracted from each class's required percent increase to rate revenue.

Based on Table 2, on a revenue neutral basis, the RES class is providing between 8.67% and 8.32% less revenues to AmerenUE than AmerenUE's cost to serve that class, the SGS class is providing between 4.24% and 4.27% more revenues to AmerenUE than AmerenUE's cost to serve that class. The LGS class is providing 11.40% and 11.19% more revenues to AmerenUE than AmerenUE's cost to serve that class, AmerenUE's revenues from the LPS class nearly match AmerenUE's cost to serve that class as Staff's studies show that the LPS class is providing between 0.55% and 0.10% more revenues to AmerenUE than AmerenUE's cost of serving that class, the LTS class is providing between 3.57% and 4.56% less revenues to AmerenUE than AmerenUE's cost of serving that class. Because a CCOS study is not precise it should be used only as a guide for rate design. Based on its study results and judgment Staff recommends only revenue neutral adjustments to the RES and LGS classes. Only the Staff's CCOS study results for these two classes show a greater than five percent (5%) differential from AmerenUE's revenues from them and AmerenUE's cost to serve them. The Staff's CCOS studies show that AmerenUE's revenues from the SGS, LPS, and LTS classes are each within 5% of AmerenUE's cost to serve them; therefore, Staff is not recommending any revenue neutral adjustments for these classes.

A summary of model output for Staff's CCOS studies are attached as Schedule MSS-1 and MSS-2.

B. Class Cost-of-Service Overview

Staff's CCOS study generally follows the procedures described in Chapter 2 of the NARUC Manual. Staff produced an embedded cost study using historical information developed from data collected over the twelve months ended July 31, 2009. Because of a trend Staff observed in customer usage and the availability of data through July 31, 2009, the Staff used customer usage data known and measureable as of July 31, 2009, rather than at the end of the test year, March 31, 2009. While reviewing AmerenUE's daily load research and net system input data for the twelve months ending March 2009, the Staff discerned an unanticipated trend. The average daily load for the spring of 2009 trended lower and appeared possibly less responsive to weather than the average daily load for the spring of 2008. This led to further Staff analysis of the Net System Input average daily load through July 31, 2009. Further analysis confirmed that the trend of lower daily load for the spring of 2009 compared to 2008 continued through July 31, 2009. After careful deliberation, the Staff chose the option of normalizing data for the twelve months ending July 31, 2009. Before electing this option the Staff explained to other parties, including AmerenUE, why it was planning to choose the twelve months ending July 31, 2009, and no party objected or raised any concern. This is further discussed in Staff Report dated December 18, 2009 on pages 51 though 53.

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

1. Functionalization

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. Major functional areas include generation, transmission, distribution, and customer services. Schedule MSS-3 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 (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). 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 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. An example of a direct assignment is the assignment of the cost of a transmission system 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. For example, high-voltage customers do not utilize the portion of the distribution system that operates at lower voltages, even though the distribution function may contain both high-voltage and low-voltage service components.

2. Classification

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.

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. 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.

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. For example, high voltage customers do not utilize the portion of the distribution system that operates at lower voltages, even though the distribution function may contain high voltage and low voltage service components.

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

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. The operating revenues of each customer class minus its total operating expenses 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.

C. Staff Class Cost-of-Service Studies

Staff's costs and revenues from the rate case with Staff's estimated true-up costs and revenues through January 31, 2010, were used in Staff's CCOS studies.

1. Data Sources

Staff's CCOS studies are a continuation and refinement of a prior Missouri jurisdictional cost of service study. Data was also obtained from Staff's direct revenue requirement cost of service filing on December 18, 2009 for this case and include:

- Adjusted Missouri Jurisdictional Investment and cost data by FERC account;
- Annualized, Normalized Rate Revenues;
- Peak Demand and Energy consumption data for all rate classes; and
- Off-System Sales.

Data was also obtained from AmerenUE witness William M. Warwick's Direct Testimony and Workpapers from this case which include:

- Customer Demand Splits;
- Customer Non-Coincidental Peaks;
- Customer Maximums;
- Annual Energy by Class; and
- Certain allocation factors (AF-7, AF-7A and AF-12)

2. Classes

Staff used the following customer classes that correspond to AmerenUE's current rate schedules: RES; SGS; LGS, which includes both LGS and SPS; LPS; LTS; and LTG. AmerenUE currently provides service to its customers in a number of rate classifications that are designated for residential or non-residential service. The non-residential customer groups are differentiated by customer size and the voltage level at which AmerenUE provides their service.

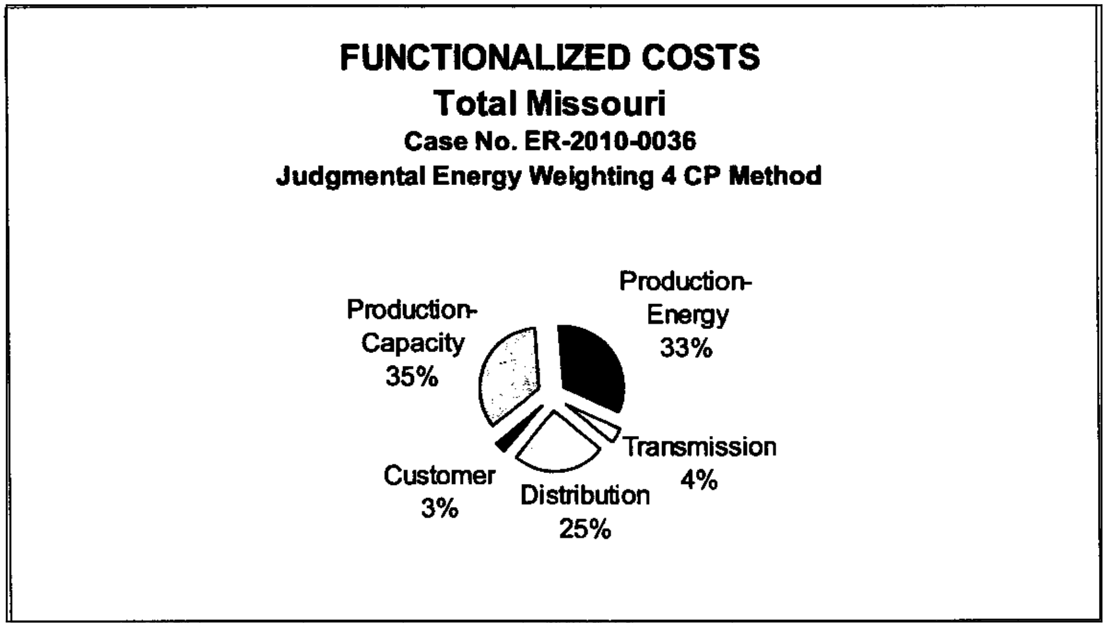
Lighting has a unique load pattern because it is on at night and, for the most part, off during the day; therefore, its class load is typically very low during periods of peak demand. Several of the key allocation factors for Production, Transmission and Distribution costs, calculated for this case, are based on periods of peak demand. Using these demand dependent factors for allocating costs to the LTG class, which does not participate during peak demand periods, produces erroneous results for the LTG class and skews the results for the other classes. Therefore, Staff did not allocate any costs to the LTG class. Costs and revenues directly assigned to the LTG class were allocated to the other classes based on each class's share of AmerenUE's total cost-of-service. This approach consisted of allocating all direct lighting costs and other allocated investment and expenses to the non-lighting classes, and offsetting the allocation of such costs by also allocating all lighting revenue to the same non-lighting classes in the same manner. The net effect of such allocations of costs and revenues should be negligible, under the assumption that the rates for lighting service have been established at or near their cost of service.

Staff combined the SPS and LGS 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 kilowatts (kW). Within this group, a customer may choose to take service at secondary voltage level under the Large General Service 3(M) rate schedule or at a primary voltage level under the Small Primary Service 4(M) rate schedule. The rate structures are identical, except that the rate levels on the Small Primary Service rate schedule have been adjusted for the loss differential between primary and secondary voltages and to account for customer provision of voltage transformation equipment. Staff witness David Roos presented loss differential factors based on AmerenUE's new system loss study in Staff's Cost of Service study filed on December 18, 2009 on pages 111-112.

3. <u>Functions</u>

The major functional cost categories used in Staff's CCOS study are Production, Transmission, Distribution, and Customer. Within the Production Function, a distinction was made between "Production-Capacity" and "Production-Energy." 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 chart below shows the percentage of total costs associated within each major function.

Table 3



The Production Function (combination of Production-Capacity and Production-Energy) is the single largest cost component, and represents 68% of the total cost. The Distribution Function, at 25% of the total cost, is the second largest contributor to total cost, and includes substations, overhead and underground lines, line transformers, and meters, as well as the costs to operate and maintain this equipment. Customer Services and Transmission each account for approximately 3% to 4% of the total cost.

Production-Capacity includes AmerenUE's investment in generating plants and fixed operation and maintenance expenses. Production-Energy includes the costs of fuel (less the cost of fuel for off-system sales) and variable operations and maintenance expenses. Fuel for off-system sales is not included in this calculation, because it is used to calculate the margin from off-system as part of revenue. This approach to off-system sales is further described in the revenue section of this report.

In its CCOS study AmerenUE divided the production operations and maintenance expenses between the Production-Capacity and the Production-Energy functions, with approximately 21% of the costs applied to Production-Capacity function and 79% of the costs applied to Production-Energy function. Staff used this AmerenUE split as a guideline for functionalizing production operations and maintenance expenses.

4. Allocation of Production and Transmission Costs

Allocators are used to distribute the functionalized costs to the classes. The Production and Transmission investment and costs comprise approximately 72% of the functionalized investment and cost to the classes. Both demand and energy characteristics of AmerenUE's load are important determinants of production and transmission investment and costs, since production and transmission must produce output to satisfy periods of normal use and intermittent peak use throughout the year. These functionalized costs are 1) Production–Capacity; 2) Production–Energy; and 3) Transmission. Staff has two CCOS studies because it used different production–capacity allocators in each. First, Staff allocated production–capacity costs based on a Judgmental Energy Weighting Four (4) CP Method. That method recognizes that energy loads are an important determinant of production–capacity investment and costs. This methodology requires the incorporation of judgmentally-established energy weightings into cost studies for each customer class based on a four-month coincidental peak method described in the NARUC Manual. Second, alternatively, Staff used a Capacity Utilization Model method to allocate production-capacity investment and costs based on Staff's Capacity and Utilization Model which Staff has relied on in CCOS studies for many years. For each CCOS study, Staff developed a weighted allocator that includes each class share of peak and energy use.

In the first CCOS study, Staff used each class's four (4) Coincident Peaks (4 CP) to determine the production–capacity cost allocator, which is the average of the four highest system use hours. This method allows discretion in the selection of the number of coincident peaks. Table 4 shows the coincident peaks for the twelve months ending July 2009.

Table 4

Coincident System Peak @ Generation (kW)								
Month	RES	SGS	LGS & SPS	LPS	LTS (1)	Lighting	Total	% of Peak
Jan-09	3,198,526	682,816	1,990,288	481,994	484,390	16,585	6,854,599	83.3%
Feb-09	2,904,564	651,250	1,877,333	479,968	482,130	5,038	6,400,284	77.8%
Mar-09	2,445,232	586,296	1,801,796	477,049	480,581	0	5,790,954	70.4%
Apr-09	2,186,449	428,064	1,456,417	434,858	479,392	57,864	5,043,045	61.3%
May-09	2,103,873	712,310	1,946,943	554,950	479,894	0	5,797,971	70.5%
Jun-09	3,822,839	901,535	2,213,757	527,053	483,660	0	7,948,844	96.6%
Jul-09	3,184,878	775,807	2,127,952	543,753	479,509	0	7,111,899	86.4%
Aug-08	3,982,203	855,416	2,277,562	633,581	479,163	0	8,227,926	100.0%
Sep-08	2,990,752	890,214	2,171,335	630,053	482,296	0	7,164,650	87.1%
Oct-08	1,764,804	473,592	1,785,894	506,388	470,667	23,460	5,024,805	61.1%
Nov-08	2,224,255	543,525	1,800,866	520,812	464,899	0	5,554,357	67.5%
Dec-08	3,684,898	566,251	1,539,233	417,255	482,510	58,672	6,748,818	82.0%

(1) LTS Class at full load, used 2008 data for January through December.

Staff used the four highest peaks during the twelve months ending July 31, 2009, for calculating the production–capacity cost allocator since the four highest peaks are in excess of 85% of the annual system peak. Using peaks in excess of 85% of the annual system peak in determining each class's relative share of the variation in system peak demands maintains a framework for class diversity in the allocation of investment and costs. Staff supports the 4 CP method instead of simply applying the highest single peak to reflect the production–capacity cost allocator. The monthly variation in each class's contribution to system peak demands is outlined below in Table 5.

Table 5

	CP @ Generation						
Month	RES	SGS	LGS & SPS	LPS	LTS(1)	Lighting	Total
Jun-09	48.09%	11.34%	27.85%	6.63%	6.08%	0.00%	100.00%
Jul-09	44.78%	10.91%	29.92%	7.65%	6.74%	0.00%	100.00%
Aug-08	48.40%	10.40%	27.68%	7.70%	5.82%	0.00%	100.00%
Sep-08	41.74%	12.43%	30.31%	8.79%	6.73%	0.00%	100.00%

(1) LTS Class at full load, used 2008 data for January through December.

Furthermore, the Judgmental Energy Weightings 4 CP method is outlined in the NARUC Manual in Part IV B Section 4. Schedule MSS-5 details the Judgmental Energy Weightings criteria.

One aspect of the 4 CP method involves the weighting of the average energy component. This method assigns the production function on a composite allocator that has (1) a demand-related component and (2) an energy-related component. This method reflects peak demand using a four (4) coincident peak component which is the average of the four highest system use hours or the highest four coincident peaks. The particular weighting for the average energy component is called the "load factor," which is the ratio of the average system use for the twelve months to the total system use. One minus the load factor is the ratio of total system use associated with the remaining system peak. This allocator is effectively the average of the monthly class coincident peaks and class average demand.

In Staff's second CCOS study, Staff used a Capacity Utilization Model method to allocate production-capacity costs based on Staff's Capacity and Utilization Model which Staff has used for many years. The Capacity Utilization Model recognizes that generation is built to meet both peak demands and energy usage. The basic components of the Capacity Utilization production–capacity cost allocator are:

1) a portion of total costs are attributed to each class based upon the class's contribution to annual energy;

2) a portion of total costs are attributed to each class based upon each class's contribution to peak demand; and

3) the split between the "average" (energy-related portion) and the "peak" (demand-related portion) is determined by the system load factor.

Staff's Capacity Utilization production–capacity cost allocator is based on each class's contribution to the twelve monthly non-coincident class peak demands and applies a monthly weighting factor for capacity utilization prior to calculating the class contribution to demand.

For calculating the demand-related portion of the Capacity Utilization Model, Staff used weighted monthly class peak demands. Class peak demand is the maximum demand of each class whenever it occurs during each month.

The Capacity Utilization method was used to determine the weights Staff applied to each month's class peak demands. Capacity Utilization is a method developed by Dr. Michael S. Proctor when he was the Manager of the Commission's Research and Planning Department. The details of this method are presented in an article entitled "Capacity Utilization Responsibility: An Alternative to Peak Responsibility" published in the April 28, 1982 issue of *Public Utilities Fortnightly*. This article is attached as Schedule MSS-4.

As shown below in Table 6, the results of Staff's CCOS studies using Weighted Judgmental Energy 4 CP method and the Capacity Utilization Method are very similar. Staff is recommending the 4 CP method.

Table 6

	Production Capacity Cost Allocator				
	RES	SGS	LGS & SPS	LPS	LTS
Judgmental Energy Weighting 4 CP Method	41.08%	10.42%	30.66%	9.20%	8.64%
Capacity Utilization Method	40.60%	10.40%	30.85%	9.31%	8.84%

For both of its CCOS studies, Staff allocated Production-Energy costs, which consist mostly of fuel and variable operation expenses on the basis of class contribution to annual energy, since these costs typically vary with the amount of energy used.

The Transmission investment and costs comprise approximately 4% of the functionalized investment and costs to the classes. AmerenUE'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. Transmission costs are allocated by Staff to customer classes on a 12 coincident peak (12 CP) basis. The 12 CP allocation method is used as it satisfies periods of normal use and intermittent peak use throughout all twelve months of the year.

5. Allocation of Distribution Costs

Voltage level and load diversity were two factors that Staff considered when allocating distribution costs to classes. A customer's use or non-use of specific utility-owned equipment is directly related to the voltage level requirement of the customer. All residential customers are served at secondary voltage; non-residential customers are served at secondary, primary, or transmission level voltages. Therefore, all customers are allocated a portion of transmission costs because all customers use transmission equipment, but only those customers served at or below primary voltage are allocated costs for primary distribution facilities.

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

Table 7
Allocation of Demand Related Distribution Facilities

Functional Category	Demand Measure	Amount of Diversity
N/A	Coincident Peak	High
Substations	Class Peak	Moderate to High
OH/UG Lines, Services	Diversified Demand	Low to Moderate
Line Transformers	Customer Maximum Demand Measure	None

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

Diversified demand is the weighted average of the class's customer maximum demand and its annual maximum class peak demand. The weighting factors are based on the average number of customers in each class who share a transformer. This information was obtained from AmerenUE's 2008 AmerenUE System Loss Study in the sections labeled: "Residential Secondary and Service Drop Model" and "Commercial Secondary and Service Drop Model." As constructed, diversified demand has less diversity than the class peak, but more diversity than the customer maximum demand. Customer maximum demand has no diversity. It is defined as the sum of the annual peak demands of each customer, whenever it occurs. If there is no sharing of equipment, there is no diversity.

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

AmerenUE conducted special studies that split the cost of overhead (OH) and underground (UG) distribution lines between the portions that are customer related and demand related. Staff used Diversified Demand at primary voltage and a Diversified Demand at secondary voltage to allocate primary demand and secondary demand, respectively.

Staff allocated the costs of line transformers on the basis of each class's customer maximum demand measured at secondary voltage. Only secondary customers (i.e., no primary, substation, or transmission voltage customers) were allocated any portion of these costs. Staff allocated the demand portion on the basis of each class's customer maximum demand measured at secondary voltage. The customer portion was allocated by weighted secondary customer counts. The weighting factors were based on the number of customers in each class who typically share a transformer.

Meter costs were allocated using AmerenUE's AF-7 allocator. This allocator is based on an AmerenUE study that weights the meter count by class, and by the cost of the meter used to serve that class.

6. Allocation of Customer Service Costs

Customer-related costs are minimum 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 used AmerenUE's allocators AF-7A for allocating meter reading costs and AF-12 for allocating customer advances/deposits. These two allocators are derived in AmerenUE's studies that directly assign the costs of meter reading and customer advances/deposits to the classes. The allocators AF-7A and AF-12 are the fraction of total costs of meter reading and customer advances/deposits assigned to each class, respectively. Other customer service accounts were allocated on unweighted customer counts.

7. Revenues

Operating revenues consists of two components: the revenue that the Company collects from the sales of electricity to Missouri retail customers (rate revenue); and the revenue the Company 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 tariffs required to implement the Commission's ordered revenue requirement and rate design for AmerenUE in this case. AmerenUE's Missouri rate schedules are designated as RES, SGS, LGS, SPS, LPS, and LTS. There are also four separate Missouri lighting rate schedules.

Rate Revenues in Staff's Cost-of-Service Revenue Requirement Report filed December 18, 2009, were used to obtain normalized and annualized rate revenues. About $31.3 million of lighting revenues were then allocated to the other class revenues by each class's percentage of total cost of service. The Total Rate Revenues as shown in the Rate Revenue Summary in Staff's Accounting Schedules filed on December 18, 2009 is $2.195 billion.

Fuel expenses for off-system sales and the cost of purchased power for off-system sales were subtracted from off-system sales revenues to obtain the margin from off-system sales. The margin from off-system sales was then allocated to the rate classes using Staff's production-capacity cost allocator. Other Electric Revenues of $209 million were also allocated to the rate classes using Staff's production-capacity cost allocator.

Staff Expert: Michael S. Scheperle

III. Rate Design

Staff's rate design objectives in this case are:

- To provide a method to collect the Commission ordered overall increase in revenues;
- To recommend retaining all of the existing rate schedules, rate structures and important features of the current rate design;
- To recommend revenue neutral adjustments.

Staff's rate design recommendations in this case are:

1. That AmerenUE's rate schedules should be uniform for certain interrelationships among the non-residential rate schedules that are integral to AmerenUE's rate design. The following features were uniform until implementation of the rate design in AmerenUE's last rate case (Case No. ER-2008-0318). Staff recommends returning these features to uniformity.

- The value 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 rate associated with Time-of-Day meter charge be the same for all applicable non-residential rate schedules.

2. That, based on the results of Staff's CCOS studies, the LGS class, on a revenue neutral basis, receive a reduction of $3,000,000 in its revenue responsibility. To offset the revenue shift to the LGS class, Staff proposes a $3,000,000 increase to the residential class revenue responsibility. These adjustments represent approximately a 0.3% increase in revenue responsibility to the RES class and an approximately 0.5% decrease in revenue responsibility to the LGS class. Staff believes these revenue adjustments represent a step towards matching revenues with the results of Staff CCOS studies.
3. That, after the revenue neutral adjustments in 2. above, any overall revenue increase be implemented as an equal percentage increase to each class including lighting.
4. That the RES customer charge be increased from $7.25 to $8.50 per month.
5. That the energy charges for the residential class be increased uniformly, after making the adjustments described in 2. and 4. above.
6. That the SGS customer charge be increased from $8.03 to $9.28 for the single-phase service and the customer charge be increased from $16.71 to $18.56 for three-phase service.
7. That the energy charges for the SGS class be increased uniformly, after making the adjustments described in 6. above.

8. That the demand and energy charges for the LGS and SPS classes be increased based on Staff's Cost of Service Report adjustments as described in David Roos's explanation in Staff's Revenue Requirement Cost of Service Report filed December 18, 2009 (page 112) and after making the adjustments described in 1. and 2. above.
9. That the demand and energy charges for the LPS class be increased uniformly after making the adjustments described in 1. above.
10. That the demand and energy charges for the LTS class be increased uniformly after making the adjustments described in 1. above.

Staff believes that a summary/review of previous CCOS studies since 2007 are appropriate to provide a starting point for understanding Staff's current CCOS studies and rate design proposal. The two previous AmerenUE general rate cases were Case Nos. ER-2007-0002, in which the Commission ordered an overall rate increase, after revenue neutral adjustments, of 2.12% which became effective on July 23, 2007, and ER-2008-0318, in which the Commission ordered an overall rate increase of 7.75%, after revenue neutral adjustments, which became effective March 1, 2009.

The Commission's approval of the Stipulation and Agreement in Case No. ER-2007-0002 resulted in the following revenue neutral percentage changes to class revenues.

TABLE 8
Revenue Neutral Changes to Class Revenues From Case No. ER-2007-0002

	RES	SGS	LGS(1)	LPS	LTS	System Average
Percentage Increase	1.12%	0.66%	-0.32%	0.66%	-7.48%	0.00%

(1) LGS = LGS and SPS Combined

Table 8 shows that the RES, SGS, and LPS classes received revenue neutral increases to their class revenue requirements, while LGS, and LTS classes received revenue neutral decreases to their class revenue requirement. These changes represented a movement toward matching class revenues (rates) with class cost-of-service. After the changes in revenues indicated above, each class received an overall increase of 2.12% (referred to as an equal percentage increase). The new rate sheets in Case No. ER-2007-0002 took effect on July 23, 2007.

The Commission's Report and Order in Case No. ER-2008-0318 ordered the following overall revenue neutral percentage changes to class revenues.

TABLE 9
Revenue Neutral Changes to Class Revenues From Case No. ER-2008-0318

	RES	SGS	LGS(1)	LPS	LTS	System Average
Percentage Increase	0.30%	-0.08%	-0.08%	0.11%	-1.68%	0.00%

(1) LGS = LGS and SPS Combined

Table 9 shows that the RES and LPS classes received a revenue neutral increase to their class revenue requirements, while the SGS, LGS, and LTS classes each received decreases to their revenue neutral class revenue requirement. After the changes in revenues indicated above, each class received an overall increase of 7.75% (referred to as an equal percentage increase). The new rate sheets in Case No. ER-2008-0318 became effective March 1, 2009.

Tables 8 and 9 show revenue neutral changes to AmerenUE's customer rates that were implemented in 2007 and 2009 with small percentage changes that have narrowed the gap between the CCOS results of various parties and class revenues, without substantial overall customer impacts. Staff's revenue neutral proposal in this case attempts to further narrow the gap of the cost to serve each class without a substantial overall bill impact to any customer. Staff proposes a revenue neutral increase of approximately three-tenths of one percent for the RES class with a concomitant approximately five-tenths of one percent decrease to the LGS class.

Schedule MSS-6 shows that AmerenUE's residential customer charge is the lowest of the five electric utility tariffs in the state. The results of Staff's CCOS studies shows customer costs of over two times the $7.25 existing customer charge. AmerenUE's residential customer charge has not increased since 2000, and was unchanged through AmerenUE's last two rate cases. Staff recommends increasing AmerenUE's residential customer charge by $1.25, from $7.25 to $8.50, after considering and taking into account the customer charges of other electric utilities this Commission regulates and Staff's revenue neutral rate increase recommendation for the residential class.

Schedule MSS-7 shows that AmerenUE's SGS customer charge is within a reasonable range of the five electric utility tariffs in the state. Staff's CCOS studies produce a customer cost of over twenty-five dollars for an SGS customer. Staff recommends the same $1.25 increase to the SGS customer charge for a single phase service, increasing it from $8.03 to $9.28. Staff recommends a $2.50 increase to the SGS customer charge for a three-phase service, increasing it from $16.06 to $18.56. These increases in the SGS customer charges would maintain the existing two-to-one ratio of the single-phase service charge versus the three-phase service charge.

The LTS rate schedule tariff sheets became effective June 1, 2005, when the Commission approved them in Case No. EA-2005-0180 so that AmerenUE could serve Noranda Aluminum, Inc. (Noranda). Currently, Noranda is the only customer served under the LTS tariff (12M), and Noranda accounts for approximately 6% of AmerenUE's total base rate revenues.

Any customer who satisfies the following criteria may take service from AmerenUE as a member of the LTS service class:

1. Meets the service application conditions of the Large Primary Service rate;

2. Can demonstrate to AmerenUE's satisfaction that such energy was routinely consumed at a load factor of 95% or higher or that customer operates at a similar load factor;
3. If necessary, arranges and pays for transmission service for the delivery of electricity over the transmission facilities of a third party;
4. Does not require use of AmerenUE's distribution system or distribution arrangements that are provided by AmerenUE at AmerenUE's cost, excepting AmerenUE's metering equipment, for service to customer; and
5. Meets all other required terms and conditions of the service classification.

Noranda is an aluminum smelter. An ice storm occurred January 26-28, 2009, that cut power to Noranda and caused it to shut down its operations for an extended period of time. Noranda has not yet operated at its full load capacity (approximately 470 MW) although it began bringing up its smelting operations again soon after power was restored after the ice storm. Through a Data Request response, Noranda stated that it expects to reach full production during middle to late portion of the first quarter of 2010. The operation of law date in this case is in June 2010.

Staff's direct case assumes Noranda is operating at full load (approximately 470 MW) in determining AmerenUE's cost of service revenue requirement. Staff also assumed Noranda is operating at full load in performing its CCOS studies, which are based on 2008 calendar year data. AmerenUE also assumed in its retail jurisdictional CCOS study that Noranda was operating at its full, historical load (approximately 470 MW). Thus, AmerenUE and Staff used the same billing determinants in calculating revenues received from Noranda and for their CCOS studies (2008 usage data). Therefore, since Noranda anticipates returning to full load capacity in the first quarter of 2010, Staff is not recommending any term or condition revisions to the LTS tariff sheets, but Staff is recommending the rate changes to the LTS as shown in Staff's rate design recommendations above.

Staff Expert: Michael S. Scheperle

IV. ENVIRONMENTAL COST RECOVERY MECHANISM

Staff's Environmental Cost Recovery Mechanism (ECRM) rate design objectives are:

- To explain, for rate design purposes, Staffs' understanding of the mechanics and procedures in implementing an ECRM.
- To present Staff's ECRM rate design recommendation for the Commission to consider if the Commission approves an ECRM for AmerenUE.

AmerenUE has proposed an ECRM in this case as outlined in Direct Testimony filed by AmerenUE's witnesses Mark C. Birk and Gary S. Weiss (Pg 40 - 46). Staff witness Lena M. Mantle addressed Staff's analysis and recommendation concerning the adoption of an ECRM for AmerenUE at pages 114-122 in Staff's Revenue Requirement Cost of Service Report filed in this case on December 18, 2009. In Staff's Revenue Requirement Cost of Service Report, Staff recommended that the Commission grant AmerenUE an ECRM with conditions detailed in that report.

The Commission recently adopted new sections to its Chapter 3 Rules (4 CSR 240-3.162) and Chapter 20 Rules (4 CSR 240-20.091) allowing for the establishment of an ECRM as authorized by the Missouri Legislature in section 386.266, RSMo. Supp. 2009. The new rules (which became effective August 31, 2009) provide definitions and requirements for the establishment of an ECRM. An ECRM allows an electric utility regulated by the Commission to have periodic rate adjustments outside of general rate cases of net increases/decreases in its prudently-incurred costs that are directly related to compliance with any federal, state, or local environmental law, regulation, or rule. An ECRM is established by tariff sheets approved by the Commission. AmerenUE states that its proposed ECRM will allow it the opportunity to recover qualified capital investment and expenses it incurs on a timelier basis than through general rate cases. Section 386.266, RSMo. Supp. 2009 and Commission rules (4 CSR 240-3.162 and 20.091) limit any rate adjustment made under an

ECRM to not exceed an annual amount equal to two and one-half percent (2.5%) of an electrical corporation's Missouri gross jurisdictional revenues. For AmerenUE, the 2.5% threshold is approximately $55.0 million, based on AmerenUE's Missouri jurisdictional base revenue of $2.2 billion.

An ECRM, as outlined in Section 386.266, RSMo. Supp. 2009, and Commission rules (4 CSR 240-3.162 and 20.091) must satisfy certain requirements and procedures. Schedule MSS-8 is a list of each requirement with the citation to Section 386.266, RSMo. Supp. 2009, 4 CSR 240-3.162 and 4 CSR 240-20.091 where the requirement is found. Also, listed on Schedule MSS-8 are where these various ECRM requirements are located in the exemplar ECRM tariff provisions. Staff recommends the Commission adopt Staff's ECRM, if it determines to approve an ECRM for AmerenUE. Those exemplar tariff provisions are found in the exemplar ECRM tariff sheets in Schedule MSS-9 – exemplar tariff sheets 98.8 through 98.13.

Staff believes that these exemplar ECRM tariff sheets include provisions that meet each of the requirements of Section 386.266, RSMo. Supp. 2009, 4 CSR 240-3.162 and 4 CSR 240-20.091. The ECRM Staff proposes includes recovery from ratepayers of capital investment, and operation and maintenance expenses, for projects and operations directly related to compliance with environmental laws.

The ECRM Staff proposes has three significant differences from the ECRM AmerenUE proposes. The differences are (Staff vs. AmerenUE):

- The ECRM rate (percentage) is applied to customers' retail base revenue, not on per kWh.
- The accumulation periods and recovery periods all are six months in duration. -- two accumulation periods and two recovery periods covering twelve months, not accumulation periods of eight months and four months' duration, and recovery periods of twelve months' duration.

- The wording on customers' bills is to be "ENVIRONMENTAL COST RECOVERY ADJUSTMENT, not "RIDER ECRM ADJUSTMENT."

First, Staff believes that the ECRM amount billed should be based on customers' retail base revenue, not on kWhs. This is because in reviewing AmerenUE's workpapers for its direct case, over 99.9% of net plant investment subject to the ECRM occurs in production plant (capitalized) accounts and over 97.3% of total ECRM expenses occur in production expense accounts. The production function CCOS study is a combination of production-capacity (approximately 35% of total CCOS) and production-energy (approximately 33% of total CCOS) cost to serve. Staff believes a more comprehensive approach for an ECRM is basing the recovery from customers on each customer's total base retail revenue amount, and not directly on a kWh basis as AmerenUE proposes. Staff proposes that the ECRM amount paid by a customer be based on that customer's bill for electric service (exclusive of taxes and the FAC fuel adjustment) multiplied by an ECRM revenue factor. This is the same process that AmerenUE is proposing to implement in its interim rate relief request. In that request AmerenUE proposes a revenue factor rate be applied to customers' monthly billing amounts, exclusive of taxes.

The Commission's ECRM rules allows a maximum of two ECRM-related rate changes in a year (4 CSR 240-20.091(4)(D)). Staff recommends that if the Commission authorizes AmerenUE to use an ECRM, the Commission makes each ECRM Accumulation Period and each ECRM Recovery Period six months in duration. AmerenUE recommends the Accumulation Periods be eight months and four months in duration each year and the Recovery Periods be twelve months in duration. Staff provided its rationale for its recommendation for the appropriate lengths of the ECRM accumulation and recovery periods for AmerenUE in Staff's Revenue Requirement and Cost of Service Report filed in this case on December 18, 2009 (pg. 120-121). There the Report states:

> Unlike the statutory language regarding rate adjustment mechanisms (e.g. fuel adjustment clauses (FACs)), section 386.266, RSMo. Supp. 2009, restricts the costs annually recovered by an ECRM to 2.5% of the electric utility's "Missouri gross jurisdictional revenues, excluding gross receipts tax, sales tax and other similar pass-through taxes not included in tariffed rates, for regulated services as established in the utility's most recent general rate case or complaint proceeding." This adds some complications to an ECRM that do not exist with a FAC. When the Commission makes a final determination on AmerenUE's gross jurisdictional revenues for regulated services, the cap amount will be calculated. This will provide the maximum amount that AmerenUE can recover through an ECRM in a twelve month period. Six month accumulation and recovery periods will make it easier to determine whether or not AmerenUE recovers more than the cap amount in the twelve months.

Schedule MSS-10 provides a timeline of events for the first four accumulation periods of the ECRM proposed by Staff. The first accumulation would begin June 2010 and end September 2010, based on the assumption that Commission authorizes new rates and the ECRM for AmerenUE in June 2010. The timelines in Schedule MSS-10 include the dates for:

- Accumulation Periods;
- AmerenUE filing date for proposing a change to the ECRM revenue factor that reflects the change in AmerenUE's environmental revenue requirement during the accumulation period;
- Commission Staff Review and Commission Approval/Rejection of AmerenUE's proposed change to the ECRM revenue factor;
- Recovery Periods; and
- True-Up process dates for each accumulation period and corresponding recovery period.

As noted in Schedule MSS-10, there are accumulation periods, dates by which AmerenUE is to make filings after each accumulation period to seek recovery of the changes in AmerenUE's environmental revenue requirement during the accumulation period, a timeline for Commission Staff review and Commission approval/rejection of AmerenUE's proposed changes to the ECRM revenue factor, and recovery periods where net increases/decreases in AmerenUE's environmental revenue requirement will be reflected in AmerenUE's ECRM revenue factor. Staff recommends two ECRM rate adjustments per year. With Staff's proposal each accumulation period and recovery period is six months in duration and each successive recovery period begins when the preceding one ends. The accumulation period April through September (six-month period) and October through March (six-month period) are outlined. After each accumulation period, AmerenUE would have two months to gather information and submit to Staff its work papers and calculations to support the new ECRM revenue factor AmerenUE proposes. Staff and the Commission would have two months to review the information provided by AmerenUE and approve/reject the newly proposed ECRM revenue factor. The recovery periods (i.e., the time over which AmerenUE recovers revenue from customers) for each accumulation period is six months.

As stated above, any rate adjustment made under an ECRM is not to exceed an annual amount equal to two and one-half percent (2.5%) of the electric utility's Missouri gross jurisdictional revenues. Staff realizes that with non-overlapping, six-month recovery periods, if the utility is allowed to recover the entire annual limit in the first recovery period the monthly customer impact during those six months could be greater than if the twelve-month periods are used. For that reason Staff recommends the Commission allow AmerenUE to recover no more than 1.25% of its Missouri gross jurisdictional revenues in each six-month period.

Staff, in proposing six-month periods for both the ECRM accumulation periods and recovery periods looked at AmerenUE's normalized monthly revenues for the twelve months ending July 2009. The recovery periods of February through July and August through January each encompass a six-month period with four winter month rates and two summer month rates, and AmerenUE collected in each of these periods approximately 50% of its annual revenues during the twelve months ended July 2009. After establishing recovery periods, Staff established filing dates and accumulation periods.

Also, Staff reviewed AmerenUE's current Fuel and Purchased Power Adjustment Clause for similar dates. AmerenUE's current FAC is designed with three accumulation periods (four-month duration) and starts three new recovery periods (twelve month duration) in every twelve months. One advantage of the six-month recovery periods is that a recovery period ECRM begins with the February billing month which is also the billing month in which one of AmerenUE's current FAC recovery periods begins. Thus, Staff's proposed ECRM accumulation and recovery periods are intended to minimize overall the number of times in a year when FAC adjustments and ECRM revenue factor changes occur by overlapping the dates FAC adjustments and ECRM revenue factor changes are implemented.

After each ECRM recovery period, AmerenUE is to submit work papers to show the difference between what it actually recovered from customers during the recovery period versus what the ECRM revenue factor was designed to collect during that recovery period. (i.e., workpapers that show the over/under collection) The over/under collection would be reflected in future ECRM calculations of the amount the ECRM revenue factor should be changed to collect/return the under/over collection.

Schedule MSS-11 is an illustrative calculation that details the base rate (revenue factor) contained in the calculation of net base revenue. If the Commission adopts the Staff proposed ECRM, Commission determinations including but not limited to rate of return, depreciation expense, and retail revenues, must be inputs to the calculation to determine the base revenue factor.

Schedule MSS-12 is an illustrative example, based on Staff's proposed ECRM, of the calculation of the part of the amount to be recovered during a recovery period for an accumulation period.

Staff's Proposed ECRM includes a calculation to determine for each accumulation period AmerenUE's net capital additions, operating and maintenance costs and any revenues received consistent with factors included in an ECRM Rider. Also, Staff's proposed ECRM includes an ECRM revenue factor that will be applied to all retail billings for electric service on a revenue basis. Since the ECRM factor would be on a revenue basis, no voltage level adjustment would be necessary since each rate schedule has already accounted for voltage level adjustments in its rate structure and specific rate schedule. Customers are served at the secondary, primary, or large transmission voltage level.

Second, Staff is recommending that the wording on customers' bills be "ENVIRONMENTAL COST RECOVERY ADJUSTMENT". By using words rather than an acronym such as "RIDER ECRM ADJUSTMENT" (proposed by AmerenUE), Staff believes customers will gain a better understanding of what the charge is. Also, to help inform AmerenUE's customers regarding its ECRM, if the Commission authorizes an ECRM for AmerenUE, Staff recommends the Commission require AmerenUE to briefly explain the ECRM on its customers' bills for the first three billing months starting with the first billing month where the ECRM charge appears on the bills.

Staff Expert: Michael S. Scheperle

V. Fuel and Purchased Power Adjustment Clause

In its Revenue Requirement Cost of Service Report in this case, Staff provided its analysis of and expressed its agreement with some of AmerenUE's changes included in Schedule LMB-E3 attached to the prefiled direct testimony of AmerenUE witness Lynn M. Barnes. These changes include the following:

1. Refinement of the Fuel and Purchased Power Adjustment Clause (FAC) true-up process to allow each true-up to occur after the completion of a full recovery period;
2. Inclusion of the cost of quality adjustments related to the sulfur content of coal assessed by coal suppliers;
3. Changes in the Taum Sauk factor to update the value of Taum Sauk; and
4. Changes to voltage level adjustments consistent with updated system loss factors.

Also, in its Revenue Requirement Cost of Service Report in this case, Staff proposed that the last sentence in the APPLICABILITY section of Sheet No. 98.1 be changed to the following: "All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact."

In its tariff filing that started this case, AmerenUE filed revisions to its original FAC tariff sheets *numbered 98.1 through 98.6* the Commission approved in Case No. ER-2008-0318 and made effective March 1, 2009. The FAC includes three 4-month accumulation periods, which end on May 31, September 30 and January 31. It is likely that the effective date of FAC tariff sheets approved in this case will not be May 31, September 30, or January 31, and, therefore, an accumulation period will be covered in part by the currently effective FAC tariff sheets and in part by the new FAC tariff sheets the Commission approves in this case. Therefore, Staff proposes the exemplar tariff sheets in Schedule JAR-1 be approved in this case. Schedule JAR-1 specifies that the provisions of the current FAC tariff sheets be applicable for determining the difference between Actual Net Fuel Costs and Net Base Fuel Costs for service provided prior to the effective date of the new FAC tariff sheets approved in this case and that the provisions of the new FAC tariff sheets be applicable to service provided on and after the effective date of the new FAC tariff sheets.

Finally, Staff recommends the Commission change the amount of the net base fuel costs (NBFC) used in the FAC to match what it orders included in AmerenUE's cost of service for generally increasing AmerenUE's rates in this case. Based on the NBFC the Staff determined from the fuel, purchased power and other costs and offsets the Staff determined are appropriate for AmerenUE in Staff's direct case, Staff presently recommends the Commission approve a rebased Summer NBFC Rate of 1.449 cents per kWh and a rebased Winter NBFC Rate of 1.275 cents per kWh as indicated on Sheet No. 98.11 of Schedule JAR-1.

Staff Expert: John A. Rogers

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service.	)))	Case No. ER-2010-0036

AFFIDAVIT OF MICHAEL S. SCHEPERLE

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Michael S. Scheperle, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Staff Report on pages 1 - 35, 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 6th day of January, 2010.

Susan L. Sundermeyer

Notary Public

NOTARY PUBLIC STATE OF MISSOURI NOTARY SEAL

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service.	)))	Case No. ER-2010-0036

AFFIDAVIT OF JOHN A. ROGERS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

John A. Rogers, employee of the Staff of the Missouri Public Service Commission, being of lawful age and after being duly sworn, states that he has participated in the preparation of the accompanying Staff Report on pages 36 - 37, and the facts therein are true and correct to the best of his knowledge and belief..

John A Rogers
John A. Rogers

Subscribed and sworn to before me this 6th day of January, 2010.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
Commission #06942086

Susan L Sundermeyer
Notary Public

CLASS COST-OF-SERVICE RESULTS

(At Staff Midpoint ROR 7.558)

AmerenUE

CASE NO. ER-2010-0036 (4 CP Method)

FUNCTIONAL CATEGORY			RES	SGS	LGS	LPS	LTS	Other	TOTAL	% OF TOTAL
PRODUCTION	CAPACITY		$380,983,627	$96,601,494	$284,417,379	$85,365,376	$80,183,778	$0	$927,531,655	35.15%
PRODUCTION	ENERGY		$319,451,238	$83,845,022	$276,898,223	$90,201,746	$90,948,532	$0	$861,344,760	32.64%
TRANSMISSION	CAPACITY		$48,286,196	$11,292,956	$32,182,262	$8,690,053	$8,048,061	$0	$108,499,528	4.11%
DISTRIBUTION	SUBSTATIONS	SUBSTATION DEMAND	$54,491,251	$12,852,941	$32,272,384	$8,283,179	$0	$0	$107,899,756	4.09%
DISTRIBUTION	POLES AND CONDUCTORS	CUSTOMER	$156,490,828	$21,413,650	$1,597,299	$10,412	$0	$0	$179,512,189	6.80%
DISTRIBUTION	POLES AND CONDUCTORS	PRIMARY DEMAND	$113,342,510	$28,895,482	$62,143,555	$11,050,592	$0	$0	$215,432,138	8.16%
DISTRIBUTION	POLES, CONDUCTORS, SERVICES	SECONDARY DEMAND	$33,464,247	$8,531,352	$13,723,358	$0	$0	$0	$55,718,954	2.11%
DISTRIBUTION	TRANSFORMERS	SECONDARY CUSTOMER	$22,870,331	$6,259,014	$876,810	$0	$0	$0	$30,006,154	1.14%
DISTRIBUTION	TRANSFORMERS	DEMAND	$15,428,425	$3,126,988	$4,017,231	$0	$0	$0	$22,572,644	0.86%
DISTRIBUTION	SERVICES	CUSTOMER	$20,618,539	$2,821,375	$197,610	$0	$0	$0	$23,637,524	0.90%
DISTRIBUTION	METERS	CUSTOMER	$15,544,242	$4,577,883	$3,097,972	$233,935	$16,876	$0	$23,470,907	0.89%
	CUSTOMER INSTALLATIONS	CUSTOMER	($1,076,657)	$0	$2,097,798	$2,097,798			$3,118,938	0.12%
	CUSTOMER DEPOSITS	CUSTOMER	($794,649)	($400,161)	($291,805)	($96,544)	$0	$0	($1,583,158)	-0.06%
	METER READING	CUSTOMER	$16,565,301	$2,165,816	$275,142	$4,353	$114	$0	$19,010,727	0.72%
	BILLING, SALES, SERVICE	CUSTOMER	$54,640,674	$7,476,862	$557,696	$3,625	$53	$0	$62,678,908	2.38%
	ASSIGNED LGS/LPS/LTS	CUSTOMER	$0	$0	$0	$0	$0	$0	$0	0.00%
	ASSIGNED RES/SGS	CUSTOMER	$0	$0	$0	$0	$0	$0	$0	0.00%
TOTAL			$1,250,306,102	$289,460,674	$714,062,911	$205,844,523	$179,177,414	$0	$2,638,851,624	100.00%
Allocate Cost of Service for Others			$0	$0	$0	$0	$0	$0	$0	
TOTAL COST OF SERVICE			$1,250,306,102	$289,460,674	$714,062,911	$205,844,523	$179,177,414	$0	$2,638,851,624	
%			47.38%	10.97%	27.06%	7.80%	6.79%	0.00%	100.00%	
RATE REVENUE			$963,237,556	$248,265,263	$646,173,550	$167,220,228	$139,156,447	$31,295,159	$2,195,348,203	
Allocate Rate Revenues for Others			$14,827,862	$3,432,826	$8,468,347	$2,441,190	$2,124,934	($31,295,159)	$0	
Other			$25,733,630	$6,524,971	$19,211,040	$5,766,025	$5,414,682	$0	$62,650,347	
Margin From Off-System Sales			$60,112,990	$15,242,137	$44,876,414	$13,469,261	$12,648,534	$0	$146,349,336	
TOTAL REVENUE			$1,063,912,038	$273,465,197	$718,729,351	$188,896,703	$159,344,597	$0	$2,404,347,886	
%			44.25%	11.37%	29.89%	7.86%	6.63%	0.00%	100.00%	
REVENUE DEFICIENCY			$186,394,064	$15,995,478	($4,666,440)	$16,947,820	$19,832,817	$0	$234,503,738	
% CHANGE			19.35%	6.44%	-0.72%	10.14%	14.25%	0.00%	10.68%	
Less System Average Increase			-10.68%	-10.68%	-10.68%	-10.68%	-10.68%		-10.68%	
Revenue Neutral % Change			8.67%	-4.24%	-11.40%	-0.55%	3.57%	0.00%	0.00%	

SCHEDULE MSS-1

CLASS COST-OF-SERVICE RESULTS

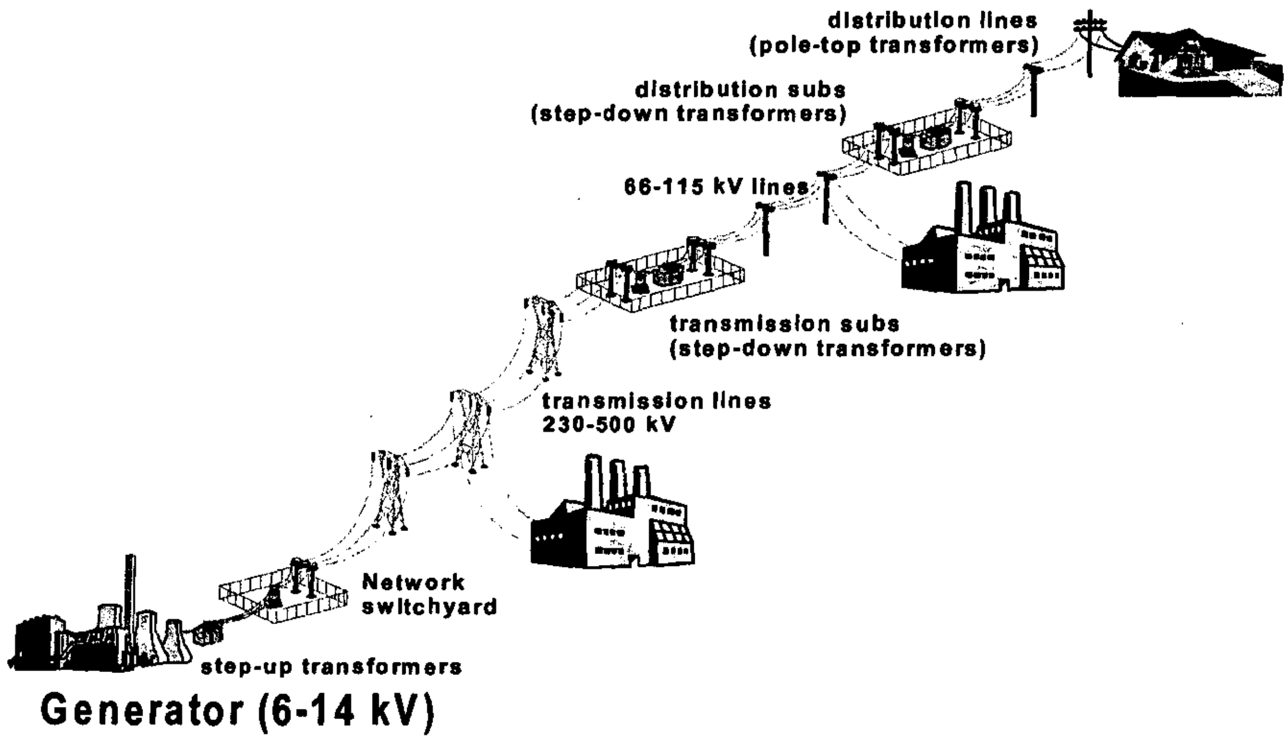
(At Staff Midpoint ROR 7.558)

AmerenUE

CASE NO. ER-2010-0036 (Capacity Utilization)

FUNCTIONAL CATEGORY			RES	SGS	LGS	LPS	LTS	Other	TOTAL	% OF TOTAL
PRODUCTION	CAPACITY		$376,530,548	$96,481,843	$286,206,588	$86,339,284	$81,973,393	$0	$927,531,655	35.15%
PRODUCTION	ENERGY		$319,451,238	$83,845,022	$276,898,223	$90,201,746	$90,948,532	$0	$861,344,760	32.64%
TRANSMISSION	CAPACITY		$48,288,196	$11,292,956	$32,182,262	$8,690,053	$8,048,061	$0	$108,499,528	4.11%
DISTRIBUTION	SUBSTATIONS	SUBSTATION DEMAND	$54,491,251	$12,852,941	$32,272,384	$8,283,179	$0	$0	$107,899,758	4.09%
DISTRIBUTION	POLES AND CONDUCTORS	CUSTOMER	$156,490,828	$21,413,650	$1,597,299	$10,412	$0	$0	$179,512,189	6.80%
DISTRIBUTION	POLES AND CONDUCTORS	PRIMARY DEMAND	$113,342,510	$28,895,482	$62,143,555	$11,050,592	$0	$0	$215,432,138	8.16%
DISTRIBUTION	POLES, CONDUCTORS, SERVICES	SECONDARY DEMAND	$33,464,247	$8,531,352	$13,723,356	$0	$0	$0	$55,718,954	2.11%
DISTRIBUTION	TRANSFORMERS	SECONDARY CUSTOMER	$22,870,331	$6,259,014	$876,810	$0	$0	$0	$30,006,154	1.14%
DISTRIBUTION	TRANSFORMERS	DEMAND	$15,428,425	$3,126,988	$4,017,231	$0	$0	$0	$22,572,644	0.86%
DISTRIBUTION	SERVICES	CUSTOMER	$20,618,539	$2,821,375	$197,610	$0	$0	$0	$23,637,524	0.90%
DISTRIBUTION	METERS	CUSTOMER	$15,544,242	$4,577,883	$3,097,972	$233,935	$16,876	$0	$23,470,907	0.89%
	CUSTOMER INSTALLATIONS	CUSTOMER	($1,076,657)	$0	$2,097,798	$2,097,798			$3,118,938	0.12%
	CUSTOMER DEPOSITS	CUSTOMER	($794,649)	($400,161)	($291,805)	($96,544)	$0	$0	($1,583,158)	-0.06%
	METER READING	CUSTOMER	$16,565,301	$2,165,816	$275,142	$4,353	$114	$0	$19,010,727	0.72%
	BILLING, SALES, SERVICE	CUSTOMER	$54,640,674	$7,476,862	$557,696	$3,625	$53	$0	$62,678,908	2.38%
	ASSIGNED LGS/LPS/LTS	CUSTOMER	$0	$0	$0	$0	$0	$0	$0	0.00%
	ASSIGNED RES/SGS	CUSTOMER	$0	$0	$0	$0	$0	$0	$0	0.00%
TOTAL			$1,245,853,022	$289,341,023	$715,852,119	$206,818,432	$180,987,028	$0	$2,638,851,624	100.00%
Allocate Cost of Service for Others			$0	$0	$0	$0	$0	$0	$0	
TOTAL COST OF SERVICE			$1,245,853,022	$289,341,023	$715,852,119	$206,818,432	$180,987,028	$0	$2,638,851,624	
%			47.21%	10.96%	27.13%	7.84%	6.86%	0.00%	100.00%	
RATE REVENUE			$963,237,556	$248,265,263	$646,173,550	$167,220,228	$139,156,447	$31,295,159	$2,195,348,203	
Allocate Rate Revenues for Others			$14,775,061	$3,431,407	$8,489,566	$2,452,740	$2,146,395	($31,295,159)	$0	
Other			$25,432,846	$6,516,889	$19,331,892	$5,831,808	$5,536,912	$0	$62,650,347	
Margin From Off-System Sales			$59,410,367	$15,223,258	$45,158,722	$13,622,928	$12,934,062	$0	$146,349,336	
TOTAL REVENUE			$1,062,855,820	$273,436,817	$719,153,731	$189,127,705	$159,773,816	$0	$2,404,347,886	
%			44.21%	11.37%	29.91%	7.87%	6.65%	0.00%	100.00%	
REVENUE DEFICIENCY			$182,997,203	$15,904,206	($3,301,611)	$17,690,729	$21,213,212	$0	$234,503,738	
% CHANGE			19.00%	6.41%	-0.51%	10.58%	15.24%	0.00%	10.68%	
Less System Average Increase			-10.68%	-10.68%	-10.68%	-10.68%	-10.68%		-10.68%	
Revenue Neutral % Change			8.32%	-4.28%	-11.19%	-0.10%	4.56%	0.00%	0.00%	

Basic Components of Electricity Production and Delivery



Capacity Utilization Responsibility: An Alternative to Peak Responsibility

By MICHAEL S. PROCTOR

The intent of this article is to demonstrate that capacity utilization is a proper measure for determining production capacity responsibility, and that under certain assumptions, this results in allocating production capacity costs by the average and peak method.

THE purpose of this article is to show the logical fallacy involved in the argument for the use of peak responsibility as the basis for allocating the embedded cost of production plants used to generate electricity. The crux of the argument for peak responsibility is that since peak demand determines the capacity required for production plant, the cost of that plant should be allocated to customers based on their share of peak demand. The principle is one of cost causality; i.e., whatever factor(s) cause cost, those same factors should be used as the basis for allocating cost. On this principle there is no disagreement. However, there is disagreement on whether peak demand is the only causal factor for the entire production plant.

In the process of showing the fallacy involved in peak responsibility, a natural outcome is the development of a causation principle that is theoretically correct. This causation principle is called *capacity utilization responsibility.*

As one might imagine, the load data requirements for an allocation method that is correct for all possible load situations could be overly restrictive. Thus, an approximation to the correct method is developed for the case where the load can be characterized by the typical load data available: class kilowatt-hour consumption and class contribution to peak. This allocation method is called the *average and peak.*

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The Record on Peak Responsibility

As early as 1921, H. E. Eisenmenger[1] recognized that peak responsibility is not the correct measure for allocating production costs to customers. In the summary to Eisenmenger's argument against peak responsibility, he states:[2] "We see that the consumer's demand cost is an intricate function of the entire load curve of the central station and of the entire load curve of the respective consumer, not only of certain parts of those curves."

In 1956, R. E. Caywood[3] recognized potential problems that exist in the use of peak responsibility. In discussing the peak responsibility method, Caywood states:[4]

> It is obvious that this method is not entirely satisfactory because a class load at the time of the system peak might be zero, while at some other time it might be of considerable size; yet no expense would be allocated to it. Furthermore, an allocation made on the basis of today's load conditions might be widely differ-

[1] "*Central Station Rates in Theory and Practice,*" by H. E. Eisenmenger, Fredrick J. Drake and Company, Chicago, Illinois, 1921, pp. 277-299.
[2] Ibid., p. 295.
[3] "*Electric Utility Rate Economics,*" by R. E. Caywood, McGraw-Hill, New York, 1956, pp. 156-167.
[4] Ibid., pp. 156, 157.

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ent in the future as the result of a shift of the system peak or a shift of the peak of the load of the class itself.

In 1963, C. W. Bary[5] recognized that peak responsibility is a naive approach to allocating capacity costs. In discussing the distribution of load diversity benefits, Bary states:[6]

> The one which is farthest from meeting the requirements of the general unified theory is the so-called system peak responsibility method, which reflects the demand-cost assignment to individual components on the basis of their loads at the *time* of the system peak load. This method reflects little conceptual perception of the nature and the mutual benefits of load diversity, nor the complex laws of probability governing its behavior.

In 1970, Alfred E. Kahn[7] published his two volumes on the economics of utility regulation. While Kahn seems to support the concept of peak responsibility, it is important to keep in mind Kahn's own qualifications placed on the principle:[8]

> The principle is clear, but it is more complicated than might appear at first reading. Notice, first, the qualification: "if the same type of capacity serves all users." In fact it does not always; in consequence, as we shall see, off-peak users may properly be charged explicitly for some capacity costs. Second, the principle applies to the explicit charging of capacity costs, "as such." Off-peak users, properly paying *short-run* marginal costs [SRMC] will be making a contribution to the covering of capital costs also, if and when SRMC exceeds average variable costs. Third, the principle is framed on the assumption that all rates will be set at marginal cost [MC] (including marginal capacity costs). Under conditions of decreasing costs, uniform marginal cost pricing will not cover total costs. Lacking a government subsidy to make up the difference, privately owned utilities have to charge more than MC on some of their business. In some of these "second-best" circumstances, some (of the difference between average and marginal) capacity costs might better be recovered from off-peak than from peak users.

While the arguments against peak responsibility are well documented in the literature, this method has gained wide acceptance as an appropriate procedure for allocating embedded production plant costs to jurisdictions and customer classes. Perhaps one reason for the acceptance of peak responsibility is that both the National Association of Regulatory Utility Commissioners[9] and the American Public Power Association[10] cost allocation manuals give qualified recognition to the concept of peak responsibility. It should be noted that peak responsibility involves not only the single peak method, but also any method that uses coincident peaks; e.g., summer-winter peaks, summer month peaks, winter month peaks, and 12 coincident month peaks. Also, probabilistic methods, such as loss-of-load probability, that are based on building plant to meet peak-load distributions (load plus plant outages), should be classified as peak responsibility methods.

A second reason for general acceptance of peak responsibility is its ease of application. One generally only needs to look at demands for one to twelve hours and determine the share of demand in those few hours going to each class or jurisdiction.

A third reason for the acceptance of peak responsibility is that it seems to have a strong theoretical foundation in the peak-load pricing literature in economics. The noneconomist reads peak-load pricing in the context that all capacity costs go to the peak period, and as the quote from Kahn indicates, this is a basic misconception.

A final reason for the acceptance of peak responsibility is its intuitive appeal; i.e., peak causes capacity, therefore capacity costs should be allocated on a peak responsibility basis. It is this intuitive appeal that will be challenged in this article.

Capacity Utilitization Responsibility

A basic assumption in the peak responsibility approach is that the production plant is assumed to be characterized by one type of production plant; i.e., no distinction is made between peak, intermediate, and base-load plants. In the case of a single type of plant, the total annual production capacity cost can be determined by the level of peak demand, and no matter what the load shape happens to be, if the peak demand level stays the same, the total production capacity costs also stay the same. It is this observed relationship that has led supporters of the peak responsibility allocation method to claim that peak demand causes production capacity costs.

If production capacity costs are viewed as being fixed over the year, then those fixed costs have been caused by the peak demand. However, the view that production capacity costs are fixed costs within a year, and can only vary from one year to the next places a restriction on one's view of causality. Even if there is only one type of production capacity, why should one's view of that capacity be limited to a single unit whose size is fixed by the level of peak demand? Why should not the decision as to the variable cost of production capacity be viewed as a decision made on small increments of capacity over small periods of time?

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[5] "*Operational Economics of Electric Utilities*," by C. W. Bary, Columbia University Press, New York, 1963, pp. 56-64.

[6] Ibid., p. 58.

[7] "*The Economics of Regulation*," by Alfred E. Kahn, John Wiley and Sons, New York, 1970, pp. 87-122.

[8] Ibid., pp. 89, 90.

[9] *Electric Utility Cost Allocation Manual*, National Association of Regulatory Utility Commissioners, Washington, D. C., 1973, pp. 40-53.

[10] *Cost of Service Procedures for Public Power Systems*, American Public Power Association, Washington, D. C., 1979, pp. X1-X4.

The purpose for determining the causality of production capacity costs is ultimately to determine the cost responsibility of the customers that use the production plant. While it is true that at only the time of peak is the fixed plant fully utilized, it is not true that this is the only time that the production plant provides services to the customers. A proper view of cost causality should recognize that during the peak period a greater amount of production capacity is required than at other times, but the fact that peak demand is higher should *only reflect the additional production capacity costs incurred because of the higher demand level.* Within this context production capacity is seen to be a variable cost of production in each and every hour.

A simple example can be used to illustrate the concept of treating production capacity as variable in each hour and calculating capacity responsibility based on the utilization (use) of production capacity. Consider a simplified load curve for two hours. In the first hour total demand is 50 megawatts, and in the second hour total demand is 100 megawatts. In this case 50 megawatts of production capacity is needed to meet demand in the first hour and an *additional* 50 megawatts of production capacity is needed to meet demand in the second hour. In terms of utilization of production capacity, the first and second hour share equal responsibility for the initial 50 megawatts of production capacity, while the second hour carries the full responsibility for the additional 50 megawatts. Thus the total *capacity responsibility* of each hour is given by

Hour One: $(\frac{1}{2})(50) = 25$ megawatts
Hour Two: $(\frac{1}{2})(50) + (50) = 75$ megawatts

Notice that this capacity utilization responsibility is not the same as the energy responsibility of 50 megawatt-hours for the first hour and 100 megawatt-hours for the second hour. Nor is the capacity utilization responsibility the same as would be determined by peak responsibility which would place zero megawatts on the first hour and 100 megawatts on the second hour. Moreover, using energy responsibility will understate the production capacity caused by the peak hour, while using peak responsibility will overstate the production capacity caused by the peak hour. Table 1 summarizes the results of applying these three different methods of calculating responsibility for capacity.

TABLE 1

HOURLY RESPONSIBILITIES

	Energy Responsibility	*Capacity Utilization Responsibility*	*Peak Responsibility*
Hour One	⅓	¼	0
Hour Two	⅔	¾	1

The final piece of information needed is the share of demand for each customer class in each hour. Suppose there are just two customers: A and B, with demands in each hour as given in Table 2.

TABLE 2

CUSTOMER LOADS

Customer	*Megawatts Hour One*	*Share*	*Megawatts Hour Two*	*Share*	*Megawatt-Hours Total*	*Share*
A	25	½	75	¾	100	⅔
B	25	½	25	¼	50	⅓
System	50	1	100	1	150	1

Customer A's share of hour one's demand is one-half, and hour one's share of capacity utilization responsibility is one-quarter, giving customer A a capacity utilization responsibility for hour one equal to $(\frac{1}{2})(\frac{1}{4}) = \frac{1}{8}$. Customer A's share of hour two's demand is three-quarters, and hour two's share of capacity utilization responsibility is three-quarters, giving customer A a capacity utilization responsibility for hour two equal to $(\frac{3}{4})(\frac{3}{4}) = \frac{9}{16}$. Adding customer's A's capacity utilization responsibility for both hours gives $\frac{1}{8} + \frac{9}{16} = \frac{11}{16}$. A similar calculation for customer B gives a capacity utilization responsibility of five-sixteenths.

Table 3 summarizes the capacity responsibility going to each customer using energy, capacity utilization, and peak as the basis for calculating these responsibilities.

TABLE 3

CUSTOMER RESPONSIBILITIES

Class	*Energy Responsibility*	*Capacity Utilization Responsibility*	*Peak Responsibility*
A	⅔	11/16	¾
B	⅓	5/16	¼

Notice that energy responsibility allocates too little capacity to A and too much to B, and peak responsibility allocates too much capacity to A and too little to B. Also notice that A's load factor (average energy divided by demand at peak) is below the system average, and B's load factor is above the system average. Moreover, this observation can be generalized to the principle that peak responsibility will always result in allocating too much capacity to customers (classes or jurisdictions) whose load factors are below the system average, and too little capacity to customers (classes or jurisdictions) whose load factors are above the system average. Of course, energy responsibility has the opposite result.

The Average and Peak Allocation Of Production Capacity Costs

The observations from the previous section lead to the following question: If a certain percentage of capacity is allocated based on energy responsibility and the remainder based on peak responsibility, how can that percentage be chosen so that the resulting allocations are the same as those derived using the capacity utiliza-

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tion method? The answer is to use the system load factor to determine the percentage of capacity to be allocated by energy responsibility. This is called the *average and peak* method and is given by the following formula:

$$\left(\begin{matrix}\text{Load}\\\text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Energy}\\\text{Responsibility}\end{matrix}\right) + \left(1 - \begin{matrix}\text{Load}\\\text{Factor}\end{matrix}\right)\left(\begin{matrix}\text{Peak}\\\text{Responsibility}\end{matrix}\right)$$

The system load factor is the ratio of average demand to peak demand. For this example it is given by:

$$\begin{aligned}\text{Average Demand} &= (150 \div 2) = 75 \text{ Mw}\\ \text{Peak Demand} &= 100 \text{ Mw}\\ \text{Load Factor} &= (75 \div 100) = 3/4\end{aligned}$$

The average and peak allocation factor for each customer is given by:

$$\begin{aligned}\text{Customer A: } &(3/4)(2/3) + (1/4)(3/4) = 11/16\\ \text{Customer B: } &(3/4)(1/3) + (1/4)(1/4) = 5/16\end{aligned}$$

While the average and peak method has only been shown to produce the same answer as the capacity utilization method for the example of this section, it can also be shown to hold for any case in which demand is characterized by two levels, that is a peak and off-peak (base) level, and the result is independent of the number of hours associated with each period; c.f., the appendix to this article.

Before arriving at any conclusions about applying the average and peak method, keep in mind two very important assumptions. First, production capacity is characterized by one type of production plant. Second, demand is characterized by two levels. Much work has and is being done to develop allocation methods that will allow these two assumptions to be relaxed. These methods are called *time-of-use* cost allocations of embedded production costs.[11] Time-of-use allocations require substantially more load data (essentially they require hourly load profiles for all classes of service). When this type of load information is not available, then the average and peak method provides a viable alternative for reflecting the capacity utilization responsibility approach to the causation of production capacity.

[11] *Time of Use Cost Allocation and Marginal Cost*, by M. S. Proctor, Missouri Public Service Commission, November, 1979.

Appendix

Average and Peak Capacity Allocation

In this appendix two basic assumptions are made. First, demand is served from a single type plant with constant capacity and running cost. Second, demand is characterized by two periods: peak demand; and base (off-peak) demand. The following definitions are used.

D_p = megawatt demand at peak
D_b = megawatt demand at base
a_p = fraction of time applied to peak demand
a_b = fraction of time applied to base demand

where $a_p + a_b = 1$; i.e., the fraction of time for base and peak demand adds up to the total amount of time serving load.

These fractions can be used to calculate both average demand (energy) and capacity utilization. The following table gives these calculations.

Period	*Average Demand*	*Capacity Utilization*
Base	$a_b D_b$	$a_b D_b$
Peak	$a\ D_p$	$a_p D_b + (D_p - D_b$
Total	$a_b D_b + a_p D_p$	D_p

Average demand during the base and peak periods is simply the demands of those periods times the fraction of time applied to each. The capacity utilization in the base period is simply that period's fraction of time of use of the capacity required to meet base-load demand ($a_b D_b$). The capacity utilization for the peak period is that period's fraction of time of use of the capacity required to meet base-load demand ($a_p D_b$) plus the difference between base and peak demand ($D_p - D_b$), which represents that portion of total capacity used exclusively during the peak period. When these two are added together, the total capacity utilization is given by $(a_b + a_p)D_b + D_p - D_b = D_b + D_p - D_b = D_p$.

The system load factor is the ratio of the average demand to peak demand, and is given by

$$\text{System Load Factor} = (a_b D_b + a_p D_p) \div D_p$$

Since $D_b < D_p$, it follows that $a_b D_b + a_p D_p < a_b D_p + a_p D_p = (a_b + a_p) D_p = D_p$. Thus, the system load factor is less than one. It also follows that

$$\frac{a_b D_b}{a_b D_b + a_p D_p} > \frac{a_b D_b}{D_p}$$

Thus the average demand contribution to the base period is greater than the capacity utilization contribution to the base period, and subsequently the average demand contribution to the peak period is less than the capacity utilization contribution to the peak period.

Given these basic concepts, the objective in this appendix is to show that *the average and peak method for capac-*

ity allocation to customer classes is equivalent to the capacity utilization method no matter where the levels for α_b and α_p may occur. The following definitions are used for the customer class demand responsibilities:

β_{jp} = class j's contribution (fraction) of demand in the peak period.

β_{jb} = class j's contribution (fraction) of demand in the base period.

The table below (in frame) specifies the average demand (energy), capacity utilization and peak responsibility to demand for the j[th] class.

The average and peak method simply assumes that class contribution to energy and class contribution to peak is known. Then the system load factor is used to define the following allocation factor:

$$\left(\text{Load Factor}\right)\left(\text{Class Contribution to Energy}\right) + \left(1 - \text{Load Factor}\right)\left(\text{Class Contribution to Peak}\right)$$

Substituting into this definition the appropriate terms gives the following results:

1) (Load Factor) (Class Contribution to Energy):

$$\left(\frac{\alpha_b D_b + \alpha_p D_p}{D_p}\right)\left(\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{\alpha_b D_b + \alpha_p D_p}\right) = \left(\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{D_p}\right)$$

2) (1 − Load Factor) (Class Contribution to Peak):

$$\left(\frac{D_p - \alpha_b D_b - \alpha_p D_p}{D_p}\right)\left(\beta_{jp}\right) = \frac{\beta_{jp}\,(D_p - \alpha_b D_b) - \beta_{jp}\,\alpha_p D_p}{D_p}$$

3) Average and Peak (1 + 2):

$$\frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{D_p} + \frac{\beta_{jp}\,(D_p - \alpha_b D_b) - \beta_{jp}\,\alpha_p D_p}{D_p}$$

$$= \frac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,(D_p - \alpha_b D_b)}{D_p}$$

But this gives exactly the same result as the capacity utilization method for determining class responsibility for capacity. Moreover, no matter how the peak and base periods are chosen, one needs only to determine class contribution to energy, class contribution to peak, and the system load factor in order to calculate the capacity utilization responsibility for each class of load. At the same time it is important to keep in mind the basic assumptions being made; i.e., demand is served from a single type plant and demand can properly be characterized by a peak and base load.

Method	*Base*	*Peak*	*Class Contribution*
Energy	$\beta_{jb}(\alpha_b D_b)$	$\beta_{jp}(\alpha_p D_p)$	$\dfrac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,\alpha_p D_p}{\alpha_b D_b + \alpha_p D_p}$
Capacity Utilization	$\beta_{jb}\,(\alpha_b D_b)$	$\beta_{jp}\,(D_p - \alpha_b D_b)^*$	$\dfrac{\beta_{jb}\,\alpha_b D_b + \beta_{jp}\,(D_p - \alpha_b D_b)}{D_p}$
Peak	$\beta_{jb}(0)$	$\beta_{jp}\,(D_p)$	β_{jp}

*Notice that $\alpha_b D_b = (1 - \alpha_p)D_b$, so that the capacity utilization contribution to peak can be rewritten as $\alpha_p D_b + (D_p - D_b) = D_p - (1 - \alpha_p)D_b = D_p - \alpha_b D_b$.

West Valley Project Gets Extra Money

An additional $5 million of federal funding has been targeted for the West Valley demonstration project. The extra money, plus some creative managing of the design and construction of the nuclear waste solidification project at the site, could result in the conversion of the radioactive liquid there to a durable solid two years sooner than had been originally planned. Dr. William H. Hannum, project director for the U. S. Department of Energy, said recently that the additional money is being transferred to this project from another DOE activity. "The extra funding indicates the importance the Department places on the timely solidification of the liquid wastes stored here." Hannum said that about sixty engineers and nuclear technicians will be added to the project staff in the next several months.

As the first U. S. nuclear waste solidification program of its kind, the West Valley demonstration project will convert almost 600,000 gallons of highly radioactive liquid waste into a durable solid which will be transported to a federal repository for disposal. The project began in February, 1982, when DOE assumed control of the former nuclear fuel reprocessing site. The liquid waste stored there was a by-product of reprocessing from 1966 to 1972. As the prime contractor to the DOE, West Valley Nuclear Services Company, a subsidiary of Westinghouse Electric Corporation, will design, build, and operate the solidification equipment.

4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 1 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Avg. Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	34.84	233,869,251	30.96	120,512,062	354,381,313
LSMP	37.25	250,020,306	33.87	131,822,415	381,842,722
LP	24.63	165,313,703	31.21	121,450,476	286,764,179
AG&P	3.29	22,078,048	3.22	12,545,108	34,623,156
SL	0.00	0	0.74	2,864,631	2,864,631
TOTAL	100.00	671,281,308	100.00	389,194,692	$1,060,476,000

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

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

Schedule MSS 5-1

TABLE 4-15

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	198,081,400	30.96	137,226,133	335,307,533
LSMP	38.43	237,225,254	33.87	150,105,143	387,330,397
LP	26.71	164,899,110	31.21	138,294,697	303,193,807
AG&P	2.42	14,960,151	3.22	14,285,015	29,245,167
SL	0.35	2,137,164	0.74	3,261,933	5,399,097
TOTAL	100.00	617,303,080	100.00	443,172,920	$1,060,476,000

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

Schedule MSS 5-2

Missouri Public Service Commission
Case No. ER-2010-0036
Customer Charges for Residential Class

Company	Current Residential Customer Charge	Current Residential Optional Time of Day Rate
AmerenUE (1)	$7.25	$15.00
Empire District Electric Company (2)	$11.04	$21.04
Kansas City Power & Light Company (3)	$8.67	$13.37
KCP&L Greater Missouri Operations Company - L&P (4)	$7.90	$27.52
KCP&L Greater Missouri Operations Company - MPS (5)	$9.73	$17.23

(1) Mo. P.S.C. Schedule No. 5 , Sheet No. 28

(2) P.S.C. Mo. No. 5, Section 1, Sheet No.1; P.S.C. Mo. No. 5, Section 4, Sheet No. 18

(3) P.S.C. Mo. No. 7, Sheet No. 5A; P.S.C. Mo. No. 7, Sheet No. 8

(4) P.S.C. Mo. No. 1, Sheet No. 18; P.S.C. Mo. No. 1, Sheet No. 35

(5) P.S.C. Mo. No. 1, Sheet No. 51; P.S.C. Mo. No. 1, Sheet No. 66

Missouri Public Service Commission
Case No. ER-2010-0036
Customer Charges for Small General Service (SGS) Class

Company	Current SGS Customer Charge	Current SGS Optional Time of Day Rate
AmerenUE - Single Phase (1)	$8.03	$16.60
AmerenUE - Three Phase (1)	$16.71	$33.19
Empire District Electric Company - Single Phase (2)	$15.58	$25.58
Empire District Electric Company - Three Phase (2)	$15.58	$30.58
Kansas City Power & Light Company (3)	$15.25	$10.00
KCP&L Greater Missouri Operations Company - L&P (4)	$15.65	$35.27
KCP&L Greater Missouri Operations Company - MPS (5)	$16.03	$22.69

(1) Mo. P.S.C. Schedule No. 5 , Sheet No. 32
(2) P.S.C. Mo. No. 5, Section 2, Sheet No. 1
(3) P.S.C. Mo. No. 7, Sheet No. 9A; P.S.C. Mo. No. 7, Sheet No. 20D
(4) P.S.C. Mo. No. 1, Sheet No. 23; P.S.C. Mo. No. 1, Sheet No. 35
(5) P.S.C. Mo. No. 1, Sheet No. 53; P.S.C. Mo. No. 1, Sheet No. 67

Missouri Public Service Commission
Environmental Cost Recovery Mechanism (ECRM)
Case No. ER-2010-0036

Requirements of an ECRM

Requirement	Missouri Statute / Rule Location	Staff Proposed Tariff Sheets / Staff Report (1)
Environmental Compliance Plan	Rule 3.162(1)(2)	ECRM Minimum Filing Requirements - Schedule MCB E3 (HC); (Direct Testimony of Mark C. Birk, AmerenUE)
Tariff Schedules	Statute 386.266.2 & .4, Rules 3.162(2) & 20.091(2)	Sheets 98.8 through 98.13
Rider calculation sheet in tariff	Statute 386.266.2 & .4, Rules 3.162(2) & 20.091(2)	Sheet 98.13
Environmental Capital Costs	Statute 386.266.2, Rules 3.162(1)(2) & 20.091(1)	Sheet 98.10
Base Environmental Revenue Requirement	Rules 3.162(1)(2) & 20.091(2)	Sheet 98.10, Staff Report
All expensed environmental costs	Statute 386.266.2, Rules 3.162(1)(2) & 20.091(1)	Sheet 98.10
Allowed interest costs	Statute 386.266.2 and 386.266.4; Rule 20.091(5)	Sheets 98.9, 98.11, & 98.12
Prior period(s) over/under recovery costs	Statute 386.266.2, Rules 3.162(2) & 20.091(5)	Sheets 98.9 & 98.11
Means of collection from customer	Statute 386.266.6, Rule 20.091(2)	Sheet 98.13
True-Up mechanism procedure	Statute 386.266.4, Rules 3.162(2) & 20.091(1) & (5)	Sheet 98.12
Prudence Review procedure	Statute 386.266.4, Rules 3.162(2) & 20.091(7)	Sheet 98.12
Limitation on ECRM (limitation that ECRM not generate revenue over 2.5% of gross jurisdictional revenue)	Statute 386.266.2, Rules 20.091(2) & (4)	Sheet 98.9
Disclosure on Customers' bills	Statute 386.266.6, Rules 3.162(2) & 20.091(2) & (8)	Sheet 98.9, Staff Report
Rate Case Provisions (utility file a general rate increase with the effective date to be no later than 4 years after the effective of Commission Order approving ECRM)	Statute 386.266.4, Rule 20.091(6)	Sheet 98.12
Example of Notice to customers	Rules 3.162(2) & 20.091(2)	Sheet 98.9, Staff Reports
Specifc rate class cost allocations	Rules 3.162(2) & 20.091(1)	Sheet 98.8
Voltage level	Rule 3.162(5)	Staff proposal on rate design revenue factor considers voltage adjusted rates
Authorization for Commission Staff to release the previous five (5) years of historical Surveillance Reports	Rule 3.162(2)	ECRM Minimum Filing Requirements MCB-E2 (page 12); (Direct Testimony of Mark C. Birk, AmerenUE)

(1) Staff proposed Tariff Sheets - Staff Report
(Schedule MSS-9)

***RIDER ECRM**

ENVIRONMENTAL COST RECOVERY MECHANISM

APPLICABILITY

This Rider is applicable to Missouri jurisdictional retail revenue ($)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), 8(M), 11(M), and 12(M).

Costs passed through this Environmental Cost Recovery Mechanism (ECRM) reflect differences between the actual environmental revenue requirement (factor ERR, as defined below) and the base environmental revenue requirement (factor ERRB, as defined below), calculated and recovered as provided for herein.

For the purpose of this ECRM, the Accumulation Periods, Filing Dates, and Recovery Periods for adjustments to the Company's ECRM are set forth in the following table:

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

Accumulation Period (AP) means the historical calendar months over which environmental revenue requirement is calculated. The initial Accumulation Period shall begin on the date this Rider becomes effective and ends on the last day of September 2010. The subsequent Accumulation Periods shall be from October through March and from April through September of each succeeding year. Each subsequent Accumulation Period shall begin immediately following the end of the previous Accumulation Period.

Recovery Period (RP) means the billing months during which the difference between the actual environmental revenue requirement (factor ERR, defined below) during an Accumulation Period and the base environmental revenue requirement (factor ERRB, defined below) is applied to and reflected through retail customer billings on a retail revenue basis. Each Recovery Period shall be the six (6) billing month period beginning on the first billing cycle of the billing month following two (2) months after the Filing Date.

The Company will make an Environmental Cost Adjustment (ECA) filing by each Filing Date, which shall be not more than two (2) calendar months after the end of the applicable Accumulation Period as shown in the above table. The new ECA rates for which the filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All ECRM adjustment filings shall be accompanied by detailed work papers supporting the filing in an electronic format with all formulas intact.

ECA DETERMINATION

The difference between the actual environmental revenue requirement and the base environmental revenue requirement shall be reflected as an ECA_C credit

* Indicates Addition.

***RIDER ECRM**
ENVIRONMENTAL COST RECOVERY MECHANISM (CONT'D)

or debit, stated as a separate line item on the customer's bill, and will be calculated according to the formulas below.

Any adjustment made to the applicable ECRM factor (ECA_c) shall not generate an annual amount of revenue that exceeds two and one-half percent (2.5%) of the Company's annual Missouri gross jurisdictional base rate retail revenues established in the most recent general rate proceeding (CAP). The Company shall also be able to collect any applicable gross receipts taxes, sales taxes, and other similar pass-through taxes on ECRM billing amounts and such taxes shall not be counted against the 2.5% rate adjustment cap. Any amounts not recovered by the Company under this Rider ECRM as a result of this 2.5% limitation on rate adjustments will be deferred, at a carrying cost each month equal to the Company's net of tax cost of capital (i.e., the return on rate base, or return on capital, as allowed by the Missouri Public Service Commission (Commission) in the most recent general rate proceeding), to be recovered in a subsequent Recovery Period or in the Company's next general rate proceeding if not fully recovered in a subsequent Recovery Period.

The Recovery Period rate component to reflect differences (increases or decreases) in the actual environmental revenue requirement and the environmental revenue requirement collected in retail rates during the recently-completed Accumulation Period is the Environmental Cost Adjustment factor (ECA_C) applicable starting with the Recovery Period following the applicable Filing Date. ECA_C is calculated as:

$$ECA_C = BRR / R_{RP}$$

where:

R_{RP} = Applicable Recovery Period estimated retail revenue in dollars

and

BRR = the Revenue Requirement to be collected in the recovery period in dollars. BRR is the lesser of

$$[ERR - (ERRB \times R_{AP}) + DEF_{AP-1} + I + T] \text{ or } [CAP * 0.5]$$

Where:

* Indicates Addition.

***RIDER ECRM**

ENVIRONMENTAL COST RECOVERY MECHANISM (CONT'D)

ERR = Environmental revenue requirement actually incurred during the applicable Accumulation Period, which shall encompass (i) all expensed environmental costs (other than taxes and depreciation associated with capital projects) incurred during the Accumulation Period to comply with federal, state or local environmental laws, regulations or rules (to be offset by net revenues from the sale of emission allowances); and (ii) the depreciation, taxes and return on capital for any major capital projects whose primary purpose is to permit the Company to comply with any federal, state or local environmental law, regulation or rule, as reflected in the Company's rate base accounts at the end of the Accumulation Period. The accounts shall be those accounts specified by the Commission in the prior rate case. No major capital projects shall be included until the Commission determines that the project is operational and useful for service as required by 393.135 RSMo. 2000.

ERRB = The base environmental revenue requirement as determined in the Company's general rate proceeding in which the ECRM is established consisting of (i) expensed environmental costs included in factor ERR for the normalized test year, as updated or trued-up (other than taxes and depreciation) and (ii) the depreciation, taxes and return on capital for any major capital projects whose primary purpose is to permit the Company to comply with any federal, state or local environmental law, regulation or rule, as reflected in the rate base approved by the Commission in the Company's general rate proceeding in which the ECRM was established. The ERRB expressed in a retail revenue factor basis, included in the Company's retail rates is 0.023801 revenue factor.

R_{AP} = Supplied retail revenue during the Accumulation Period that ended prior to the applicable Filing Date.

DEF_{AP} = Environmental costs deferred due to the application of the 2.5% limitation on annual adjustments. DEF_{AP} is the greater of zero (0) or [ERR - (ERRB x R_{AP}) DEF_{AP-1}+ I + T] - (CAP*0.5)

* Indicates Addition.

***RIDER ECRM**

ENVIRONMENTAL COST RECOVERY MECHANISM (CONT'D)

DEF_{AP-1} = DEF_{AP} from the previous accumulation period. For the calculation of BRR for the first accumulation period, DEF_{AP-1} is zero (0)

I = Interest applicable to (i) the difference between the actual environmental revenue requirement and the environmental revenue requirement recovered in rates; (ii) refunds due to prudence reviews and other regulatory adjustments (a portion of factor R below); and (iii) all under- or over-recovery balances created through operation of this ECRM, as determined in true-up filings provided for herein (also a portion of factor T, 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.

T = Under/over recovery,if any, from currently active and prior Recovery Periods as determined for the ECRM 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. This would include any amounts collected over the CAP.

CAP = Annual amount of revenue that is two and one-half percent (2.5%) of company's annual Missouri gross jurisdictional base rate retail revenues established in the most recent general rate proceeding. The CAP amount is $54,883,705 ($2,195,348,203 x 2.5%).

* Indicates Addition.

***RIDER ECRM**
ENVIRONMENTAL COST RECOVERY MECHANISM (CONT'D)

The ECA factor shall be rounded to the nearest 0.00001, to be charged on a retail revenue basis on retail revenue billed.

TRUE-UP OF ECRM

After the completion of each Recovery Period, the Company will make a true-up filing in conjunction with an adjustment to its ECRM, where applicable. The true-up filings shall be made on the first Filing Date that occurs at least two (2) months after completion of each Recovery Period. Any true-up adjustments or refunds shall be reflected in item T above, and shall include interest calculated as provided for in item I above.

True-up adjustments shall be the difference between the revenue billed and the revenue authorized for collection during the Recovery Period.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this ECRM, in accordance with Section 386.266.4, RSMo.and applicable 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 established in such general rate case to be no later than four (4) years after the effective date of a Commission order implementing or continuing this ECRM. The four (4) year period referenced above shall not include any periods in which the Company is prohibited from collecting any charges under this ECRM, or any period for which charges hereunder must be fully refunded. In the event a court determines that this ECRM is unlawful and all moneys collected hereunder are fully refunded, the Company shall be relieved of the obligation under this ECRM to file such a rate case.

Prudence reviews of the costs subject to this ECRM shall occur no less frequently than every eighteen (18) months, and any such costs which are determined by the Commission to have been imprudently incurred shall be returned to customers with interest at the Company's short-term borrowing rate.

* Indicates Addition.

***RIDER ECRM**
ENVIRONMENTAL COST RECOVER MECHANISM (CONT'D.)

Calculation of Current ECA_C Rate:

	Accumulation Period Ending:	mm/dd/yy
1.	Total Environmental Revenue Requirement (ERR)	$0
2.	Base Environmental Revenue Requirement	$0
2.1	Revenue Factor in Base Rates (ERRB)	0.023801
2.2	Accumulation Period Retail Revenue (R_{AP})	$0
3.	Amount to be Recovered above Base (Line 1 - Line 2)	$0
4.	Deferred Environmental Costs from Prior Periods (DEF_{AP-1})	$0
5.	Adjustment for under/over recovery from prior periods plus Interest (I + T)	$0
6.	Amount Subject to Recovery this Accumulation Period (Line3 + Line4 + Line 5)	$0
7.	Base Retail Revenue with 2.5% CAP (BRR)	$0
8.	Amount Deferred (DEF_{AP})	$0
9.	Carrying Cost on Deferred Amount	$0
10.	Estimated Revenue for Recovery Period (R_{RP})	$0
11.	ECRM Revenue Factor (ECA_C)	.00000

CAP amount is $54,883,705 ($2,195,348,203 x 2.5%)

* Indicates Addition.

Missouri Public Service Commission
ECRM Timeline
Case No. ER-2010-0036

Accumulation Period (AP)	Filing Date by AmerenUE	Commission Review & Approval	Recovery Period (6 months)
April through September (6 Months)	By December 1	Two months	February through July
October through March (6 months)	By June 1	Two months	August through January

Description	1st Accumulation Period	2nd Accumulation Period	3rd Accumulation Period	4th Accumulation Period
Accumulation Period	June 2010 - September 2010	October 2010 - March 2011	April 2011 - September 2011	October 2011 - March 2012
Filing Date By:	December 1, 2010	June 1, 2011	December 1, 2011	June 1, 2012
Recovery Period	February 1, 2011 - July 31, 2011	August 1, 2011 - January 31, 2012	February 1, 2012 - July 31, 2012	August 1, 2012 - January 31, 2013
True-Up - Reflected in Filing By:	December 1, 2011	June 1, 2012	December 1, 2012	June 1, 2013

Missouri Public Service Commission
Environmental Cost Recovery Mechanism Base Revenue Factor **Illustrative Purposes Only**
Case No. ER-2010-0036

	Total Electric	Allocation (1)(2)(3)	Missouri Jurisdictional	
Environmental Rate Base				
Environment Plant in Service	$563,331,558	95.59%	$538,488,636	
Less: Accumulated Depreciation Reserve	$259,099,760	95.59%	$247,673,461	
Net Environmental Rate Base	$304,231,798		$290,815,176	
Environmental Revenue Requirement				
Depreciation on Environmental Plant in Service	$17,198,813	95.59%	$16,440,345	
Return and Income Taxes (8.557% ROR or 12.03%)	$36,599,085	95.59%	$34,985,066	
Environmental Chemicals (urea) - Variable Allocator	$1,046,424	94.92%	$993,266	
Environmental Production Expenses-Operations	$108,152	95.59%	$103,382	
Environmental Production Expenses-Maintenance	$3,050,304	95.59%	$2,915,786	
Solid Waste Operating Expenses - Labor Allocator	$111,586	96.75%	$107,959	
Sales of Emission Allowances	($925,862)	95.59%	($885,031)	
Total Environmental Revenue Requirement	$57,188,502		$54,660,773	
Missouri Revenue	$2,698,818,000	Illustrative Purposes	$2,296,548,000	GSW-E10-1
Net Base Environmental Cost Factor	0.021190	Illustrative Purposes	2.380128%	

(1) Schedule GSW-E15 Allocator
(2) Schedule GSW-E16 Allocator
(3) Schedule GSW-E17 Allocator

Missouri Public Service Commission
ECRM Calculation - Illustrative Purposes Only
Case No. ER-2010-0036

	Revenue (Illustrative Purposes Only)	$2,296,548,000
	2.5% Limit (Illustrative Purposes Only)	$57,413,700
		Accumulation Period
1	Total Environmental Revenue Requirement (ERR)	$50,000,000
2	Base Environmental Revenue Requirement	$26,181,408
2.1	Revenue Factor in Base Rates (ERRB)	2.380128%
2.2	Accumulation Period Retail Revenue (R_{AP})	$1,100,000,000
3	Amount to be Recovered above Base - 1st Subtotal (Line1 - Line2)	$23,818,592
4	Deferred Environmental costs from prior periods (DEF_{AP-1})	$0
5	Adjustment for Under/Over recovery for prior periods plus interest (I + T)	$0
6	Amount Subject to Recovery this Accumulation Period (2nd Subtotal) Line 3 + Line4 + Line 5	$23,818,592
7	Base Rate Retail Revenue with 2.5% cap (BRR)	$23,818,900
8	Amount Deferred (DEF_{AP})	$0
9	Carrying Cost on Deferred Amount	$0
10	Estimated revenue for Recovery Period (R_{RP})	$1,100,000,000
11	ECRM Revenue Factor (ECA_C)	2.1654%

FORMULAS

Line 11 = [Line 1 - (Line 2.1 * Line 2.2) + Line 4 + Line 5] / Line 10 (If equal to or below CAP)

Line 11 = Line 7 / Line 10 (If greater than CAP)

Six Month CAP amount = $57,413,700 x 0.5 or $28,706,850

*** RIDER FAC**

FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE

(Applicable to Service Provided Prior to Month Day, 2010)

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), 8(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, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Fuel Costs) and Net Base Fuel Costs (factor NBFC, as defined below), calculated and recovered as provided for herein.

For purposes of this FAC, the true-up year shall be from March 1 through the last day of February of the following year. 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 September
June through September	By December 1	February through January
October through January	By April 1	June through May

Accumulation Period (AP) means 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.

Recovery Period (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 applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.

The Company will make a Fuel and Purchased Power Adjustment (FPA) filing by each Filing Date. The new FPA rates for which the filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format.

FPA DETERMINATION

Ninety five percent (95%) of the difference between Actual Net Fuel Costs and NBFC for all kWh of energy supplied to Missouri retail customers during the respective Accumulation Periods shall be reflected as an FPA_C credit or debit, stated as a separate line item on the customer's bill and will be calculated according to the following formulas.

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 Addition.

*** RIDER FAC**

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

(Applicable to Service Provided Prior to Month Day, 2010)

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

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:

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

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

* Indicates Addition.

*** RIDER FAC**

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

(Applicable to Service Proviced Prior to Month Day, 2010)

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; and

(ii) 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, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

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

CPP = 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. Also included in factor "CPP" are insurance premiums in FERC Account Number 924 for replacement power insurance (other than relating to the Taum Sauk Plant) to the extent those premiums are not reflected in base rates. Changes in replacement power insurance premiums (other than those relating to the Taum Sauk Plant) 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 (other than those relating to the Taum Sauk Plant) qualifying as assets under Generally Accepted Accounting Principles. Notwithstanding the foregoing, concurrently with the date the "TS" factor is eliminated as provided for in this tariff, the premiums and recoveries relating to replacement power insurance coverage for the Taum Sauk Plant shall be included in this CPP Factor.

OSSR = Revenues from Off-System Sales allocated to Missouri electric operations.

Off-System Sales shall include all sales transactions (including MISO revenues in FERC Account Number 447), excluding Missouri retail sales and long-term full and partial requirements sales, that are associated with (1) AmerenUE Missouri jurisdictional generating units, (2) power purchases made to serve Missouri retail load, and (3) any related transmission.

* Indicates Addition.

*** RIDER FAC**

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

(Applicable to Service Provided Prior to Month Day, 2010)

TS = The Accumulation Period value of Taum Sauk. This factor will be used to reduce actual fuel costs to reflect the value of Taum Sauk, and will be credited in FPA filings (of which there are three each year as shown in the table above), until the next rate case or, if sooner, until Taum Sauk is placed back in service. This value is $22.7 million annual for each true-up year as determined in the rate proceeding in which this FAC was established, one third of which (i.e., $7.56 million) will be applied to each Accumulation Period.

S = The Accumulation Period value of Blackbox Settlement Amount of $3 million annually, which shall expire on September 1, 2010. One third of the annual value ($1 million) shall be applied to each Accumulation Period. For the Accumulation Period during which the factor expires, the factor shall be prorated according to the number of days during which it was effective during that Accumulation Period.

I = Interest applicable to (i) the difference between Actual Net Fuel Costs (adjusted for Taum Sauk and factor "S") and NBFC for all kWh of energy supplied to Missouri retail customers during an Accumulation Period until those costs have been recovered; (ii) refunds due to prudence reviews (a portion of factor R, below); and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the annual true-up filings 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.

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

S_{AP} = Supplied kWh during the Accumulation Period that ended prior to the applicable Filing Date, at the generation level.

S_{RP} = Applicable Recovery Period estimated kWh, at the generation level, subject to the FPA_{RP} to be billed.

* Indicates Addition.

*** RIDER FAC**

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

(Applicable to Service Provided Prior to Month Day, 2010)

NBFC = Net Base Fuel Costs are the net costs determined by the Commission's order as the normalized test year value (and reflecting an adjustment for Taum Sauk, consistent with the term TS) for the sum of allowable fuel costs (consistent with the term CF), plus cost of purchased power (consistent with the term CPP), less revenues from off-system sales (consistent with the term OSSR), less an adjustment (consistent with the term "S"), expressed in cents per kWh, at the generation level, as included in the Company's retail rates. The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is 1.001 cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is 0.690 cents per kWh.

To determine the FPA rates applicable to the individual Service Classifications, the FPA_C rate determined in accordance with the foregoing will be multiplied by the following voltage level adjustment factors:

Secondary Voltage Service	1.0888
Primary Voltage Service	1.0492
Large Transmission Voltage Service	1.0147

The FPA rates applicable to the individual Service Classifications shall be rounded to the nearest 0.001 cents, to be charged on a cents/kWh basis for each applicable kWh billed.

***TRUE-UP OF FAC**

After the completion of each true-up year, the Company will make a true-up filing by May 1 of each year (starting by May 1, 2010) with the Commission. Such filings shall be made by May 1 of every subsequent year until all fuel and purchased power costs accumulated during the effective period of the FAC have been recovered and trued-up. Any true-up adjustments or refunds shall be reflected in item R above, and shall include interest calculated as provided for in item I above.

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

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this Fuel and Purchased Power Adjustment Clause, 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

*Indicates Addition.

*** RIDER FAC**

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

(Applicable to Service Provided Prior to Month Day, 2010)

Purchased Power Adjustment Clause. 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, 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 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 to file such a rate case.

Prudence reviews of the costs subject to this Fuel and Purchased Power Adjustment Clause 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 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.

*Indicates Addition.

~~*~~ RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE
(Applicable to Service Provided Month Day, 2010 and Thereafter)

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), 8(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, net of Off-System Sales Revenues (OSSR) (i.e., Actual Net Fuel Costs) and Net Base Fuel Costs (factor NBFC, as defined below), calculated and recovered as provided for herein.

For purposes of this FAC, the true-up year shall be from March 1 through the last day of February of the following year. 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 September
June through September	By December 1	February through January
October through January	By April 1	June through May

Accumulation Period (AP) means 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.

Recovery Period (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 applied to and recovered through retail customer billings on a per kWh basis, as adjusted for service voltage level.

The Company will make a Fuel and Purchased Power Adjustment (FPA) filing by each Filing Date. The new FPA rates for which the filing is made will be applicable starting with the Recovery Period that begins following the Filing Date. All FPA filings shall be accompanied by detailed workpapers supporting the filing in an electronic format with all formulas intact.

FPA DETERMINATION

Ninety five percent (95%) of the difference between Actual Net Fuel Costs and NBFC for all kWh of energy supplied to Missouri retail customers during the respective Accumulation Periods shall be reflected as an FPA_C credit or debit, stated as a separate line item on the customer's bill and will be calculated according to the following formulas.

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 Addition.~~

~~*~~ RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
(Applicable to Service Provided Month Day, 2010 and Thereafter)

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

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:

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

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

~~* Indicates Addition~~Change~~.~~

~~*~~ RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
(Applicable to Service Provided Month Day, 2010 and Thereafter)

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; and

(ii) 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, and revenues and expenses resulting from fuel and transportation portfolio optimization activities;

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

CPP = 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. Also included in factor "CPP" are insurance premiums in FERC Account Number 924 for replacement power insurance (other than relating to the Taum Sauk Plant) to the extent those premiums are not reflected in base rates. Changes in replacement power insurance premiums (other than those relating to the Taum Sauk Plant) 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 (other than those relating to the Taum Sauk Plant) qualifying as assets under Generally Accepted Accounting Principles. Notwithstanding the foregoing, concurrently with the date the "TS" factor is eliminated as provided for in this tariff, the premiums and recoveries relating to replacement power insurance coverage for the Taum Sauk Plant shall be included in this CPP Factor.

OSSR = Revenues from Off-System Sales allocated to Missouri electric operations.

Off-System Sales shall include all sales transactions (including MISO revenues in FERC Account Number 447), excluding Missouri retail sales and long-term full and partial requirements sales, that are associated with (1) AmerenUE Missouri jurisdictional generating units, (2) power purchases made to serve Missouri retail load, and (3) any related transmission.

~~* Indicates Addition.~~

~~*~~ RIDER FAC

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

(Applicable to Service Provided Month Day, 2010 and Thereafter)

~~*~~TS = The Accumulation Period value of Taum Sauk. This factor will be used to reduce actual fuel costs to reflect the value of Taum Sauk, and will be credited in FPA filings (of which there are three each year as shown in the table above), until the next rate case or, if sooner, until Taum Sauk is placed back in service. This value is ~~$22.7~~$26.8 million ~~annual~~ annually ~~for each true-up year as determined in the rate proceeding in which this FAC was established~~, one third of which (i.e., ~~$7.56~~$8.93 million) will be applied to each Accumulation Period.

S = The Accumulation Period value of Blackbox Settlement Amount of $3 million annually, which shall expire on September 1, 2010. One third of the annual value ($1 million) shall be applied to each Accumulation Period. For the Accumulation Period during which the factor expires, the factor shall be prorated according to the number of days during which it was effective during that Accumulation Period.

~~*~~I = Interest applicable to (i) the difference between Actual Net Fuel Costs (adjusted for Taum Sauk and factor "S") and NBFC for all kWh of energy supplied to Missouri retail customers during an Accumulation Period until those costs have been recovered; (ii) refunds due to prudence reviews (a portion of factor R, below); and (iii) all under- or over-recovery balances created through operation of this FAC, as determined in the ~~annual~~ true-up filings 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.

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

S_{AP} = Supplied kWh during the Accumulation Period that ended prior to the applicable Filing Date, at the generation level.

S_{RP} = Applicable Recovery Period estimated kWh, at the generation level, subject to the FPA_{RP} to be billed.

~~* Indicates Addition~~Change~~.~~

~~*~~ RIDER FAC
FUEL AND PURCHASED POWER ADJUSTMENT CLAUSE (CONT'D.)
(Applicable to Service Provided Month Day, 2010 and Thereafter)

~~*~~NBFC = Net Base Fuel Costs are the net costs determined by the Commission's order as the normalized test year value (and reflecting an adjustment for Taum Sauk, consistent with the term TS) for the sum of allowable fuel costs (consistent with the term CF), plus cost of purchased power (consistent with the term CPP), less revenues from off-system sales (consistent with the term OSSR), less an adjustment (consistent with the term "S"), expressed in cents per kWh, at the generation level, as included in the Company's retail rates. The NBFC rate applicable to June through September calendar months ("Summer NBFC Rate") is ~~1.001~~1.449 cents per kWh. The NBFC rate applicable to October through May calendar months ("Winter NBFC Rate") is ~~0.690~~1.275 cents per kWh.

~~*~~To determine the FPA rates applicable to the individual Service Classifications, the FPA_C rate determined in accordance with the foregoing will be multiplied by the following voltage level adjustment factors:

Secondary Voltage Service	1.0789~~888~~
Primary Voltage Service	1.0459~~92~~
Large Transmission Voltage Service	1.0124~~47~~

The FPA rates applicable to the individual Service Classifications shall be rounded to the nearest 0.001 cents, to be charged on a cents/kWh basis for each applicable kWh billed.

~~*~~TRUE-UP OF FAC

After completion of each Recovery Period, ~~After the completion of each true-up year,~~ the Company will make a true-up filing in conjunction with an adjustment to its FAC, where applicable. The true-up filings ~~make a true-up filing by May 1 of each year (starting by May 1, 2010) with the Commission. Such filings~~ shall be made on the first Filing Date that occurs at least two (2) months after completion of each Recovery Period.~~by May 1 of every subsequent year until all fuel and purchased power costs accumulated during the effective period of the FAC have been recovered and trued-up.~~ Any true-up adjustments or refunds shall be reflected in item R above, and shall include interest calculated as provided for 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~~true-up year~~.

GENERAL RATE CASE/PRUDENCE REVIEWS

The following shall apply to this Fuel and Purchased Power Adjustment Clause, 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

~~*Indicates Addition~~Change.

~~*~~ RIDER FAC

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

(Applicable to Service Provided Month Day, 2010 and Thereafter)

Purchased Power Adjustment Clause. 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, 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 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 to file such a rate case.

Prudence reviews of the costs subject to this Fuel and Purchased Power Adjustment Clause 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 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.

~~*Indicates Addition.~~