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MISSOURI PUBLIC SERVICE COMMISSION

STAFF REPORT

CLASS COST OF SERVICE
&
RATE DESIGN

UNION ELECTRIC COMPANY
D/B/A AMERENUE

CASE NO. ER-2008-0318

Jefferson City, Missouri
September 11, 2008

** **Denotes Highly Confidential Information** **

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CLASS COST-OF-SERVICE AND RATE DESIGN REPORT

I. Executive Summary

The Staff's class cost of service and rate design objectives in this case are:

1. Provide the Commission with a relative measure of class cost responsibility.
2. Provide a method to collect any Commission ordered overall increase in revenues.
3. Retain all of the existing rate schedules, rate structures and important features of the current rate design.

The results of the Staff's Class Cost-of-Service (CCOS) study for Union Electric Company d/b/a AmerenUE (AmerenUE) are summarized in Table 1 which shows the changes necessary for each class' current rate revenues to exactly match class revenues with the cost of serving that class at the overall level, with allowance for true-up, as determined by the Staff and presented in the Staff's Cost of Service study filed on August 28, 2008.

Table 1
Summary Results of the Staff's Revenue Neutral CCOS Study

	Residential	Small General Service	Large General Service[1]	Large Primary Service	Large Transmission Service	System Average
Revenue Deficiency	$50,989,472	-$1,458,449	-$16,379,564	$8,715,910	$9,595,063	$51,462,432
Required % Increase	5.62%	-0.60%	-2.63%	5.36%	7.34%	2.46%

[1] Large General Service and Small Primary Service classes combined

Based on the Staff's CCOS study results, the Staff proposes no revenue shifts among classes, so that the current revenue relationships among the classes are maintained. Any Commission-ordered overall revenue increase should be implemented as an equal percentage increase to each rate component of each rate schedule.

The Staff is concerned regarding the efficacy of AmerenUE's Voluntary Green Power Program ("VGP" or "program") in its current form. The program was instituted as a result of

AmerenUE's last rate case. In Section III of this Report, the Staff sets out in detail its concerns regarding this program and offers recommendations for Commission ordered changes should the Commission determine that the program continue.

II. Class Cost-of-Service

A summary of the Rate Design that was agreed to and implemented in the previous AmerenUE rate case (Case No. ER-2007-0002) provides the starting point below for explaining the Staff's CCOS study in this rate case. The report then provides a description of the results of the Staff's CCOS study, an overview of the purpose of a conducting a CCOS study and the general methodology used to develop the Staff's CCOS study.

A. Revenue Shifts and Rate Design from Rate Case ER-2007-0002

The Commission's approval of the Stipulation and Agreement Concerning Class Cost of Service and Certain Rate Design Issues (Rate Design Agreement) in Case No. ER-2007-0002 resulted in the following overall revenue neutral percentage changes to class revenues.

Table 2

Revenue Neutral Changes to Class Revenues From ER-2007-0002

	RES	SGS	LGS[1]	LPS	LTS	System Average
Percentage Increase	1.11%	0.66%	-0.32%	0.66%	-7.48%	0.00%

[1] LGS = LGS and SPS Combined

The Residential (RES), Small General Service (SGS), and Large Primary Service (LPS) classes received increases to their class revenue requirements, while Large General Service and Small Primary Service combined (LGS), and Large Transmission Service (LTS) received decreases to their class revenue requirement. These changes were agreed upon by the signatory parties, and represented a general movement toward matching class revenues (rates) with class cost-of-service.

After the changes in revenue (rates) indicated above, each class received an overall revenue increase of 2.07% (referred to as an equal percentage increase).

B. The Results of the Staff's CCOS Study in the Current Case

The purpose of a CCOS study is to determine whether each class of customers is providing the utility with a reasonable level of revenue necessary to cover the cost of providing electrical service to that class. The Staff allocates costs to five customer classes that correspond to AmerenUE's current rate schedules as follows: Residential (RES), Small General Service (SGS), Large General Service (LGS) in which Staff has included AmerenUE's Small Primary Service customer class (SPS), Large Primary Service (LPS), and Large Transmission Service (LTS). The Staff used cost-of-service factors to refunctionalize the costs and revenue of the final AmerenUE customer class, lighting (LTG), to the other classes that were included in the Staff's CCOS study.

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 rate of return for all classes. A negative amount or percentage indicates revenue from the class exceeds the cost of providing service to that class and therefore, the revenues collected from that class 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, the revenues collected from that class should be increased, i.e., the class has underpaid. The 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 providing service to all indicated classes.

The results of the Staff's CCOS study are repeated in Table 3 below which shows the changes to each class' current rate revenues required to exactly match class revenues with the cost of serving that class as determined by the Staff's CCOS study. The Staff's results are also presented as a revenue neutral, percent increase to each class' rate revenues. This 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 allows for revenue neutral shifts between classes, if appropriate. The revenue neutral, percent increase to the classes' rate revenue is obtained by subtracting the overall system average increase of 2.46% from each class' required percent increase to rate revenue.

Table 3
Summary Results of the Staff's Revenue Neutral CCOS Study

	RES	SGS	LGS[1]	LPS	LTS	System Average
Revenue Deficiency	$50,989,472	-$1,458,449	-$16,379,564	$8,715,910	$9,595,063	$51,462,432
Required % Increase	5.62%	-0.60%	-2.63%	5.36%	7.34%	2.46%
Less System Average	-2.46%	-2.46%	-2.46%	-2.46%	-2.46%	-2.46%
Revenue Neutral % Increase	3.16%	-3.06%	-5.09%	2.90%	4.88%	0.00%

[1] LGS = LGS and SPS Combined

Table 3 shows that on a revenue neutral basis, the RES class is providing approximately 3.16% less revenues than the cost of serving that class, while the SGS and the LGS classes are providing 3.06% and 5.09% more revenues, respectively, than the cost of serving them. The LPS and the LTS classes are providing 2.90% and 4.88% less, respectively, in revenues than the cost of serving them.

On a revenue neutral basis, all of these classes, except for the LGS class, are within 5% of their cost of service. The LGS class is only 0.09% above that level. Because a CCOS study is not a precise measurement of actual class cost-of-service, and should be used only as a guide for rate design, the Staff believes that a revenue neutral deviation of 5% (positive or negative) from the cost of service is an acceptable range for rate revenues.

A summary of model output for Staff's CCOS study is attached as Schedule DCR-1.

C. Class Cost of Service Overview

The Staff's CCOS study generally follows the procedures described in Chapter 2 of the National Association of Regulatory Utility Commissioners (NARUC) ELECTRIC UTILITY COST ALLOCATION MANUAL, January 1992 (NARUC Manual). The Staff produces an embedded cost study using historical information developed from data collected over the test year. Costs are distributed to the classes through a three step process of functionalization, classification and allocation.

1. Functionalization

A utility's equipment investment and operations can be organized along the lines of the purpose or the function that each piece of equipment or task provides in delivering electricity to customers. Major functional areas include generation, transmission, distribution, and customer services. Schedule DCR-2 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 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. 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 can be 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 that rate class.

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 that the customer received 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

Functionalized costs are then subdivided into measurable, cost-defining 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 components and the cost to be allocated. Functionalized costs are often classified as customer-related costs and demand–related costs. Customer-related costs are the costs to connect the customer to the electrical system and to maintain that connection. Demand-related costs are based on the maximum rate of use (maximum demand) of electricity by the customer.

In addition, some functionalized costs can be classified on the basis of voltage level that 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.

The purpose of classification is to make the third step, allocation, more accurate. For example, 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 now be allocated on the basis of customer maximum demands and the customer related portion can now 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 transmission and distribution systems. 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. The allocation factor or allocators determine the results of this process. An allocation factor is chosen that will reasonably distribute a portion of the functionalized costs to each customer class on the basis of cost causation. Reasonably, means that the allocation factor distributes cost to the classes based on the class' responsibility for incurring these costs. 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.

D. The Staff Class-Cost-of-Service Study

The Staff's costs and revenues from the rate case test year, i.e., the 12-month period ending March 31, 2008, with the Staff's estimated true-up costs and revenues through September 30, 2008, were used in the Staff's CCOS study.

1. Data Sources

Data was obtained from the Staff's direct revenue requirement cost of service filing on August 28, 2008 for this case and include:

Adjusted Missouri Jurisdictional cost data by FERC account,
Estimated true-up cost data
Annualized, Normalized Rate Revenues
Off-System Sales

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

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

2. Classes

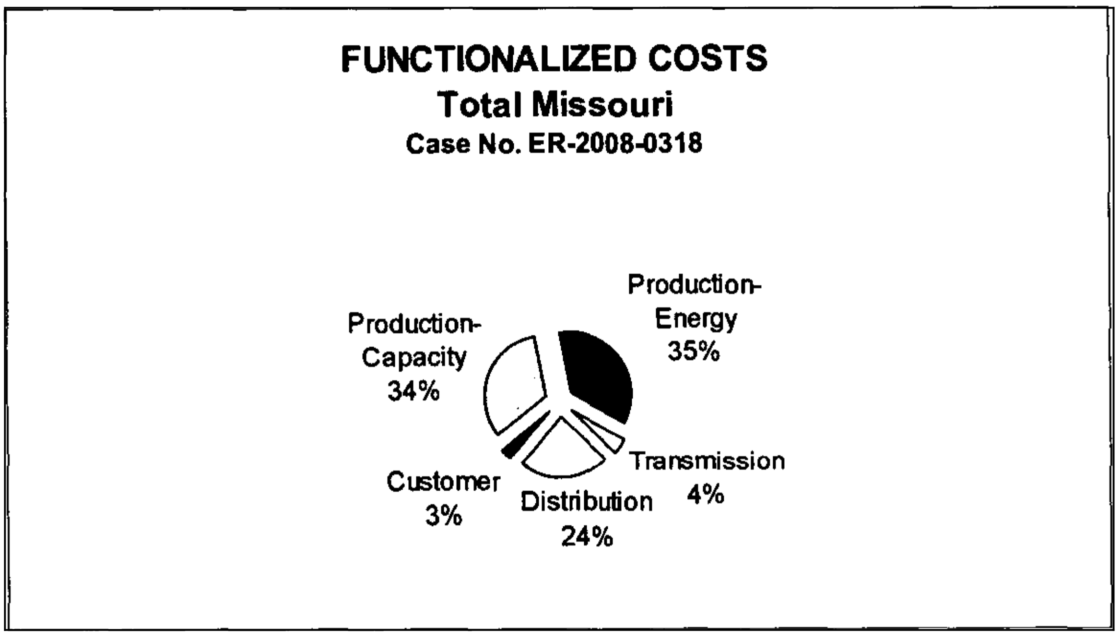
The Staff used the following customer classes that correspond to AmerenUE's current rate schedules: RES, SGS, and LGS, which includes both LGS and SPS, LPS, LTS, and LTG.

LTG 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 demands. 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 LTG and skews the results for the other classes. Therefore, the Staff did not allocate any costs to the LTG class. The directly assigned LTG costs and revenues were allocated to the other classes based on each class' share of total cost-of-services.

The SPS and LGS rate classes were combined for the following reasons. First, both rate schedules serve non-residential customers with billing demands of at least 100 kW. Within this group, a customer may choose to take service at secondary voltage level under the LGS rate schedule or at a primary voltage level under the SPS rate schedule. The rate structures are identical, except that the rate levels on the SPS rate schedule have been adjusted for the loss differential between primary and secondary voltages and to account for customer provision of transformation equipment.

3. Functions

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



The Production Function (combination of Production-Capacity and Production-Energy) is the single largest cost component and represents 69% of the total cost. The Distribution Function, at 24% 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 about 4% of 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 in 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.)

In its CCOS study, AmerenUE divides the production operations and maintenance expenses between the Production-Capacity and the Production-Energy functions with approximately 10% of the costs applied to Production-Capacity function and 90% of the costs applied to Production-Energy function. The 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 Staff used an Average and Peak (A&P) method to allocate production-capacity and transmission costs. This method recognizes that generation is built to meet both peak demands and average demands (energy). The basic components of the A&P allocator are that:

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

2) a portion of total costs are attributed to each class based upon each class' 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.

The Staff's allocator is based on each class' contribution to the 12 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 A&P allocator, the Staff used weighted monthly class peak demands. Class peak demand is the maximum demand of each class whenever it occurs during each month. While using coincident peak demand is theoretically appropriate, the Staff uses class peak demands because of the relative stability of class contribution to class peak demands, when compared to class contribution to system (coincident) peak demand. Each class' contribution to class peak is independent of when the system peaks; however, using coincident peaks would complicate comparisons over time.

The Capacity Utilization method was used to determine the weights applied to each month's class peak demands. Capacity Utilization is a method developed by Dr. Michael S. Proctor of the Staff 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 DCR-3.

Transmission costs are allocated in the same manner as Production-Capacity costs. The transmission plant is generally considered to be an extension of the production plant. The planning and operation of the transmission plant is strongly linked to the planning and operation of production plant, with the major factors that drive production costs tending to also drive transmission costs.

The 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.

5. Allocation of Distribution Costs

Voltage level and load diversity were two factors that the 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 electric 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 the Staff used in the allocation of the demand related portions of the various distribution function categories.

Table 4
Allocation of Demand Related Distribution Facilities

Functional Category	Demand Measure	Amount of Diversity
N/A	Coincident Peak	High
Substations	Class Peak	Moderate to High
OH/UG Lines[1]	Diversified Demand	Low to Moderate
Line Transformers	Customer Maximum Demand	None

[1] OH/UG = overhead and underground

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 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 system peak (coincident 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' customer maximum demand and its annual maximum class peak demand. The weighting factors were based on the average number of customers in each class who share a transformer. This information was obtained from AmerenUE's 2006 Supplement to the 2003 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.

The Staff allocated the costs of distribution substations on the basis of each class' annual peak demand measures 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. The 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. The Staff used weighted customer counts to allocate the customer portion of the costs for OH/UG lines. The weighting approximately reflects the customer density for each class and accounts for customer density in allocating the length-related portion of the distribution system. The Staff used Diversified Demand at primary voltage and a Diversified Demand at secondary voltage to allocate primary demand and secondary demand, respectively.

The Staff allocated the costs of line transformers on the basis of each class' 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. The Staff allocated the demand portion on the basis of each class' 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

The 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

Rate Revenues from the Staff's Cost-of-Service were combined with the Staff's accounting estimate of True-up Revenues changes to produce Rate Revenues post true-up.

About $28.7 million of lighting revenues were then allocated to the other class revenues by each class' percentage of total cost of service which resulted in $2.093 billion of Total Rate Revenues.

Fuel expenses for off-system sales and the cost of purchased power for off-system sales were subtracted from off-system sales revenues to provide the margin from off-system sales. The margin from off-system sales was then allocated to the rate classes using the Staff's production-capacity allocator. Other Electric Revenues were also allocated to the rate classes using the Staff's production-capacity allocator which resulted in about $2.67 billion of Total Revenues.

Staff Expert/Witness: David C. Roos

II. Rate Design

The revenue shifts indicated by the CCOS study do not rise to such a level of significance that disproportionate adjustments to the rates are required at this time. The Staff is not aware of any flaws in AmerenUE's present rate structure or rate design.

Staff Expert/Witness: James C. Watkins

III. Voluntary Green Power Program

Staff is concerned with the efficacy of AmerenUE's Voluntary Green Power Program ("VGP" or "program") in its current form, since much of the money collected pursuant to the program is possibly lost in the cost of administration, and the stimulation of "green" generation due to this program is questionable. Staff recommends that the Commission require AmerenUE to produce an accounting in its rebuttal testimony in this case of how much of its customer's VGP payments actually were paid to "green" electricity producers so that the Commission can determine the appropriateness of continuing the VGP.

If the program is continued, Staff recommends that the Commission order AmerenUE to disclose in its tariff the amount of the customer's VGP payment AmerenUE retains for its administrative costs, and to account for VGP revenues and costs above-the-line. In addition, if the VGP continues, the Commission should require AmerenUE to disclose to all participants the percentage of the payment that actually goes to "green" energy producers.

A. Program Description

In its last rate case, Case No. ER-2007-0002, AmerenUE was given the authority from the Commission to establish a Voluntary Green Power Program in its tariff. In Ameren's marketing materials, the ultimate stated purpose of the VGP is to supplement those entities generating "green" electricity. Under this tariff provision, AmerenUE customers can choose to donate money to purchase the attributes of past "green" electrical generation. Customers who choose to participate are given the option of each month paying a surcharge of one and a half cents per each kilowatt hour (kWh) that they use, or donating in increments of $15. AmerenUE bills and collects these voluntary contributions. AmerenUE draws, as an un-tariffed reimbursement of expenses incurred in administering this voluntary program, $1 of each $15 paid by customers. AmerenUE, through Ameren Energy Fuels and Services,[1] "buys" retail (with customer-contributed money) Renewable Energy Certificates ("REC") at $14.00 per REC. Participating AmerenUE customers get nothing of material value in return. AmerenUE promises that these RECs will be retired – that is, AmerenUE warrants that the RECs will not be resold.

RECs are defined as **the attributes of electricity generated** from a renewable energy source. **These attributes are unbundled from the physical electricity.** These two separate products: 1) the attributes embodied in the certificates and 2) the commodity electricity itself -

[1] In its responses to Staff Data Requests, AmerenUE personnel have used the entity names "AmerenUE" and "Ameren Energy Fuel Services ("AEFS") somewhat interchangeably. In spite of this, Staff has endeavored to distinguish between these entities based on Staff's understanding of their relationship.

may be sold or traded separately. RECs reflect the "sale" of intangible attributes of green electricity. Through the Pure Power program, AmerenUE only buys attributes embodied in RECs, not the commodity electricity, itself.

Ameren Energy Fuels and Services ("Ameren") purchases RECs for AmerenUE from a third party, 3Degrees Group, Inc, ("3Degrees") which acts as a middleman or "wholesaler." 3Degrees is responsible for program development, marketing, and procurement of Green-e RECs. 3Degrees seeks out generators of green power and purchases the RECs. The REC is not the commodity electricity itself. The electricity associated with the REC has already been generated and consumed. No new or additional generation is required when purchasing a REC; the REC purchaser simply receives the right to the attributes that convert to a REC representing 1000 kWh of past production. 3Degrees is also responsible for ensuring compliance with the Green-e standards.

Money contributed by participating AmerenUE customers is passed from AmerenUE through these two entities' hands, Ameren Energy Fuels and Services, and 3Degrees. Each entity retains a portion of the customer's payment, with the understanding that 3Degrees will purchase RECs from producers of electricity generated by a "green" source. 3Degree will supply AmerenUE RECs at $14.00 per REC. No known guarantees are made as to how the electricity producer may ultimately use the portion of the customer's payment that it receives. The participating customer neither actually purchases "green" electricity nor directly causes a reduction in fossil-fueled generation. According to AmerenUE, it knows nothing about the arrangements between 3Degrees and the producers concerning the purchase price of wholesale RECs.

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B. Staff Concerns

Absent a thorough understanding of exactly what a REC is, one might view a REC as a means to expand the production and usage of "green" electricity, in lieu of traditional fossil fuel power. One might view RECs as a cash donation of sorts, designed to finance future "green" energy projects or as a subsidy to reduce the more costly production of "green" energy. Both of which would result in the "green" generation becoming more cost effective as an alternative to all other sources of electricity. However, there are no restrictions on producers on how they use REC sales proceeds. It is not evident that AmerenUE clearly relates to its customers what a REC is and what a REC is not, although there are disclaimers that the customer is not buying actual electricity.

REC programs may appeal to customers who place a great value on "green" energy and who want to encourage the future benefits of more green power to supplant fossil-fuel power in the future. REC programs typically appeal to those customers who are willing to pay more to ensure energy is produced by what are now more costly "green" sources. Until the purchaser of RECs knows where the RECs are coming from and what the seller of the RECs plans to do with the money received, the purchaser cannot know for sure what happens to contributed monies.

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They likely expect that the majority of their contributions go to further future development of renewable projects, or support current producers of "green" electricity, and not stay with the intermediaries.

Based on Staff's analysis, a "green" producer selling RECs could invest its REC sales proceeds however it chooses. The VGP program allows for a current "green" energy producer to sell its "green" attributes of energy that it has already produced to an aggregator, whether or not that producer remains in business. Similarly, the VGP program allows a "green" producer to use REC proceeds to pay the day-to-day operating costs of its current level of green production. This is problematic if a customer participates in the VGP program based on an expectation that the customer's VGP payments will be used to promote future "green" production, or an expansion of "green" generation facilities.

Under AmerenUE's current program, there is no requirement that customer VGP payments go to stimulate further green production. There is no requirement, no "earmarking" of funds, and no tracking that such payments are actually converted to investments that would boost the production of green electricity. This would appear to be a common trait of these types of programs.

The "green" producers that benefit from the VGP are not required to use the portion of the customer's VGP payment that it receives to increase renewable fuel generation. The only restriction is that RECs must relate to past production of "green" kWhs. Other than this restriction, AmerenUE does not impose any restrictions or tracking obligations on 3Degrees regarding the monies collected for REC sales. Of further concern, the retail price of an REC is not universal, and varies among utility programs. AmerenUE's Missouri customers contribute $15.00 for a REC representing the attributes of 1,000 previously sold kWhs. Florida Power and

Light Company has a similar program where participating customers pay $9.75 for the retirement of a REC representing a like magnitude of 1000 kWh.

The Staff has made various attempts to discover the inter-relationship between wholesale price and retail price of AmerenUE RECs acquired from 3Degrees, in an effort to discover the administrative cost associated with the Program, but such information has not been forthcoming. In its responses to DR 174 - 4, DR 174- 19, DR 174 - 32, DR 174 - 33, response to DR 280- 3, and response to DR 284 -1, AmerenUE indicated that it has no knowledge as to what 3Degrees pays at the wholesale level for RECs from any of its three suppliers.

Staff was able to get an estimate from the Federal Department of Energy that the price paid for a REC was typically between $2 to $5 dollars. That is a current price. However, perhaps the more relevant price is the average price for voluntary RECs acquired at the time the contract was entered into. That translates to expectation of an average REC price that is at the lower end of the spectrum of the range of average prices being quoted. Staff anticipates the wholesale price of $2.00 to be more relevant.

Given this range, and the lack of information from AmerenUE, it may be that of the $15 customers give AmerenUE for a REC, $1 goes to AmerenUE, $2 to $5 dollars go to producers of green power, and the remaining $8 to $11 dollars may be retained by 3Degrees. Again, the $11 margin is more anticipated because the contract is a year-old.

Since AmerenUE is retaining $1 of every $15 collected, AmerenUE's tariff should include a provision that provides for AmerenUE retaining that $1 of every $15 collected

Of greater Staff concern, the $1 of every $15 collected from customers participating in the VGP ** ____

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The Florida Public Service Commission (Florida Commission) recently terminated Florida Light and Power Company's Sunshine Energy Program, a program equivalent to AmerenUE's Pure Power program. (Docket # 070626) Florida Commission Staff found that approximately 75% to 80% of the customers' payments to Florida Light and Power for that program were kept by intermediaries for administrating the Sunshine Energy Program. Ultimately, it was found by the Florida Commission that it was unacceptable that only 20% to 25% of total customer contributions under the program went to "green" energy producers. The Florida Staff's report indicates as much as estimated 74% of customer contributions went to administrative costs between 2004 and 2007, although a particular year reached 80%. The

Florida Commission has ordered Florida Power and Light Company to discontinue its REC program. A Florida Commission order has not yet been filed in the case.

3Degrees Group, Inc. filed its Creation Filing with the Missouri Secretary of State on July 7, 2008. A Creation Filing is the initial filing of a foreign corporation seeking authority to do business in the State of Missouri. There is no indication that 3Degrees complied with Missouri Secretary of State registration requirements prior to July 7, 2008.

C. Staff Recommendations Concerning the VGP

Staff recommends that the Commission:

1) Require AmerenUE to produce an accounting in its rebuttal testimony in this case of how much of it customer's VGP payments actually were paid to green electricity producers. AmerenUE should also provide the contracts and any addendums that 3Degrees has with each generators that clearly denote the wholesale price paid. If the information is not provided, and a determination as to the appropriateness of these contributions cannot be made, then the VGP should be discontinued.

2) If the VGP is to be continued, Staff recommends that AmerenUE be required to:

A) Disclose to participants the amount that AmerenUE retains for administrative purposes and the percentage of each dollar's payment that is actually received by the generator of the REC;

B) Include the administrative fee that AmerenUE retains in its tariff; and

C) To avoid cross-subsidy, increase the administrative fee to cover all AmerenUE 's administrative costs, and track both the revenues and costs above-the-line.

Staff Expert/Witness: Michael J. Ensrud

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2008-0318

AFFIDAVIT OF MICHAEL J. ENSRUD

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Michael J. Ensrud, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 16 to 23; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

Michael J. Ensrud
Michael J. Ensrud

Subscribed and sworn to before me this 10th day of September, 2008.

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

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	Case No. ER-2008-0318

AFFIDAVIT OF DAVID C. ROOS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

David C. Roos, of lawful age, on his oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1 to 16; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

David C Roos

David C. Roos

Subscribed and sworn to before me this 10th day of September, 2008.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

SUSAN L. SUNDERMEYER
My Commission Expires
September 21, 2010
Callaway County
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BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	))))))	Case No. ER-2008-0318

AFFIDAVIT OF JAMES C. WATKINS

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

James C. Watkins, of lawful age, on oath states: that he has participated in the preparation of the foregoing Staff Report in pages 1 and 2, and page 16; that he has knowledge of the matters set forth in such Report; and that such matters are true to the best of his knowledge and belief.

James C. Watkins

James C. Watkins

Subscribed and sworn to before me this 10th day of September, 2008.

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

David C. Roos

Present Position: I am a Regulatory Economist III in the Economic Analysis Section, Energy Department, Operations Division of the Missouri Public Service Commission.

Educational Background and Work Experience:

In May 1983, I graduated from the University of Notre Dame, Notre Dame, Indiana, with a Bachelor of Science Degree in Chemical Engineering. I also graduated from the University of Missouri in December 2005, with a Master of Arts in Economics. I have been employed at the Missouri Public Service Commission as a Regulatory Economist III since March 2006. Prior to joining the Public Service Commission I taught introductory economics and conducted research as a graduate teaching assistant and graduate research assistant at the University of Missouri. Prior to the University of Missouri, I was employed by several private firms where I provided consulting, design, and construction oversight of environmental projects for private and public sector clients.

Previous Cases

Empire District Electric Company	MoPSC Case# ER-2006-0315
AmerenUE	MoPSC Case# ER-2007-0002
Aquila Inc.	MoPSC Case# ER-2007-0004
Kansas City Power and Light	MoPSC Case# ER-2007-0291
Ameren UE	MoPSC Case# EO-2007-0409
Empire District Electric Company	MoPSC Case# ER-2008-0093

Michael J. Ensrud

My educational and professional experience is as follows:

I have a Bachelor of Science from Drake University. I attended the NARUC Annual Regulatory Studies Program at Michigan State University. In the regulatory field, I've worked for CompTel Missouri, and CommuniGroup, Inc., Teleconnect, TeleCom* USA, and General Telephone Company of the Midwest in the private sector. In addition, I have four-years of experience with the Iowa Public Utility Board – Iowa's equivalent to the Missouri Commission.

I have filed written testimony and have testified in several cases before Missouri Public Service Commission. Schedule 1 lists the cases where I have filed testimony (or otherwise materially participated) as a Staff witness before this Commission. (There are numerous cases going back to the mid-1980s where I filed testimony on behalf of Teleconnect (TeleCom*USA), CompTel of Missouri & CommuniGroup, Inc. - various private entities or trade associations - that are not listed). I have also testified in other jurisdictions.

<u>Schedule 1</u>

Cases that I have testified (or otherwise materially participated) in as a Staff witness:

Atmos Energy Corporation - GR-2006-0387 - Miscellaneous Rate Issues & Seasonal Reconnection Charge.

Missouri Gas Energy (a Division of Southern Union Company) - GR-2006-0422 - Miscellaneous Rate Issues & Seasonal Reconnection Charge.

AmerenUE (Union Electric Company) - GR- 2007-0003 - Miscellaneous Rate Issues & Seasonal Reconnection Charge.

Laclede Gas Company - GR-2005-0284 - Miscellaneous Rate Issues & Credit Scoring / **GR - 2007-0208** - Miscellaneous Rate Issues & Credit Scoring & Rate Switching Customers

Southern Missouri Natural Gas Company (Southern Missouri Natural Gas Company) - GE-2005-0189 - Promotional Practices

Empire District Electric Company of Joplin - ER-2006-0315 - Street Lighting

Missouri Gas Utilities, Inc. (MGU) - GR-2008-0060 - Miscellaneous Rate Issues

Trigen Kansas City Energy Corporation - HR-2008-0300 - Miscellaneous Rate Issues

CLASS COST-OF-SERVICE RESULTS

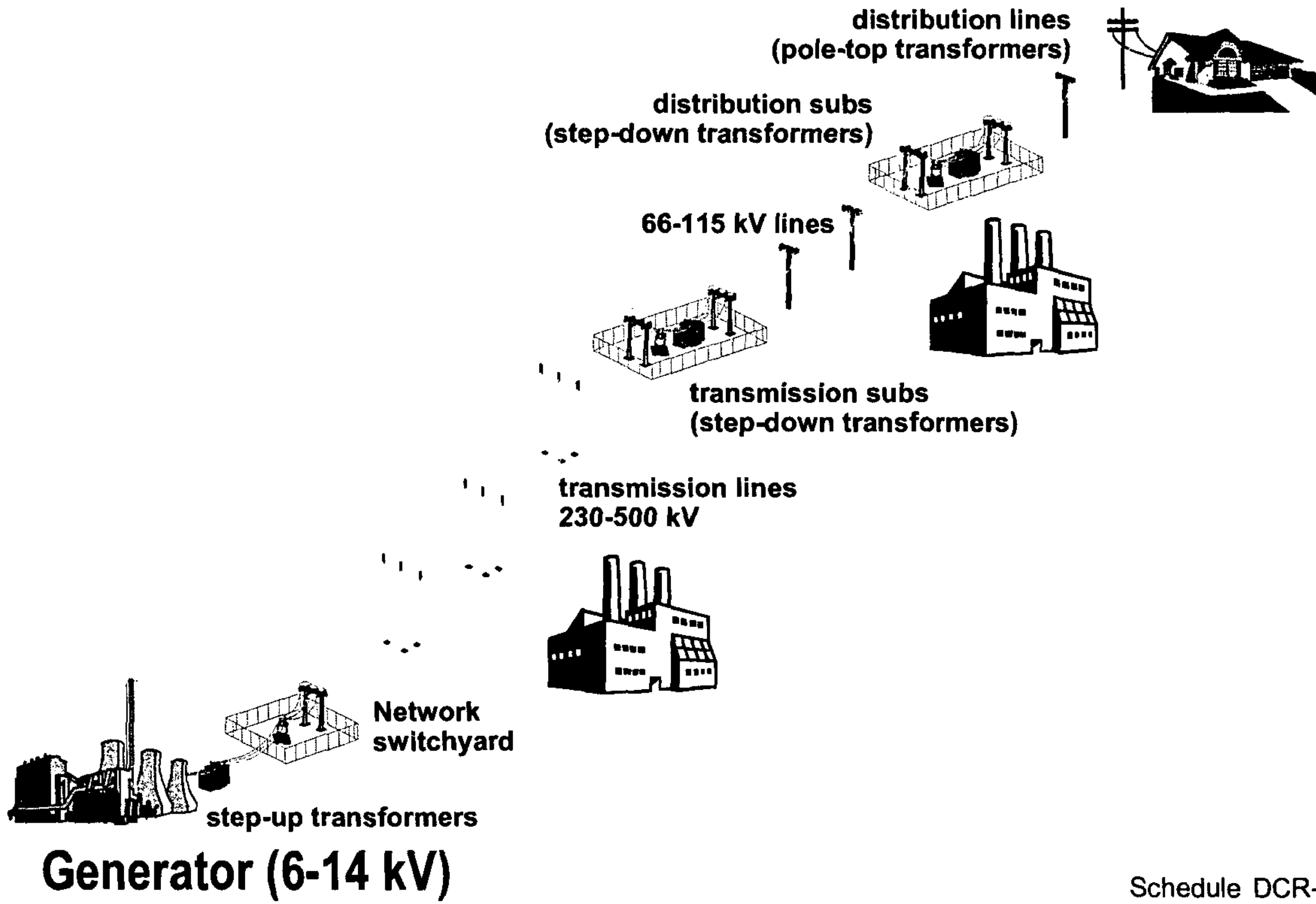
(At Staff Midpoint ROR 7.63)

AmerenUE

CASE NO. ER-2008-0318

FUNCTIONAL CATEGORY			RES	SGS	LGS	LPS	LTS	Other	TOTAL	% TOTAL
PRODUCTION	CAPACITY		$325,450,314	$88,175,133	$259,295,187	$79,670,385	$70,005,710	$0	$822,596,729	33.14%
PRODUCTION	ENERGY		$324,490,477	$87,829,042	$291,029,240	$96,264,975	$91,768,667	$0	$891,382,403	35.91%
TRANSMISSION	CAPACITY		$42,774,023	$11,588,882	$34,079,237	$10,471,100	$9,200,870	$0	$108,114,112	4.36%
DISTRIBUTION	SUBSTATIONS	SUBSTATION DEMAND	$56,207,932	$13,274,789	$32,878,357	$8,325,265	$0	$0	$110,686,343	4.46%
DISTRIBUTION	POLES AND CONDUCTORS	CUSTOMER	$48,717,329	$19,881,740	$2,962,218	$27,163	$0	$0	$71,588,451	2.88%
DISTRIBUTION	POLES AND CONDUCTORS	PRIMARY DEMAND	$124,187,314	$24,352,941	$72,988,419	$11,347,945	$0	$0	$232,876,619	9.38%
DISTRIBUTION	POLES AND CONDUCTORS	SECONDARY DEMAND	$35,106,527	$6,884,336	$15,176,302	$0	$0	$0	$57,167,165	2.30%
DISTRIBUTION	TRANSFORMERS	SECONDARY CUSTOMER	$21,856,102	$5,946,333	$830,744	$0	$0	$0	$28,633,179	1.15%
DISTRIBUTION	TRANSFORMERS	DEMAND	$13,971,497	$1,857,025	$4,234,182	$0	$0	$0	$20,062,704	0.81%
DISTRIBUTION	SERVICES		$30,777,934	$6,070,957	$3,368,570	$0	$0	$0	$40,217,461	1.62%
DISTRIBUTION	METERS		$14,887,445	$4,818,076	$2,765,326	$293,460	$12,948	$0	$22,777,255	0.92%
	CUSTOMER DEPOSITS		($869,835)	($355,207)	($332,662)	$0	$0	$0	($1,557,704)	-0.06%
	METER READING		$16,595,462	$2,257,559	$300,101	$4,386	$104	$0	$19,157,612	0.77%
	BILLING, SALES, SERVICE		$48,552,614	$6,604,840	$492,034	$3,008	$47	$0	$55,652,542	2.24%
	ASSIGNED LGS/LPS/LTS		$0	$0	$323,426	$1,977	$31	$0	$325,434	0.01%
	ASSIGNED RES/SGS		$1,982,510	$269,690	$0	$0	$0	$0	$2,252,200	0.09%
	TOTAL		$1,104,687,647	$279,456,134	$720,390,680	$206,409,665	$170,988,378	$0	$2,481,932,505	100.00%
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	$0	
	TOTAL COST OF SERVICE		$1,104,687,647	$279,456,134	$720,390,680	$206,409,665	$170,988,378	$0	$2,481,932,505	
	%		44.51%	11.26%	29.03%	8.32%	6.89%	0.00%	100%	
	RATE REVENUE		$907,461,753	$241,523,515	$622,104,807	$162,634,458	$130,706,919	$28,667,613	$2,093,099,065	
	Allocate Rate Revenues for Others		$12,759,718	$3,227,864	$8,320,888	$2,384,139	$1,975,005	($28,667,613)	$0	
	Other		$34,291,278	$9,290,629	$27,320,801	$8,394,520	$7,376,196	$0	$86,673,424	
	Margin From Off-System Sales		$99,185,426	$26,872,576	$79,023,748	$24,280,637	$21,335,196	$0	$250,697,584	
									$0	
	TOTAL REVENUE		$1,053,698,175	$280,914,583	$736,770,244	$197,693,755	$161,393,316	$0	$2,430,470,073	
	%		43.35%	11.56%	30.31%	8.13%	6.64%	0.00%	100%	
	REVENUE DEFICIENCY		$50,989,472	($1,458,449)	($16,379,564)	$8,715,910	$9,595,063	$0	$51,462,432	
	% CHANGE		**5.62%**	**-0.60%**	**-2.63%**	**5.36%**	**7.34%**	**0.00%**	**2.46%**	
	Less System Average increase		-2.46%	-2.46%	-2.46%	-2.46%	-2.46%		-2.46%	
	Revenue Neutral % Change		**3.16%**	**-3.06%**	**-5.09%**	**2.90%**	**4.88%**	**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.*

Michael S. Proctor is an assistant director of the Electric Utilities Division of the Missouri Public Service Commission, and is in charge of the research and planning department, which is responsible for class cost of service and rate design studies. **Dr. Proctor** received his PhD degree in economics from Texas A & M University, and BA and MA degrees from the University of Missouri at Columbia, where he also currently teaches courses on utility regulation.

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.

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?

[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.

Schedule DCR-3-2

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-

Schedule DCR-3-3

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
α_p = fraction of time applied to peak demand
α_b = fraction of time applied to base demand

where $\alpha_p + \alpha_b = 1$; 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	$\alpha_b D_b$	$\alpha_b D_b$
Peak	αD_p	$\alpha_p D_b + (D_p - D_b$
Total	$\alpha_b D_b + \alpha_p D_p$	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 ($\alpha_b D_b$). 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 ($\alpha_p D_b$) 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 $(\alpha_b + \alpha_p)D_b + D_p - D_b = D_b + D_p - D_b = D_p$.

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

$$\text{System Load Factor} = (\alpha_b D_b + \alpha_p D_p) \div D_p$$

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

$$\frac{\alpha_b D_b}{\alpha_b D_b + \alpha_p D_p} > \frac{\alpha_b D_b}{D_p}$$

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-*

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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.