Exhibit No.:
Issues: Class Cost of Service
Witness: David C. Roos
Sponsoring Party: MO PSC Staff
Type of Exhibit: Direct Testimony
Case No.: ER-2007-0002
Date Testimony Prepared: December 29, 2006

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

DIRECT TESTIMONY

OF

DAVID C. ROOS

UNION ELECTRIC COMPANY d/b/a AMERENUE

CASE NO. ER-2007-0002

Jefferson City, Missouri
December 2006

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-2007-0002

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 following Direct Testimony in question and answer form, consisting of 14 pages of Direct Testimony to be presented in the above case, that the answers in the following Direct Testimony were given by him; that he has knowledge of the matters set forth in such answers; 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 28th day of December, 2006.

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

My commission expires 9-21-10

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UNION ELECTRIC COMPANY d/b/a AMERENUE

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Q. Q. Please state your name and business address.

A. My name is David C. Roos and my business address is Missouri Public Service Commission, P.O. Box 360, Jefferson City, MO 65102.

Q. What is your present position with the Missouri Public Service Commission (Commission)?

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

Q. What is your educational background and work experience?

A. I graduated from the University of Notre Dame, Notre Dame, Indiana, with a Bachelor of Science degree in Chemical Engineering in May 1983. I received a Master of Arts degree in Economics from the University of Missouri in December 2005. 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.

Q. Have you previously filed testimony before the Commission?

A. Yes, I have. I filed testimony in the Empire District Electric Company's most recent general electric rate increase case, Case No. ER-2006-0315.

EXECUTIVE SUMMARY

Q. What is the purpose of your direct testimony?

A. I present the results of the Staff's Class Cost-of-Service (CCOS) study that I performed for this case. I also provide a brief overview of the purpose of conducting a CCOS study and the general methodology used in performing a CCOS study.

Q. How does your testimony relate to the testimony of other Staff witnesses?

A. Staff witness James A. Busch relied on the results of the study I performed to develop Staff's rate design recommendations in this case.

Q. What are the results of Staff's CCOS study for the various customer classes?

A. Table 1 below summarizes the changes to each class's current rate revenues required to exactly match class revenues with the cost of serving that class as determined by the Staff's CCOS study.

Table 1
Summary Results of Staff's CCOS

	RES	SGS	LGS	LPS	LTS	System
Revenue Deficiency:	($83,963,652)	($41,775,749)	($87,553,217)	$9,103,701	$1,324,904	($202,864,013)
Required % Increase:	-9.50%	-17.46%	-14.05%	5.73%	0.98%	-9.94%

CLASS COST OF SERVICE OVERVIEW

Q. Why did the Staff perform a CCOS Study?

A. The purpose of a CCOS study is to determine whether each class of customers is providing the utility with the level of revenue necessary to cover the cost of providing electrical service to that class. 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. A positive amount or percentage indicates revenue from the class is less than the cost of providing service to that class.

A well-designed CCOS study considers the utility's prudently incurred costs, which include operating expenses, depreciation, amortization, and a fair rate of return on equity and the income available to cover these costs, which includes rate revenues, generated from the customer classes, and non-rate revenues, such as revenues from off-system sales and the sales of emission credits.

Q. How did the Staff perform its CCOS study?

A. 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). 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.

Q. What is functionalization?

A. 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-1 is a diagram of a typical vertically integrated electrical system, and illustrates the concept of functionalization. Electric power is produced at the generating 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 re-functionalized 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 the 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.

Q. What is classification?

A. 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 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 next step, allocation, more accurate. For example, a special study shows that overhead transmission lines for distribution can be apportioned 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 transmission 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.

Q. What is allocation?

A. After the costs have been functionalized and classified, the next step to a CCOS study is to allocate costs to the customer classes. The allocation factors or allocators chosen by the analyst 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. "Reasonably" means that the allocation factor distributes costs 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.

Q. Does performing a CCOS study require analyst discretion?

A. Yes. Each step of functionalizing, classifying and allocating costs requires analyst discretion.

STAFF CLASS COST OF SERVICE STUDY

Q. What is the purpose of the Staff's CCOS study?

A. The purpose of Staff's CCOS study is to provide the Commission with a relative measure of class cost responsibility.

Q. What test year did you use for Staff's CCOS study?

A. I used the rate case test year for this CCOS study, i.e. the 12-month period ending June 30, 2006.

Q. Where did you get the data you used in Staff's CCOS study?

A. I used data from the Staff's accounting schedules filed in this case on December 15, 2006; weather normalized revenues from Staff witness Jim Bush's December 15, 2006 direct testimony in this case; large customer annualizations from Staff witness Curt Wells' direct testimony in this case; customer/demand splits from Union Electric Company d/b/a AmerenUE witness Michael E. Vandas' direct testimony in AmerenUE Case No. EO-96-15; and data from AmerenUE accounting schedules, customer non-coincidental peaks, customer maximums and certain allocation factors in the direct testimony of AmerenUE witness William Warwick in this case.

Q. What customer classes did you use in Staff's CCOS study?

A. I used the following customer classes that correspond to Ameren UE's current Missouri rate schedules: Residential (RES), Small General Service (SGS); Large General Service (LGS), which includes customers served on the Large General Service and Small Primary Service rate schedules; Large Primary Service (LPS); Large Transmission Service (LTS); and Lighting (LTG).

Q. How did you treat Lighting in Staff's CCOS study?

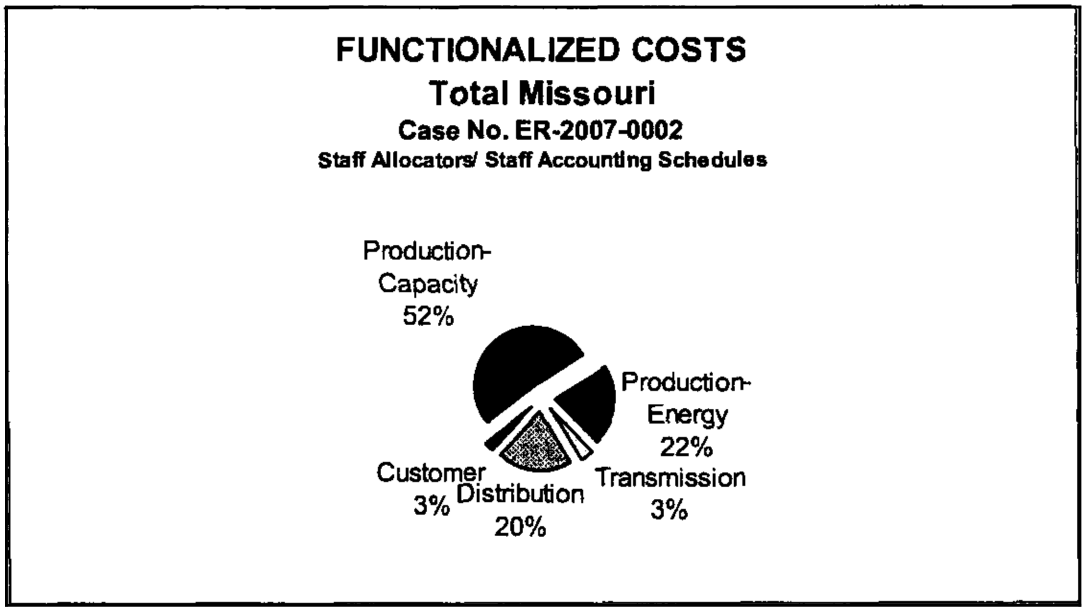
A. I assumed that the current rate revenue collected from the Lighting class matches AmerenUE's cost to serve that class.

Q. Why did you assume current rate revenue from the Lighting class matches AmerenUE's cost to serve that class?

A. Lighting has a unique load pattern because it is on at night and off during the day; therefore, it is typically off 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 demands. Using these demand dependent factors for allocating costs to the LTG class which does not participate during peak demand periods produces erroneous results for lighting and skews the results for the other classes.

Q. What functional Cost categories did you use in Staff's CCOS study?

A. The Major functional cost categories I used in Staff's CCOS study are Production--Capacity, Production--Energy, Transmission, Distribution, and Customer. The chart below shows the percentage of total costs associated with each major function.



Q. What tools did you use to perform Staff's CCOS study?

A. I used Staff's in-house model to perform the calculations. This model is an EXCEL spreadsheet.

Q. What steps did you follow in using the Staff's in-house model?

A. First, I calibrated the model by inputting AmerenUE's accounting data and using AmerenUE's allocation factors. By doing this I was able to closely simulate AmerenUE's CCOS study, and obtained nearly identical results. Second, I replaced AmerenUE's production capacity cost allocator with the Staff's 12 Non-Coincident Peak Average & Peak (12NCP A&P) allocator. Third, I input Staff's accounting data into the model. These steps produced CCOS study results for the Staff's midpoint rate of return on rate base. Table 2 presents the results in terms of the percent change to current rate revenues by class needed to equalize the rate of return from each class. Also presented in Table 2 for comparison are the model's results for AmerenUE's inputs and AmerenUE's allocators and for AmerenUE's inputs with the Staff's production capacity cost allocator.

TABLE 2: CASE STUDY RESULTS							
CASE:	TYPE:		DESCRIPTION:				
1	Revenue Neutral		AUE Allocators/ AUE Accounting				
		RES	SGS	LGS	LPS	LTS	System
	Revenue Deficiency:	$48,191,411	($15,624,452)	($42,882,584)	$17,395,860	($7,080,436)	$0
	Required % Increase:	5.67%	-6.89%	-7.14%	11.15%	-5.16%	0.00%
	AUE CCOS	5.68%	-6.86%	-7.13%	11.14%	-5.24%	0.00%
CASE:	TYPE:		DESCRIPTION:				
2	Revenue Neutral		Staff Allocators/ AUE Accounting				
		RES	SGS	LGS	LPS	LTS	System
	Revenue Deficiency:	($11,957,138)	($18,941,849)	($18,448,499)	$31,263,888	$18,083,597	$0
	Required % Increase:	-1.41%	-8.36%	-3.07%	20.05%	13.18%	0.00%
CASE:			**DESCRIPTION:**				
3			**Staff Allocators/ Staff Accounting/ Staff Midpoint Rate of Return**				
		RES	**SGS**	**LGS**	**LPS**	**LTS**	**System**
	Revenue Deficiency:	**($83,963,652)**	**($41,775,749)**	**($87,553,217)**	**$9,103,701**	**$1,324,904**	**($202,864,013)**
	Required % Increase:	**-9.50%**	**-17.46%**	**-14.05%**	**5.73%**	**0.98%**	**-9.94%**
	- System % Increase:	**9.94%**	**9.94%**	**9.94%**	**9.94%**	**9.94%**	**9.94%**
	Revenue Neutral % Inc.	**0.44%**	**-7.52%**	**-4.11%**	**15.67%**	**10.92%**	**0.00%**

Q. What does Table-2, Case 1 show?

A. Case 1 shows that, when using the same inputs, the output of the Staff's model is nearly identical to the output of AmerenUE's (AUE) model.

Q. What does Table-2, Case 2 show?

A. Case 2 is the same as Case 1 except I used Staff's 12 Non-Coincident Peak Average & Peak method for allocating the costs associated with production and transmission capacity to classes and I used Staff's Diversified Demand Allocators to appropriately diversify the demand components; otherwise, the Staff used the same allocation methods as AmerenUE.

Q. Why did you use the Staff's Average & Peak method to allocate production and transmission costs?

A. That method recognizes that generation is built to meet both peak demands and average demands (energy). The basic components of any Average & Peak 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.

Q. What Average & Peak allocator did Staff use?

A. Staff used 12 monthly non-coincident (class peak) demands. Staff's version of A&P also applies a monthly weighting factor for capacity utilization prior to calculating the class contribution to demand.

Q. What peak demand did Staff use?

A. Staff used weighted monthly class peak demands in the allocation of the demand–related portion of the A&P allocator. Class peak demand is the maximum demand of each class whenever it occurs. Staff's rationale for using class peak demands is the relative stability of class contribution to class peak demands, when compared to class contribution to system (coincident) peak demand. For example, a class's contribution to coincident peak demand may be quite different if the system peaks at 4:00 PM than if it peaks at 6:00 PM.

Q. How did you determine the monthly class peak demands used in Staff's CCOS study?

A. Ameren UE estimates hourly class loads using hourly metered load research data. Staff used the Capacity Utilization method 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, 1983, issue of Public Utilities Fortnightly. This article is attached as Schedule DCR-2.

Q. How did you allocate transmission costs?

A. Transmission costs were 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 one is strongly linked to the other with the major factors that drive production costs tending to also drive transmission costs.

Q. How did the Staff allocate production-energy costs to classes?

A. Staff allocated production-energy costs, which mostly consist 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.

Q. How did Staff allocate the costs of distribution substations to classes?

A. Staff allocated the costs of distribution substations on the basis of each class' 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 use these facilities.

Q. Why did the Staff use the annual class peak to allocate the costs of substations?

A. Substation costs are demand related and class peaks represent the appropriate level of diversity at the distribution substation.

Q. How did Staff allocate the costs of distribution lines to classes?

A. AmerenUE conducted special studies that split the cost of distribution lines between the portions that are customer related and demand related. The demand related portion was further subdivided into primary and secondary demand. Staff used AmerenUE's customer counts to allocate the customer portion of the costs, and Diversified Demand at Primary and a Diversified Demand at Secondary to allocate primary demand and secondary demand, respectively.

Q. What is diversified demand?

A. Staff defines diversified demand for each class as the weighted average of the class' customer maximum demand and its annual maximum class peak demand.

Class customer maximum demand reflects a no-diversity situation. 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. Since not all customers peak at the same time (diversity), class peak demand, which is defined as the demand of all customers within a specific class at the hour when the class peak occurs, will be smaller than customer maximum demand. The spread of the 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. The weighting factors were based on a typical number of customers in each class who share a transformer.

Q. How did Staff determine a typical number of customers who share a transformer within AmerenUE's service territory?

A. Staff used information from AmerenUE's 2006 Supplement to the 2003 System Loss Study within the Residential Secondary and Service Drop Model and the Commercial Secondary and Service Drop Model.

Q. Is load diversity an important consideration when allocating distribution costs?

A. Yes. Diversity is a condition that exists when the peak demands of electric customers do not all occur at the same time. The greater the amount of diversity among the customers within a class or between classes, the smaller the total capacity (and the total cost) of the equipment required for the utility company to meet its customers' needs.

Q. How did Staff allocate the costs of line transformers to classes?

A. Staff allocated the demand portion on the basis of each class' customer maximum demand measured at secondary voltage. The customer portion was allocated by customer counts at secondary voltage.

Q. How are Staff's CCOS study results affected by using Staff's allocators to allocate AmerenUE's cost data rather than AmerenUE's allocators?

A. Table-2, Case 2 shows the effect. of Staff's choice of 12 NCP A&P to allocate Production –Capacity makes the largest single difference to changes in revenue deficiency and the required percentage rate increase in Table-2. A summary of model output for Case 2 is provided as Schedule DCR-3-2.

Q. What does Case 3 show?

A. Case 3 shows the results of using Staff's allocators and data from Staff's accounting schedules. The results are first shown at Staff's midpoint for rate of return on rate base of 7.44%. Staff's recommended revenue requirement decreases total revenues by 9.94%. This decrease in revenue requirement, if spread across the rate classes such that, for each class, revenues match cost of service, would result in rate decreases for the RES, SGS, and LGS classes of 9.5%; 17.46% and 14.05%, respectively; and the LPS and LTS classes would experience rate increases of 5.73%; and 0.98%, respectively.

Staff's CCOS results can also be presented on a revenue neutral basis by subtracting the percentage decrease in total revenues from each class. Case 3 shows that, on a revenue neutral basis, the RES class is providing approximately 0.44% less revenues than the cost of serving that class, while the SGS and LGS classes are providing 7.52% and 4.11% more revenues, respectively, than the cost of serving them. The LPS and LTS classes are providing 15.67% and 10.92% less, respectively, in revenues than the cost of serving them. These results suggest AmerenUE's revenues from the RES class nearly equal AmerenUE's cost of providing service to the RES class; that AmerenUE's revenues from the SGS and LGS classes exceed AmerenUE's cost to serve them; and that AmerenUE's revenues from the LPS and the LTS classes are less than AmerenUE's cost to serve them. A summary of Model output for Case 3 is attached as Schedule DCR-3-3.

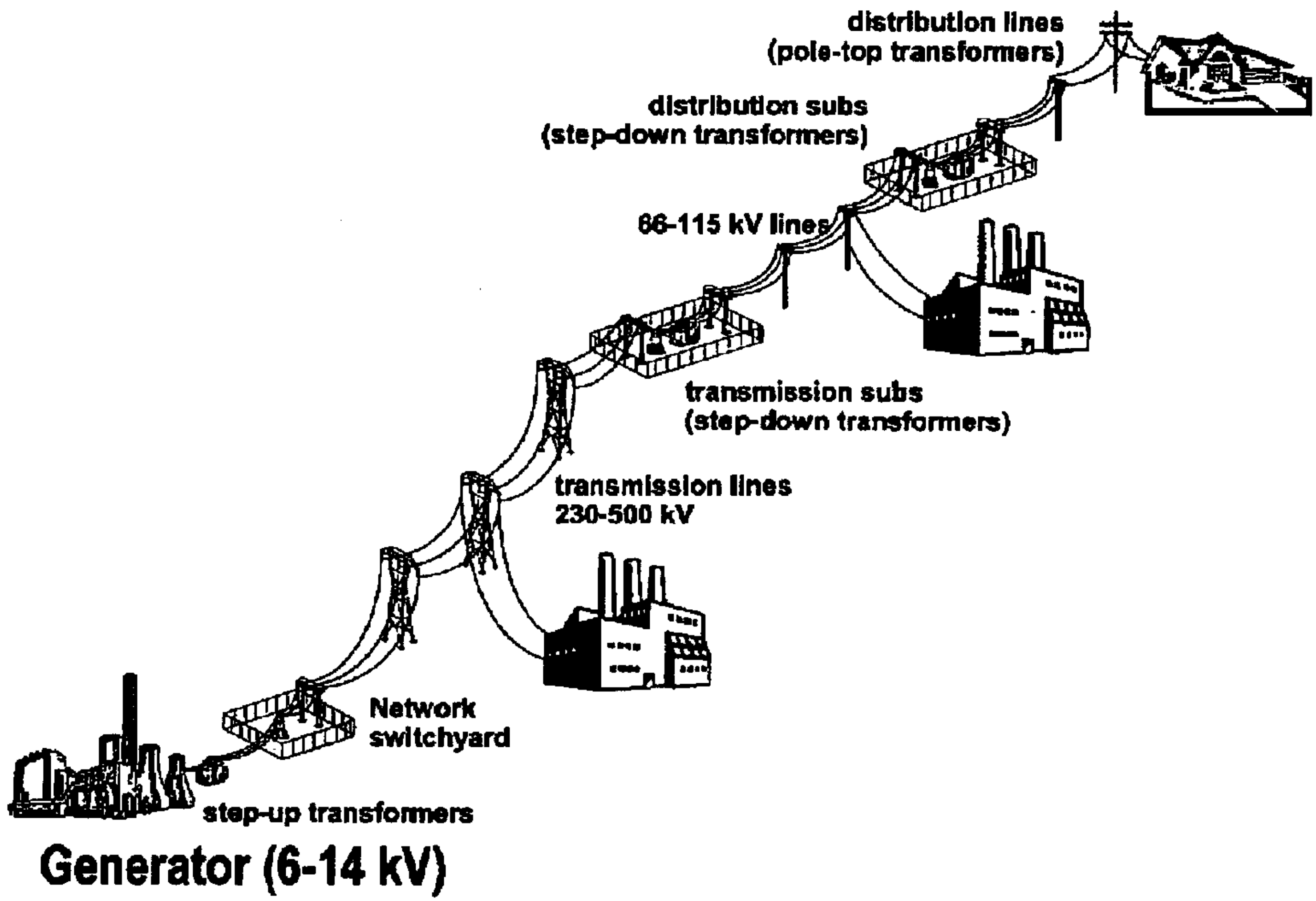
Q. What is Staff's recommendation to the Commission regarding redistributing class revenue requirement in this case?

A. That recommendation is presented by Staff witness James A. Busch in his rate design direct testimony prefiled in this case December 29, 2006.

Q. Does this conclude your direct testimony?

A. Yes.

Basic Components of Electricity Production and Delivery



Schedule DCR-1

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.

Schedule DCR-2-1

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 Utilization 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. 58-64.
[6] Ibid., p. 90.
[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-2-2

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	1/3	1/4	0
Hour Two	2/3	3/4	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	1/2	75	3/4	100	2/3
B	25	1/2	25	1/4	50	1/3
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	2/3	11/16	3/4
B	1/3	5/16	1/4

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:

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

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:

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

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.

CASE 1: AUE ALLOC/ AUE ACCT CLASS COST-OF-SERVICE RESULTS

REVENUE NEUTRAL

CASE NO. ER-2007-0002

FUNCTIONAL CATEGORY			RES	SGS	LGS	LP	Trans	TOTAL	% OF TOTAL
PRODUCTION	CAPACITY		$223,183	$63,471	$135,082	$29,784	$27,602	$479,182	20.26%
PRODUCTION	ENERGY		$325,990	$87,800	$287,413	$93,051	$90,763	$890,018	37.62%
TRANSMISSION	CAPACITY		$31,342	$8,109	$21,155	$6,290	$5,218	$72,114	3.05%
DISTRIBUTION	SUBSTATIONS	DEMAND	$44	$10	$11	$0	$0	$65	0.00%
	SUBSTATIONS	DEMAND	$14,278	$3,269	$8,145	$2,215	$0	$27,906	1.18%
DISTRIBUTION	OH/UG	SEC DEMAND	$7,949	$1,818	$3,199	$0	$0	$12,966	0.55%
DISTRIBUTION	OH/UG	CUSTOMER	$17,716	$2,397	$176	$1	$0	$20,290	0.86%
DISTRIBUTION	OH/UG	PRI DEMAND	$29,586	$6,771	$16,641	$4,003	$0	$57,001	2.41%
DISTRIBUTION	TRANSFORMERS	SEC. CUSTOMER	$4,746	$642	$44	$0	$0	$5,432	0.23%
DISTRIBUTION	TRANSFORMERS	DEMAND	$1,005	$230	$405	$0	$0	$1,640	0.07%
DISTRIBUTION	OPERATIONS		$14,403	$3,480	$5,214	$1,418	$40	$24,556	1.04%
DISTRIBUTION	MAINTENANCE		$2,778	$569	$1,113	$255	$8	$4,723	0.20%
DISTRIBUTION	METERS		$4,283	$1,387	$571	$38	$3	$6,282	0.27%
DISTRIBUTION	DIRECT ASSIGNMENTS		($634)	$0	$1,091	$1,091	$0	$1,547	0.07%
	CUSTOMER DEPOSITS		$250	$177	$141	$20	$0	$589	0.02%
	METER READING		$14,635	$1,960	$258	$4	$0	$16,857	0.71%
	BILLING, SALES, SERVICE		$22,306	$1,524	$1,058	$1,113	$0	$26,001	1.10%
	A & G		$131,257	$29,482	$75,981	$23,957	$15,390	$276,066	11.67%
	CUSTOMER RECORDS		$13,358	$1,478	$2,267	$15	$0	$17,118	0.72%
	DEPRECIATION, TAXES, CWC		$227,753	$50,165	$106,852	$27,459	$13,464	$425,733	17.99%
TOTAL			$1,086,205	$254,756	$666,797	$205,703	$152,599	$2,366,061	100.00%
TOTAL COST OF SERVICE			$1,086,205	$254,756	$666,797	$205,703	$152,599	$2,366,061	
%			45.91%	10.77%	28.18%	8.69%	6.45%	100%	
RATE REVENUE			$850,213	$226,710	$600,707	$155,952	$137,209	$1,970,790	
Allocate Rate Revenues for Lighting			$13,516	$3,093	$7,247	$2,024	$1,231	$27,111	
OTHER REVENUE			$32,743	$6,417	$15,356	$4,991	$3,324	$62,831	
System and Interchange Sales			$141,552	$34,164	$86,376	$25,343	$17,917	$305,352	
Rate Revenue Variance			($11)	($2)	($6)	($2)	($1)	($22)	
TOTAL REVENUE			$ 1,038,013	$270,381	$709,680	$188,307	$159,680	$2,366,061	
%			43.87%	11.43%	29.99%	7.96%	6.75%	100%	
REVENUE DEFICIENCY			$48,191	($15,624)	($42,883)	$17,396	-$7,080	($0)	
% CHANGE			5.67%	-6.89%	-7.14%	11.15%	-5.16%	0.00%	

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CASE 2: STAFF ALLOC/ AUE ACCT CLASS COST-OF-SERVICE RESULTS

REVENUE NEUTRAL

CASE NO. ER-2007-0002

FUNCTIONAL CATEGORY			RES	SGS	LGS	LP	Trans	TOTAL	% OF TOTAL
PRODUCTION	CAPACITY		$192,969	$50,662	$148,184	$47,119	$40,228	$479,162	20.25%
PRODUCTION	ENERGY		$325,930	$87,600	$287,413	$98,051	$90,103	$890,018	37.62%
TRANSMISSION	CAPACITY		$25,042	$7,626	$22,302	$7,081	$8,054	$72,114	3.06%
DISTRIBUTION	SUBSTATIONS	DEMAND	$40	$10	$15	$0	$0	$65	0.00%
	SUBSTATIONS	DEMAND	$14,278	$3,269	$8,145	$2,215	$0	$27,908	1.18%
DISTRIBUTION	OH/UG	SEC DEMAND	$7,909	$2,056	$3,001	$0	$0	$12,966	0.55%
DISTRIBUTION	OH/UG	CUSTOMER	$17,716	$2,387	$178	$1	$0	$20,280	0.86%
DISTRIBUTION	OH/UG	PRI DEMAND	$30,138	$7,834	$15,930	$3,097	$0	$57,001	2.41%
DISTRIBUTION	TRANSFORMERS	SEC. CUSTOMER	$4,745	$642	$44	$0	$0	$5,432	0.23%
DISTRIBUTION	TRANSFORMERS	DEMAND	$1,112	$245	$283	$0	$0	$1,640	0.07%
DISTRIBUTION	OPERATIONS		$12,017	$3,557	$6,302	$2,621	$59	$24,558	1.04%
DISTRIBUTION	MAINTENANCE		$2,822	$659	$1,059	$181	$12	$4,733	0.20%
DISTRIBUTION	METERS		$4,283	$1,367	$571	$56	$3	$6,282	0.27%
DISTRIBUTION	DIRECT ASSIGNMENTS		($634)	$0	$1,091	$1,091	$0	$1,547	0.07%
	CUSTOMER DEPOSITS		$250	$177	$141	$20	$0	$589	0.02%
	METER READING		$14,635	$1,980	$238	$4	$0	$16,857	0.71%
	BILLING, SALES, SERVICE		$22,386	$1,568	$932	$1,126	$0	$26,001	1.10%
	A & G		$113,877	$28,295	$82,767	$27,548	$23,479	$276,066	11.67%
	CUSTOMERRECORDS		$13,358	$1,476	$2,267	$15	$0	$17,115	0.72%
	DEPRECIATION, TAXES, CWC		$219,884	$49,451	$110,370	$21,324	$17,165	$423,733	17.89%
TOTAL			$1,026,056	$251,439	$691,231	$219,571	$177,763	$2,366,061	100.00%
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	
	TOTAL COST OF SERVICE		$1,026,056	$251,439	$691,231	$219,571	$177,763	$2,366,061	
	%		43.37%	10.63%	29.21%	9.28%	7.51%	100%	
RATE REVENUE			$ 850,213	$ 226,710	$ 600,707	$ 156,862	$ 137,209	$1,970,790	
	Allocate Rate Revenues for Lighting		$13,515	$3,093	$7,247	$2,024	$1,231	$27,111	
	OTHER REVENUE		$32,743	$8,417	$16,368	$4,981	$3,324	$62,831 $0	
	System and Interchange Sales		$141,552	$34,164	$86,376	$25,343	$17,917	$305,352 $0	
	Rate Revenue Variance		($11)	($2)	($6)	($2) $0	($1)	($22) $0	
TOTAL REVENUE			$ 1,038,013	$270,381	$709,680	$188,307	$159,680	$ 2,366,061	
	%		43.87%	11.43%	29.99%	7.96%	6.75%	100%	
REVENUE DEFICIENCY			($11,957)	($18,942)	($18,448)	$31,264	$18,084	($0)	
% CHANGE			-1.41%	-8.38%	-3.07%	20.05%	13.18%	0.00%	

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CASE 3: STAFF ALLOC STAFF ACCTCLASS COST-OF-SERVICE RESULTS

(AMEREN UE)

AT STAFF'S MIDPOINT OF RATE OF RETURN ON RATE BASE OF 7.44%

CASE NO. ER-2007-0002

FUNCTIONAL CATEGORY			RES	SGS	LGS	LP	Trans	TOTAL	% OF TOTAL
PRODUCTION	CAPACITY		$422,782,695	$110,987,687	$324,681,129	$103,230,455	$88,136,427	$1,049,811,392	42.67%
PRODUCTION	ENERGY		$158,639,119	$42,727,006	$159,866,333	$47,715,416	$44,168,587	$430,118,481	17.60%
TRANSMISSION	CAPACITY		$28,958,280	$7,877,842	$20,701,649	$8,682,884	$5,819,919	$66,940,033	2.72%
DISTRIBUTION	SUBSTATIONS	DEMAND	$2,384,876	$814,748	$1,250,014	$243,047	$0	$4,472,595	0.13%
	SUBSTATIONS	DEMAND	$20,873,403	$4,801,672	$11,965,083	$3,253,657	$0	$40,893,716	1.67%
DISTRIBUTION	OH/UG	SEC DEMAND	$14,971,167	$3,891,744	$5,581,736	$0	$0	$24,444,646	1.00%
DISTRIBUTION	OH/UG	CUSTOMER	$27,833,142	$3,765,302	$276,297	$1,874	$27	$31,878,443	1.30%
DISTRIBUTION	OH/UG	PRI DEMAND	$45,733,545	$11,888,401	$24,173,608	$4,700,204	$0	$86,495,758	3.52%
DISTRIBUTION	TRANSFORMERS	SEC. CUSTOMER	$11,308,550	$1,528,835	$105,101	$0	$0	$12,943,485	0.53%
DISTRIBUTION	TRANSFORMERS	DEMAND	$1,108,474	$243,555	$281,143	$0	$0	$1,631,172	0.07%
DISTRIBUTION	OPERATIONS		$12,078,024	$3,580,102	$6,108,958	$2,387,888	$55,014	$24,199,998	0.98%
DISTRIBUTION	MAINTENANCE		$2,842,472	$843,120	$1,066,499	$192,709	$11,502	$4,758,301	0.19%
DISTRIBUTION	METERS		$6,315,450	$2,015,448	$842,049	$85,519	$5,035	$8,263,509	0.36%
DISTRIBUTION	DIRECT ASSIGNMENTS		($571,897)	$0	$952,167	$952,167	$0	$1,333,236	0.05%
	CUSTOMER DEPOSITS		($396,995)	($280,178)	($225,699)	-$32,478	$0	($933,351)	-0.04%
	METER READING		$14,808,245	$2,003,278	$241,039	$3,886	$69	$17,858,517	0.69%
	BILLING, SALES, SERVICE		$17,069,922	$1,222,110	$779,916	$818,906	$73	$19,892,922	0.81%
	A & G		$147,816,103	$36,539,549	$102,421,602	$32,867,313	$27,233,363	$347,877,929	14.11%
	CUSTOMER RECORDS		$17,094,951	$1,888,376	$2,900,751	$18,618	$593	$21,903,289	0.89%
	DEPRECIATION, TAXES, CWC		$143,261,486	$33,520,254	$84,681,066	$16,002,008	$7,493,585	$263,058,459	10.69%
TOTAL			**$1,093,189,799**	**$266,650,549**	**$708,732,422**	**$219,137,836**	**$172,724,194**	**$2,460,434,600**	**100.00%**
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	
	TOTAL COST OF SERVICE		$1,093,189,799	$266,650,549	$708,732,422	$219,137,836	$172,724,194	$2,460,434,600	
	%		44.43%	10.84%	28.81%	8.91%	7.02%	100%	
RATE REVENUE			$ 883,572,678	$ 238,245,325	$ 623,036,744	$ 158,871,464	$ 135,652,313	$2,040,378,545	2087572472
	Allocate Revenue for Others		$ 13,852,110	$ 3,133,228	$ 7,117,815	$ 1,940,783	$ 1,150,012	$27,193,976	
	OTHER REVENUE		$ 32,291,407	$ 8,328,265	$ 15,144,012	$ 4,921,843	$ 3,278,452	$61,963,968	61963968
	System and Interchange Sales		$ 247,437,258	$ 58,719,491	$ 150,987,068	$ 44,299,846	$ 31,318,512	$533,762,173	533,762,173
			$0	$0	$0	$0			
TOTAL REVENUE			$ 1,177,153,451	$308,426,298	$796,285,639	$210,033,936	$171,399,290	$2,663,298,613	
%			44.20%	11.58%	29.90%	7.89%	6.44%	100%	
REVENUE DEFICIENCY			($83,963,652)	($41,775,749)	($87,553,217)	$9,103,701	$1,324,904	($202,864,013)	
% CHANGE			-9.50%	-17.46%	-14.05%	5.73%	0.88%	-9.94%	

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