V. Cost Allocation and Rate Design

Q Please provide an overview of the cost allocation and rate design proposed by AmerenUE.

A The Company performed a fully distributed class cost of service study (CCOS) in which it allocates the Missouri jurisdictional test year rate base, expenses and revenues to six classes of customers: Residential, Small General Service, Large General Service, Small Primary, Large Primary and Large Transmission. The results of the CCOS are presented in the testimony of AmerenUE witnesses William Warwick and Wilbon Cooper, with inputs from other witnesses.

The CCOS follows the familiar pattern of 1) functionalizing plant and expenses (e.g., Production, Transmission, Distribution, Customer-related), 2) classifying those functionalized costs (e.g., Demand, Energy and Customer-related) and then 3) allocating the classified costs to the various customer classes. The most salient aspects of the AmerenUE CCOS concern the allocation of production demand costs and the allocation of distribution system costs. As in this case, these are usually among the most contested judgments that a company makes in its CCOS.

Q What are production demand costs and how has AmerenUE proposed to allocated those costs?

A Production demand costs are the costs of producing electricity that tend to be fixed with respect to level of generation output. An example is the capital costs of power plants. The capital cost is the same whether a plant operates at 100% of capacity or not at all.

These costs are in contrast to energy-related production costs like fuel that varies more or less directly with the amount of electricity produced. Production demand costs usually constitute the single largest category of costs for an electric utility that owns most of the generation capacity it requires.

In its CCOS, AmerenUE has allocated its production demand costs to customer classes on the basis of a commonly used factor called the Average and Excess Demand (AED) Factor. In general terms, generation costs are allocated to the customer classes based on a factor derived from of each class's average level of demand throughout the year and the class's (non-coincident) peak demand during the year. In AmerenUE's proposal, each class's non-coincident peak demand is calculated using the four highest monthly peak demands.

Q Do you agree with the methodology chosen by AmerenUE in this case to allocate generation costs?

A No; I think there are superior methods. While the non-coincident AED method continues to be used in some state jurisdictions, its use appears to be declining in my experience. The major shortcoming of the method is its reliance on the <u>non</u>-coincident peak demands of the customer classes, whether or not the peak coincides with the system peak. To fairly apportion the costs of peak demand, it is obviously preferable to consider the demand of each class at the time of the system peak (the coincident demand).

There are other widely-used cost allocation methods that incorporate more directly the class coincident peak demands to allocate demand costs. One such method is the Peak and Average Method discussed in the NARUC Cost Allocation Manual. This method develops allocation factors that appropriately combine the coincident peak demand of each class with each class's average demand (its energy use).

There are also more sophisticated methods for allocating costs, such as methods that measure the contribution of each customer class to the total system demand in each hour of the year. In my view, such methods would produce fairer results than the 4-NCP AED used by AmerenUE.

Later in my testimony I will present the results of using the Peak and Average method to allocate production demand costs, among other changes.

Q Please discuss AmerenUE's method of allocating the cost of the distribution system.

A The costs associated with the distribution are often the next-largest category of costs for an electric utility, second to production demand costs. AmerenUE allocates a large fraction of the distribution system costs (the investment and expenses associated with poles, transformers and wires) using the so-called "zero-intercept" method. Advocates of this method argue that some fraction of distribution costs appears to vary with the number of customers, while the balance of the costs varies with the maximum demand of these customers.

The term "zero-intercept" comes from the fact that the relationship between distribution system costs, system sales, and the number of customers is analyzed using multivariate regression analysis. The value where the curve of the equation crosses the y-axis is the hypothetical distribution cost for a system with zero usage. If the cost does not vary with usage, so goes the argument, it must vary with the number of customers.

This method is closely related to the "minimum system" concept that is sometimes advocated by utilities as a justification of higher customer charges. Each method (zero-intercept and minimum system) attempts to prove that a fraction of the distribution system is properly classified as a "customer-related" cost.

Q Do you agree with this method of allocating some distribution costs to the customer function?

A No. There are several shortcomings of this method, and several errors in the logic that undergirds the theory. The Commission should not set the monthly customer charge based on a mathematical abstraction like the "zero-intercept" of a regression equation. Instead, the Commission should limit the customer charge to those costs that vary directly with the number of customers. In this approach, customer-related costs are limited to metering and billing costs, and the cost of service laterals. This approach excludes the consideration of demand-related costs.

I have several objections to the practice:

- The theory is based on a fictional or hypothetical distribution system;
- The costs are not truly customer-related costs;
- The theory does not account for differences in density of customers;
- The methods shift costs between customer classes in unacceptable fashion and produces a too-high customer charge.

Q In what sense is this allocation approach based on a fictional concept?

A At base, this theory invites us to imagine a distribution system so small that it can serve a system made up only of customers who do not purchase any electricity. Under this theory, the utility must add this hypothetical amount when a new customer comes on the system. This "connection system" which the theory seeks to describe does not, and cannot, exist except in the imagination of a person doing the cost allocation study.

The concept is foreign, not only in utility circles, but also in real life. If one were to analyze the cost "caused" by a visitor to one's business, what would it mean to calculate the customer-related costs of a grocery store or automobile dealership? A grocery store does not seek to collect from each customer the per-customer cost of a parking lot or the capital cost of a store's lighting fixtures even though those costs are "capacity costs" that are unrelated to the amount of product that customers purchase. Similarly, while these costs will ultimately vary with the number of customers who use the store (more customers mean more parking spaces and more lighted floor space) the grocery store does not attempt to assess a minimum-grocery charge to each customer.

Q Have similar analyses been provided by others?

A Yes. In his testimony in this case, AmerenUE witness quotes from James C. Bonbright in his classic 1961 work "Principles of Public Utility Rates." Mr. Hanser is correct to quote from Dr. Bonbright, who is the academic dean of public utility regulation. In that same influential work, Dr. Bonbright, addresses the issue of assigning distribution system costs to the customer charge. While Dr. Bonbright acknowledged that utilities might well try to estimate the cost of the hypothetical minimum system, he describes the inclusion of these costs in the customer charge as "indefensible."[2] For Bonbright, such

[2] Bonbright, James C., Principles of Public Utility Rates, by Columbia University Press, 1961 (1st edition) pp. 348-349.

costs are cannot be allocated because they are not "caused" by the addition of customers to the utility system; nor are they strictly related to the customers' demand. Here is a quote from Bonbright on the topic.

> … [the cost of a "minimum system"] should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole". They are therefore under impelling pressure to fudge their cost apportionments <u>by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.</u>[3] (Emphasis added.)

I have included an extended quote from this same section of Bonbright's text in Exhibit RJB-8. In this longer excerpt, Dr. Bonbright explains the problem of ignoring customer densities when conceptualizing the minimum system. He also questions whether there is any correlation at all between the number of customers and the costs of the minimum system.

Q Why should "zero-intercept" or "minimum system" costs not be considered to be customer-related costs?

A As a general matter, customer-related costs are those utility costs that vary more or less directly with the number of customers and are "caused" when a customer is added to the system. The clearest example of this category of costs is the utility's meter. Especially for the residential customer class, the number of meters is very nearly in a one-to-one relationship with the number of households served by the utility. Further, the meters are

[3] Ibid.

similarly-sized and have about the same capital costs across the class of residential customers. It is easy to see that the addition of a new customer to the utility's system requires the acquisition of one more meter. Similarly, the cost of the service lateral connecting the customer's meter to the utility's electric distribution system is directly related to the number of customers.

On the other hand, the investment in poles or wires for the distribution system may or may not change with the addition of customers. Overhead lines are shared by many customers and, depending on factors such as density and customer size, additional investment may or may not be needed when new customers are added. In the extreme case, the addition of one more customer in an area could trigger the need to spend significant sums reinforcing primary distribution investment somewhere upstream from the new customer. Utilities attempt to avoid reopening a trench by planning for growth, of course. This illustration shows why there is not a conceptual basis for classifying any part of the system as customer-related.

Q What is the effect of using the zero-intercept method?

A There are two major effects. First, the method shifts the Company's revenue requirement away from large distribution customers such as Large General Service and Primary General Service and toward the Residential customer class. The reason is easy to see: some fraction of distribution costs is being allocated on per-customer basis. In this circumstance, an individual residential customer is allocated the same cost as a large commercial customer using hundreds of times more electricity.

The second impact of the zero-intercept method is that it results in a higher monthly service charge for residential customers. Since the method classifies relatively more costs as "customer-related," (even though these costs are for poles, transformers and overhead lines) it drives up the pool of dollars to be collected in the customer charge. It is important to understand that this effect is separate and independent of the class revenue-shifting effect discussed above.

Q What method do you recommend the Commission use to allocate distribution system costs?

A I agree with the Company's allocation of meters, billing and services using a weighted number of customers. However, I do not agree that accounts 364 (wires & devices), 365 (poles & fixtures), 366 (conduit), 367 (cable & devices) and 368 (line transformers) should be allocated in part though the customer function. These costs should be allocated based on the non-coincident class peak, in the same way that the balance of those accounts (the portion not classified as customer-related) is allocated.

Q Have you performed a cost of service study that incorporates the changes you recommend?

A Yes. I modified the Company's CCOS to reflect three changes:

- Using the 4-CP Peak and Average Method to allocate production demand costs;
- Classifying accounts 364 through 368 as demand-related and allocating these costs using the Company's distribution demand allocators;
- For the residential customer class, recovering 55% of annual demand costs in the summer season, compared to 60% in AmerenUE's CCOS study.

I have already discussed the first two changes. I will discuss the third change later in this testimony when discussing residential rate design.

Q Please describe Exhibit RJB-1.

A Exhibit RJB-1 is a two page exhibit that provides a summary of allocated costs by customer class first at current rates and then using the Company's proposed revenue requirement. These schedules are derived from the Company's CCOS and are exactly comparable to Schedules WMW-E1 and WMW-E2 of AmerenUE witness William Warwick.

Exhibit RJB-2 is a one page exhibit that shows the resulting "unbundled" revenue requirement for the customer classes. For ease of comparison, I have included the comparable results from the Company's filed CCOS study contained in the testimony of AmerenUE witnesses Cooper and Warwick. My exhibit assumes the same revenue requirement as Mr. Warwick, making it an apples-to-apples comparison.

Q Please summarize the impact of using the Peak and Average Method instead of the NCP Average and Excess method used by AmerenUE.

A Changing to the Peak and Average Method modifies a single allocation factor, the one used to allocate production demand costs. This change affects the allocation of production plant directly, and then other account allocations indirectly. A useful way to describe this change is to show the impact on the allocation factor itself.

Production Demand Allocation Factors	Residential	Small GS	Large GS	Small Pri	Large Pri	Large TS	System
4-NCP Average and Excess	46.57%	11.16%	19.62%	8.57%	8.30%	5.78%	100.00%
4-CP Peak and Average	40.98%	10.63%	20.92%	9.62%	9.59%	8.26%	100.00%
Change	-5.60%	-0.53%	1.30%	1.05%	1.30%	2.48%	0.00%

The effect of this single modification is to reduce the revenue requirement for the Residential Class by about $30.8 million compared to the CCOS filed by AmerenUE.[4]

Exhibit RJB-2 shows that the combination of two changes: the change in allocation methods to Peak and Average and eliminating the zero-intercept method. The combination of these changes reverses the shift of revenue requirement from the large commercial customers to residential customers and lowers the residential revenue requirement by about $55 million. The largest beneficiaries of this shift had been the rate classes of the largest customers. In percentage terms, these changes reduce the residential revenue requirement by 5.7%, while increasing rates for the commercial rate classes by 5.3% to 9.4%, compared to the method proposed by AmerenUE.

Q What is the impact of the zero-intercept method on the Residential Class monthly customer charge?

A Eliminating the zero-intercept allocation shifts costs from the residential Customer function to the residential Demand function. Referring again to Exhibit RJB-2 we see that the zero-intercept method had shifted about $40 million from demand costs to customer-related costs. Reversing this classification of costs has important implications for the monthly customer charge for residential customers.

[4] The adjustments to the CCOS interact with each other, making it difficult to state the stand-alone effect of each change.

In his testimony, AmerenUE witness Wilbon Cooper calculated that the residential customer charge should be $8.22, after limiting the increase to the residential class to 10%. (Without this mitigation, the residential monthly customer charge would have been $9.48.) I have calculated the residential customer charge after modifying the Company's CCOS to eliminate the use of the zero-intercept method.

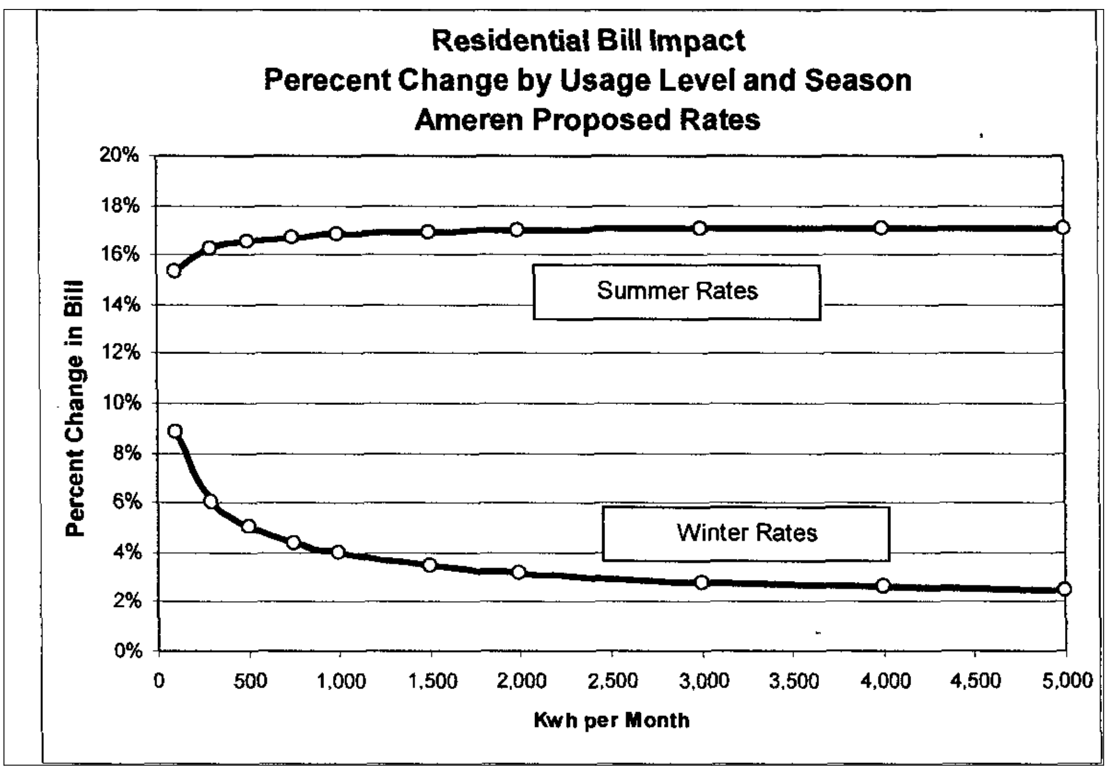
The results are shown in Exhibit RJB-3. This schedule shows that, using the modified CCOS the residential customer charge would be $4.46 assuming the residential increase is limited to 10% as proposed by AmerenUE. Without this mitigation, and assuming the Company's full revenue increase were granted, the customer charge would be $5.06 per month. These values are, on average, about $4.00 less than the comparable customer charges developed by AmerenUE.

Q Please discuss your change to the percentage of demand revenues collected during the summer months.

A In its CCOS, the Company calculates the total amount of demand-related revenues that should be collected within each customer class. This data can be seen in the "unbundling" information contained in Exhibit RJB-2, which I discussed earlier. In order to design separate rates for the summer season (June-September) and the winter season (October-May), the Company proposes to collect 60% of the demand costs during the four summer season months and 40% of the demand costs in the eight winter season months.

The decision to collect 60% of demand costs in four months has the expected effect on rates: summer residential rates are much higher than winter rates. This may be a desirable effect to encourage conservation during peak months. It also has a plausible cost-based rationale. However, the differential between summer prices and winter prices is becoming quite large as this method is applied year after year.

Under the rates proposed by AmerenUE, the average residential summer kWh would cost 9.64 cents, while an average kWh in the winter would cost 5.64 cents, a ratio of 1.7 to 1. A related effect is that the Company's rate design raises summer rates by about 16%, while winter rates are raised by only about 2.8%. The following chart shows how the impact of the Company's choice of 60% loads the increase on summer rates.



Q Do you recommend a change to the seasonal differential in your proposal for designing residential electric rates?

A Yes. The decision to collect 60% of demand costs during the summer is arbitrary in the sense that the percentage was once probably chosen to obtain a result. As such, it should be changed if the result is no longer desirable. In the rate design proposed by AARP in this case, I recommend that the fraction of demand costs recovered in the summer be reduced to 55% from 60%. This has the effect of reducing the ratio of summer and winter prices. Under AARP's proposal, any rate increase would be spread more evenly between summer and winter rates.

Q Have you designed residential rates based on a CCOS with the changes you recommend?

A Yes. The following table shows the residential rates necessary to collect the revenue requirement associated with a 10% (mitigated) increase to the customer class as proposed by the Company. For ease of comparison, I have included the Company's proposed rates on the same table. As can be seen by inspection, the AARP-recommended rates have a lower customer charge, relatively lower summer rates and relatively higher winter rates. This same table is contained in Exhibit RJB-5.

Rate Design Proposed by AARP

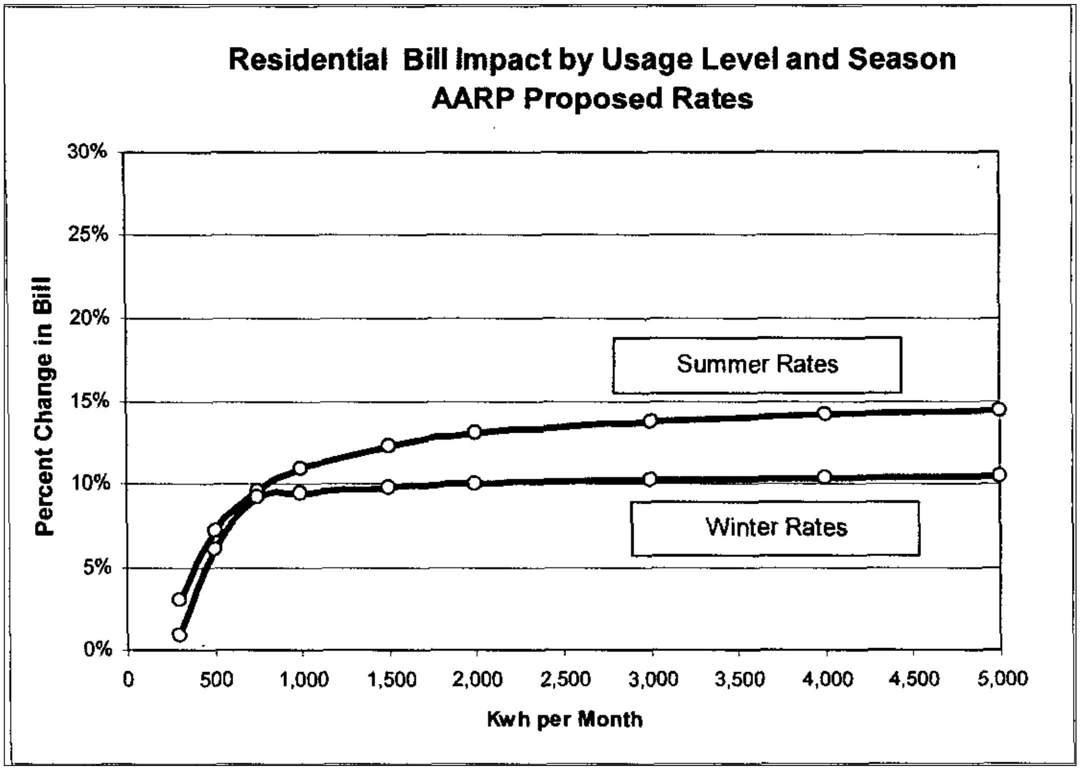
Residential

	Present	AmerenUE Proposed*	AARP Proposed*
	Summer (June-September)		
Basic Charge	$ 7.25	$ 8.22	$ 4.64
All kWh	$0.0764	$0.0895	$0.0881
	Winter (October-May)		
Basic Charge	$ 7.25	$ 8.22	$ 4.64
Per kWh <750	$0.0542	$0.0557	$0.0636
Per kWh >750	$0.0366	$0.0373	$0.0406

*Assumes Capped 10% Residential Increase

Q **How do the AARP-proposed residential rates affect summer and winter rates?**

A As I explained earlier, the AmerenUE residential rate design proposal places a much higher share of the rate increase on summer prices due to the decision to assign 60% of demand costs to the four summer months. Unlike the rates proposed by the Company, the AARP-recommended residential rates have a similar impact on rates in the winter and summer, as can be seen from the following chart. The chart also shows that the AARP-recommended rates have a smaller impact on smaller-use customers.



I have included the two charts together in Exhibit RJB-6 so that they can be more easily compared. Recall that the revenue requirement is the same for both situations illustrated by the graphs.

Q Your cost allocation and rate design proposals are illustrated assuming that the Company's full rate request is granted and that the increase to the residential customer class is limited to 10%. What happens if the Commission denies the rate increase or orders a reduction in revenues as advocated by some parties to this case?

A Obviously, the results of cost allocation and rate design would be significantly different with a different revenue requirement. However, the principles I've described in this testimony apply directly to a different revenue requirement. These principles include:

- Use the 4-CP Peak and Average allocation methodology to allocate production demand costs;

- Classify and allocate 100% of distribution-related costs in Accounts 364 to 368 as demand costs;

- For the residential customer class, consider adjusting the portion of demand costs recovered in the summer months downward from 60% to achieve a desirable summer/winter price ratio.

VI. Summary of Testimony

Q Mr. Binz, please summarize your recommendations.

A Here are my findings and recommendations:

The AmerenUE FAC Proposal

- No FAC should be approved for AmerenUE. In general, regulators should avoid using "automatic" cost adjustment mechanisms for rate regulated companies. While there are valid arguments for and against their use, I think the balance weighs against cost adjustment mechanisms in most cases.

- Cost adjustment mechanisms should be used only for utility costs that meet three qualifications:

    - They represent a significant portion of a utility's costs;
    - They fluctuate significantly;
    - The costs are outside the utility's control.

  The costs examined in this case meet the first of these criteria: fuel and purchased power costs comprise a significant portion of AmerenUE's total electric costs. However, these costs only partially meet the second and third criteria.

- If, despite the objections of consumer representatives, the Commission decides to adopt any cost adjustment mechanism for AmerenUE in Missouri, then it should be designed to retain as many of the desirable incentives of cost of service regulation as possible. These include valuable incentives for the utility to operate efficiently and to manage its power costs.

- If the Commission decides to approve an FAC for AmerenUE in Missouri, it should be constructed so that some significant fraction of AmerenUE's energy costs remains at risk. Such a feature is critical to maintain the correct incentives for the Company. An FAC recently adopted in Wyoming contains some desirable features that this Commission should consider.

- In its alternative proposal for treating off-system energy sales, AmerenUE provides the Commission (perhaps inadvertently) with an approach that can be used for the FAC. The Company commends this mechanism to the Commission as one way to allow relatively automatic adjustments to the revenue to be included.

- If the Commission decides to adopt a sharing mechanism for treating margins from off-system sales, the base level of revenue credits should be set on the basis of the best evidence of the likely future value. The Commission should not set the base amount below the likely future margins, the approach advocated by AmerenUE.

- If the Commission adopts an incentive-based Cost Adjustment Mechanism of any kind, it should consider directing the parties to negotiate the details of implementation of the mechanism in line with principles the Commission would include in its order.

Cost Allocation and Rate Design

- The cost allocation methodology used by AmerenUE – the 4-NCP AED method – should not be used to allocate production demand costs. There are superior allocation methods that consider the coincident peak of the customer classes, something the AmerenUE method ignores.

- The Commission should reject the "zero-intercept" methodology used by AmerenUE to allocate distribution costs. The method shifts revenue requirements from commercial customers onto residential customers and inflates the monthly customer charge.

- The costs assigned to the residential customer charge should not exceed the sum of those costs of metering and billing plus the customer service lateral. These are costs are directly related to the number of customers on the AmerenUE system.

- The Commission should adopt a rate design developed by AARP and presented in this testimony. The rate design lowers the monthly service charge and is more equitable to smaller consumers within the residential class. The AARP-recommended rates also produce a more desirable relationship between summer and winter rates.

Q Does this conclude your testimony?

A Yes.

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** Tariff No. YE-2007-000

AFFIDAVIT OF RONALD J. BINZ

STATE OF COLORADO)
) ss
CITY AND COUNTY OF DENVER)

Ronald J. Binz, being first duly sworn on his oath states:

1. My name is Ronald J. Binz. I work in Denver, Colorado and am President of Public Policy Consulting.

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on Behalf of AARP consisting of 49 pages, Attachment A and Exhibits RJB-1 to RJB-8, which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Ronald J. Binz

Ronald J. Binz
333 Eudora Street
Denver, Colorado 80220
303-393-1556 (O)

Employment History

1995-present President, Public Policy Consulting

Consultant, specializing in energy and telecommunications regulatory policy issues. Assignments include strategic counsel to clients and research and testimony before regulatory and legislative bodies. Since 1995, a wide range of clients has included: consumer advocate offices, rural electric utilities, senior citizen advocacy groups, industrial electric users, homebuilders, telecommunications resellers, an incumbent local exchange company, low-income advocacy organizations, and municipal utilities.

1996-present President and Policy Director, Competition Policy Institute

Competition Policy Institute is an independent non-profit organization that advocates state and federal policies to bring competition to energy and telecommunications markets in ways that benefit consumers. Duties include: determining the organization's policy position on a wide range of telecommunications and energy issues; conducting research, producing policy papers, presenting testimony in regulatory and legislative forums, hosting educational symposia for state regulators and state legislators.

.1984-1995 Director, Colorado Office of Consumer Counsel

Director of Colorado's first state-funded utility consumer advocate office. By statute, the OCC represents residential, small business and agricultural utility consumers before state and federal regulatory agencies. The office has been a party to more than two hundred legal cases before the Colorado Public Utilities Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission and the courts. Annual office budget is $1 million.

Managed a staff of eleven, including attorneys, economists, and rate analysts who conduct economic, financial and engineering research in public utility matters.

Testified as an expert witness on subjects of utility rates and regulation. Negotiated rate settlement agreements with utility companies. Regularly testified before the Colorado general assembly and spoke to professional business and consumer organizations on utility rate matters. Consulted with advisory board of consumer leaders from around the state.

Leadership role in National Association of State Utility Consumer Advocates. Member of high-level advisory boards to Federal Communications Commission (Network Reliability Council) and Environmental Protection Agency (Acid Rain Advisory Council). Frequent witness before congressional committees and invited speaker before national industry and regulatory forums.

1977-1984 Consulting Utility Rate Analyst

Represented clients in public utility rate cases and testified as an expert witness in more than twenty utility cases before regulatory commissions in Utah, Wyoming, Colorado and South Dakota. Clients included state and local governments, low income advocacy groups, irrigation farmers and consumer groups. Testimony spanned topics of telephone rate design, electric cost-of-service studies, avoided cost valuation of nuclear generation, electric rate design for irrigation customers and municipal water rate design.

1975-1984 Instructor in Mathematics

Taught mathematics at the University of Colorado, Denver and Boulder campuses. Nominated three times for outstanding part-time faculty member.

1971-1974 Manager, Blue Cross and Blue Shield

Managed major medical claims processing department. Responsibilities included budgets, hiring, training, managing supervisors, and coordinating with medical peer review committee.

Other Business Interests

1994-present Managing Partner, Trail Ridge Winery

Partner and Secretary/Treasurer of Trail Ridge Winery. Trail Ridge is a Colorado winery located in Loveland, Colorado, producing a variety of wines from Colorado-grown grapes. Duties include service on board of directors; duties of corporate secretary/treasurer; development of business plans; legislative, regulatory and other external affairs; assistance in winery operations and tasting room; assistance in public relations and marketing.

Education

M.A. (Mathematics) 1977. University of Colorado. Course requirements met for Ph.D.

Graduate courses toward M.A. in Economics 1981-1984. University of Colorado. Twenty-seven hours including Economics of Regulated Industries, Natural Resource Economics, Econometrics.

Advanced Course in Utility Regulation 1986. National Association of Regulatory Utility Commissioners.

B.A. with Honors (Philosophy) 1971. St. Louis University.

Diploma 1967. Catholic High School, Little Rock, Arkansas.

Professional Associations and Activities

Colorado Legislative Task Force on Information Policy, Gubernatorial Appointee 2000-2001

National Association of State Utility Consumer Advocates
President 1991-1992, Vice-President 1990, Treasurer 1987-1989
Chair, Telecommunications Committee 1992-1995

Network Reliability Council to the Federal Communications Commission

North American Numbering Council to Federal Communications Commission, Co-Chair

Harvard Electric Policy Group, John F. Kennedy School, Harvard University

Denver Mayor's Council on Telecommunications Policy

Exchange Carriers Standards Association Network Reliability Steering Committee

Colorado Telecommunications Working Group, Gubernatorial Appointee

Colorado Energy Assistance Foundation, Board Member, Past President

Legislative Commission on Low-Income Energy Assistance, Past President

Colorado Public Interest Research Foundation, Board Member

Colorado Common Cause, Board Member

Acid Rain Advisory Council to the Environmental Protection Agency

Outreach Committee, Western States Coordinating Council Regional Planning Committee

Total Compensation Advisory Council to the State of Colorado Department of Personnel

New Mexico State University Public Utilities Program, Faculty and Advisory Council

Aspen Institute for Humanistic Studies, Telecommunications Policy Meetings 1986-1997

Who's Who in Denver Business

Council on Economic Regulation, Past Fellow

Colorado Wine Industry Development Board, Chairman

American Vintners Association, Executive Committee, Membership Chair

Recent Regulatory Testimony and Presentations

Since 1977, Mr. Binz has participated in more than 150 regulatory proceedings before the Federal Energy Regulatory Commission, the Federal Communications Commission, State and Federal District Courts, the 8th Circuit, 10th Circuit and D.C. Circuit Courts of Appeal, the U.S. Supreme Court and state regulatory commissions in California, Colorado, Georgia, Idaho, Maine, New York, South Dakota, Texas, Utah, and Wyoming. He has filed testimony in approximately fifty proceedings before these bodies. His testimony and comments have addressed a wide variety of technical and policy issues in telecommunications, electricity, natural gas and water regulation. Following is a sample of recent testimony and presentations before regulatory commissions.

Testimony

Before the West Virginia Public Service Commission. In The Matter Of the Petition of Verizon West Virginia, Inc. To Cease Rate Regulation of Certain Workably Competitive Telecommunications Services. Case No. 06-0481-T-PacifiCorp (June 2006)

Before the Utah Public Service Commission. In The Matter Of The Division's Annual Review and Evaluation of Electric Lifeline Program, HELP Rate Design Testimony. Docket No. 04-035-21 (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Rebuttal Testimony. Docket No. 05F-167G. (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Direct Testimony. Docket No. 05F-167G. (June 2005)

Before the Michigan Public Service Commission. Testimony on behalf of the Michigan Attorney General. In The Matter Of SBC Michigan's Request For Classification Of Business Local Exchange Service As Competitive Pursuant To Section 208 Of The Michigan Telecommunications Act. Case No. U-14323. (March 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel. In the Matter of the Combined Application of Qwest Corporation for Reclassification and Deregulation of Certain Part 2 Products and Services and Deregulation of Certain Part 3 Products and Services. Docket No. 04A-411T. (February 2005)

Before the Utah Public Service Commission. In The Matter Of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Rate Design Testimony. Docket No. 04-035-42. (January 2005)

Before the Utah Public Service Commission. In The Matter Of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Revenue

Requirements Testimony. Docket No. 04-035-42. (December 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Building Owners and Managers Association of Metropolitan Denver (BOMA) in the Matter of The Investigation And Suspension Of Tariff Sheets Filed By Public Service Company Of Colorado With Advice Letter No. 1411—Electric Docket No. 04S-164E (October 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of The Application of Public Service Company of Colorado for Approval of its 2003 Least-Cost Resource Plan. Docket No. 04A-214E (filed: September 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of the Application of Public Service Company of Colorado For An Order Authorizing It To Implement A Purchased Capacity Cost Adjustment Rider In Its PUC No. 7 – Electric Tariff. Docket No. 03A-436E. (filed: March 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of Wyoming Industrial Energy Consumers (WIEC) and AARP In the Matter of the Application of PacifiCorp for Approval of a Power Cost Adjustment Mechanism. Docket No. 20000- ET-03-205 (filed: January 2004).

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel Regarding The Unbundling Obligations Of Incumbent Local Exchange Carriers Pursuant To The Triennial Review Order – Initial Commission Review. Docket No. 03I-478T. (January 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of The Application Of PacifiCorp For A Retail Electric Utility Rate Increase Of $41.8 Million Per Year Docket No. 20000-ER-03-198 (January 2004).

Before the Wyoming Public Service Commission. Public hearings testimony on behalf of AARP in the matter of an application by Kinder Morgan to modify the provider selection process in its Choice Gas Program. (December 2003).

Before the Public Service Commission of North Dakota. Testimony on behalf of AARP in the matter of In the Matter of the Notice of Montana-Dakota Utilities Co. for an Electric Rate Change. Case No. PU-399-03-296. (October 2003)

Before the Colorado Public Utilities Commission. Testimony in the matter of Public Service Company of Colorado's Advice Letter No. 598 – Natural Gas Extension Policy. Docket No. 02S-574G. (March 2003)

Before the Colorado Public Utilities Commission. Testimony in the remand hearings in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (January 2003)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning A Proposed General Rate Increase And Surcharge For Previous Power Costs. (November 2002).

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning Hunter Unit 1 Issues. (November 2002).

Before the Colorado Public Utilities Commission. Comments on behalf of the Colorado Energy Assistance Foundation. Docket No. 02R-196G. In the Matter of the Proposed Repeal and Reenactment of the Rules Regulating Gas Utilities. (November 2002)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Assistance Foundation and Catholic Charities of the Archdiocese of Denver. Docket No. 02A-158E. In the Matter of the Application of Public Service Company of Colorado for an Order to Revise its Incentive Cost Adjustment. (April 2002)

Before the Idaho Public Utilities Commission. Testimony on behalf of Astaris, in the matter of Case No. IPC-E-01-43 concerning the buy back rates under an electric load reduction program. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in matter of the investigation of Advice Letters 579 and 581 of Xcel Energy on behalf of Homebuilders Association of Denver. Dockets 01S-365G and 01S-404G. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (August 2001)

Before the Colorado Public Utilities Commission. Testimony in the matter of the investigation and suspension of Advice Letter No. 566 of Xcel Energy on behalf of the Homebuilders Association of Metropolitan Denver. Docket No. 00S-422G. (November 2000)

Before the American Arbitration Association. In the Matter of Univance Telecommunications, Inc. v. Venture Group Enterprises, Inc. Arbitration No. 77 Y 147 00099 00 (November 2000)

Testimony of Ronald Binz at FCC Public Forum on SBC/Ameritech merger (May 1999)

Docket No. 97-106-TC -- Testimony of Ron Binz before New Mexico State Corporation Commission on Investigation Concerning USWest's Compliance with Section 271(c) of the Telecommunications Act (July 1998)

Before the Colorado Public Utilities Commission. Testimony Concerning the Investigation of Telephone Numbering Policies. (March 1998)
Docket No. 6717-U • •Testimony before the Georgia Public Service Commission Concerning the Service Provider Selection Plan of Atlanta Gas Company. (January 1997)

Case 96-C-0603 and Case 96-C-0599--Testimony of Ronald J. Binz on behalf of CPI before the New York State Public Service Commission concerning the Bell Atlantic/NYNEX Merger (November 1996)

Docket No. 96-388 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of the Office of the Public Advocate (October 1996) State of Maine, Public Utilities Commission Joint Petition of New England Telephone and Telegraph Company and NYNEX Corporation for Approval of the Proposed Merger of a Wholly-Owned Subsidiary of Bell Atlantic Corporation into NYNEX Corporation.

Application No. 96-04-038 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of Intervener, Utility Consumers Action Network (September 1996) Before the Public Utilities Commission of the State of California In the Matter of the Joint Application of Pacific Telesis Group (Telesis) and SBC Communications (SBC) for SBC to Control Pacific Bell (U 1001 C), Which Will Occur Indirectly as a Result of Telesis' Merger With a Wholly Owned Subsidiary of SBC, SBC Communications (NV) Inc.

Presentation to Federal-State Joint Board on Universal Service (April 12, 1996)

Testimony before the Texas Public Utility Commission on the Integrated Resource Planning Rule (March, 1996)

Presentations

"Looking Back on the 1996 Telecom Act." Presentation to CLE International, Telecommunications Law. (December 2003)

"How to Pay for Gas Line Extensions." Presentation to CLE International, Energy Regulatory Law. (October 2003)

"Are Telecommunications Customers Expecting Too Much Customer Service?" Presentation to the National Association of Regulatory Utility Commissioners (July 2003)

"Will We Need Regulatory Attorneys in Ten Years?" Presentation to CLE International. Denver, Colorado. December 2002.

"Section 271: Is it a '10' for Consumers?" Presentation to the National Association of State Utility Consumer Advocates. Chicago, Illinois. November 2002

"CLEC Market Share--What do the Numbers Say?" Presentation to the Regional Oversight Committee of Qwest state regulators. Santa Fe, New Mexico. April 2002

"Public Utility Regulation and Low Income Issues," Presentation of Ron Binz before the Colorado Public Utilities Commission on behalf of the Colorado Energy Assistance Foundation, December 5, 2001.

"Some Natural Gas Issues," Presentation by Ron Binz for the Western Conference of Public Service Commissioners, June 14, 2000.

"Consumer Issues in Natural Gas Unbundling" -- Presentation of Ron Binz before the National Association of Regulatory Utility Commissioners (November 9, 1999)

Ron Binz Presentation to the 25th Annual Rate Symposium on Competition for small customers in natural gas markets (April 27, 1999)

"Best Practices in Telecommunications Regulation"; Presentation before NARUC Communications Committee and National Regulatory Research Institute at NARUC Winter Meeting (February 1999)

Congressional Testimony

United States House of Representatives Judiciary Committee, November 1999. Testimony concerning H.R. 2533, The Fairness in Telecommunications License Transfer Act of 1999.

United States Senate Judiciary Committee; Antitrust, Business Rights and Competition Subcommittee, April 1999. Testimony concerning S.467, The Antitrust Merger Review Act.

United States Senate Commerce Committee, Telecommunications Subcommittee, May 1998. Testimony in oversight hearings concerning the performance of the Common Carrier Bureau of the Federal Communications Commission.

United States Senate Judiciary Committee, Washington, D.C., September 1996. Presented testimony on behalf of the Competition Policy Institute on the competitive impact of proposed mergers of Regional Bell Operating Companies.

United States House of Representatives Subcommittee on Telecommunications and Finance of the Committee on Commerce, May 1995. Testimony presenting NASUCA's position on H.R. 1555 by Representative Fields.

United States Senate Subcommittee on Antitrust, Washington, D.C., September 1994. Testimony presenting NASUCA's position on S. 1822 by Senator Hollings.

United States House of Representatives Subcommittee on Telecommunications and Finance of the House Energy and Commerce Committee, Washington, D.C., February 1994. Presented testimony on H.R. 3636.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., October 1992. Supplemental testimony presenting NASUCA's position on legislation concerning the Modified Final Judgment introduced by Representative Brooks.

United States House of Representatives Subcommittee on Telecommunications and Finance, Washington, D.C., October 1991. Testimony on RBOC entry into telecommunications manufacturing and information services.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., August 1991. Testimony presenting NASUCA's position on possible federal legislation concerning the Modified Final Judgment.

United States Senate Subcommittee on Energy Regulation and Conservation, Denver, Colorado, April 1991. Testimony presenting NASUCA's position on federal legislation concerning regulation of the natural gas industry, introduced by Senator Wirth.

United States Senate Communications Subcommittee, Washington, D.C., February 1991. Testimony on behalf of NASUCA concerning S.173, telecommunications legislation introduced by Senator Ernest Hollings.

United States Senate Communications Subcommittee, Washington, D.C., July 1990. Testimony on behalf of NASUCA concerning S.2800, telecommunications legislation introduced by Senator Conrad Burns.

United States House of Representatives Subcommittee on Telecommunications and Finance, July 1988. Testimony on the FCC Price Cap proposal.

Legislative Testimony

New Mexico State Legislature, Joint Oversight Committee on Regulation. November 2003. Testimony concerning the appropriate regulatory treatment of mid-sized telecommunications carriers.

Wyoming State Legislature, Senate Committee on Corporations, Elections & Political Subdivisions. February 2003. Testimony on legislation to create a division of utility consumer advocate within the Wyoming Public Services Commission.

Colorado General Assembly. March 2004. Testimony on the impact on retail utility rates of a renewable energy portfolio standard.

Colorado State Senate and Colorado House of Representatives 1984-1995. Frequent witness on variety of energy and telecommunications issues.

Georgia State Legislature Interim Committee on Natural Gas Competition. Fall 1996. Testimony on the consumer impacts of restructuring the natural gas industry in Georgia.

Iowa General Assembly, Des Moines, Iowa, November 1992. Testimony on legislation concerning incentive regulation.

American Legislative Exchange Council, November 1999. "The Changing Role of Public Utilities Commissions"

American Legislative Exchange Council concerning Rights-of-Way and Competition in Telecommunications, July 1998.

American Legislative Exchange Council Committee on Rights of Way. Testimony on rights of way policies, taxation and telecommunications development. May 1998.

Publications

Mr. Binz has published two reports, funded by the Energy Foundation, of the impact of a renewable energy standard in Colorado:

The Impact of the Renewable Energy Standard in Amendment 37 on Electric Rates in Colorado. **(September 2004)**

The Impact a Renewable Energy Portfolio Standard On Retail Electric Rates In Colorado. **(February 2004)**

Mr. Binz is the co-author of two major reports on electric industry restructuring:

Navigating a Course to Competition: A Consumer Perspective on Electric Restructuring.

Addressing Market Power: The Next Step in Electric Restructuring.

In the telecommunications area, Mr. Binz published a major discussion paper entitled ***Qwest, Consumers and Long Distance Entry: A Discussion Paper.***

These publications (along with copies of other testimony and reports) are available at the Public Policy Consulting website: www.rbinz.com.

TITLE: SUMMARY

		MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SERV	SMALL PRIMARY	LARGE PRIMARY	LARGE TRANS
1	BASE REVENUE	$ 1,970,790	$ 850,213	$ 226,710	$ 418,267	$ 182,440	$ 155,952	$ 137,209
2	OTHER REVENUE	$ 62,831	$ 31,808	$ 6,401	$ 11,185	$ 4,793	$ 5,137	$ 3,506
3	LIGHTING REVENUE	$ 27,111	$ 13,515	$ 3,093	$ 5,129	$ 2,117	$ 2,024	$ 1,231
4	SYSTEM REVENUE	$ 305,352	$ 125,005	$ 32,567	$ 63,976	$ 29,287	$ 29,200	$ 25,317
5	RATE REVENUE VARIANCE	$ (22)	$ (11)	$ (2)	$ (4)	$ (2)	$ (2)	$ (1)
6	TOTAL OPERATING REVENUE	$ 2,366,061	$ 1,020,530	$ 268,769	$ 498,553	$ 218,635	$ 192,311	$ 167,262
7								
8	TOTAL PROD, T&D, CUST, AND A&G EXP	$ 1,466,770	$ 610,498	$ 150,471	$ 299,596	$ 142,432	$ 144,477	$ 119,296
9	TOTAL DEPR AND AMMORT EXPENSES	$ 386,941	$ 177,002	$ 43,676	$ 79,691	$ 32,804	$ 31,743	$ 22,003
10	REAL ESTATE AND PROPERTY TAXES	$ 99,528	$ 45,593	$ 11,243	$ 20,484	$ 8,424	$ 8,149	$ 5,630
11	INCOME TAXES	$ 233,191	$ 116,251	$ 26,604	$ 44,120	$ 18,212	$ 17,410	$ 10,592
12	PAYROLL TAXES	$ 19,601	$ 8,677	$ 2,060	$ 3,913	$ 1,844	$ 1,827	$ 1,280
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$ 2,206,031	$ 958,022	$ 234,054	$ 447,804	$ 203,716	$ 203,605	$ 158,803
17								
18	NET OPERATING INCOME	$ 160,030	$ 62,509	$ 34,715	$ 50,749	$ 14,920	$ (11,294)	$ 8,459
19								
20	GROSS PLANT IN SERVICE	$ 11,224,426	$ 5,141,335	$ 1,267,706	$ 2,309,965	$ 950,253	$ 919,343	$ 635,188
21	RESERVES FOR DEPRECIATION	$ 4,500,562	$ 2,119,991	$ 512,649	$ 913,333	$ 364,947	$ 351,729	$ 237,874
22								
23	NET PLANT IN SERVICE	$ 6,723,865	$ 3,021,344	$ 755,058	$ 1,396,632	$ 585,306	$ 567,614	$ 397,313
24								
25	MATERIALS & SUPPLIES - FUEL	$ 227,226	$ 83,227	$ 22,416	$ 49,074	$ 24,304	$ 25,033	$ 23,172
26	MATERIALS & SUPPLIES -LOCAL	$ 21,434	$ 11,985	$ 2,729	$ 4,287	$ 1,285	$ 1,109	$ 35
27	CASH WORKING CAPITAL	$ (13,595)	$ (5,659)	$ (1,395)	$ (2,777)	$ (1,320)	$ (1,339)	$ (1,106)
28	CUSTOMER ADVANCES & DEPOSITS	$ (14,677)	$ (6,243)	$ (4,406)	$ (2,673)	$ (845)	$ (511)	$ -
29	ACCUMULATED DEFERRED INCOME TAXES	$ (1,095,577)	$ (501,871)	$ (123,759)	$ (225,485)	$ (92,724)	$ (89,702)	$ (61,974)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$ 5,848,677	$ 2,602,783	$ 650,643	$ 1,219,059	$ 516,006	$ 502,204	$ 357,442
32								
33	RATE OF RETURN	2.736%	2.402%	5.335%	4.163%	2.891%	-2.249%	2.367%

TITLE: SUMMARY EQUAL ROR ($000's)

		MISSOURI	RESIDENTIAL	SMALL GEN SERV	LARGE GEN SERV	SMALL PRIMARY	LARGE PRIMARY	LARGE TRANS
1	BASE REVENUE	$2,331,499	$ 1,020,300	$ 249,805	$ 475,674	$ 213,303	$ 211,891	$ 160,451
2	OTHER REVENUE	$ 62,831	$ 31,808	$ 6,401	$ 11,185	$ 4,793	$ 5,137	$ 3,506
3	LIGHTING REVENUE	$ 27,111	$ 13,515	$ 3,093	$ 5,129	$ 2,117	$ 2,024	$ 1,231
4	SYSTEM REVENUE	$ 305,352	$ 125,005	$ 32,567	$ 63,976	$ 29,287	$ 29,200	$ 25,317
5	RATE REVENUE VARIANCE	$ (22)	$ (11)	$ (2)	$ (4)	$ (2)	$ (2)	$ (1)
6	TOTAL OPERATING REVENUE	$2,726,770	$ 1,190,617	$ 291,864	$ 555,960	$ 249,498	$ 248,251	$ 190,504
7								
8	TOTAL PROD., T&D, CUSTOMER, AND A&G EXP.	$1,468,790	$ 612,253	$ 150,576	$ 299,634	$ 142,449	$ 144,582	$ 119,296
9	TOTAL DEPR. AND AMMOR. EXPENSES	$ 386,941	$ 177,002	$ 43,676	$ 79,691	$ 32,804	$ 31,743	$ 22,003
10	REAL ESTATE AND PROPERTY TAXES	$ 99,528	$ 45,593	$ 11,243	$ 20,484	$ 8,424	$ 8,149	$ 5,630
11	INCOME TAXES	$ 233,191	$ 116,251	$ 26,604	$ 44,120	$ 18,212	$ 17,410	$ 10,592
12	PAYROLL TAXES	$ 19,601	$ 8,677	$ 2,060	$ 3,913	$ 1,844	$ 1,827	$ 1,280
13	FEDERAL EXCISE TAX	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	REVENUE TAXES	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15								
16	TOTAL OPERATING EXPENSES	$2,208,051	$ 959,776	$ 234,158	$ 447,842	$ 203,733	$ 203,711	$ 158,803
17								
18	NET OPERATING INCOME	$ 518,719	$ 230,841	$ 57,706	$ 108,118	$ 45,765	$ 44,541	$ 31,701
19								
20	GROSS PLANT IN SERVICE	#########	$ 5,141,335	$ 1,267,706	$ 2,309,965	$ 950,253	$ 919,343	$ 635,188
21	RESERVES FOR DEPRECIATION	$4,500,562	$ 2,119,991	$ 512,649	$ 913,333	$ 364,947	$ 351,729	$ 237,874
22								
23	NET PLANT IN SERVICE	$6,723,865	$ 3,021,344	$ 755,058	$ 1,396,632	$ 585,306	$ 567,614	$ 397,313
24								
25	MATERIALS & SUPPLIES - FUEL	$ 227,226	$ 83,227	$ 22,416	$ 49,074	$ 24,304	$ 25,033	$ 23,172
26	MATERIALS & SUPPLIES -LOCAL	$ 21,434	$ 11,985	$ 2,729	$ 4,287	$ 1,285	$ 1,109	$ 35
27	CASH WORKING CAPITAL	$ (13,595)	$ (5,659)	$ (1,395)	$ (2,777)	$ (1,320)	$ (1,339)	$ (1,106)
28	CUSTOMER ADVANCES & DEPOSITS	$ (14,677)	$ (6,243)	$ (4,406)	$ (2,673)	$ (845)	$ (511)	$ -
29	ACCUMULATED DEFERRED INCOME TAXES	#########	$ (501,871)	$ (123,759)	$ (225,485)	$ (92,724)	$ (89,702)	$ (61,974)
30								
31	TOTAL NET ORIGINAL COST RATE BASE	$5,848,677	$ 2,602,783	$ 650,643	$ 1,219,059	$ 516,006	$ 502,204	$ 357,442
32								
33	RATE OF RETURN	8.869%	8.869%	8.869%	8.869%	8.869%	8.869%	8.869%

AARP Revised Cost Allocation
Comparison of Unbundled Revenue Requirements

AmerenUE	Total Missouri	Residential	Small Gen Serv	Large Gen Serv	Small Primary	Large Primary	Large Lg Trans
Base Revenue							
Customer	$ 139,186	$ 115,418	$ 16,673	$ 5,030	$ 1,050	$ 1,014	$ 1
Production -- Demand	$ 879,478	$ 410,171	$ 97,520	$ 171,849	$ 75,658	$ 73,387	$ 50,893
Production -- Energy	$ 917,296	$ 336,242	$ 90,202	$ 197,488	$ 98,370	$ 101,420	$ 93,573
Transmission -- Demand	$ 22,366	$ 10,042	$ 2,260	$ 4,138	$ 2,136	$ 2,181	$ 1,609
Distribution -- Demand	$ 373,173	$ 206,287	$ 45,342	$ 73,067	$ 25,352	$ 22,484	$ 642
	$ 2,331,499	$ 1,078,160	$ 251,997	$ 451,572	$ 202,566	$ 200,486	$ 146,718

AARP	Total Missouri	Residential	Small Gen Serv	Large Gen Serv	Small Primary	Large Primary	Large Lg Trans
Base Revenue							
Customer	$ 77,881	$ 61,588	$ 9,630	$ 4,599	$ 1,056	$ 1,005	$ 3
Production -- Demand	$ 877,313	$ 369,792	$ 93,593	$ 180,622	$ 82,939	$ 82,449	$ 67,917
Production -- Energy	$ 915,831	$ 338,399	$ 90,493	$ 197,182	$ 97,750	$ 100,588	$ 91,420
Transmission -- Demand	$ 22,290	$ 12,095	$ 2,517	$ 3,882	$ 1,727	$ 1,656	$ 413
Distribution -- Demand	$ 438,109	$ 238,426	$ 53,572	$ 89,389	$ 29,830	$ 26,193	$ 697
	$ 2,331,423	$ 1,020,300	$ 249,805	$ 475,674	$ 213,303	$ 211,891	$ 160,451

Difference	Total Missouri	Residential	Small Gen Serv	Large Gen Serv	Small Primary	Large Primary	Large Lg Trans
Base Revenue							
Customer	$ (61,305)	$ (53,831)	$ (7,043)	$ (431)	$ 6	$ (9)	$ 3
Production -- Demand	$ (2,165)	$ (40,379)	$ (3,927)	$ 8,773	$ 7,282	$ 9,062	$ 17,024
Production -- Energy	$ (1,465)	$ 2,157	$ 290	$ (306)	$ (620)	$ (832)	$ (2,153)
Transmission -- Demand	$ (76)	$ 2,053	$ 257	$ (256)	$ (410)	$ (525)	$ (1,196)
Distribution -- Demand	$ 64,936	$ 32,140	$ 8,230	$ 16,323	$ 4,479	$ 3,709	$ 55
	$ (75)	$ (57,860)	$ (2,192)	$ 24,102	$ 10,737	$ 11,406	$ 13,733
	0.00%	-5.37%	-0.87%	5.34%	5.30%	5.69%	9.36%

Assumes requested revenue requirement, no mitigation

Development of Residential Customer Charge

Comparison of AARP Method and AmerenUE Zero-Intercept Method

Allocation Method	Residential Customer-Related RR		Res Bills	Customer Charge	
	Filed RR	Mitigated RR		Filed RR	Mitigated RR
AmerenUE Zero-Intercept Method	$ 115,418	$ 100,118	12,170,226	$ 9.48	$ 8.23
AARP Method	$ 61,588	$ 56,452	12,170,226	$ 5.06	$ 4.64

Rate Design Proposed by AmerenUE

Residential

	Present	AmerenUE Proposed
Summer (June-September)		
Basic Charge	$ 7.25	$ 8.22
All kWh	$0.0764	$0.0895
Winter (October-May)		
Basic Charge	$ 7.25	$ 8.22
Per kWh <750	0.054	$0.0557
Per kWh >750	0.037	$0.0373

Summer
Monthly Billing

kWh	Present Rates	AmerenUE Proposed	Change	Percent
0	$7.25	$8.22	$0.97	
100	$14.89	$17.17	$2.28	15.3%
300	$30.17	$35.07	$4.90	16.2%
500	$45.45	$52.97	$7.52	16.5%
753	$64.78	$75.61	$10.83	16.7%
1,000	$83.65	$97.72	$14.07	16.8%
1,500	$121.85	$142.47	$20.62	16.9%
2,000	$160.05	$187.22	$27.17	17.0%
3,000	$236.45	$276.72	$40.27	17.0%
4,000	$312.85	$366.22	$53.37	17.1%
5,000	$389.25	$455.72	$66.47	17.1%

Winter
Monthly Billing

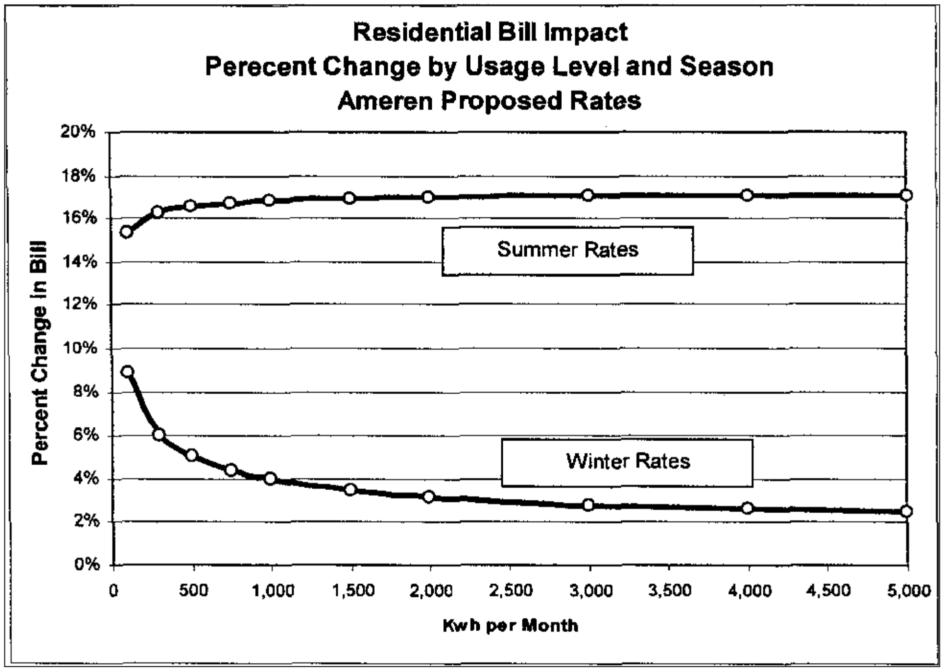
kWh	Present Rates	AmerenUE Proposed	Change	Percent
0	$7.25	$8.22	$0.97	
100	$12.67	$13.79	$1.12	8.8%
300	$23.51	$24.93	$1.42	6.0%
500	$34.35	$36.07	$1.72	5.0%
753	$48.01	$50.11	$2.10	4.4%
1,000	$57.05	$59.32	$2.27	4.0%
1,500	$75.35	$77.97	$2.62	3.5%
2,000	$93.65	$96.62	$2.97	3.2%
3,000	$130.25	$133.92	$3.67	2.8%
4,000	$166.85	$171.22	$4.37	2.6%
5,000	$203.45	$208.52	$5.07	2.5%

Rate Design Proposed by AARP

Residential

	Present	AmerenUE Proposed*	AARP Proposed*
Summer (June-September)			
Basic Charge	$ 7.25	$ 8.22	$ 4.64
All kWh	$0.0764	$0.0895	$0.0881
Winter (October-May)			
Basic Charge	$ 7.25	$ 8.22	$ 4.64
Per kWh <750	$0.0542	$0.0557	$0.0636
Per kWh >750	$0.0366	$0.0373	$0.0406

*Assumes Capped 10% Residential Increase


Residential Bill Impact
Perecent Change by Usage Level and Season
Ameren Proposed Rates
Percent Change in Bill
20%
18%
16%
14%
12%
10%
8%
6%
4%
2%
0%
Summer Rates
Winter Rates
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
Kwh per Month

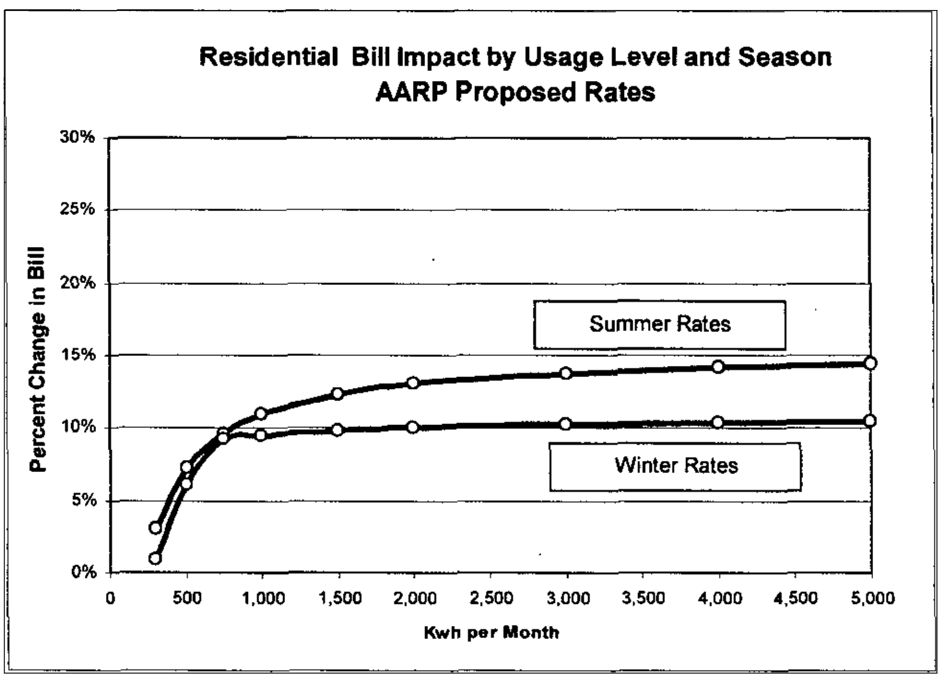

Residential Bill Impact by Usage Level and Season
AARP Proposed Rates
Percent Change in Bill
30%
25%
20%
15%
10%
5%
0%
Summer Rates
Winter Rates
0
500
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
Kwh per Month

EXHIBIT RJB-7

Excerpt from Electric Tariff of Rocky Mountain Power - Wyoming

8 Pages

NPC PCAM Tariff
Schedule 94

Available

In all territory served by the Company in the State of Wyoming.

Applicable

All retail tariff rate schedules shall be subject to two normally scheduled rate elements, a Base Net Power Costs (NPC) charge and Deferred NPC Adjustment that together recover total net power costs including fuel, purchased power (including NPC financial hedges), wheeling, and sales for resale for natural gas and electricity and excluding other NPC costs not specifically modeled in the Company's production cost model.

Definitions and Basic Concepts:

NPC Rate Effective Period shall be the 12 month period beginning April 1, 2007 and extending through March 31, 2008 in the first PCAM application filed on or before February 1, 2007. In each succeeding PCAM application, the NPC Rate Effective Period shall be the 12-month period beginning April 1st and extending through March 31st following the NPC Comparison Period. The Company may file and the Commission may approve PCAM applications with amortization periods for deferred amounts longer than 12 months to reflect extraordinary circumstances.

NPC Comparison Period shall be the five-month historic period beginning July 1, 2006 through November 30, 2006 in the first PCAM application filed on February 1, 2007. In each succeeding PCAM application, the NPC Comparison Period shall be the historic 12-month period beginning December 1 and extending through November 30th prior to the NPC Rate Effective Period.

Base NPC is calculated by taking the sum of the monthly total Company NPC as approved by the Commission in a stipulated agreement or as a result of the most recent Wyoming general rate case (GRC). The Base NPC shall be recovered from all retail tariff rate schedules through the unbundled rate elements as set forth in this Schedule. The Base NPC shall reflect an Embedded Cost Differential (ECD) adjustment.

(continued)

Definitions and Basic Concepts *(continued)***:**

Adjusted Actual NPC: Adjusted Actual NPC is the annual sum of the monthly total Company amounts properly recorded in FERC Account Numbers: 501 (Steam Power Generation – Fuel), 503 (Steam Power Generation – Steam from other Sources) and 547 (Other Power Generation – Fuel) for coal, steam and natural gas purchased and or sold; 555 (Purchased Power), 565 (Wheeling); and 447 (Sales for Resale). Adjustments shall be made to actual costs that are consistent with the Company's production dispatch model, to remove prior period accounting entries made during the accrual period, and to include applicable Commission-adopted adjustments from the most recent general rate case. Hydro normalization, forced outages and other operational volatility circumstances shall be excluded from adjustment because these unpredictable events result in net power cost volatility that the PCAM captures for rate making purposes.

Deferred NPC Adjustment is a charge applicable to all retail tariff rate schedules as set forth in this schedule. The Deferred NPC Adjustment is calculated by taking the sum of the monthly differences between the Adjusted Actual NPC and the corresponding monthly Base NPC adjusted for the Revenue Variation Adjustment, and adjusted to reflect the prorated total Company Dead Band, Sharing Proportions, and Wyoming Allocated Share and include Symmetrical Interest accrual on the Customer Proportion of net Deferred NPC Adjustment balances outside of the Dead Bank.

TABLE 1

Adjusted Actual Total NPC Layer	Customer Proportion	Company Proportion
Over $200 million above Base	Company recovers 90% from Customers	Company absorbs 10%
Over $100 million and up to $200 million above Base	Company recovers 85% from Customers	Company absorbs 15%
Over $40 million and up to $100 million above Base	Company recovers 70% from Customers	Company absorbs 30%
$40 million above Base (Dead Band)	Company recovers 0% from Customers	Company absorbs 100%

(continued)

Definitions and Basic Concepts *(continued)*:

$40 million below Base (Dead Band)	Company returns 0% to Customers	Company retains 100%
Over $40 million and up to $100 million below Base	Company returns 70% to Customers	Company retains 30%
Over $100 million and up to $200 million below Base	Company returns 85% to Customers	Company retains 15%
Over $200 million below Base	Company returns 90% to Customers	Company retains 10%

Dead Band is illustrated in Table 1 above is a total Company annual symmetrical range of plus $40 million above the base and $40 million below the base. There will be no deferral or accrual of interest for costs which fall within the Dead Band. If the NPC Comparison Period is longer or shorter than an annual period, the Dead Band shall be prorated on the basis of the applicable monthly NPC Base included in the NPC Comparison Period.

Sharing Proportion is also illustrated in Table 1 above and is the symmetrical proportion of Deferred NPC Adjustment eligible for recovery from, or repayment to customers. The Sharing Proportion shall be layered to reflect a Customer Proportion and a Company Proportion. There will be no deferral or accrual of interest for costs which are included in the Company Proportion. If the NPC comparison period is longer or shorter than an annual period, the thresholds between the various layers shall be prorated based on the number of months in the comparison period.

Revenue Variation Adjustment is equal to the ratio of actual Wyoming monthly kilowatt-hours sold divided by the Wyoming monthly kilowatt-hours assumed in the load forecast used to calculate the Base NPC rate elements.

Symmetrical Interest shall be computed on the net accumulated Deferred NPC Adjustment balance monthly at the rate determined by the Commission pursuant to Rule 241, Customer Deposits. Interest shall be paid to the Company on net Deferred NPC under-collections and interest shall be paid to Customers on net deferred NPC over-collections. Appropriate provisions for interest during the amortization period shall be included in the calculation of Deferred NPC

(continued)

Definitions and Basic Concepts *(continued)*:

Symmetrical Interest *(continued)*

Adjustments in the NPC Rate Effective Period. If the Commission implements a proposed Deferred NPC Adjustment on an interim basis, any excess charges or under charges shall be refunded to or collected from customers with interest at the rate established by the Commission pursuant to Rule 241. If the Commission approves an amortization period for a Deferred NPC balance of longer than 12 months, interest on any balance not recovered within 12 months shall be calculated based on the Company's most recent authorized weighted average cost of capital.

Wyoming Allocated Share shall be calculated using Wyoming Allocation Factors. Wyoming Allocation Factors where Wyoming's percent of total system factors prescribed for allocation of net power costs pursuant to the Revised Protocol or current Commission approved interjurisdictional allocation methodology as approved in the most recent general rate case.

Wyoming Actual Adjusted ECD is recalculated for each NPC Comparison Period. The Wyoming Actual Adjusted ECD will be calculated in the same manner that the Wyoming ECD Base was calculated except the only values that will be updated in the recalculation are the amounts from the FERC accounts included in the definition of Adjusted Actual NPC and associated megawatt hours for the NPC Comparison Period.

Wyoming ECD Base is the sum of the ECD adjustments included in the Wyoming revenue requirement as most-recently approved by the Commission either in a stipulated agreement or as a result of a GRC.

Timing

The Company shall file Deferred NPC Adjustment applications on or before February 1st of each year under normal circumstances. The implementation and effective date of the Deferred NPC Adjustment shall be April 1st of each year under normal circumstances. Nothing shall prevent the Company from filing out-of-period PCAM applications to reflect extraordinary circumstances. The Company may elect

(continued)

Timing *(continued)*

to defer recovery of a NPC under collection at its discretion and the Company may elect to defer refund of a NPC over recovery if the balance in the deferred account is less than $1 million on a Wyoming Jurisdiction allocated basis.

Deferred NPC Adjustment:

Deferred NPC for the Comparison Period shall be calculated monthly and recorded on the Company's books, based on the following formula:

Deferred NPC adjustment = ((((Adjusted Actual NPC – (Base NPC x Revenue Variation adjustment)) +/- Dead band) x Sharing Proportion) x Wyoming Allocated Share) + Symmetrical Interest.

At the end of each comparison period, the Deferred NPC Adjustment may also include an ECD Adjustment. An ECD Adjustment shall be included in the Deferred NPC Adjustment if the value of the Deferred NPC Adjustment is not zero. The ECD adjustment formula is as follows:

ECD Adjustment = (Wyoming Actual Adjusted ECD – (Wyoming ECD Base x Revenue Variation Adjustment))

The initial Base NPC will be set at $660 million on an annual basis. For purposes of the first comparison period from July 1, 2006 through November 30, 2006 as adjustment will be made in the deferral calculation, which increases the Base NPC for those months from $321 million to $336 million. If the Company has not or will not file a new general rate case prior to February 1, 2007, the Base NPC will remain $660 million for the new NPC Comparison Period starting December 1, 2006 and shall remain at that level until rates are set in the Company's next general rate case. Otherwise, the Base NPC will be revised to $700 million on an annual basis on December 1, 2006 for purposes of the deferral calculation only.

Base NPC and the Deferred NPC Adjustment shall be allocated to all retail tariff rate

(continued)

Deferred NPC Adjustment: *(continued)*

schedules and, where applicable, to the demand and energy rate components within each schedule based on the applicable allocation factors and cost of service study relationships established in the Company's last GRC. The allocated and classified costs shall then be divided by appropriate billing determinants to calculate the specific rates set forth in this schedule for the Base NPC and Deferred NPC Adjustment. As such, the Deferred NPC adjustment will be spread to customer classes and rate elements in the same proportion as Base NPC.

Monthly Billing

All charges and provisions of the applicable rate schedule will be applied in determining a Customer's bill except that the Customer's total electric bill will be increased or decreased by an amount equal to the product of all kilowatt demand multiplied by the following dollar per kilowatt rate plus all kilowatt-hours of use multiplied by the following cents per kilowatt-hour rate:

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
2	**	Demand per kWh	0.148¢	0.000¢
		Energy per kWh	1.180¢	0.000¢
15	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
25	Secondary	Demand in excess of 15 kW per kW	$0.89	$0.00
		Energy per kWh	1.185¢	0.000¢
	Primary	Demand in excess of 15 kW per kW	$0.87	$0.00
		Energy per kWh	1.159¢	0.000¢
33	Primary	Supp. Demand per kW	$0.78	$0.00
		Energy per kWh	1.160¢	0.000¢

(continued)

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
33	Transmission	Supp. Demand per kW	$0.77	$.000
		Energy per kWh	1.135¢	0.000¢

40	**	Demand per kW	$0.74	$0.00
		Energy per kWh	1.210¢	0.000¢
46	Secondary	On-Peak Demand per kW	$0.79	$0.00
		Energy per kWh	1.186¢	0.000¢
	Primary	On-Peak Demand per kW	$0.78	$0.00
		Energy per kWh	1.160¢	0.000¢
48T	Transmission	On-Peak Demand per kW	$0.77	$0.00
		Energy per kWh	1.135¢	0.000¢
51	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
53	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
54	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
57	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
58	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢

(continued)

Monthly Billing *(continued)*

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
207	**	Demand per kWh	0.013¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
210	**	Demand per kW	$0.73	0.000¢
		Energy per kWh	1.209¢	0.000¢
211	**	Demand per kWh	0.013¢	0.000¢
		Energy per kWh	1.186¢	0.000¢

212-1	**	Demand per kWh	0.013¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
212-2	**	Demand per kWh	0.076¢	0.000¢
		Energy per kWh	1.189¢	0.000¢
212-3	**	Demand per kWh	0.076¢	0.000¢
		Energy per kWh	1.189¢	0.000¢

** Rates will be applicable for all Delivery Voltage levels.

Rules

Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by regulatory authorities.

Excerpt from "Principles of Public Utility Regulation"
by James C. Bonbright

[w]hat this last-named cost imputation overlooks, of course, is the very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by this system. For it makes no allowance for the density factor (customers per linear mile or per square mile). Our casual empiricism is supported by a more systematic regression analysis in (Lessels, 1980) where no statistical association was found between distribution costs and number of customers. Thus, if the company's entire service area stays fixed, an increase in number of customers does not necessarily betoken any increase whatever in the costs of a minimum-sized distribution system. While, for the reasons just suggested, the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible, its exclusion from the demand-related costs stands on much firmer ground.

For this exclusion of minimum-sized distribution system costs makes more plausible the assumption that the remaining cost of the secondary distribution system is a cost which varies continuously (and, perhaps, even more or less directly) with the maximum demand imposed on this system as measured by peak load. But if the hypothetical cost of a minimum-sized distribution system is properly excluded from the demand-related costs for the reason just given, while it is also denied a place among the customer costs for the reasons stated previously, to which cost function does it then belong? The only defensible answer, in our opinion, is that it belongs to none of them. Instead, it should be recognized as a strictly unallocable portion of total costs. And this is the disposition that it would probably receive in an estimate of long-run marginal costs. But fully distributed cost analysts dare not avail themselves of this solution, since they are the prisoners of their own assumption that "the sum of the parts equals the whole". They are therefore under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground for costs that they cannot plausibly impute to any of their other cost categories.

From:

James C. Bonbright (with edition co-authors Albert L. Danielsen and David R. Kamerschen.) "Principles of Public Utility Rates," Public Utility Reports, Inc., 1988 (2nd edition), pp. 491-492.