

Exhibit No.: _____
Issue(s): Fuel Adjustment Clause
Class Cost Allocations
Residential Rate Design
Sponsoring Party: AARP

BEFORE THE PUBLIC SERVICE COMMISSION OF MISSOURI

DIRECT TESTIMONY OF RONALD J. BINZ

ON BEHALF OF AARP

**Union Electric Company d/b/a AmerenUE
Case No. ER-2007-0002**

Filed: December 29, 2006

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DIRECT TESTIMONY OF RONALD J. BINZ

1 **Q What is your name and address?**

2 A My name is Ronald J. Binz. My business address is 333 Eudora Street, Denver,
3 Colorado 80220-5721.

4 **Q On whose behalf are you testifying in this case?**

5 A I am testifying on behalf of AARP, a nonprofit, nonpartisan membership
6 organization for people aged fifty and over. AARP provides information and resources;
7 advocates on legislative, consumer, and legal issues; assists members to serve their
8 communities; and offers a wide range of products and services to its members.
9 Nationally, AARP has over thirty-six million members, including more than 778,000
10 members in Missouri.

11 **Q What is your occupation?**

12 A I am President of Public Policy Consulting, a firm specializing in energy
13 and telecommunications regulatory matters. I provide consulting services to a variety of
14 public-sector and private-sector clients in the energy and telecommunications industries,
15 primarily in the regulatory arena. These have included consumer organizations, senior
16 citizen groups, agricultural utility consumers, homebuilders, state agencies, commercial
17 customer groups, telecommunications carriers, resellers and local governments. My
18 consulting practice dates to 1979, except for the years 1984-1995 when I served as
19 Colorado Consumer Counsel.

20 In my role as Consumer Counsel for the State of Colorado, I represented the
21 interests of residential, small business and agricultural consumers of telecommunications

1 and energy before the Colorado Public Utilities Commission, the Federal
2 Communications Commission (FCC), the Federal Energy Regulatory Commission
3 (FERC), the courts and legislative bodies.

4 While Consumer Counsel I served as the President of the National Association of
5 State Utility Consumer Advocates (NASUCA) for two years and chaired the
6 organization's Telecommunications Committee for three years. In those roles, and as
7 President of the Competition Policy Institute, I have testified fourteen times before
8 Congressional committees on energy and telecommunications matters.

9 These have included consumer organizations, senior citizen groups, agricultural
10 utility consumers, homebuilders, state agencies, telecommunications resellers and local
11 governments.

12 I am a frequent speaker and presenter at industry, regulatory and legislative
13 conferences and symposia. I am a member of the Harvard Electricity Policy Group and
14 recently served on two advisory commissions to the Federal Communications
15 Commission. My *curriculum vitae* is attached as Appendix A to this testimony.

16 **Q What is your educational background?**

17 A I received a B.A in Philosophy from St. Louis University in 1971. I received an
18 M.A in Mathematics from the University of Colorado in 1977. I entered the Masters
19 Program in Economics in 1980 and completed 27 hours of graduate work. I was
20 researching my Masters Thesis on Regulated Industries in 1983 when I was appointed to
21 the Public Utilities Commission by Colorado Governor Richard Lamm.

1 **Q What is the purpose of your testimony in this case?**

2 A I was asked by AARP to review the proposals of Union Electric Company d/b/a
3 AmerenUE (“AmerenUE” or “Company”) in three areas: 1) the proposed Fuel
4 Adjustment Clause (“FAC”); 2) the option for treating off-system energy sales within this
5 adjustment mechanism; and 3) the Company’s proposed class cost allocation and
6 residential rate design. In this testimony I examine the Company’s proposals in these
7 areas and make recommendations to the Commission.

8 **Q How is your testimony organized?**

9 A First, I present an introduction to the testimony and a summary of my findings
10 and recommendations for the Commission. Second, I summarize the Company’s
11 proposals for class cost allocation and rate design, for a Cost Adjustment Mechanism
12 (Fuel Adjustment Clause or FAC) and for an optional means for treating off-system
13 energy sales. Third, I discuss the role and impact of cost adjustment mechanisms in
14 utility rate making and offer an alternative approach to the Company’s proposal for the
15 Commission’s consideration. Fourth, I recommend three modifications to AmerenUE’s
16 cost allocation methodology and present an alternative rate design for residential electric
17 rates in Missouri. Finally, I summarize my findings and recommendations.

I. Introduction and Summary of Testimony

18 **Q Mr. Binz, why is this case important to AARP members in Missouri?**

19 A From my discussions with AARP, I understand that AARP is the nation’s largest
20 membership organization representing the interests of Americans aged 50 and older and

1 is concerned about the health, safety and financial security of older Americans. AARP
2 advocates for affordable and accessible energy services on the federal and state levels.

3 AARP knows that electricity service is crucial to health and personal welfare,
4 especially for older Americans: the ability to have air conditioning during the summer
5 and heat during the winter at affordable rates is absolutely necessary. AARP understands
6 that the loss of affordable utility services would have devastating consequences.

7 The Company is proposing a very large base rate increase for customers in
8 Missouri – an overall increase of \$360 million, or 18% for the average customer.
9 Although the Company proposes to limit the increase to 10% for residential customers,
10 this is still a substantial increase. Not surprisingly, this proposal will be attacked by
11 representatives of other customer classes, so AARP must consider that residential
12 customer could be at risk for an increase larger than 10%.

13 My testimony is designed to ensure that, whatever level of rates the Commission
14 decides to award the Company, the residential customer class bears only its fair share.
15 For that reason, AARP is interested that the class cost allocation adopted in this case be
16 fair and that the rate design methodology apportions costs among residential customers
17 fairly.

18 Finally, AmerenUE is proposing to modify substantially the manner in which it
19 collects its rates by instituting a Cost Adjustment Mechanism called the Fuel Adjustment
20 Clause or FAC. As I discuss later in the testimony, a FAC will significantly affect the
21 Company's incentives. This has implications for rates in the future, another item of
22 concern for AARP.

1 **Q Please summarize your conclusions and recommendations to the**
2 **Commission.**

3 A After reviewing the Company’s testimony and exhibits, I have developed the
4 following findings and recommendations for the Commission:

5 **The AmerenUE FAC Proposal**

- 6 ▪ No FAC should be approved for AmerenUE. In general, regulators
7 should avoid using “automatic” cost adjustment mechanisms for rate
8 regulated companies. While there are valid arguments for and against
9 their use, I think the balance weighs against cost adjustment
10 mechanisms in most cases.
- 11 ▪ Cost adjustment mechanisms should be used only for utility costs that
12 meet three qualifications:
 - 13 ▪ They represent a significant portion of a utility’s costs;
 - 14 ▪ They fluctuate significantly;
 - 15 ▪ The costs are outside the utility’s control.

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

- 20
- 21 ▪ If, despite the objections of consumer representatives, the Commission
22 decides to adopt any cost adjustment mechanism for AmerenUE in
23 Missouri, then it should be designed to retain as many of the desirable
24 incentives of cost of service regulation as possible. These include
25 valuable incentives for the utility to operate efficiently and to manage
26 its power costs.
- 27 ▪ If the Commission decides to approve an FAC for AmerenUE in
28 Missouri, it should be constructed so that some significant fraction of
29 AmerenUE’s energy costs remains at risk. Such a feature is critical to
30 maintain the correct incentives for the Company. An FAC recently
31 adopted in Wyoming contains some desirable features that this
32 Commission should consider.
- 33 ▪ In its alternative proposal for treating off-system energy sales,
34 AmerenUE provides the Commission (perhaps inadvertently) with an

1 approach that can be used for the FAC. The Company commends this
2 mechanism to the Commission as one way to allow relatively
3 automatic adjustments to the revenue to be included.

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

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

13 **Cost Allocation and Rate Design**

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

19 ▪ The Commission should reject the “zero-intercept” methodology used
20 by AmerenUE to allocate distribution costs. The method shifts
21 revenue requirements from commercial customers onto residential
22 customers and inflates the monthly customer charge.

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

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

II. The AmerenUE Proposals

1 **Q What is AmerenUE seeking in this case with respect to increased revenues?**

2 A The Company is seeking an increase in annual base electric revenues of
3 \$360 million, an increase of about 17.7% over the revenues produced by existing rates.
4 The rate increase is being contested by several other parties, including the Commission
5 staff, the Office of the Public Counsel and the Missouri Attorney General each of whom
6 is recommending a *reduction* in base rates.

7 **Q What is the Company proposing for cost allocation and rate design?**

8 A The Company filed a class cost of service study that indicates how its proposed
9 increase would be spread to the various customer classes. The study produces an
10 increase for each customer class required to bring that class's earned rate of return to the
11 Company's average target rate of return. However, the Company does not strictly apply
12 the results of study for class cost allocation. Instead, the Company is proposing to limit
13 the rate increase to the residential to a 10% increase in base rates, with the shortfall
14 spread to other customer classes other than lighting customers.

15 Among many features of the class cost of service study, there are two salient
16 features: 1) the study uses the Average and Excess Demand (4-NCP) methodology to
17 allocate generation demand costs; and 2) the study uses the "zero-intercept" method to
18 classify and allocate a portion of distribution costs as customer-related.

19 This Company's class cost of service study is also used to design rates for the
20 various customer classes. For residential customers the study results in a monthly
21 customer service charge of \$8.22, an increase from the existing level of \$7.25. All costs

1 not recovered in the customer service charge are collected in the per-kilowatt-hour charge
 2 for residential customers. The study yields a summer month energy charge of \$0.0895
 3 per kWh, up from the current rate of \$0.0764 per kWh. The winter month energy charge
 4 for the first 750 kWh in a month was increased to \$0.0557 from the existing level of
 5 \$0.0540; for kWh in excess of 750, the energy charge was increased to slightly, to
 6 \$0.0373 per kWh from \$0.0370.

7 The following table summarizes the existing and proposed rate elements for the
 8 Residential customer class.

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

1 **Q How do these price changes affect customer bills at various usage levels?**

2 **A** The following table shows the percentage change in monthly bills for customers
3 at various usage levels. Since the rate structures are different for the summer and winter
4 seasons, the table shows bills in each season separately.

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%

5 Both of these tables are attached to this testimony as Exhibit RJB-4.

1 **Q What other proposals are made by AmerenUE in this case?**

2 In its filing, the Company is proposing to institute a cost allocation mechanism
3 called the FAC. The mechanism is designed to track the Company's expenses related to
4 fuel and purchased power and will flow through to customers any differences between
5 the level of these costs collected in base rates and the costs actually incurred in the future.

6 The FAC will be updated quarterly, based on fuel costs and purchased power
7 costs incurred in the quarter prior to the most recent quarter. Since actual expenses may
8 be higher or lower than the base rate level, the FAC rate increment applied to customer
9 bills may be positive or negative. The FAC also contains a true-up mechanism to account
10 for under-collection of over-collection of target costs subject to the mechanism. The
11 FAC is also designed to permit the Commission, if it chooses, to flow through variations
12 in the level of margins from the Company's off-system energy sales.

13 Concerning off-system energy sales, AmerenUE describes two proposals for
14 accounting for these revenues in its rates. The first method is straightforward: the base
15 rate revenue requirement would be credited with \$183 million, the estimated test year
16 level of margins for off-system energy sales. The second method includes a smaller level
17 of revenues in base rates (\$120 million), and proposes to use a tapered percentage sharing
18 mechanism for margins in excess of \$120 million. The customers' share of the margin in
19 excess of the base amount would be flowed through the FAC. The following table,
20 which repeats information contained in the testimony of AmerenUE witness Schukar
21 describes the alternative treatment of margins from off-system sales.

<u>Level of Off-System Sales Margins (in millions of \$)</u>	<u>Customer Share</u>	<u>AmerenUE Share</u>	<u>Effective Share for Customers</u>
\$0 - \$120	100%	0%	100%
\$121 - \$180	80%	20%	100% - 93%
\$181 - \$360	50%	50%	92% - 72%
Over \$360	100%	0%	72% or more

III. Analysis of the FAC Proposal

1 **Q Do you recommend that the Commission adopt an energy cost adjustment**
2 **mechanism for AmerenUE?**

3 A. In general, I do not recommend that Commissions establish “automatic” cost
4 adjustment mechanisms for regulated companies. While there are valid arguments for
5 and against their use, I think the balance weighs against cost adjustment mechanisms in
6 most cases. There are several reasons for my position.

7 First, a cost adjustment mechanism tends to dull the incentives to efficiency that
8 cost of service regulation provides to utilities. To see why, consider that a firm operating
9 in a competitive market is not able to change prices to accommodate changes in costs, at
10 least not unilaterally – not until the market price changes. Pressure from cost increases
11 requires a competitive firm to become more productive in order to maintain its
12 profitability.

13 It has long been recognized that “regulatory lag” in cost of service regulation
14 mimics this process in a competitive market. It can benefit customers and the utility alike
15 by supplying the incentives that competition provides in other industries.

1 There are certainly specific situations in which regulators might usefully consider
2 adopting cost recovery mechanisms to speed up utility cost recovery or to simplify
3 regulatory practices. However, I do not think the situation of AmerenUE in Missouri is
4 one of those cases. Those situations are usually triggered by the very poor financial
5 health of a utility or the need to ease the burden on regulators.

6 Indeed, fuel adjustment clauses originated during a period when increases in
7 certain expense items were badly hurting utility earnings and regulators were being
8 swamped with “pancaked” rate cases. As I will explain further below, those may be valid
9 reasons for using cost allocation mechanisms, as long as regulators understand the
10 trade-offs and find that the benefits obtained from using such mechanisms outweigh the
11 damage done to the utility’s incentives.

12 The most important thing to remember when considering whether to adopt a cost
13 adjustment mechanism is that moving away from traditional regulatory treatment comes
14 with a potentially large cost. In my opinion, cost adjustment mechanisms are often
15 adopted by regulators not because of the incentives they provide, but in spite of them.

16 **Q Please discuss your other reasons for opposing implementation of most cost**
17 **adjustment mechanism.**

18 My second reason is that cost adjustment mechanisms tend to skew choices the
19 regulated company must make by rearranging its economic incentives. A utility is
20 continuously faced with short-term and long-term decisions about fuel and power
21 purchases, whether to “build or buy,” etc. To the extent that an adjustment mechanism is
22 a “thumb on the scale” for some choices in preference to others, it may induce the

1 Company to make choices it might not otherwise make, to the detriment of the
2 Company's customers.

3 My third concern with cost adjustment mechanisms relates to their fairness. Cost
4 adjustment mechanisms shift the balance of risk between utilities and their customers;
5 more generally, they change the balance of equities embodied in cost of service
6 regulation. Cost adjustment mechanisms are usually applied only to costs that trend
7 upward over time. It would be a rare utility that would propose a cost mechanism to
8 track decreasing costs. By removing an upward-trending cost and tracking it with a cost
9 adjustment mechanism, the balance of fairness in ratemaking is changed.

10 **Q. What policy questions should the Commission examine in determining**
11 **whether to approve a cost adjustment mechanism as proposed by AmerenUE in this**
12 **case?**

13 A. At the outset, I suggest the Commission should address at least these three basic
14 policy questions:

- 15 ▪ What is the purpose of a FAC in Missouri? What feature of regulation
16 needs repair?
- 17 ▪ How does the FAC modify the equities of cost of service regulation as
18 it is currently practiced?
- 19 ▪ How does the FAC affect the incentives facing AmerenUE? How can
20 the Commission retain the desirable aspects of current regulation?

1 **Q What types of cost are typically considered candidates for recovery through**
2 **cost adjustment mechanisms?**

3 The AmerenUE proposal is to establish a cost adjustment mechanism for changes
4 in fuel costs (including fuel transportation costs) and purchased power. More generally,
5 it is well established in utility regulation that cost adjustment mechanisms should apply
6 only to costs that meet three criteria:

- 7 ▪ They represent a significant portion of a utility's costs;
 - 8 ▪ They fluctuate significantly;
 - 9 ▪ The costs are outside the utility's control.
- 10

11 **Q. Are fuel and purchased power costs a significant portion of AmerenUE's**
12 **revenue requirement?**

13 A. Yes, they are. Fuel costs and purchased power costs are large fraction of the
14 Company's proposed revenue requirement in the case pending before the Commission at
15 the current time.

16 **Q. Do the Company's power costs fluctuate?**

17 A While it might be argued that these costs will trend upward over time, I am
18 unaware of any evidence that fuel and purchased power costs in Missouri are expected to
19 fluctuate significantly in the intermediate future. The Company has not offered any
20 evidence in support of the FAC proposal that shows the Company's power costs are
21 expected to change rapidly in Missouri.

22 Of course, increases over time in any cost category do not necessarily indicate
23 that a Commission should institute a "recovery mechanism." To the extent that increases

1 in cost cannot be offset by productivity gains, increased sales, etc., the utility always has
2 the alternative to file to increase rates. This type of pressure on a utility to become
3 progressively more efficient is actually a *good thing*: good for customers and companies
4 alike.

5 **Q. Are variations in fuel and purchased power costs within the control of**
6 **AmerenUE?**

7 A. It is true that AmerenUE cannot affect two determinants of its power costs:
8 wholesale market prices and the weather. On the other hand, there are other
9 determinants of fuel and power costs that AmerenUE can influence or even control in the
10 short-run and long-run. Here is a partial list of drivers for fuel and purchased power over
11 which the Company exercises control or significant influence:

- 12 ▪ Basic choices in the utility's resource plan
- 13 ▪ The ratio of owned generation and purchased power
- 14 ▪ Terms of wholesale contracts
- 15 ▪ Efficiency of system operations
- 16 ▪ Transmission system design and operation
- 17 ▪ Degree and type of fuel risk in purchase decisions
- 18 ▪ Hedging activities
- 19 ▪ Demand side choices
- 20 ▪ Advocacy for beneficial rate design proposals

21
22 Thus we see that the Company is neither passive nor powerless in the face of
23 changing fuel and power costs. The Company shapes its power cost future by the
24 numerous choices it makes in these areas. The Commission should tread carefully when

1 changing the way it regulates these activities and the basic incentives provided to
2 AmerenUE.

3 **Q. What about the effect of an FAC on AmerenUE's incentives?**

4 A. In many ways, regulation may have its greatest effect, not through limits on prices
5 in the short run, but rather through the incentives it creates for utilities in the longer run. It
6 is important to consider some of the signals that will flow from approval of the FAC.

7 The Commission is undoubtedly aware of the debates about incentives that cost
8 regulation provides: examples include the Averch-Johnson effect for capital investment
9 levels; the connection between cost regulation and quality of service; and the incentives
10 inherent in price cap regulation.

11 For better or for worse, the presence of regulation in a market shapes the behavior
12 of the market participants. While utility regulators might want to limit their role to being a
13 substitute for the competition that is missing in these industries, it is rarely possible to limit
14 regulation's effects that way. The question is usually not how to eliminate stray incentives
15 in decisions but, instead, which ones to accept.

16 AmerenUE has operated in Missouri without a power cost adjustment mechanism
17 since at least 1979. In my view, this has created a desirable risk/reward proposition for
18 consumers and for the Company.

19 Under the current regulatory regime for AmerenUE in Missouri, fundamental
20 decisions such as whether to "build or buy," whether and how to hedge power costs,
21 choices of fuel acquisition strategies, and even rate design choices are shaped by the fact
22 that differences between projected and actual power costs accrue to the benefit or detriment

1 of shareholders between rate cases. A FAC mechanism alters in a fundamental way the
2 risk analysis that AmerenUE executive will consider when making those decisions. As I
3 will explain later in this testimony, if the Commission decides to adopt some form of a
4 FAC in this case, it should try to retain as many of the desirable incentives of standard
5 regulation as possible when designing the FAC.

6 **Q What is AARP's overall position on the FAC?**

7 A For the reasons I have articulated above, AARP opposes implementation of an FAC
8 or other "pass-through" mechanisms, primarily because of the damage such clauses do to
9 the utility's incentives to be efficient. In addition, counsel for AARP has informed me that
10 AmerenUE's ability to request an FAC in this case is still subject to objections relating to
11 AmerenUE's failure to file an FAC tariff along with the tariffs that initiated this rate case
12 and that these arguments will be further explored in legal briefs. For these reason, my
13 testimony addressing modifications to the proposed FAC should not be taken as a waiver of
14 AARP's primary recommendation that the Commission reject the FAC or its legal
15 objections related to the filing of an FAC in this case.

16 **Q Is it necessary for the Commission to adopt an FAC in order to ensure that**
17 **AmerenUE recovers its costs?**

18 A No. It is a common misconception that utility regulation is a "cost-plus" exercise
19 and that a regulator's duty is to ensure that companies "recover" their costs. This is
20 factually incorrect. Under cost of service regulation, past costs are not "recovered;" they
21 are simply used as a guide to the future costs that new rates attempt to match. In fact,
22 "recovering" past costs, absent a specific exception, is retroactive ratemaking. An FAC

1 distorts the traditional ratemaking equation and essentially inoculates a future rate request
2 of a utility from a claim of retroactive ratemaking with respect to the subject costs.

3 The “regulatory bargain” in Missouri is similar to that in many other states: a
4 utility’s rates are set on the basis of a reasonable projection of future costs. The traditional
5 ratemaking method uses an adjusted “test year” to estimate the required future revenues by
6 estimating the future costs and future level of profit required. To the extent that actual
7 costs are lower or higher than these estimated costs, a utility’s shareholders are better off
8 (or worse off) for a period of time. If a utility can justify changing its base rates, it files a
9 case and the Commission renders a decision. If the Commission (or another party) believes
10 rates are systematically too high going forward, that party can file to reduce rates, and the
11 Commission renders a decision.

12 Missouri utilities have functioned since 1979 without the advantage of an FAC and
13 none to my knowledge has alleged that regulation is impossible without an FAC. The new
14 law passed by the Missouri general assembly (SB 179) authorizes, but does not require, the
15 Commission to approve an FAC. Importantly, SB 179 also contemplates that the
16 Commission may modify a proposed adjustment mechanism to provide “incentives to
17 improve the efficiency and cost-effectiveness” of the utility’s fuel and purchased power
18 procurement activities.

1 **Q Mr. Binz, before discussing your recommendations concerning AmerenUE’s**
2 **FAC proposal, please discuss the rate treatment of off-system energy sales as a**
3 **component of a FAC mechanism.**

4 A To begin with, AmerenUE proposes to include the margins from off-system sales as
5 an “above-the-line” item, ensuring that these substantial profits are counted towards the
6 Company’s regulated revenue requirement. This is a continuation of current Commission
7 practice that recognizes these unregulated sales and the related margins are made possible
8 only through the use of generating plants and fuel stocks paid for by ratepayers. Through
9 the testimony of its witness Shawn Schukar, the Company estimates that the sales margins
10 will be \$183 million in the first year of new rates. The Company proposes to credit this
11 amount – \$183 million – against the revenue requirement in the case.

12 **Q What is the alternative proposal presented by AmerenUE?**

13 In his testimony, AmerenUE Chief Financial Officer Warner L. Baxter describes an
14 optional approach to the handling of off-systems sales margins in which amounts above a
15 base level (proposed to be \$120 million) would be shared between customers and the utility
16 in a percentage that varies with the size of the variance from the base level. The proposal is
17 also discussed in the testimony of AmerenUE witness Shawn Schukar. The following chart
18 from Mr. Schukar’s testimony summarizes this option.

<u>Level of Off-System Sales Margins (in millions of \$)</u>	<u>Customer Share</u>	<u>AmerenUE Share</u>	<u>Effective Share for Customers</u>
\$0 - \$120	100%	0%	100%
\$121- \$180	80%	20%	100% - 93%
\$181 - \$360	50%	50%	92% - 72%
Over \$360	100%	0%	72% or more

1 Mr. Baxter argues that this sharing proposal

2 ...provides important, yet balanced incentives to the
3 Company to improve its plant operations and lower its costs
4 in a safe and reliable manner.

5 He adds that the sharing mechanism

6 ...addresses a significant uncertainty associated with
7 determining the appropriate level of off-system sales margins
8 to include in base rates by establishing a baseline target that
9 is likely to be achieved under most circumstances, thereby
10 mitigating the possibility that the baseline amount will not be
11 achieved due to uncontrollable, volatile market conditions or
12 uncertain operating conditions.

13 To paraphrase, Mr. Baxter is arguing that the sharing structure he recommends is a
14 way to pass through volatile sales margins to customers while maintaining incentives for
15 the company to be efficient.

16 The margin-sharing proposal is tied to the FAC proposal in the testimony of
17 AmerenUE's witness Martin J. Lyons, Jr. He identifies a factor called "SMS" (the
18 customer share of margins from off-system sales) in the FAC that can be used to flow
19 through the customer share of off-system sales margins above a base amount contained in
20 rates.

21 **Q Is AmerenUE proposing to use the margin-sharing mechanism as part of the**
22 **FAC in this case?**

23 A Not exactly. Although the margin-sharing proposal is addressed by three
24 AmerenUE witnesses, Mr. Schukar says that the Company is not actually proposing it and
25 that the Company's rate filing assumes that \$183 million in off-system sales is credited to

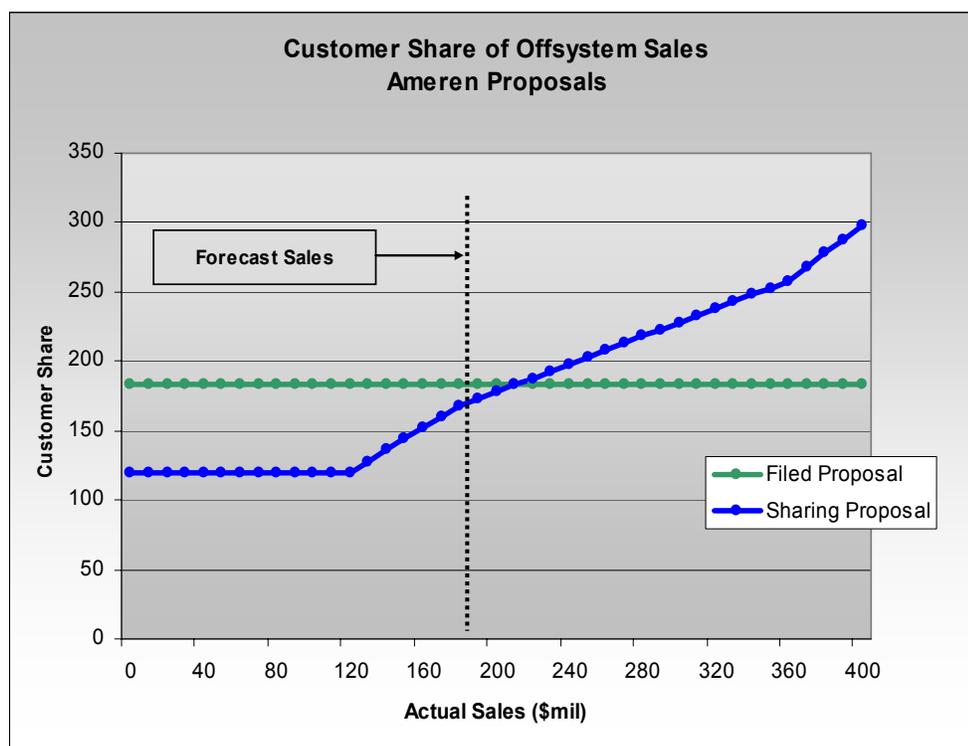
1 rates with no sharing mechanism. Mr. Lyons states that “the mechanism discussed above
2 could be implemented as part of the resolution of this case.”

3 **Q What is your opinion of the AmerenUE margin-sharing proposal and its**
4 **connection to the FAC proposal?**

5 A I have two comments. First, the base amount and sharing percentages must be
6 revised before the proposal should have any interest for consumers. To see why, note that
7 AmerenUE projects the most likely level of off-system sales margins is \$183 million. If
8 this level is achieved under AmerenUE’s sharing proposal, customers would be credited
9 with only \$169.5 million of the \$183 million (\$120 million base plus 80% of \$60 million
10 plus 50% of \$3 million). The Company would keep \$13.5 million.

11 This is clearly inferior to the current Missouri practice (and AmerenUE’s primary
12 proposal) in which base rates would be credited with the full \$183 million. In a sense,
13 AmerenUE would be getting a “bonus” of \$13.5 million merely for achieving the level of
14 off-system sales margins that the Company itself has projected as the most likely. (Stated
15 another way, customers would “break even” with the alternative sharing proposal only if
16 AmerenUE achieved margins of \$210 million, in which case the shared amount would be
17 \$183 million.)

18 The following chart compares the Company’s proposal in this case (\$183 million in
19 revenue credits against cost of service) versus this sharing plan.



1 I should also note that there is substantial debate in the revenue requirement
 2 testimony filed by intervening parties about the correct estimate of margins associated with
 3 off-system sales. For example, in his non-proprietary testimony for Missouri Industrial
 4 Energy Consumers, Mr. Dauphinais estimates that the Company’s margin estimate of \$183
 5 million is too low by about \$30.5 million.

6 As with the FAC, AARP opposes the sharing mechanism proposed by AmerenUE
 7 to treat off-system sales as unfair to consumers. However, later in my testimony I will
 8 describe modifications to the margin-sharing structure that would make it more equitable,
 9 assuming there is interest in adopting a mechanism like this and coupling it with any FAC
 10 that the Commission might approve.

1 **Q What is your second comment about the Company’s margin-sharing proposal?**

2 A My second observation arises from Mr. Baxter’s testimony about the merits of the
3 Company’s margin-sharing proposal. Recall that his basic message is that the sharing
4 mechanism would be a way to pass through volatile sales margins to customers while
5 maintaining incentives for the company to be efficient.

6 My observation is this: the exact same comments can be made about an FAC that
7 employs a sharing mechanism. If we simply exchange “volatile sales margins” for
8 “fluctuating power costs” and switch the roles of the utility and its consumers, the very
9 same formulation applies. Mr. Baxter would have to agree that a properly designed sharing
10 mechanism for the FAC can retain some of the same desirable incentives that would
11 otherwise be jettisoned if an FAC were set up to track exactly the Company’s expense
12 levels.

IV. Changes to the FAC Proposal

13 **Q Mr. Binz, please summarize your testimony to this point concerning the**
14 **Company’s FAC proposal.**

15 A In general, I think the Commission should not authorize automatic cost adjustment
16 mechanisms such as the FAC. While these mechanisms might superficially be said to track
17 a utility’s costs more accurately, their effects can be much larger and more injurious to
18 consumers than that simple description. Adjustment clauses such as the FAC significantly
19 reduce the pressure on a utility to be efficient, in its fuel and purchased power operations,
20 but more generally in all its operations. Simply put, the “cure” offered by an FAC can be
21 worse than the “disease”.

1 For these reasons, I think the Commission should conclude that there is no
2 compelling reason to approve the FAC proposal. Since an FAC will likely increase
3 consumer costs in the longer run by reducing efficiency incentives for AmerenUE, the
4 Commission should reject the use of an FAC.

5 **Q Assuming, instead, that the Commission decides to authorize a version of the**
6 **FAC, what modifications would you recommend to the AmerenUE proposal?**

7 A If the Commission decides to approve a version of the FAC despite these
8 reservations, it should modify the Company’s proposal. The Missouri statute governing
9 Cost Adjustment Mechanisms contains several qualifications on a CAM, which are
10 designed to protect consumers. These are useful and should be (must be) included in the
11 design of any FAC.

12 But there is another way in which the statute can be used by the Commission to
13 design an FAC for AmerenUE that lessens some of the negative effects that could
14 otherwise accompany an FAC. I am speaking, of course, about incentives to efficiency for
15 the Company. The statute clearly gives the Commission authority and discretion on this
16 point, and if any FAC is adopted, I think the Commission must exercise that discretion.

17 I’ve already hinted that the testimony of AmerenUE witness Baxter concerning the
18 margin-sharing proposal provides some guidance for how structure a “pass-through”
19 mechanism so that it contains correct incentives. The important point is that a mechanism
20 should induce the utility to remain efficient, using a combination of risk and reward. There
21 is a very simple approach to doing this and a variety of more complex approaches.

1 **Q What is the simple approach to retaining incentives while adopting an FAC?**

2 A Recall that current regulation incorporates an estimate of fuel and purchased power
3 costs in base rates. If actual costs are lower, the utility earns more money; if actual costs
4 are higher than the base rate increment, the utility earns less. None of the variation from
5 the base is added to or subtracted from base rates. Thus, current regulation is the
6 ***0% Pass-Through Case.***

7 In contrast, the FAC proposed by AmerenUE would track every penny of
8 differences between base rates and actual power costs. Whether over or under, the entire
9 variation is passed through to customers in the form of an increment on the monthly bill.
10 The AmerenUE proposal is the ***100% Pass-Through Case.***

11 Between these extremes are infinitely many middle-ground cases. It is perfectly
12 reasonable for the Commission to apply the FAC to exactly 50% of the over/under
13 deviation from base rates.

14 **Q Does this mean that the utility will recover only 50% of its power costs?**

15 A No. If the Commission approves a ***50% Pass-Through FAC***, the vast majority of
16 AmerenUE's power costs will still be collected in base rates. The 50% fraction applies
17 only to the variation from that base amount. And since the fraction applies symmetrically
18 to cost differences, the utility will sometimes over recover, sometimes under recover, at
19 half the rate that happens today.

1 **Q If the Commission applies the FAC to 50% of the variation in power costs**
2 **from base rates, is it systematically making rates inexact?**

3 A No more than rates are only estimates of future costs today. By using the 50% rule,
4 the Commission would strike an exact middle ground between the type of regulation that
5 has existed since 1979 in Missouri and the type of regulation proposed by AmerenUE in
6 this case.

7 But it would be unfair to call the 50% proposal simply a middle ground. This
8 approach maintains the same incentives for efficiency that traditional cost of service
9 regulation provides to utilities. When faced with the choice of acting to lower its expenses,
10 AmerenUE would know that it will be allowed to “keep” half of the costs savings in this
11 approach. In contrast, under the 100% FAC proposed by the Company, any efficiency
12 gains are taken away from AmerenUE at its next FAC filing.

13 The same logic applies in reverse. Unless a utility’s bad behavior is found to be
14 imprudent (a very high standard) it faces no consequence for incurring excess costs under
15 the FAC. Excess costs will simply be passed through in the next FAC filing. On the other
16 hand, if the utility is sharing its over/under power cost results, the utility faces a
17 disincentive for bad behavior that results in higher costs because only half of such higher
18 costs are passed through the FAC, with the balance absorbed by the Company.

1 **Q Please describe more complex approaches to retain incentives in the context of**
2 **a cost adjustment mechanism.**

3 A A more sophisticated adjustment mechanism that maintains efficiency incentives
4 may involve a “tapered” sharing formula and possibly a “dead band” in which there is no
5 sharing.

6 **Q Please illustrate this concept with an example.**

7 A The following table is taken from the Wyoming tariff of Rocky Mountain Power
8 (RMP), a division of PacifiCorp, which is itself a division of Mid-American Energy
9 Holdings Company. This tariff was approved by the Wyoming PSC in May 2006.

10 As can be seen from the table, RMP is allowed to collect (or is required to pass
11 through to consumers) differences in its “net power costs” according to a schedule given in
12 the table. The company’s base rates include a level of net power cost recovery (currently
13 about \$600 million) or \$0.01328 per kWh for residential customers). If actual net power
14 costs are within a “dead band” of \$40 million on either side of the base amount, no
15 adjustment is made. Outside of the dead band, the Company returns a portion of its over
16 recovery to consumers, or passes on a portion of its under recovery to consumers. The
17 percentages change on a sliding scale until, at the outer margin, 90% of the variations in the
18 Company’s net power costs are collected from customers or refunded to them.

Excerpt from Power Cost Adjustment Mechanism (PCAM) Tariff Rocky Mountain Power – Wyoming		
Adjusted Actual Total Net Power Costs 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%
\$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%

1 **Q** What are the advantages of an approach like this, compared to a pass-through
2 **mechanism such as that proposed by AmerenUE?**

3 **A** In my view, there are several advantages. First, the presence of the dead band
4 means that the mechanism comes into play only after there is a meaningful difference
5 between base rate costs and actual costs. This means that the original incentives I
6 discussed earlier remain in place within the dead band.

7 Second, outside the dead band, the Company would still retain real incentives to
8 control costs. If RMP is able to lower its power costs, it retains the first \$40 million (the

1 dead band) plus 30% of the next \$60 million in savings. Similar, but opposite, incentives
2 work in the other direction.

3 Third, since 90% of all variations in net power costs that exceed \$200 million above
4 the base will be recovered through the mechanism, RMP is protected against very large
5 fluctuations in the wholesale power markets, as was experienced in the western U.S. in
6 2000-2001. In other words, this tariff functions as a “backstop” against serious financial
7 damage to the utility. Again, it serves this function this without completely removing
8 incentives for the utility to be efficient during normal markets.

9 **Q Are there useful parallels to the situation in the AmerenUE case?**

10 A Yes, I think so. If the Commission wishes to create a fuel and purchased power
11 recovery mechanism that provides meaningful efficiency incentives (and not simply
12 collects or refunds every penny of variation), I think the Wyoming tariff provides a good
13 starting point. I noted above that the Wyoming tariff contains a base net power cost charge
14 of \$0.01328 per kWh for residential customers. This is extremely close to the base cost
15 level contemplated by AmerenUE: in his testimony, Mr. Lyons states that the base fuel and
16 purchase power cost total \$0.01341 per kWh.

17 Other states have adopted fuel cost adjustment mechanisms with some of the
18 features illustrated in the Wyoming tariff, as well as others. While the details are important
19 and must be considered carefully, there are undoubtedly many potential arrangements of
20 the details that would serve both Missouri consumers and AmerenUE well. I have included
21 a complete copy of the Rocky Mountain Power PCAM tariff as Exhibit RJB-7.

1 **Q If, despite objections of the parties, the Commission decides to consider a**
2 **margin-sharing proposal in a FAC, what changes do you recommend the Commission**
3 **make to the sharing proposal described in AmerenUE’s testimony?**

4 A I wish to repeat that it is perfectly defensible to continue the practice of including a
5 fixed level of margin revenue in base rates. However, if the Commission decides to
6 consider a margin-sharing proposal for off-system sales, it can build incentives into the
7 structure, similar to the discussion about the FAC. Here are two considerations the
8 Commission should make before adopting any margin-sharing proposal.

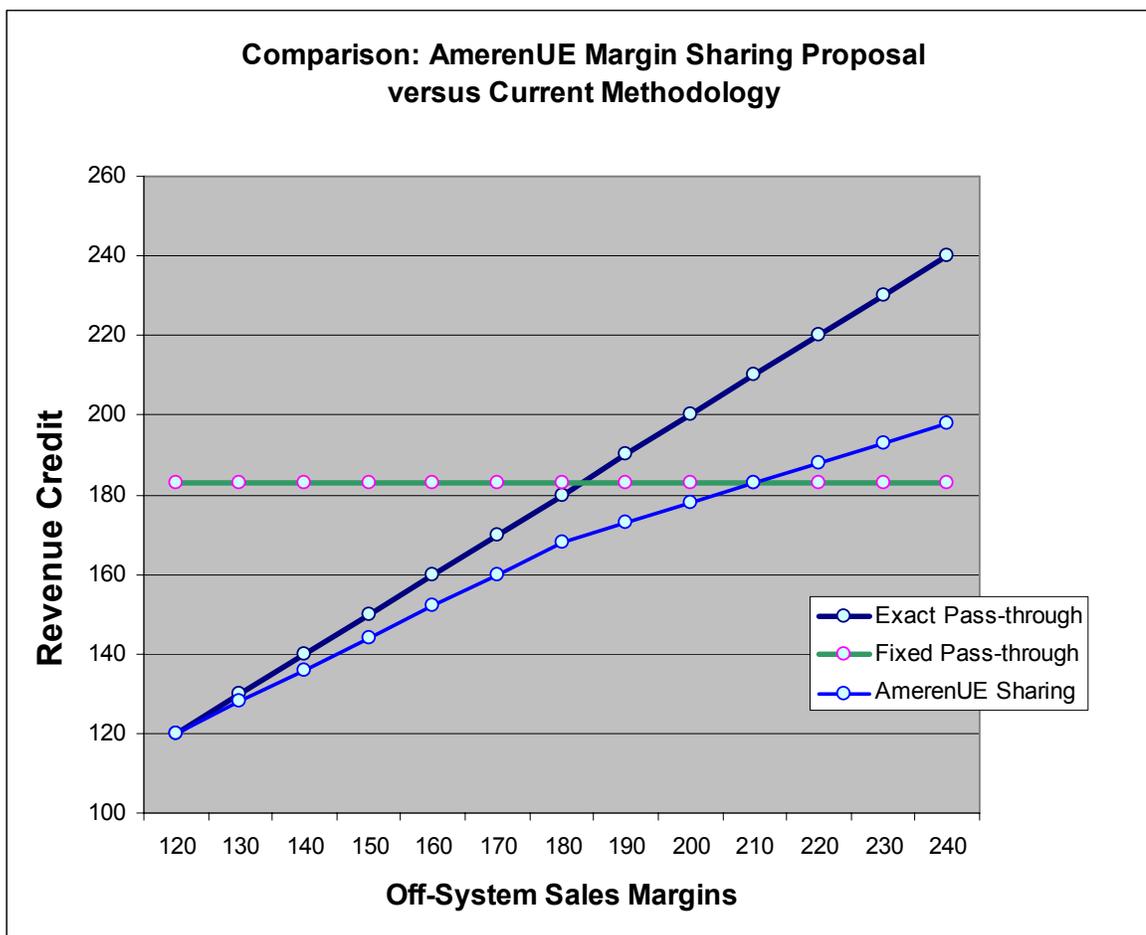
9 ▪ The base level of revenue credits should be set on the basis of the best
10 evidence of the likely future value. This level is at least \$183 million in
11 this case.¹ The Commission should not set the base amount below the
12 likely future margins, as advocated by AmerenUE when it proposes a
13 \$120 million base credit level. Any “base” level different than the likely
14 future level will result in an unfair and objectionable sharing
15 mechanism.

16 ▪ The margin sharing mechanism can have a different structure than the
17 FAC: the “bands” and sharing percentages need not be the same.

18

19 To illustrate this first point, I prepared a chart comparing the AmerenUE
20 margin-sharing proposal to the current system of simply including an estimate of future
21 margins as fixed credit against the revenue requirement. Since AmerenUE sets the base at
22 \$120 million instead of at its own estimate of \$183 million, the proposal is obviously not
23 fair to retail customers.

¹ The level of future off-system sales is a matter of dispute in the revenue requirement portion of this case. The figure of \$183 million was filed AmerenUE and is used to illustrate the concepts.



1

2 **Q Do you have any other recommendations to the Commission on these issues?**

3 **A** Yes. If the Commission wishes to adopt either an incentive-based FAC or
 4 margin-sharing mechanism, the Commission should consider ordering the parties to
 5 negotiate the details of implementation. In my experience, the implementation details of
 6 incentive-based mechanisms can be complex and are better left to technical negotiations.

V. Cost Allocation and Rate Design

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

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

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

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

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

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

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

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

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

20 There are other widely-used cost allocation methods that incorporate more directly
21 the class coincident peak demands to allocate demand costs. One such method is the
22 Peak and Average Method discussed in the NARUC Cost Allocation Manual. This

1 method develops allocation factors that appropriately combine the coincident peak demand
2 of each class with each class's average demand (its energy use).

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

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

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

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

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

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

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

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

14 I have several objections to the practice:

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

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

21 A At base, this theory invites us to imagine a distribution system so small that it can
22 serve a system made up only of customers who do not purchase any electricity. Under this

1 theory, the utility must add this hypothetical amount when a new customer comes on the
2 system. This “connection system” which the theory seeks to describe does not, and cannot,
3 exist except in the imagination of a person doing the cost allocation study.

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

13 **Q Have similar analyses been provided by others?**

14 A Yes. In his testimony in this case, AmerenUE witness quotes from James C.
15 Bonbright in his classic 1961 work “Principles of Public Utility Rates.” Mr. Hanser is
16 correct to quote from Dr. Bonbright, who is the academic dean of public utility regulation.
17 In that same influential work, Dr. Bonbright, addresses the issue of assigning distribution
18 system costs to the customer charge. While Dr. Bonbright acknowledged that utilities
19 might well try to estimate the cost of the hypothetical minimum system, he describes the
20 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.

1 costs are cannot be allocated because they are not “caused” by the addition of customers to
2 the utility system; nor are they strictly related to the customers’ demand. Here is a quote
3 from Bonbright on the topic.

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

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

20 **Q Why should “zero-intercept” or “minimum system” costs not be considered to**
21 **be customer-related costs?**

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

³ Ibid.

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

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

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

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

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

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

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

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

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

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

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

3 **Q Please describe Exhibit RJB-1.**

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

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

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

16 A Changing to the Peak and Average Method modifies a single allocation factor, the
17 one used to allocate production demand costs. This change affects the allocation of
18 production plant directly, and then other account allocations indirectly. A useful way to
19 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%

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

3 Exhibit RJB-2 shows that the combination of two changes: the change in allocation
4 methods to Peak and Average and eliminating the zero-intercept method. The combination
5 of these changes reverses the shift of revenue requirement from the large commercial
6 customers to residential customers and lowers the residential revenue requirement by about
7 \$55 million. The largest beneficiaries of this shift had been the rate classes of the largest
8 customers. In percentage terms, these changes reduce the residential revenue requirement
9 by 5.7%, while increasing rates for the commercial rate classes by 5.3% to 9.4%, compared
10 to the method proposed by AmerenUE.

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

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

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

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

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

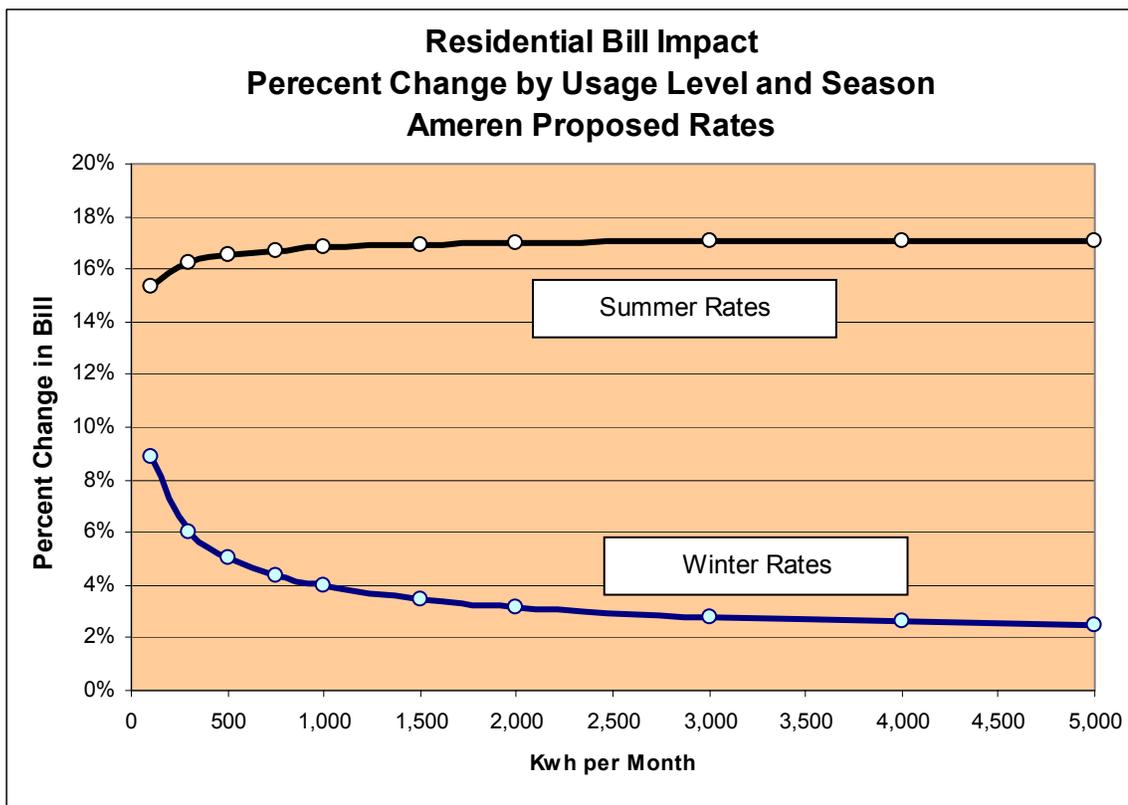
12 **Q Please discuss your change to the percentage of demand revenues collected**
13 **during the summer months.**

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

20 The decision to collect 60% of demand costs in four months has the expected effect
21 on rates: summer residential rates are much higher than winter rates. This may be a
22 desirable effect to encourage conservation during peak months. It also has a plausible

1 cost-based rationale. However, the differential between summer prices and winter prices is
2 becoming quite large as this method is applied year after year.

3 Under the rates proposed by AmerenUE, the average residential summer kWh
4 would cost 9.64 cents, while an average kWh in the winter would cost 5.64 cents, a ratio of
5 1.7 to 1. A related effect is that the Company's rate design raises summer rates by about
6 16%, while winter rates are raised by only about 2.8%. The following chart shows how the
7 impact of the Company's choice of 60% loads the increase on summer rates.



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

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

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

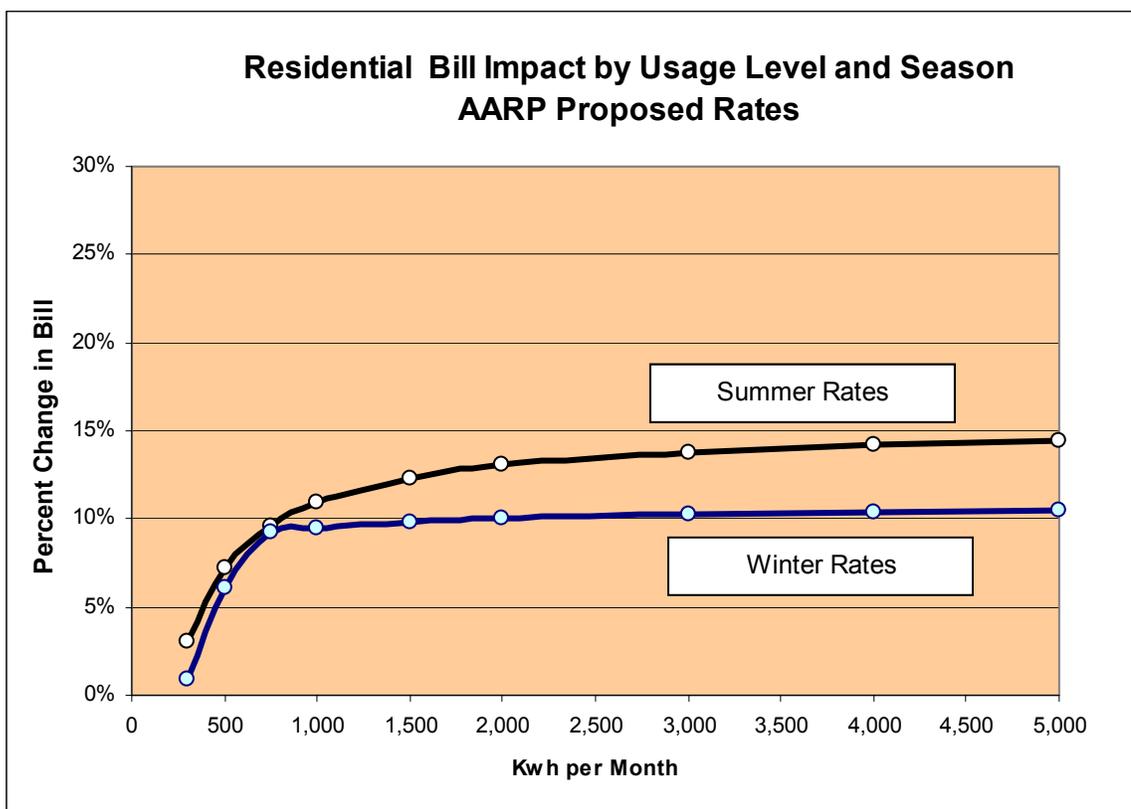
12 A Yes. The following table shows the residential rates necessary to collect the
13 revenue requirement associated with a 10% (mitigated) increase to the customer class as
14 proposed by the Company. For ease of comparison, I have included the Company's
15 proposed rates on the same table. As can be seen by inspection, the AARP-recommended
16 rates have a lower customer charge, relatively lower summer rates and relatively higher
17 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			

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

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



1
2

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

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

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

- 1 ▪ Use the 4-CP Peak and Average allocation methodology to allocate production
2 demand costs;
- 3
- 4 ▪ Classify and allocate 100% of distribution-related costs in Accounts 364 to 368
5 as demand costs;
- 6
- 7 ▪ For the residential customer class, consider adjusting the portion of demand
8 costs recovered in the summer months downward from 60% to achieve a
9 desirable summer/winter price ratio.

VI. Summary of Testimony

1 **Q Mr. Binz, please summarize your recommendations.**

2 **A** Here are my findings and recommendations:

3 **The AmerenUE FAC Proposal**

- 4 ▪ No FAC should be approved for AmerenUE. In general, regulators
5 should avoid using “automatic” cost adjustment mechanisms for rate
6 regulated companies. While there are valid arguments for and against
7 their use, I think the balance weighs against cost adjustment mechanisms
8 in most cases.
- 9 ▪ Cost adjustment mechanisms should be used only for utility costs that
10 meet three qualifications:
- 11 ▪ They represent a significant portion of a utility’s costs;
- 12 ▪ They fluctuate significantly;
- 13 ▪ The costs are outside the utility’s control.
- 14 The costs examined in this case meet the first of these criteria: fuel and
15 purchased power costs comprise a significant portion of AmerenUE’s
16 total electric costs. However, these costs only partially meet the second
17 and third criteria.
- 18
- 19 ▪ If, despite the objections of consumer representatives, the Commission
20 decides to adopt any cost adjustment mechanism for AmerenUE in
21 Missouri, then it should be designed to retain as many of the desirable
22 incentives of cost of service regulation as possible. These include
23 valuable incentives for the utility to operate efficiently and to manage its
24 power costs.
- 25 ▪ If the Commission decides to approve an FAC for AmerenUE in
26 Missouri, it should be constructed so that some significant fraction of
27 AmerenUE’s energy costs remains at risk. Such a feature is critical to
28 maintain the correct incentives for the Company. An FAC recently
29 adopted in Wyoming contains some desirable features that this
30 Commission should consider.
- 31 ▪ In its alternative proposal for treating off-system energy sales,
32 AmerenUE provides the Commission (perhaps inadvertently) with an
33 approach that can be used for the FAC. The Company commends this

1 mechanism to the Commission as one way to allow relatively automatic
2 adjustments to the revenue to be included.

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

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

12 **Cost Allocation and Rate Design**

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

17 ▪ The Commission should reject the “zero-intercept” methodology used
18 by AmerenUE to allocate distribution costs. The method shifts revenue
19 requirements from commercial customers onto residential customers and
20 inflates the monthly customer charge.

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

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

30 **Q Does this conclude your testimony?**

31 **A** Yes.

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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 C 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

	<u>MISSOURI</u>	<u>RESIDENTIAL</u>	<u>SMALL GEN SERV</u>	<u>LARGE GEN SERV</u>	<u>SMALL PRIMARY</u>	<u>LARGE PRIMARY</u>	<u>LARGE TRANS</u>	
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%

**AARP Revised Cost Allocation
Comparison of Unbundled Revenue Requirements**

AmerenUE	Total		Small	Large	Small	Large	Large
	Missouri	Residential	Gen Serv	Gen Serv	Primary	Primary	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		Small	Large	Small	Large	Large
	Missouri	Residential	Gen Serv	Gen Serv	Primary	Primary	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		Small	Large	Small	Large	Large
	Missouri	Residential	Gen Serv	Gen Serv	Primary	Primary	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

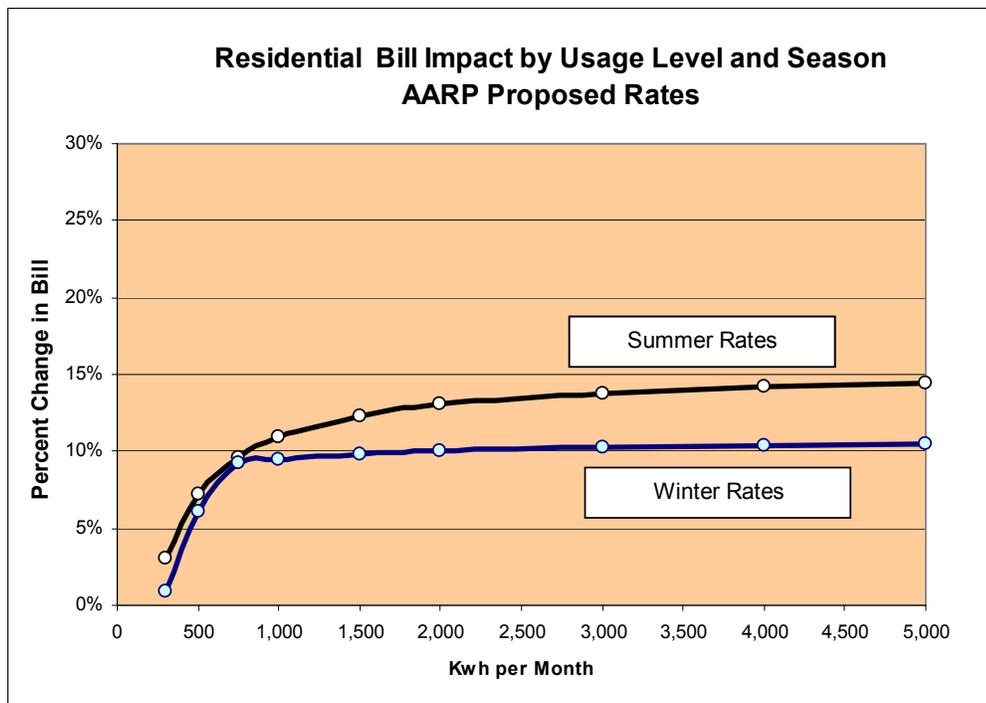
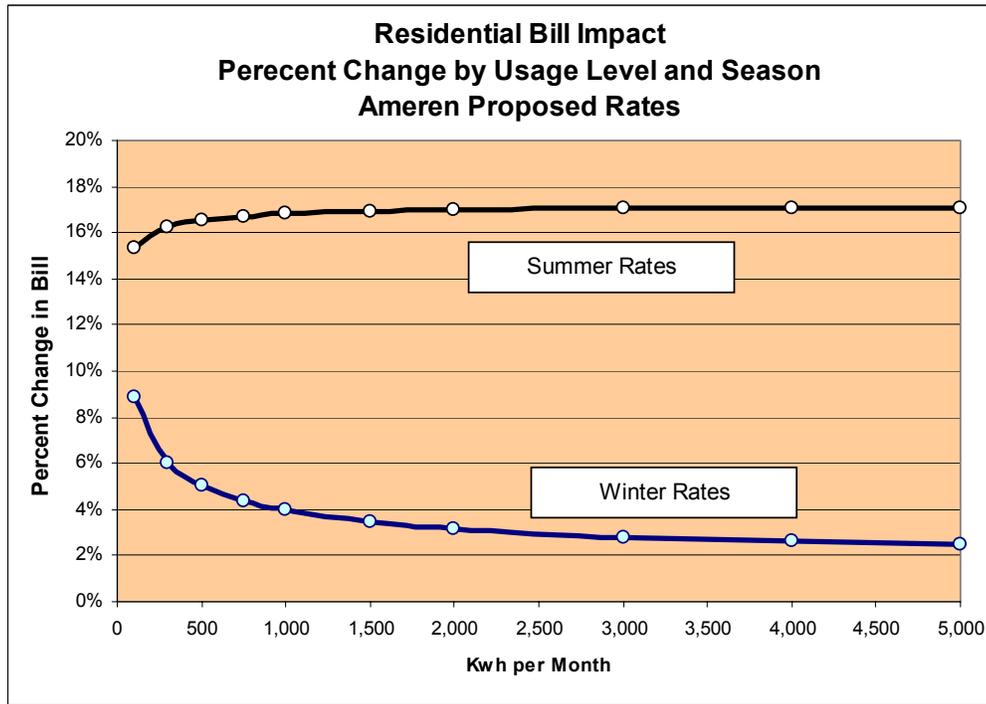
Rate Design Proposed by AmerenUE

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			



**Excerpt from Electric Tariff of
Rocky Mountain Power - Wyoming**

8 Pages

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

ROCKY MOUNTAIN POWER

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NPC PCAM Tariff Schedule 94

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)

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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)

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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)

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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	\$0.00
		Energy per kWh	1.135¢	0.000¢

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40	**	Demand per kW Energy per kWh	\$0.74 1.210¢	\$0.00 0.000¢
46	Secondary	On-Peak Demand per kW Energy per kWh	\$0.79 1.186¢	\$0.00 0.000¢
	Primary	On-Peak Demand per kW Energy per kWh	\$0.78 1.160¢	\$0.00 0.000¢
48T	Transmission	On-Peak Demand per kW Energy per kWh	\$0.77 1.135¢	\$0.00 0.000¢
51	**	Demand per kWh Energy per kWh	0.017¢ 1.186¢	0.000¢ 0.000¢
53	**	Demand per kWh Energy per kWh	0.017¢ 1.186¢	0.000¢ 0.000¢
54	**	Demand per kWh Energy per kWh	0.017¢ 1.186¢	0.000¢ 0.000¢
57	**	Demand per kWh Energy per kWh	0.017¢ 1.186¢	0.000¢ 0.000¢
58	**	Demand per kWh Energy per kWh	0.017¢ 1.186¢	0.000¢ 0.000¢
(continued)				
Monthly Billing <i>(continued)</i>				
Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
207	**	Demand per kWh Energy per kWh	0.013¢ 1.186¢	0.000¢ 0.000¢
210	**	Demand per kW Energy per kWh	\$0.73 1.209¢	0.000¢ 0.000¢
211	**	Demand per kWh Energy per kWh	0.013¢ 1.186¢	0.000¢ 0.000¢

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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.