BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a AmerenUE for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area.	)))))	**Case No. ER-2007-0002**

AFFIDAVIT OF BARBARA A. MEISENHEIMER

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Barbara A. Meisenheimer, of lawful age and being first duly sworn, deposes and states:

1. My name is Barbara A. Meisenheimer. I am Chief Utility Economist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Barbara A. Meisenheimer

Barbara A. Meisenheimer

Subscribed and sworn to me this 27nd day of February 2007.

Kendelle R. Stratton

Kendelle R. Stratton
Notary Public

My Commission expires February 4, 2011.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI

KENDELLE R. STRATTON
My Commission Expires
February 4, 2011
Cole County
Commission #07004782

SURREBUTTAL TESTIMONY

OF

BARBARA MEISENHEIMER

AMERENUE
CLASS COST OF SERVICE AND RATE DESIGN

CASE NO. ER-2007-0002

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. Barbara A. Meisenheimer, Chief Utility Economist, Office of the Public Counsel, P. O. 2230, Jefferson City, Missouri 65102.

Q. HAVE YOU TESTIFIED PREVIOUSLY IN THIS CASE?

A. Yes. I submitted direct testimony on cost of service and rate design issues on December 29, 2006. I submitted rebuttal testimony on cost of service, rate design and tariff issues on February 5, 2007. I submitted supplemental rebuttal testimony on cost of service, rate design and tariff issues on February 22, 2007.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to responsd to the rebuttal testimony of other parties.

Q. IN PREPARATION OF YOUR TESTIMONY, WHAT MATERIALS DID YOU REVIEW?

A. I have reviewed the rebuttal testimony on cost of service and rate design filed by the Staff, Noranda Aluminum Inc., Missouri Industrial Energy Consumers (MIEC), the Commercial Group, AARP and AmerenUE.

Q. WHAT IS YOUR GENERAL RESPONSE TO MR. BRUBAKER'S REBUTTAL TESTIMONY THAT CRITICIZES THE PRODUCTION CAPACITY ALLOCATOR USED BY OPC AND AARP?

A. Mr. Brubaker inaccurately claims that OPC and AARP use nontraditional production cost allocation methods which are not explained as to methodology, supported as to theory or shown to be applicable to AmerenUE system. His testimony is misleading because it fails to recognize that a weighted average and coincident peak (A& CP) method that allows discretion in selection of the number of coincident peaks is among the NARUC-recognized production capacity cost allocation methods.

Q. PLEASE EXPLAIN.

A. Part IV B. of the NARUC Electric Utility Cost Allocation Manual describes methods for developing energy weighted production plant cost allocations. Section 4 of Part IV discusses production cost allocations based on judgmental energy weightings. Page 57-59 of the NARUC Manual specifically recognize weighted average and coincident peak methods where the coincident peak (CP) may be estimated based on more than one period of peak use. The Manual describes the method as follows:

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

The Manual goes on to provide two examples of weighted methods, one based on average demand and a single period of coincident peak use (A&1CP) and another that incorporates average demand and 12 periods of peak use (A&12CP) in developing an allocator. I have included a copy of the relevant pages in Schedule 1 to this testimony.

I used an A&3CP and AARP used a A&4CP method in calculating the production allocator. Both AARP and I used a measure of load factor (LF) as the weight assigned to the average portion of the allocator and used 1- LF as the weight assigned to the peak portion of the allocator. This is a common method of assigning weights used in the NARUC Manual. Both the 3CP used by AARP and the 4CP I used to represent the peak portion of the allocator fall well within the number of peak periods recognized in the NARUC Manual.

Q. ARE BOTH THE 3CP AND 4CP REPRESENTATIVE OF THE PEAK DEMAND ON AMERENUE'S SYSTEM?

A. Yes. Both the 3CP and 4CP are reasonably representative of the peak demand on AmerenUE's system. In considering the number of peak periods to use in developing my allocator, I considered using either a 3CP or 4CP. While I selected the 3CP as the more conservative choice, I believe either is reasonable.

As illustrated in Table 1 the 4CP that AARP used includes periods when demand was in excess of 85% of the systems maximum peak. The 3CP that I used reflects periods when demand was in excess of 95% of the system's maximum peak.

Table 1

Coincident Peak (CP) @ Generation (Converterd to MWh)

	Residential	SGS	LGS	SPS	LPS	LTS	Total	% System Peak
Apr-05	1438	655	1221	545	601	474	4936	59%
May-05	2345	729	1366	652	645	474	6211	75%
Jun-05	3869	890	1535	657	584	474	8010	96%
Jul-05	3879	968	1682	664	660	468	8321	100%
Aug-05	3838	886	1518	652	617	467	7978	96%
Sep-05	2927	882	1590	649	621	457	7125	86%
Oct-05	2524	805	1468	658	648	461	6564	79%
Nov-05	2302	689	1200	470	508	471	5640	68%
Dec-05	3035	619	1270	538	520	475	6457	78%
Jan-06	2562	567	1044	477	479	477	5605	67%
Feb-06	2775	566	1133	468	490	479	5911	71%
Mar-06	2483	534	1006	473	446	479	5421	65%

Source Workbook: "Warwick Elect - MO ECCOS_AE4NCP_07.06_I", Sheet "System_Peak_CP"

Q. WHY IS IT REASONABLE TO USE MULTIPLE PEAKS IN DEVELOPING THE MEASURE OF COINCIDENT PEAK USED IN THE PRODUCTION CAPACITY ALLOCATOR?

A. As illustrated in Table 2, a class's relative share of system demand may vary significantly. Using multiple measures of coincident peak reduces the likelihood of relying on an anomalous single peak as the basis of the allocator. In addition, the system is designed to meet a range of system demands and a class's relative share may vary in that range. I believe it is reasonable to include more than simply the highest single peak to reflect the class's relative share of system demand. Allowing for peaks in excess of 85% retains the conceptual focus on determining peak demand while also reflecting each class's relative share of variation in system peak demands.

Table 2

Share Of Coincident Peak (CP) @ Generation (Converterd to MWh)

	Residential	SGS	LGS	SPS	LPS	LTS
Jun-05	48.30%	11.12%	19.16%	8.20%	7.29%	5.92%
Jul-05	46.62%	11.63%	20.21%	7.98%	7.93%	5.63%
Aug-05	48.11%	11.11%	19.02%	8.17%	7.74%	5.85%
Sep-05	41.08%	12.37%	22.32%	9.11%	8.71%	6.41%
Average 3CP	47.68%	11.29%	19.47%	8.12%	7.65%	5.80%
Average 4CP	46.03%	11.56%	20.18%	8.36%	7.92%	5.95%

Q. **WHAT IS YOUR RESPONSE TO MR. BRUBAKER'S CLAIM THAT YOU USED AN INAPPROPRIATE LOAD FACTOR IN DEVELOPING YOUR PRODUCTION CAPACITY ALLOCATOR?**

A. Mr. Brubaker's criticism is based on my use of the average of the three highest peaks as the system peak. As illustrated above, the additional 2 monthly coincident peaks I used are each approximately 96% of the single system peak. While I believe that using the average of the 3 peaks is a reasonable approximation of the system peak, I did adjust the load factor in my study to evaluate the potential difference in my study results. For the non-TOU study, using a single peak resulted in a .1% increase in Residential revenue requirement responsibility on a revenue neutral basis and a .03% reduction to LPS. Since the A&3CP was not used in the TOU version of my study altering the load factor has no affect.

Q. DO YOU AGREE THAT IT WOULD BE APPROPRIATE TO USE ANNUAL CLASS ENERGY MEASURES THAT ARE ADJUSTED FOR LOSSES?

A. Yes. I believe that it would be appropriate to reflect losses in class energy use. I have made this adjustment to my studies. The impact on the revenue neutral shifts indicated by my CCOS studies is shown below.

Table 3

Comparison Of Revenue Neutral Shifts

	Residential	SGS	LGS	SPS	LPS	LTS
Adjusted TOU	-1.03%	-7.62%	-6.70%	3.47%	22.01%	11.22%
TOU	-1.70%	-7.44%	-6.28%	3.92%	22.34%	12.97%

	Residential	SGS	LGS	SPS	LPS	LTS
Adjusted Non-TOU	3.53%	-6.19%	-8.92%	-1.30%	14.35%	1.68%
Non-TOU	2.85%	-6.00%	-8.51%	-0.85%	14.68%	3.43%

Q. MR. BRUBAKER SUGGESTS THAT AN ADJUSTMENT IS APPROPRIATE WITH RESPECT TO THE ALLOCATION OF OFF-SYSTEM SALES. HAVE YOU MADE SUCH AN ADJUSTMENT?

A. Yes. After discussion with the parties on this point I incorporated a change that allocates off-system sales revenue net of energy cost using a demand allocation factor. This change was reflected in the supplemental rebuttal testimony I filed February 22, 2007.

Q MR. BRUBAKER CRITICIZES YOUR ALLOCATION OF PRIMARY DISTRIBUTION COSTS BECAUSE IT DOES NOT IDENTIFY A CUSTOMER-RELATED COMPONENT IN THE PRIMARY DISTRIBUTION SYSTEM. WHY DO YOU ALLOCATE PRIMARY DISTRIBUTION COSTS BASED ON DEMAND?

A. With respect to the classification of costs, analysts must evaluate the uses with which functionalized costs are most closely related; energy, demand or customer. The 1992 NARUC Electric Utility Cost Allocation Manual, page 20, defines customer costs that are <u>directly related to the number of customers served</u>. The NARUC Manual, page 8, states that the distribution plant includes substations, primary and secondary conductors, poles and line transformers that are jointly used and located in the public right of way as well as the <u>services, meters, and installations that are on the customer's own premises</u>. Based on my evaluation, "services, meters and installations" satisfy the definition of customer related. It is not as obvious that substations, primary and secondary conductors, poles and line transformers, jointly used and in the public right of way are customer related or directly related to the number of customers. For example, it is my understanding that the number of electric poles and other cost driving characteristics of poles needed to serve customers depends more on land use and geographic considerations than the specific number of customers served. In areas where sufficient poles are already in place, no additional pole related costs maybe incurred to serve an additional customer. As technology grows, electric utilities as well as telephone utilities will be required (with some exceptions) to lease pole space to other entities including cable providers and competitive local telephone companies. As this consideration becomes more relevant any purported direct relationship between cost and electric customer numbers is diluted by the other uses of the facilities. These considerations argue against a proposition that the cost of poles is directly related to the number of customers. I believe that much of this reasoning applies to conduit.

Q. MR. BRUBAKER AND OTHER PARTIES CRITICIZE YOUR TOU METHOD AS OVER ALLOCATING COST TO LARGE CUSTOMERS. DO YOU AGREE?

No. These parties' methods allocate total cost of all plants based in large part on usage in a few peak hours when the average cost is relatively high due to the operation of peaking plants. This unfairly over allocates costs to the residential and small general service class because the capacity cost actually vary by hour depending on the plants in use. No higher level of costs when peaking plants are operating and the same lower level of cost when they are not running. The particular pattern of use by each class over different hours of the year appropriately leads to a difference in overall average cost by class.

Q. ARE MR. HIGGINS AND MR. WARWICK CORRECT IN CLAIMING THAT YOU IGNORE CUSTOMER-RELATED COSTS IN ALLOCATING DISTRIBUTION PLANT FOR FERC ACCOUNTS 364-368?

A. They are incorrect. I have allocated the portion of secondary facilities in FERC accounts 364-368 identified in a Company study as customer related based on weighted customer numbers.

Q. IS THIS ALLOCATION CONSISTENT WITH THE CLASSIFICATIONS SHOWN ON TABLE 6-1 OF THE NARUC MANUAL?

A. Yes.

Q. IS THE NARUC MANUAL UNEQUIVOCAL ON THE CLASSIFICATION OF THE DISTRIBUTION COSTS IN FERC ACCOUNTS 364-368?

A. No While the NARUC Manual provides an example of what it refers to as a typical functionalization and classification scheme that includes a customer-related primary component for these accounts, on page 89, the Manual recognizes that the classification of the distribution costs depends upon an analyst's evaluation of cost causation. As I have explained in this testimony and in rebuttal testimony, I believe the Company method significantly over allocates distribution costs to small customers and the zero intercept method is flawed in that it does not prove a direct relationship between the number of customers and cost causation of facilities.

Q. MR. HIGGINS AND OTHER PARTIES RAISE THE SPECTER OF DOUBLE COUNTING ENERGY IN DETERMINING THE A&CP ALLOCATOR. IS THIS A FAIR CRITICISM?

A. No. While on the one hand these parties argue that the A&CP method double counts, on the other hand they propose in the A&E method to use a measure of peak demand that is never actually realized (the sum of class non coincident peaks) to allocate excess production capacity. The A&CP method is intentionally designed to give weight to both the class share of average demand and the class share of the system peak. This does not constitute double counting but simply a different theoretical basis for the allocator than is used in the A&E method.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

4. Judgmental Energy Weightings

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

TABLE 4-14

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

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

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

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

Schedule 1

TABLE 4-15

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

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

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

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

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

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

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

O*bjective:* The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic