

Exhibit No.:

Issues: Energy Losses and Jurisdictional
Allocations

Witness: Alan J. Bax

Sponsoring Party: MoPSC Staff

Type of Exhibit: Surrebuttal Testimony

Case No.: EC-2002-1

Date Testimony Prepared: June 24, 2002

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY OPERATIONS DIVISION

SURREBUTTAL TESTIMONY

OF

ALAN J. BAX

UNION ELECTRIC COMPANY

d/b/a AMERENUE

CASE NO. EC-2002-1

Jefferson City, Missouri

April 2002

****Denotes Proprietary Information****

NP

**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**

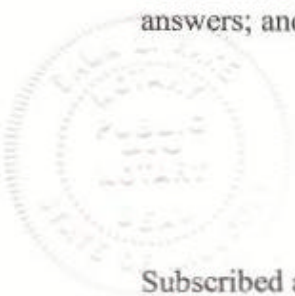
The Staff of the Missouri Public Service)
Commission,)
Complainant,)
vs.)
Union Electric Company, d/b/a)
AmerenUE,)
Respondent.)

Case No. EC-2002-1

AFFIDAVIT OF ALAN J. BAX

STATE OF MISSOURI)
) ss
COUNTY OF COLE)

Alan J. Bax, of lawful age, on his oath states: that he has participated in the preparation of the following written Surrebuttal Testimony in question and answer form, consisting of 13 pages of testimony to be presented in the above case, that the answers in the attached written Surrebuttal Testimony were given by him; that he has knowledge of the matters set forth in such answers; and that such matters are true to the best of his knowledge and belief.


Alan J. Bax
Alan J. Bax

Subscribed and sworn to before me this 23rd day of June, 2002.

My commission expires _____
DAWN L. HAKE
Notary Public - State of Missouri
County of Cole
My Commission Expires Jan 9 2005

Dawn L. Hake
Notary Public

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1 Company's Missouri retail jurisdiction of ** P-----**, and my energy allocation factor of
2 ** P-----** for the Company's Missouri retail jurisdiction.

3 **SYSTEM ENERGY LOSSES**

4 Q. Is there a difference between the Staff's calculation of the average system
5 energy loss percentage and that of the Company?

6 A. Yes, but the difference between the average system energy loss percentage
7 as calculated by the Company and the Staff is very small. The average system energy
8 loss percentage from my Direct Testimony filed in March 2002 was ** P-----** of net
9 system input. Schedule 1, attached to this Surrebuttal Testimony, contains a spreadsheet
10 received from the Company in response to Staff Data Request No. 2928. This
11 spreadsheet shows the Company's derivation of the various customer class, jurisdictional,
12 and average system energy loss percentages. The Company has calculated two average
13 system energy loss percentages: one based on theoretical loss factors that have been
14 applied to individual customer classes (bottom of column six – ** P-----** of output)
15 and the other based on the actual losses reported by the Company (bottom of column nine
16 – ** P-----** of output). It should be noted that the Staff's use of the term "net system
17 input" is equivalent to the Company's use of the term "% of output". The Company's
18 determination of an average system energy loss percentage using actual recorded data and
19 equal to ** P----- ** of output is ** P---- ** percentage points lower than the
20 corresponding theoretical percentage. Moreover, it represents only a ** P--- **
21 percentage point difference from the Staff's calculation. Both the Staff's and the
22 Company's calculations are based on data obtained for the twelve months ending
23 September 30, 2001.

1 Q. Are there any other issues regarding system energy losses?

2 A. Yes. Mr. Kovach disagrees with the method in which my average system
3 energy loss percentage was incorporated into the analyses performed by Staff witness
4 Lena M. Mantle. Please refer to the Surrebuttal Testimony of Ms. Mantle for further
5 discussion on how the average system energy loss percentage was used. I have applied a
6 loss adjustment to each jurisdiction in my determination of the energy allocation factors
7 based upon the actual losses recorded by the Company. In contrast, the Company has
8 applied adjustments for losses to their corresponding calculation of energy allocation
9 factors based upon overestimated theoretical loss percentages. This will be discussed
10 later in my testimony in the section titled "Energy Allocation Factor."

11 **DEMAND ALLOCATION FACTOR**

12 Q. Have you changed the demand allocation factors that you previously
13 provided in your Direct Testimony filed in March of 2002?

14 A. Yes. I adjusted the monthly coincident peaks of Union Electric's Missouri
15 Wholesale jurisdiction to account for the transfer of former wholesale customer City of
16 Rolla (Rolla) to Ameren Energy Marketing. In addition, I removed the demands of
17 former Illinois customer Laclede Steel Corporation (Laclede Steel) from the Illinois
18 jurisdictional loads.

19 Q. What is the result of your calculation after these adjustments?

20 A. These factors are presented in Schedule 2 and repeated here.

21 Missouri Retail ** P-----**

22 Missouri Wholesale ** P-----**

23 Illinois ** P-----**

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1 Q. Why did you make these adjustments to your calculation of the
2 jurisdictional demand allocation factors?

3 A. In reviewing the Company's filing, it was brought to my attention that I
4 had adjusted my energy allocation factors to account for the transfer of Rolla and had not
5 performed a similar adjustment to the calculation of the demand allocation factors. The
6 adjustment made for Laclede Steel is also appropriate, as it has gone out of business. I
7 became aware of this change only after receiving the Rebuttal Testimony of Richard J.
8 Kovach.

9 Q. How does your revised Missouri retail allocation factor compare to your
10 previous calculation filed in your Direct Testimony?

11 A. This current factor (** P-----**) is a little larger than the one calculated
12 previously (** P----- **). The result is a higher allocation of costs to Union Electric's
13 Missouri retail jurisdiction.

14 Q. Did you provide the result of this calculation to another Staff witness?

15 A. Yes, I provided this result to Staff witness Steve Rackers.

16 Q. Are the Staff's demand allocation factors now the same as the
17 Company's?

18 A. No. Both the Company and the Staff support the premise that capacity
19 (demand or fixed) related costs should be allocated using a coincident peak methodology.
20 However, the Company used a four coincident peak (4 CP) methodology in its
21 determination of a demand allocation factor. Schedule 15, attached to the Rebuttal
22 Testimony of Company witness Gary S. Weiss, shows that the Company averaged the
23 sum of the coincident peaks recorded in the months of June through September 2001 in

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1 calculating the Company's demand allocation factors. This was in contrast to the Staff's
2 use of the twelve coincident peak methodology (12 CP) in its calculations. Staff
3 averaged the sum of the coincident peaks recorded for each month in the twelve-month
4 period ending September 30, 2001.

5 Q. Has the Company been using the 4 CP methodology in Missouri?

6 A. No. As noted by Company witness Gary S. Weiss, "The Company has in
7 the past used the 12 CP method to calculate the fixed allocation factor." (Weiss Rebuttal,
8 Page 27, Lines 5-6).

9 Q. Has the Company been using the 4 CP methodology in other jurisdictions?

10 A. The Company's current rate design with the Federal Energy Regulatory
11 Commission (FERC) is based on the 12 CP methodology, as noted by Mr. Kovach in his
12 Rebuttal Testimony (page 72, lines 15 - 18). With respect to the Company's service
13 territory in Illinois, although the Illinois Commerce Commission (ICC), in a 1985 order,
14 opted to continue its endorsement of the 4 CP methodology, the Company argued in
15 support of the 12 CP methodology¹. Attached to my testimony as Schedule 3 is a page of
16 the ICC order, which was furnished to the Staff by the Company as part of its response to
17 Staff Data Request No. 2936.

18 Q. When did you become aware that the Company was adopting the use of a
19 4 CP methodology in Missouri?

20 A. When the Company filed its rebuttal testimony in this proceeding on May
21 10, 2002.

¹ *Union Electric Company-Proposed General Increase in Electric Rates*, Ill. Commerce Comm'n, Docket No. 85-0006 (May 1985).

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1 Q. What support does the Company offer for its position that a 4 CP
2 methodology is appropriate in this case?

3 A. The Company relies solely upon the use of three arithmetical tests used by
4 the FERC as a guide in determining the appropriate methodology. In his Rebuttal
5 Testimony, Mr. Kovach states, "All of these tests in these analyses indicate, conclusively,
6 that the Company is not a 12 CP jurisdictional demand allocation methodology utility"
7 (page 49, lines 18-19). These tests are included in a book entitled A Guide to FERC
8 Regulation and Ratemaking of Electric Utilities and Other Power Suppliers – Third
9 Edition, authored by Michael E. Small, an excerpt of which is attached to Mr. Kovach's
10 testimony as Schedule 3-2 through Schedule 3-2j. Staff has been unable to obtain a copy
11 of this book for its use because it is currently out of print. Therefore, I relied upon the
12 excerpt from Mr. Small's book for information concerning the application of these FERC
13 tests.

14 Q. Please describe how these FERC tests are used as a guide in the process of
15 determining an appropriate methodology?

16 A. These FERC tests are arithmetical calculations whose results are
17 compared to specific ranges that suggest which methodology may be more appropriate.
18 It should be noted, however, that these ranges were never specified by the FERC; rather,
19 they resulted from calculations performed in specific cases in gauging various utilities.

20 Q. Please illustrate these arithmetical relationships and define these specific
21 ranges.

22 A. **Test 1** - Computes the difference between the following two ratios:

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1 a) The average of the system peaks during the reported peak period as a
2 percentage of the annual peak, and

3 b) The average of the system peaks during the remainder of the test
4 period as a percentage of the annual peak

5 The result is compared to the following ranges:

6 18% - 19% - Reflected in cases in which FERC adopted a 12 CP methodology

7 26% - 31% - Reflected in cases in which FERC adopted a 4 CP methodology

8 **Test 2** – A ratio of the lowest monthly peak to the annual peak.

9 The result is compared to the following ranges:

10 66% - 81% - Reflected in cases in which FERC adopted a 12 CP methodology.

11 55% - 60% - Reflected in cases in which FERC adopted a 4 CP methodology.

12 **Test 3** – A ratio of the average of the twelve monthly peaks in the reporting
13 period as a percentage of the annual peak.

14 The result is compared to the following ranges:

15 81% - 88% - Reflected in cases in which FERC adopted a 12 CP methodology

16 78% - 80% - Reflected in cases in which FERC adopted a 4 CP methodology

17 Q. Have you performed calculations using these FERC tests?

18 A. Yes. As illustrated on Schedule 4, I have calculated the following
19 percentages using the demands recorded for the twelve-month period ending September
20 30, 2001:

21 Test 1 - 21.48%

22 Test 2 - 63.90%

23 Test 3 - 80.39%

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1 Q. Please discuss the significance of these results.

2 A. The results of all three of these FERC tests fall between the above-
3 indicated ranges of the percentages noted in the FERC decisions identified in Mr.
4 Kovach's Rebuttal Testimony (page 50 – lines 15 to 20) and illustrated in Schedule 3-2e
5 and 3-2f attached thereto. These tests would indicate that these results are, at best,
6 inconclusive as to which methodology is appropriate for this case. However, I would
7 note that the results of the first two tests lie closer to the range suggesting the
8 appropriateness of a 12 CP and the result of the third test leans only minimally toward the
9 4 CP range. Contrary to Mr. Kovach's suggestion, FERC has never relied solely on any
10 of these tests in determining a coincident peak methodology. Moreover, as illustrated
11 above, the results of the FERC test calculations, taken collectively or individually, are
12 hardly conclusive evidence that the 12 CP methodology should now be abandoned in
13 favor of the 4 CP methodology in the present proceeding. Clearly, additional information
14 is required in order to adopt a methodology that strays from historical practice.

15 Q. What additional information should be considered?

16 A. These three FERC tests, relied upon exclusively by Mr. Kovach, are part
17 of a larger set of factors historically utilized by the FERC in its determination of which
18 coincident peak methodology should be used in electric utility cases. The excerpt from
19 Mr. Small's book, attached as part of Schedule 3 to Mr. Kovach's testimony, cites
20 language that appears in a number of FERC decisions, indicating the additional factors
21 that, according to FERC, must be considered in determining the appropriate demand
22 allocation methodology. In a rate case decision involving Carolina Power & Light
23

1 Company², for example, the FERC states:

2 ...it is necessary to consider the full range of a company's operating
3 realities including, in addition to system demand, scheduled maintenance,
4 unscheduled outages, diversity, reserve requirements, and off-system sales
5 commitments (footnote omitted).
6

7 In addition, in this case, transfers of energy between the Company and its affiliate,
8 Ameren Energy Marketing (AEM) should be considered. In the adoption of the 12 CP
9 methodology, FERC has cited these operating realities as important to their
10 determination.

11 Q. How do these operational realities apply to the Company?

12 A. The majority of the Company's plant costs are associated with base load
13 units. These base load units represent ** P-----** of total generation plant dollars as of
14 December 31, 2001 (as reflected in the Company's FERC Form 1, pages 402 to 407).
15 These units have high capital costs but lower running costs when compared to
16 intermediate or peaking units. These plants are costly to start up and shut down and
17 therefore are in operation well over 90% of the time on average, with necessary
18 maintenance being planned in the spring and fall in the months that have lower demand
19 for energy. There are many hours during the year when the base load plants adequately
20 cover the usage of the Company's native load customers, allowing the Company the
21 opportunity to use the excess power being generated by these base load units for off-
22 system sales or to transfer this low-cost energy to AEM under the Joint Dispatch
23 Agreement (JDA).

24 Q. Are there other operational realities that should be taken into account?

² *Carolina Power & Light Co.*, Opinion No. 19, 4 FERC ¶61,107 at 61,230 (Aug. 1978).

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1 A. Yes. The Company's capacity planning process takes into account all the
2 hours of the year, not just the summer peaks. In their response to Staff Data Request
3 No. 2938, the Company replied that its planning requirement for the Mid-America
4 Interconnected Network, Inc. (MAIN) is a Loss of Load Probability (LOLP) of less than
5 0.1 days per year. This means that the Company plans its capacity for every hour of the
6 year, not just for the peak hour or seasonal peak.

7 Q. Has the Company ever invoked these operational realities in order to
8 justify a particular allocation methodology?

9 A. Yes, it has. In the 1985 Illinois Commerce Commission order, mentioned
10 on page 5 of my testimony, the ICC states:

11 Company witness Kovach testified that an examination of cost causation
12 should consider both the total kilowatt capacity and the mix or types of
13 plants which must be determined on the basis of load throughout the year,
14 including non-summer months whose peaks average about two-thirds of
15 the annual peaks.

16
17 Q. Please summarize why operational realities justify the use of a 12 CP
18 methodology in calculating jurisdictional demand allocation factors in this case.

19 A. The determination of proper cost causation involves a process much more
20 involved than any one arithmetical calculation or series of calculations based on monthly
21 or seasonal peaks. Allocation factors should be developed based on the costs associated
22 with the particular facilities one intends to allocate. Using a 4 CP methodology implies
23 that the Company's facilities were constructed as peaking facilities, operating for only a
24 limited number of hours annually. This certainly is not the case with this Company.
25 Earlier in my testimony, I pointed out that the Company's generation mix is
26 overwhelmingly base loaded, and this has certainly been the case ever since the Callaway

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1 Nuclear Plant became operational. Given that there has been minimal change in the
2 Company's generation profile since then, there is no reason for the Commission to adopt
3 a change from a 12 CP methodology to a 4 CP methodology in the present case. For this
4 Company, then, it is these operational realities, not a series of inconclusive arithmetical
5 tests, that leads one to conclude that the 12 CP continues to be the appropriate
6 methodology for allocating demand (fixed) costs. The Commission, therefore, should
7 reject the Company's proposed change to a 4 CP methodology.

8 **ENERGY ALLOCATION FACTOR**

9 Q. Have you made any adjustments to the energy allocation factors filed
10 previously in your Direct Testimony of March 2002?

11 A. Yes. Mr. Kovach notes several adjustments that he believes should have
12 been considered in the calculation of the energy allocation factors (identified as
13 Adjustments 1 through 7 on Schedule 3-3 of his Rebuttal Testimony, and attached to my
14 Surrebuttal Testimony as Schedule 5). In my previous testimony, I applied adjustments
15 for weather and the transfer of Rolla from AmerenUE to AEM (Mr. Kovach's
16 adjustments 1 and 2). The Staff agrees with Mr. Kovach that the following adjustments
17 should be made:

- 18 a. Miscellaneous Adjustment
- 19 b. Rate Switching Adjustment
- 20 c. A 365 Days Adjustment
- 21 d. Customer Growth Adjustment

22 These are shown as adjustments 3 through 6 in my revised calculations of the
23 energy allocation factors in Schedule 6, attached to this Surrebuttal Testimony. I have

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1 not, however, adjusted my factor for Laclede Steel. The energy associated with Laclede
2 Steel was included in the Staff's fuel run and thus remains in my determination of the
3 energy allocation factors. In addition, I applied the appropriate jurisdictional loss factors,
4 shown in Column 10 on Schedule 1 of my Surrebuttal Testimony, to the adjusted kWhs
5 for each corresponding jurisdiction.

6 Q. In calculating these losses in connection with your Surrebuttal Testimony,
7 did you use the same approach as the Company used in its Rebuttal filing?

8 A. No, not entirely. Although the Staff and the Company use the same
9 approach with respect to the unadjusted kWhs, the Staff does not agree with the
10 Company's inclusion of theoretical losses with the aforementioned adjustments.
11 Previously in this testimony, I discussed the Company's spreadsheet, attached as
12 Schedule 1 to this Surrebuttal Testimony, illustrating two sets of loss percentage
13 calculations: one based on actual losses reported by the Company and the other based on
14 figures determined theoretically. The Schedule illustrates that the Company applied a
15 theoretical loss percentage (Column 4) to the actual usage recorded at the meters of each
16 of the listed customer classes for the twelve months ending September 30, 2001.
17 According to the Company's response to Staff Data Request No. 2930, these loss
18 percentages were calculated from information contained in the Company's most recent
19 loss study, which was conducted back in 1983 and provided to the Staff in a Company
20 response to Staff Data Request No. 4138. Applying these theoretical loss percentages to
21 each customer class results in an average system energy loss percentage that is ** P----**
22 percentage points (nearly 16%) greater than the average system energy loss percentage
23 calculated using the actual losses reported in the Company's Financial and Statistical

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1 (F&S) statements. Thus, the losses included in the adjustments that the Company
2 incorporated into its calculation of the energy allocation factors are considerably
3 overstated.

4 Q. Did the Company make the same adjustments as the Staff in its
5 determination of the energy allocation factors?

6 A. No. The Company did not apply a miscellaneous adjustment, a 365 days
7 adjustment, or a customer growth adjustment. Furthermore, the Company calculated its
8 allocation factor using energy from the twelve months ending September 30, 2001
9 whereas Staff used the test year. The Company's weather adjustment was also based on
10 the twelve months ending September 30, 2001 and the Company applied an adjustment
11 for unbilled sales as well (Weiss Rebuttal, Schedule 16).

12 Q. What are the resulting jurisdictional energy allocation factors after
13 applying these additional adjustments?

14 A. These factors are presented in Schedule 6 and repeated here.

15 Missouri Retail ** P-----**

16 Missouri Wholesale ** P-----**

17 Illinois ** P-----**

18 Q. Did you provide the result of this calculation to another Staff witness?

19 A. Yes. I provided this result to Staff witness Steve Rackers.

20 Q. Does this conclude your Surrebuttal Testimony?

21 A. Yes.

Schedule 1

	<u>meter</u>	<u>generator</u>	<u>% of sales</u>	<u>difference</u>	<u>% of output</u>	<u>difference as % of total</u>	<u>line losses</u> [per F&S]	<u>% of output</u>	<u>% of sales</u>
<u>UE-Missouri</u>									
res	13,028,226.6	14,291,251.6	1.0969						
sgs	3,570,335.7	3,916,462.9	1.0969						
lgs	7,426,006.9	8,145,923.1	1.0969						
sps	4,189,446.6	4,438,649.2	1.0595						
lps	3,890,769.5	4,107,127.5	1.0556						
str Itg pri	4,504.7	4,776.2	1.0603						
str Itg sec	103,263.5	113,274.4	1.0969						
total-mo	32,212,553.6	35,017,465.0	1.0871	2,804,911.4	8.01%	0.930630	2,358,745.2 ✓	6.74%	7.32%
<u>UE-Illinois</u>									
res	676,520.5	742,106.0	1.0969						
sgs	318,088.2	348,925.3	1.0969						
lgs	341,168.2	374,242.9	1.0969						
ps	1,837,257.2	1,915,259.3	1.0425						
str Itg	16,319.5	17,901.6	1.0969						
total-il	3,189,353.6	3,398,435.0	1.0656	209,081.4	6.15%	0.069370	175,823.7 ✓	5.17%	5.51%
<u>UE-Wholesale</u>									
sfr	740,839.8	768,790.0	1.0377	27,950.2	3.64%	1.000000	27,950.2 ✓	3.64%	3.77%
total-ue	36,142,746.93	39,184,690.00	1.0842	3,041,943.1	7.76%		2,562,519.1	6.54%	7.09%

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4/25/02

DEMAND ALLOCATION FACTORS

Month	Ameren System Peak (MW)	MO Retail Coincident Peak (MW)	MO Wholesale Coincident Peak (MW)	Illinois Coincident Peak (MW)
Oct-00	5851	5315	112	424
Nov-00	5381	4861	103	417
Dec-00	6217	5641	117	455
Jan-01	5927	5357	109	461
Feb-01	5886	5313	118	452
Mar-01	5097	4514	99	485
Apr-01	5625	5090	108	428
May-01	6742	6153	136	455
Jun-01	7191	6544	139	510
Jul-01	7976	7313	154	510
Aug-01	7908	7238	160	509
Sep-01	7141	6479	142	521
SUM	76942	69818	1497	5627
12 CP	1.0000	0.9074	0.0195	0.0731

The Company urges the Commission to reinstate the 12 CP method for two reasons. First, because the 12 CP approach has been adopted in the other three jurisdictions which regulate the Company, use of the 12 CP method in Illinois would produce consistency among jurisdictions, and would allow the Company to earn a return on its full investment which will not occur if the 4 CP method is used because the 4 CP allocation factor for Illinois is lower than the 12 CP factor. Secondly, UE submits that the 12 CP method better reflects cost causation. Company witness Kovach testified that an examination of cost causation should consider both the total kilowatt capacity and the mix or types of plants which must be determined on the basis of load throughout the year, including non-summer months whose peaks average about two-thirds of the annual peaks. (Resp. Exh. 19, pp. 24, 25) UE contends that methodologies which presume the system was constructed to serve only summer peaks should not be applied to UE's generation and transmission systems which reflect a mix of types of capacity that is not determined by only the level of capacity required by the yearly peak.

Staff witness Lane did not agree with the Company's proposal. He recommended continued use of the 4 CP method. He testified that UE is clearly a summer peaking utility, and has not forecasted a change in this characteristic. He also stated that the 4 CP method is consistent with the strong seasonal differentials exhibited in the Company's Illinois rates which provides signals to customers that electricity is more costly in summer months.

The Commission is of the opinion that the demand allocation factor should continue to be determined by use of the 4 CP method for the reasons given by staff witness Lane. The updated allocation factors presented by the Commission staff should be used in this proceeding.

The Commission observes, however, that for reasons explained above, the use of the 4CP demand allocation factor in Illinois and the 12CP factor elsewhere may have the effect of excluding a portion of the Company's rate base from any jurisdictional rate base. That is, part of the Company's rate base is not eligible to earn a return within a regulated context. In recognition of this problem, the Company should present to the Commission within six months of the issuance of this order a plan for the treatment of this rate base in a competitive manner. One option of the plan could be action which confirms the status quo. The treatment of this rate base should be fair to both the company and its ratepayers and should provide the proper incentives to the Company. In addition, the Commission invites the company to

FERC Test Calculations

January
February
March
April
May
June
July
August
September
October
November
December

AmerenUE Monthly Peaks (MWs)

			5927	
			5886	
			5097	
			5625	
			6742	
			7191	
			7976	
			7908	
			7141	
			5851	
			5381	
			6217	
Maximum Peak	=		7976	
Minimum Peak	=		5097	
Summer Month Avg	=		7554	
Other Months Avg	=		5840.75	
12 Month Avg	=		6411.833333	
Ratio 1a = (Summer_Avg) / Max	=		0.947091274	
Ratio 1b = (8-Month_Avg) / Max	=		0.732290622	
FERC Test 1	=	Ratio 1a - Ratio 1b	0.214800652	= 21.48%
FERC Test 2)	=	Min. Peak / Max Peak	0.639042126	= 63.90%
FERC Test 3	=	(12 Month Avg) / Max Peak	0.803890839	= 80.39%

Energy Allocation Factor Adjustments (kWh's)

July 2000 - June 2001

	<u>Missouri Retail Usage (kWh)</u>	<u>Missouri Wholesale Usage (kWh)</u>	<u>Illinois Usage (kWh)</u>	<u>Total Usage (kWh)</u>
Total Usage*	32,009,845,300	854,692,200	3,171,890,900	36,036,428,400
Jurisdictional Losses**	<u>2,462,787,690</u>	<u>32,241,540</u>	<u>183,733,360</u>	<u>2,678,762,590</u>
Adjusted System Input	34,472,632,990	886,933,740	3,355,624,260	38,715,190,990
Adjustment 1	(969,081,000)	(21,481,000)	(53,747,000)	(1,044,309,000)
Losses	(74,522,329)	(809,834)	(3,111,951)	(78,444,114)
Adjustment 2		(153,593,010)		(153,593,010)
Losses		(5,790,456)		(5,790,456)
Adjustment 3			(237,362,400)	(237,362,400)
Losses			(5,127,028)	(5,127,028)
Adjustment 4	(18,103,848)			(18,103,848)
Losses	(1,091,662)			(1,091,662)
Adjustment 5	(60,553,690)			(60,553,690)
Losses	(3,651,388)			(3,651,388)
Adjustment 6	30,352,000			30,352,000
Losses	2,334,068.80			2,334,069
Adjustment 7	287,384,513			287,384,513
Losses	<u>22,099,869</u>			<u>22,099,869</u>
Output for Load	33,687,799,524	705,259,440	3,056,275,881	37,449,334,845
Percentage	89.96%	1.88%	8.16%	100.00%

* Source: Alan Bax Direct Testimony, Schedule 6.

** Adjusted for average jurisdictional losses.

Adjustment 1 - Normalized Weather per Bax, Schedule 6.

Adjustment 2 - Rolla Adjustment per Bax, Schedule 6.

Adjustment 3 - Adjustment to Laclede Steel Sales to reflect bankruptcy operation.

Adjustment 4 - Miscellaneous Adjustment per Pyatte, Schedule 2.

Adjustment 5 - Rate Switching Adjustment per Pyatte, Schedule 2.

Adjustment 6 - 365 Day Normalization Adjustment per Pyatte, Schedule 2.

Adjustment 7 - Customer Growth Adjustment per Pyatte, Schedule 2.

Schedule 5

Schedule 3-3

ENERGY ALLOCATION FACTOR

<u>MONTH</u>	<u>Missouri Retail</u>	<u>Missouri Wholesale</u>	<u>Illinois</u>	<u>Total Usage</u>
Jul-00	3,027,773,509	130,783,637	383,384,653	3,541,941,799
Aug-00	3,321,497,154	95,627,440	303,662,338	3,720,786,932
Sep-00	2,609,118,985	118,123,590	299,887,240	3,027,129,815
Oct-00	2,279,971,370	67,286,440	326,518,515	2,673,776,325
Nov-00	2,501,403,564	44,420,322	278,290,667	2,824,114,553
Dec-00	3,194,216,344	114,314,625	328,698,952	3,637,229,921
Jan-01	2,939,323,945	89,287,554	194,616,875	3,223,228,374
Feb-01	2,372,226,907	78,171,186	474,565,162	2,924,963,255
Mar-01	2,403,186,358	67,070,075	352,752,836	2,823,009,269
Apr-01	2,366,040,397	(25,550,282)	175,366,165	2,515,856,280
May-01	2,481,147,623	7,439,643	302,921,119	2,791,508,385
Jun-01	2,698,805,190	66,865,331	399,484,180	3,165,154,701
Total	32,194,711,346	853,839,561	3,820,148,702	36,868,699,609
Adjustment 1	(969,081,000)	(21,481,000)	(53,747,000)	(1,044,309,000)
Adjustment 2		(153,593,010)		(153,593,010)
Adjustment 3	- (18,103,848)			(18,103,848)
Adjustment 4	- (60,553,690)			(60,553,690)
Adjustment 5	- 30,352,000	1,693,000	(7,739,000)	24,306,000
Adjustment 6	- 287,384,513			287,384,513
Adjusted Total	31,464,709,321	680,458,551	3,758,662,702	35,903,830,574
Loss Adjustment	2,303,216,722	25,653,287	207,102,315	2,535,972,325
Overall	33,767,926,043	706,111,838	3,965,765,017	38,439,802,899
Energy Allocation Factor	0.8785	0.0184	0.1032	1.0000

Adjustment 1	-	Weather Normalize Adjustment per Staff Data Request 2914
Adjustment 2	-	Adjustment for City of Rolla
Adjustment 3	-	Miscellaneous Adjustment
Adjustment 4	-	Rate Switching Adjustment
Adjustment 5	-	365 Day Normalization Adjustment
Adjustment 6	-	Customer Growth Adjustment