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and Rate Design
Witness: Maurice Brubaker
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Sponsoring Party: Missouri Industrial Energy Consumers
Case No.: ER-2014-0258
Date Testimony Prepared: January 16, 2015

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

Filed
March 23, 2015
Data Center
Missouri Public
Service Commission

In the Matter of Union Electric Company,)
d/b/a Ameren Missouri's Tariff to Increase)
Its Revenues for Electric Service)
_____)

Case No. ER-2014-0258

Rebuttal Testimony and Schedules of

Maurice Brubaker

**on Cost of Service, Revenue
Allocation and Rate Design**

On behalf of

Missouri Industrial Energy Consumers

January 16, 2015



MIEC Exhibit No. 504
Date 3/3/15 Reporter SB
File No. ER-2014-0258

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OF THE STATE OF MISSOURI

In the Matter of Union Electric Company,
d/b/a Ameren Missouri's Tariff to Increase
Its Revenues for Electric Service

Case No. ER-2014-0258

STATE OF MISSOURI)
)
COUNTY OF ST. LOUIS) SS

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

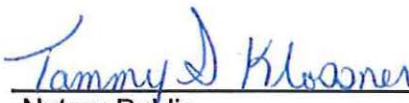
1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Missouri Industrial Energy Consumers in this proceeding on their behalf.
2. Attached hereto and made a part hereof for all purposes are my rebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2014-0258.
3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things that they purport to show.



Maurice Brubaker

Subscribed and sworn to before me this 15th day of January, 2015.





Notary Public

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**BEFORE THE PUBLIC SERVICE COMMISSION
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Case No. ER-2014-0258

Rebuttal Testimony of Maurice Brubaker

1 **Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 **A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140,**
3 **Chesterfield, MO 63017.**

4 **Q ARE YOU THE SAME MAURICE BRUBAKER WHO HAS PREVIOUSLY FILED**
5 **TESTIMONY IN THIS PROCEEDING?**

6 **A Yes. I have previously filed direct testimony on class cost of service, revenue**
7 **allocation and rate design issues presented in this proceeding.**

8 **Q ARE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE OUTLINED IN**
9 **YOUR PRIOR TESTIMONY?**

10 **A Yes. This information is included in Appendix A to my revenue requirement direct**
11 **testimony filed December 19, 2014.**

12 **Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

13 **A This testimony is presented on behalf of the Missouri Industrial Energy Consumers**
14 **("MIEC"), including Noranda Aluminum, Inc. ("Noranda").**

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INTRODUCTION AND SUMMARY

1

2 **Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

3 **A**In my rebuttal testimony I will address the cost of service and revenue allocation
4 proposals put forth by the Staff of the Missouri Public Service Commission ("Staff")
5 and the Office of Public Counsel ("OPC"). I also will comment briefly on certain
6 proposals made by the Missouri Department of Economic Development, Division of
7 Energy.

8 **Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

9 **A**They may be summarized as follows:

- 10 1. OPC's preferred allocation of generation fixed, or demand-related, costs is
11 premiered on an average and peak ("A&P") allocation method that has been
12 rejected by this and other commissions. It double counts energy consumption
13 and over-allocates costs to high load factor customers, and should again be
14 rejected.
- 15 2. OPC's proposal to allocate all of the revenue from off-system sales ("OSS")
16 using a demand allocation has previously been rejected by the Missouri Public
17 Service Commission ("Commission") and should continue to be rejected in this
18 case. OPC compounds the error by failing to recognize that 100% of the energy
19 costs associated with OSS has been allocated to customers on an energy basis.
20 Allocating the costs on an energy basis, and 100% of the revenues on a
21 demand basis, creates a significant mismatch, and materially over-allocates
22 costs to the large primary service ("LPS") and the large transmission service
23 ("LTS") customer classes. This error affects both the A&P study and OPC's
24 version of the Average and Excess - 4 NCP ("A&E - 4 NCP).
- 25 3. Another deficiency in OPC's studies, both their A&P study and their version of
26 the A&E - 4 NCP study, is that OPC has failed to allocate any portion of the
27 distribution system on the basis of the number of customers or weighted number
28 of customers. This is at odds with conventional allocation procedures, and is
29 inconsistent with Commission precedent. It materially over-allocates costs to
30 the LPS customer class.
- 31 4. The Commission Staff has offered three cost of service studies, all of which are
32 outside the mainstream, conflict with prior commission rulings and contain
33 deficiencies. None of them should be adopted.
- 34 5. Staff's Detailed Base-Intermediate-Peak ("BIP") study not only is theoretically
35 incorrect but is full of implementation errors. Staff puts too much capacity in the

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1 base category, arbitrarily adjusts the costs of intermediate plants downward by
2 shifting some of the cost to the base load category, and ignores the cost of
3 approximately 25% of Ameren's capacity when performing its calculations.

4 6. Staff's Modified BIP study develops capacity allocation factors similar to the
5 A&E - 4NCP methodology, but contains significant mis-allocations of OSS
6 margins, and a flawed allocation methodology for administrative and general
7 expenses ("A&G").

8 7. Staff's Market Price study substitutes market prices of energy directly into the
9 allocation equation, and completely ignores the actual embedded costs of
10 energy and capacity when performing its study. It is based on a mis-
11 characterization of the operation of the Midcontinent Independent System
12 Operator, Inc. ("MISO"), and distorts the relationship between fixed costs and
13 variable costs.

14 8. Staff essentially has allocated the estimated margin from OSS on the basis of
15 class demands. As is the case with OPC's treatment, this is contrary to explicit
16 findings of the Commission in prior Ameren Missouri and Kansas City Power &
17 Light Company ("KCPL") cases that these are non-firm sales and should be
18 allocated among classes using the class energy allocation.

19 9. Staff's studies are also flawed because the allocation of A&G expenses is on the
20 basis of other previously allocated operation and maintenance expense that
21 includes fuel. It is conventional to exclude fuel from the base used to allocate
22 A&G expense because fuel (and purchased power) itself has little impact on
23 A&G expense. The failure to exclude fuel when developing the allocation factor
24 for A&G expense results in an over-allocation of costs to both the LPS and LTS
25 customer classes, and should be rejected.

26 10. The recommendations of the Missouri Department of Economic Development,
27 Division of Energy ("DED"), to require mandatory participation in Ameren
28 Missouri's administered energy efficiency programs as a requirement for
29 participation in economic development programs should be rejected as
30 unsupported and counter-productive.

31 **CLASS COST OF SERVICE ISSUES**

32 Q HAVE YOU REVIEWED THE STAFF RATE DESIGN AND CLASS COST OF
33 SERVICE REPORT ("STAFF REPORT") AND THE TESTIMONY OF OPC
34 WITNESS GEOFF MARKE?

35 A Yes.

1 Q DO YOU HAVE REBUTTAL TO THE COST OF SERVICE POSITIONS OF THESE
2 WITNESSES?

3 A Yes, I do. I disagree with the methods which OPC has used for the allocation of
4 production and transmission fixed costs and with respect to the allocation of certain
5 other components of the cost of service.

6 I also have significant disagreements with all three of the alternative studies
7 presented by Commission Staff, both with respect to the treatment of generation
8 facilities and costs, as well as the allocation of a number of other cost of service
9 elements.

10 **OPC's Study**

11 Q WHAT METHOD HAS OPC USED FOR THE ALLOCATION OF GENERATION
12 FIXED, OR DEMAND-RELATED, COSTS?

13 A OPC's recommended method is an A&P allocation method. In particular, OPC uses
14 the four monthly coincident peak demands of each customer class along with each
15 class's annual energy consumption. The energy component is weighted equal to the
16 system's annual load factor. The result is to give only about 41% weighting to the
17 contributions to the four monthly coincident peaks, and 59% weighting to annual
18 energy consumption.

19 Q DOES OPC EXPLAIN THE BASIS FOR SELECTING THIS ALLOCATION
20 METHODOLOGY?

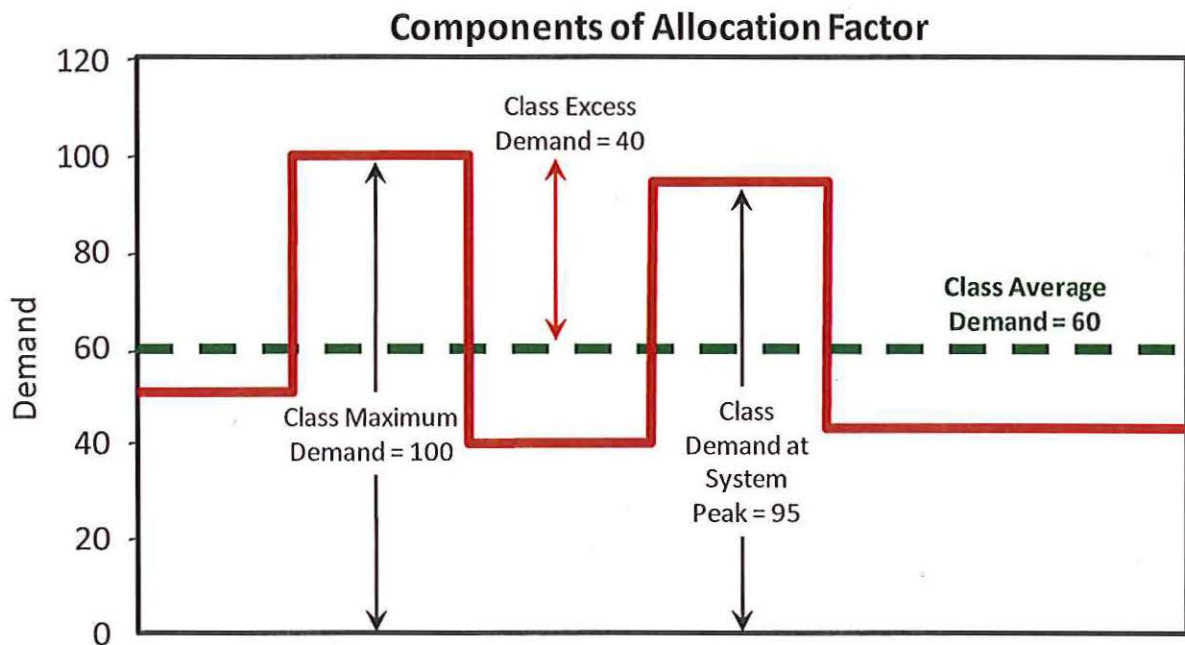
21 A No. While OPC explains the basis for the use of the four peaks, it does not explain or
22 attempt to justify why this particular averaging method is appropriate for Ameren
23 Missouri.

1 Q HOW DOES THE A&P ALLOCATION METHODOLOGY DIFFER FROM THE
2 AVERAGE AND EXCESS ("A&E") METHODOLOGY THAT YOU AND AMEREN
3 MISSOURI USED IN YOUR CCOS STUDIES, AND WHICH THE COMMISSION
4 HAS PREVIOUSLY ADOPTED?

5 A As noted above, OPC's A&P allocator is constructed by multiplying each class's
6 percentage energy responsibility factor (average demand) times the system load
7 factor, and adding that result to each class's percentage contribution to the class
8 peaks multiplied by the quantity one minus the load factor.

9 Both the A&P and A&E methods are two-step processes. In both methods,
10 the first step is to weight the average demand by the system load factor. The second
11 step is where a major difference occurs. This is illustrated in Figure 1.

Figure 1



1 Q PLEASE REFER TO FIGURE 1 AND EXPLAIN THE DIFFERENCES.

2 A Figure 1 is a simplified representation of a class load. The maximum demand of this
3 particular class is represented as 100. Its contribution at the time of the system peak
4 is 95, its average demand is 60, and the excess demand (the difference between its
5 peak demand and its average demand) is 40.

6 As explained in more detail beginning at page 25 of my direct testimony on
7 cost of service, the A&E method combines the class average demand with the class
8 excess demand in order to construct an allocation factor that reflects average use as
9 well as the excess of each class's maximum demand over its average demand. The
10 A&E allocation factor is developed using the average demand (60) and the excess
11 demand (40) for this class, along with the corresponding demands for all other
12 classes. (This is shown in detail on Schedule MEB-COS-3 attached to my direct
13 testimony on cost of service.)

14 OPC's A&P method, on the other hand, combines the average demand with
15 the class monthly peak demands. As is evident from Figure 1, the average demand
16 (60) is a component or sub-set of the class peak demand (100) and of the class load
17 coincident with the system peak (95). Accordingly, in the A&P method when roughly
18 equal weighting is given to the average demand¹ and the contribution to system peak
19 demand, the average demand is double-counted. This is a serious error, and has the
20 effect of allocating significantly more costs to high load factor customers than is
21 appropriate.

¹The weighting is actually 59% to energy and 41% to demand, making matters worse.

1 Q HAS THE COMMISSION PREVIOUSLY RULED ON OPC'S PROPOSED
2 METHOD?

3 A Yes. The Commission has previously rejected the use of the A&P method.

4 Q IS THE A&P METHOD A REASONABLE ONE TO USE?

5 A No, it is not. As noted above, this allocation gives more weighting to annual energy
6 consumption than to the class peaks used in the allocation of the investment in
7 generation facilities. Since generation facilities must be designed to carry the peak
8 loads imposed on them, the heavy weighting given to energy consumption in the
9 allocation factor is not related to cost of service at all.

10 Unlike the A&E method, which considers class individual peaks and class load
11 factors, as well as diversity between class peaks and system peak, the A&P method
12 arbitrarily allocates over half of these costs on annual energy consumption.

13 Q HOW DID MR. MARKE ALLOCATE THE REVENUES AND MARGINS FROM OSS?

14 A He allocated all of the revenues from OSS (not just the margin) using the production
15 demand allocation factor. There are two primary problems with this approach. First,
16 the margin on OSS (which is included in the OSS revenue figure) should not be
17 allocated on a demand basis. Rather, because these are largely non-firm sales, they
18 should be allocated on a kWh basis, as this Commission has found on previous
19 occasions.

1 Q PLEASE ELABORATE ON WHEN THE COMMISSION HAS FOLLOWED THE
2 PRACTICE OF ALLOCATING OSS REVENUES, INCLUDING THE MARGIN,
3 USING THE AN ENERGY ALLOCATION FACTOR.

4 A This Commission has held in a prior KCPL case (ER-2006-0314) and a prior Ameren
5 Missouri case (ER-2010-0036) that it is appropriate to allocate the margin earned
6 from OSS on an energy basis.

7 The only costs assigned to non-firm off-system sales is the fuel and
8 purchased power costs – the variable costs – hence the
9 appropriateness of using the energy allocator. This is consistent with
10 the way KCPL itself allocates the costs relating to the energy portion of
11 firm capacity contracts – using the energy allocator. The reason is
12 simple – the energy allocator is used to allocate variable costs of fuel
13 and purchased power costs relating to retail sales. Using the same
14 rationale, the energy allocator is equally appropriate to use as the
15 allocation factor for both energy of firm (as KCPL does) and non-firm
16 off-system sales. (Report and Order, Case No. ER-2006-0314,
17 December 31, 2006)

18 This is also the most commonly used approach in the industry, and should be used in
19 this case.

20 Q DID MR. MARKE GO BEYOND JUST ALLOCATING THE MARGIN ON A DEMAND
21 BASIS?

22 A Yes, he went far beyond that. Not only did he allocate the margin using a demand
23 allocator, but he allocated the remainder of the revenues the same way. These
24 remaining revenues (the vast majority of them) essentially are related to the fuel cost
25 of producing the energy that is sold off-system, while the margin is the amount of
26 revenue after covering the fuel cost. Mr. Marke's inconsistency is that he has
27 allocated to customer classes all of the energy cost, including that used to generate
28 OSS, on a kWh basis.

1 By allocating the costs on a kWh basis, and then crediting the revenues to
2 cover the fuel cost back on a demand basis, he has materially over-allocated costs to
3 high load factor customer classes. As just one example, in the A&E - 4 NCP study,
4 the LTS class is allocated 10.87% of energy cost and 6.5% of generation demand-
5 related costs. Considering the approximately \$134 million of fuel cost associated with
6 OSS, Mr. Marke's allocation in the A&E - 4 NCP study over-allocates these costs to
7 the LTS customer class by almost \$6,000,000.

8 **Q DO YOU HAVE ANY DISAGREEMENT WITH HOW OPC ALLOCATED**
9 **DISTRIBUTION INVESTMENT AND EXPENSES?**

10 **A** Yes. When allocating distribution investment and related expenses, it is common
11 practice to recognize a customer component as well as a demand component. The
12 reason is that distribution facilities are used not only to meet customer loads, but must
13 be in place in order to move the power from the transmission system to the homes
14 and businesses who take service from the distribution system throughout the service
15 territory. (This is explained in somewhat more detail in my direct testimony from
16 page 11 to page 13.) Mr. Marke, on the other hand, ignores the customer-related
17 component that is recognized by Ameren Missouri, by Commission Staff and by me in
18 the cost of service study I filed in my direct testimony. Ignoring the customer
19 component of the distribution system as OPC has done is outside the mainstream, at
20 odds with Commission precedent and materially distorts the cost of service results
21 because it ignores a significant factor that must be considered in electric system
22 design and operations.

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1 Q WHAT IS THE IMPACT OF THIS ALLOCATION?

2 A It is significant. In terms of the LPS class, OPC's allocation allocates an additional
3 \$50 million of investment cost to that class, which is nearly one-third more than the
4 class is allocated using widely accepted allocation methods.

5 Q ARE YOU AWARE OF ANY PRECEDENT OR AUTHORITY FOR TOTALLY
6 IGNORING THE CUSTOMER COMPONENT OF THE DISTRIBUTION SYSTEM?

7 A No, I am not.

8 Q DO BOTH OF OPC'S STUDIES, THAT IS THE A&P STUDY AND THE
9 A&E - 4 NCP STUDY, SUFFER FROM THE SAME INFIRMITIES WITH RESPECT
10 TO THE TREATMENT OF OSS, REVENUES AND MARGINS, AND THE
11 TREATMENT OF DISTRIBUTION INVESTMENT AND EXPENSES?

12 A Yes. Both studies contain the same inappropriate allocations.

13 Q IN OPC'S A&P STUDY, HOW ARE ENERGY COSTS ALLOCATED?

14 A They are allocated to all customer classes in proportion to class energy usage.

15 Q IS THIS CONSISTENT WITH HOW THE A&P STUDY ALLOCATES CAPACITY
16 COSTS?

17 A No. The A&P study, by giving a significant weighting to energy consumption when
18 developing the demand allocation factor, disproportionately allocates capital cost to
19 high load factor customers. High load factor customers receive an above-average
20 allocation of capital costs, but still must pay the overall system average fuel cost.

1 Q DO YOU HAVE ANY DISAGREEMENT WITH THE ALLOCATION OF FUEL AND
2 VARIABLE PURCHASED POWER COSTS ON THE BASIS OF CLASS ENERGY
3 REQUIREMENTS, ADJUSTED FOR LOSSES?

4 A In the context of traditional studies like coincident peak and A&E, I do not. However,
5 in the context of the non-traditional studies like A&P and others, which heavily weight
6 energy in the allocation of fixed or demand-related generation costs, it is not
7 appropriate.

8 Q PLEASE EXPLAIN WHY IT IS NOT APPROPRIATE TO ALLOCATE ENERGY
9 COSTS IN THIS FASHION WHEN USING NON-TRADITIONAL STUDIES SUCH AS
10 A&P AND OTHERS.

11 A These studies allocate significantly more generation fixed costs to high load factor
12 customers than do the traditional studies. In other words, the higher the load factor of
13 a class, the larger the share of the generation fixed costs that gets allocated to the
14 class. If the costs allocated to classes under these methods were divided by the
15 contribution of these classes to the system peak demand, or by the A&E demand, the
16 result is a higher capital cost per kW for the higher load factor classes, and a lower
17 capital cost per kW for the low load factor classes. Effectively, this means that the
18 high load factor classes have been allocated an above-average share of capital costs
19 for generation, and the low load factor customer classes have been allocated a below
20 average share of capital costs.

21 Given these allocations of capital costs, it would not be appropriate to use the
22 same fuel costs for all classes. Rather, the fuel cost allocation should recognize that
23 the higher load factor customer classes should receive below average fuel costs to
24 correspond to the above-average capital costs (similar to base load units) allocated to

1 them, and the lower load factor classes should get an allocation of fuel costs that is
2 above the average, corresponding to the lower than average capital costs (i.e.,
3 peaking units) allocated to them.

4 **Q WHY WOULD IT BE APPROPRIATE TO RECOGNIZE A LOWER FUEL COST**
5 **ALLOCATION TO THOSE CLASSES THAT ARE ALLOCATED A HIGHER**
6 **CAPITAL COST?**

7 A It is not only appropriate, but it is essential if heavily energy-weighted allocations of
8 generation costs are employed. Failure to make this kind of distinction would charge
9 high load factor customers above-average capital costs, but not allow them to have
10 the related below-average energy costs; and charge the low load factor customers
11 below-average capital costs, yet still allow them to enjoy average fuel costs.

12 **Q HAVE YOU PERFORMED ANY CALCULATIONS AND DEVELOPED A**
13 **SCHEDULE TO ILLUSTRATE THIS?**

14 A Yes, I have. Please refer to page 1 of Schedule MEB-COS-R-1 attached to this
15 testimony. This schedule compares the capacity costs per kW and the energy costs
16 per kWh across classes for the traditional A&E allocation method and the A&P
17 method. To establish a common framework of costs for the analysis, so as to isolate
18 the impacts just of allocation methodology, I used the total generation capacity costs
19 and total generation energy costs from Ameren Missouri's cost of service study and
20 applied my allocation factors (traditional) as well as OPC's demand and energy
21 allocators to these total amounts. I then divided the capacity costs by the A&E
22 capacity kW, and the energy costs by the class MWh.

1 Q PLEASE EXPLAIN WHAT THIS SCHEDULE SHOWS.

2 A The top part of the schedule shows that under traditional allocation methods each
3 class has the same capacity costs per kW, and each class has the same energy cost
4 per kWh.

5 The bottom part shows the allocation results under OPC's A&P method. Note
6 that the impact is to allocate significantly more capital costs, in fact, 19% more to the
7 LPS class and 41% more to the LTS class than under the traditional approaches,
8 which allocate average capacity costs to all classes. Note also that fuel costs per
9 kWh are essentially the same for all classes.

10 Page 2 of Schedule MEB-COS-R-1 graphically shows the skewing under the
11 A&P method.

12 Q YOU INDICATED THAT THE ENERGY COSTS PER KWH ARE THE SAME
13 UNDER THESE ALLOCATIONS. HOW DIFFERENT ARE THE ENERGY COSTS
14 OF THE DIFFERENT GENERATING FACILITIES?

15 A They are quite diverse. For example, the fuel cost for the Callaway nuclear unit is
16 about 0.90¢ per kWh, the base load coal plants have fuel costs in the range of 2.0¢ to
17 2.6¢ per kWh, the more efficient peaking units have fuel costs of 4¢ to 10¢ per kWh,
18 and other peakers have costs that are as much as \$4.00 per kWh. (Note: These fuel
19 costs are taken from Ameren Missouri's 2013 FERC Form 1 report.)

20 Obviously, if some classes are allocated higher capacity costs than others,
21 they should be entitled to at least an above-average share of the energy output from
22 the higher capital cost, more fuel efficient, base load type generating units, which
23 would make their fuel cost per kWh lower than average. The A&P allocation method

1 advanced by OPC does not recognize this correspondence, and as a result
2 over-allocates costs to high load factor customers.

3 **Q WHAT SHOULD BE CONCLUDED FROM SCHEDULE MEB-COS-R-1?**

4 **A** This schedule clearly demonstrates that the non-traditional methods like A&P are
5 highly non-symmetrical. They burden high load factor classes with above-average
6 capacity costs, but do not allow them to benefit from the lower cost of energy that
7 goes with the higher capacity costs. No theory supports this result and these studies
8 should be rejected.

9 **Staff's Studies**

10 **Q WHAT COST OF SERVICE STUDIES DID STAFF PROVIDE?**

11 **A** Staff provided three different studies. It characterizes them as a Detailed BIP study,
12 a modified BIP study and a Market Price study. Staff prefers the Detailed BIP study
13 and that appears to be the primary basis for its recommendations.

14 **Q PLEASE DESCRIBE GENERALLY THE DETAILED BIP STUDY.**

15 **A** With this method, the fixed costs associated with base load generation essentially are
16 allocated on a measure of class energy consumption. The intermediate plants are
17 allocated as a function of class 12 monthly coincident peaks minus base demands.
18 Facilities identified as peaking facilities are allocated on class four summer coincident
19 peak demands reduced by the base and intermediate demands.

1 Q IS THE BIP STUDY METHODOLOGY ACCEPTED IN THE INDUSTRY?

2 A No, it is not. The BIP method first surfaced circa 1980 as an approach that some
3 thought might be useful when trying to develop time-differentiated rates. However,
4 the BIP method never caught on and is only infrequently seen in regulatory
5 proceedings. The BIP method is certainly not among the frequently used mainstream
6 cost allocation methodologies, and lacks precedent for its use.

7 Q WHAT SEEMS TO BE THE FUNDAMENTAL TENENT OF THE BIP METHOD?

8 A Staff does not say, but on page 16 of the Staff Report it says that the attempt is to
9 determine the intended use of specific plant investments. By choosing to allocate
10 100% of the investment (fixed costs) associated with base load plants essentially on
11 the basis of class energy, Staff effectively is assuming that investment in base load
12 plants is not caused by demands and that these plants don't have a capacity cost.
13 These are assumptions that we all know are false. All plants have a capacity cost,
14 and provide capacity value as well as supplying energy. It appears from Staff's
15 studies that about 66% of total generation fixed costs are allocated on the basis of
16 class energy consumption.

17 Q PLEASE EXPLAIN WHAT YOU MEAN WHEN YOU SAY THAT BASE LOAD
18 PLANTS ARE ALLOCATED "ESSENTIALLY" ON THE BASIS OF CLASS
19 ENERGY.

20 A In Staff's Detailed BIP study, 100% of the fixed costs associated with plants
21 designated as base load are allocated to customer classes using the customer class
22 energy requirement factor as the basis for the allocation. By using the energy
23 allocation factor, Staff does not include any consideration of the times that energy is

1 consumed (i.e., when demands occur), and would therefore attribute the same
2 capacity cost to a customer that takes all of its load at the system peak hour as it
3 would to a class with the same amount of energy consumption taken steadily at the
4 same amount every hour throughout the year. (Please see the discussion of demand
5 versus energy costs at pages 13-16 of my direct testimony, including Figure 3 on
6 page 15.)

7 **Q DOES THE CONCEPT OF ALLOCATING BASE LOAD PLANT ON A MEASURE**
8 **OF CLASS ENERGY MAKE SENSE IN LIGHT OF SYSTEM PLANNING**
9 **CONSIDERATIONS?**

10 **A** No. The BIP approach attempts to assign only one purpose for each class of plant.
11 In reality, when systems are planned, the utility attempts to install that combination of
12 generation facilities which, giving consideration to fixed costs and variable costs, is
13 expected to serve the needs of all customers, collectively, on a least-cost basis. All
14 plants contribute to meeting peak demands, and the failure to allocate the fixed costs
15 associated with base load plants on a measure of peak demand produces a biased
16 result that over-allocates costs to high load factor customers and under-allocates
17 costs to low load factor customers.

18 **Q DID THIS COMMISSION RECENTLY RULE ON THE USE OF DEMAND**
19 **ALLOCATION METHODS THAT ARE HEAVILY DEPENDENT UPON THE**
20 **ENERGY USAGE BY THE VARIOUS CUSTOMER CLASSES?**

21 **A** Yes. In a recent Ameren Missouri electric rate case, Case No. ER-2010-0036, cost of
22 service studies were offered wherein the allocation basis for fixed generation cost
23 was a weighted average of class energy consumption and class contribution to peak

1 demands. In ruling on the case, the Commission rejected these heavily energy-
2 weighted methods.

3 **Q IN THE AMEREN MISSOURI CASE, WHAT PERCENTAGE OF GENERATION
4 FIXED COSTS WAS ALLOCATED ON ENERGY UNDER THESE PROPOSALS?**

5 **A** About 55%.

6 **Q IS THE ALLOCATION OF GENERATION CAPACITY COSTS MORE HEAVILY
7 DEPENDENT UPON CLASS ENERGY CONSUMPTION UNDER THE BIP METHOD
8 IN THIS CASE THAN WAS TRUE IN THE AMEREN MISSOURI CASE WHERE
9 THE ENERGY BASED ALLOCATION WAS REJECTED?**

10 **A** Yes, much more. It is almost 67% with BIP as compared to 55% in the Ameren case.

11 **Q AT PAGE 16 OF THE REPORT, STAFF INDICATES THAT THE BIP METHOD IS
12 DISCUSSED IN THE NATIONAL ASSOCIATION OF REGULATORY UTILITY
13 COMMISSIONERS COST ALLOCATION MANUAL ("NARUC MANUAL"). DOES
14 THE FACT THAT A GENERATION ALLOCATION METHOD IS MENTIONED IN
15 THE NARUC MANUAL GIVE IT CREDIBILITY OR SUGGEST THAT IT IS
16 ACCEPTED IN THE INDUSTRY?**

17 **A** No.

18 **Q PLEASE EXPLAIN.**

19 **A** The fact that a particular generation allocation method is noted in the NARUC Manual
20 simply means that the individuals who prepared the NARUC Manual included it
21 because it had been recommended by participants in one or more rate cases. There

1 are a number of allocation methods that are described in the NARUC Manual that are
2 not commonly used and that have not found wide support in the industry. Staff's BIP
3 allocator clearly falls into that category.

4 **Q PUTTING ASIDE FOR THE MOMENT THE THEORETICAL PROBLEMS THAT**
5 **YOU HAVE IDENTIFIED WITH RESPECT TO THE DETAILED BIP METHOD, ARE**
6 **THERE SOME PRACTICAL OR IMPLEMENTATION ISSUES WITH STAFF'S**
7 **STUDY?**

8 **A** Yes. There are several. First, in the determination of how much capacity is base
9 load, Staff simply divides Ameren Missouri's total annual retail energy sales by the
10 8,760 hours in the year to arrive at approximately 4,500 megawatts as the amount of
11 capacity to be considered base load. Conceptually, it is generally regarded that in the
12 BIP method the base load should be considered that load which is present at all
13 times. In the case of the Ameren Missouri system, however, the retail load is less
14 than the 4,500 megawatts calculated by Staff in 57% of the hours in the test year.
15 Obviously, the amount of capacity Staff has identified as base load is much higher
16 than the capacity required to serve the load at all times. This skews the costs into the
17 base load category and, since it is allocated on energy, the result is an over-allocation
18 of costs to high load factor customers.

19 **Q ARE THERE OTHER IMPLEMENTATION ISSUES?**

20 **A** Yes. According to the theory expressed by Staff, intermediate units should have a
21 lower capacity cost than base load units. When Staff stacked up Ameren Missouri's
22 generating units from the lowest generation cost to the highest, and made its "cut"
23 between base load and intermediate load units, the Sioux units fell into the

1 intermediate category. When Staff calculated the costs per kW of the Sioux units, the
2 result was that the Sioux units have a higher capacity cost per kW than the base load
3 units ... completely at odds with Staff's theory.

4 **Q WHY DID THIS OCCUR?**

5 A One of the reasons for this is the recent addition of costly scrubbers to the Sioux
6 units. This points up another problem, namely that of the vintage of addition of a unit.
7 Because of inflation, changing rules and standards, etc., it can easily happen that a
8 more recently installed intermediate or peaking unit is higher than the depreciated
9 value of a base load unit installed some years ago. This phenomena has caused a
10 distortion in the Staff's study and skews the results for reasons completely apart from
11 the theory used by Staff to partition units into the different categories.

12 **Q HOW DID STAFF DEAL WITH THIS ISSUE?**

13 A Staff "fixed" the problem by arbitrarily removing, and ignoring, about \$115 million of
14 the cost of the Sioux scrubbers (classified into the intermediate category) from the
15 development of the BIP Production Capacity allocators. The result of this adjustment
16 reduces the intermediate categories allocation of production plant from 29% to 27%.
17 The majority of this cost is picked up by the base load category increasing its
18 allocated share of production plant from 64% to 66% This, of course, is totally
19 without theoretical support and further increases the costs attributed to base load
20 units, again to the detriment of high load factor customers.

1 Q **HAVE YOU IDENTIFIED OTHER MAJOR IMPLEMENTATION PROBLEMS?**

2 A Yes. When Staff stacks up Ameren Missouri's generating units on the basis of
3 variable cost, there are approximately 2,500 megawatts of capacity that are in excess
4 of customer load. In calculating the average cost per kW of the peaking units in the
5 BIP formulation, Staff simply ignored the costs associated with these approximately
6 2,500 megawatts of generating units that were not "needed" under its theory of
7 cost-causation and cost responsibility allocation.

8 Q **HAVE YOU REVIEWED STAFF'S MODIFIED BIP STUDY?**

9 A Yes. Staff's modified BIP study develops a single composite allocator to be applied
10 to 100% of the fixed costs of all generating units taken together. In that respect, it is
11 similar to the traditional A&E - 4NCP study. In fact, the way that Staff combines class
12 loads to develop the composite allocation factor produces an overall demand
13 allocation factor under the modified BIP study that is quite similar to the allocation
14 factor under the A&E - 4NCP study.

15 Q **DO YOU TAKE ISSUE WITH ANY PARTS OF THE MODIFIED BIP STUDY?**

16 A Yes. First, I should note that the fact the demand allocation factors between the
17 Modified BIP study and the A&E - 4NCP study are similar may be due in part to
18 coincidence. The fact that I do not object more vigorously to the allocation factor in
19 this study should not be interpreted as an endorsement of the study methodology.

20 Beyond the allocation issue, I disagree with Staff's treatment of OSS, and also
21 with its allocation of A&G expenses.

1 Q WHAT IS YOUR ISSUE WITH RESPECT TO HOW STAFF HAS ALLOCATED
2 OSS?

3 A Staff has allocated the portion of OSS revenues that it attributes to energy cost using
4 an energy cost allocator (which is reasonable), but has allocated what it deems to be
5 the "margin" on a demand basis. This treatment fails to recognize that the OSS
6 revenues are essentially non-firm, and occur as a matter of opportunity, rather than
7 as a matter of planning or obligation, and therefore these sales do not have an
8 allocable capacity component to them. This is discussed previously in my testimony
9 in connection with my review of the OCA class cost of service allocation assumptions.
10 This same shortcoming is contained in each of Staff's cost of service studies.

11 Q HAVE YOU REVIEWED STAFF'S STUDY WHICH IT CALLS THE "MARKET
12 PRICE" STUDY?

13 A Yes. Under the guise of expanding on cost issues that arose in Case
14 No. EC-2014-0224, Staff develops and presents what it calls a "Market Price" cost
15 allocation study.

16 Q DO YOU AGREE WITH STAFF'S CHARACTERIZATION?

17 A No, I do not. The costing analysis discussed in Case No. EC-2014-0224 was in the
18 nature of avoidable costs and the role of market price in that determination. It was
19 not used, and was not represented as a means, to determine how to allocate a
20 utility's embedded cost of service.

1 Q HOW DOES STAFF DEVELOP ALLOCATIONS UNDER ITS MARKET PRICE
2 METHOD?

3 A The first step in Staff's allocation is to multiply the hourly loads of each class times the
4 hourly locational marginal price ("LMP") in each hour over a three-year period.² This
5 total is then divided by three to develop an average. This average LMP amount is
6 then taken to be a component of production cost for each customer class. Staff
7 subtracts the total of the LMPs from its total embedded cost of the production function
8 and allocates this residual to customer classes based on a three-year average of
9 customer 4CP demands. The sum of the two pieces equals the cost allocated to
10 each customer class.

11 The market price allocation loads up the costs on the energy side, and
12 minimizes the costs on the demand side. Because the LMPs are higher than
13 embedded energy cost, there is a disproportionately large allocation of these costs to
14 high load factor customers. In fact, roughly two-thirds of the cost component are
15 allocated on an energy basis, and only about one-third on a demand basis.

16 Staff inappropriately also uses this allocation for OSS revenues, for other
17 MISO-related items, and for transmission plant.

18 Q IN ONE OF THE JUSTIFICATIONS FOR ITS PARTICULAR ALLOCATION OF
19 OSS, STAFF STATES THAT MISO DISPATCHES CAPACITY (STAFF REPORT AT
20 PAGE 28). IS THIS TRUE?

21 A No. Essentially, all generators make a price bid to MISO, and MISO selects which
22 units are to run so as to clear the market based on input bids and load bids. The

²Curiously, the three-year period used (2011-2013) does not include any data during the test year, and is not normalized.

1 incurred fuel costs and the revenues received from OSS are a function of this market
2 clearing activity, and not the result of any dispatch of a capacity by MISO.

3 **Q DO YOU HAVE AN ISSUE WITH STAFF'S ALLOCATION OF A&G EXPENSE?**

4 **A** Yes. I have an issue with Staff's allocation of A&G expense in each of its studies.

5 **Q WHAT IS THE ISSUE?**

6 **A** A significant portion of A&G expense is allocated to classes on the basis of other
7 O&M expenses, which include significant amounts of fuel and purchased power
8 expense. Fuel and purchased power expense do not give rise to the incurrence of
9 A&G expense in proportion to the level of fuel and purchased power expense
10 because these costs are largely generated externally, as opposed to the labor and
11 other costs of maintaining the generation, transmission, distribution and other
12 functions of the utility, which are internally incurred and do give rise to the occurrence
13 of A&G expense.

14 **Q STAFF HAS REFERRED TO THE NARUC MANUAL FOR CERTAIN**
15 **ALLOCATIONS. DOES THE NARUC MANUAL CONTAIN A DISCUSSION OF THE**
16 **ALLOCATION OF GENERAL PLANT AND A&G EXPENSES?**

17 **A** Yes. Pages 105-107 of the January 1992 NARUC Manual discusses A&G expenses.
18 I have attached these pages as Schedule MEB-COS-R-2. Note that the majority of
19 A&G expenses are allocated on labor. Wherever the Manual refers to a more general
20 category of expenses, note that the phrase "less fuel and purchased power" appears.
21 This means that fuel and purchased power should be excluded from the allocations.

1 From a cost causation point of view, none of the salary expense, pensions
2 and benefits, plant-related or other costs vary with energy consumption. This is why it
3 is traditional to exclude fuel and purchased power from any allocation of A&G
4 expenses and focus on the cost-causative nature for these expenses. That is what I
5 have done; it clearly is not what Staff has done.

6 **Q DID STAFF ALLOCATE A&G EXPENSE THE SAME WAY IN EACH OF ITS**
7 **THREE STUDIES?**

8 **A Yes, it did.**

9 **Q SHOULD THE COMMISSION RELY UPON THE RESULTS OF STAFF'S COST OF**
10 **SERVICE STUDIES?**

11 **A No. As noted previously, these studies are outside the mainstream, conflict with prior**
12 **Commission rulings and contain inappropriate allocations. None of them should be**
13 **adopted.**

14 **Q YOU HAVE NOTED THAT THE STAFF AND OPC METHODS PROPOSED IN THIS**
15 **PROCEEDING ARE NOT USED IN OTHER JURISDICTIONS AND ARE NOT**
16 **SUPPORTED BY PRECEDENT OR ACCEPTED IN THE INDUSTRY. WHAT IS**
17 **THE SIGNIFICANCE OF THIS?**

18 **A Cost of service studies for electric systems has been performed for well over 50**
19 **years. This means that there has been a significant amount of analysis that has gone**
20 **into the question of determining how best to ascertain cost-causation on electric**
21 **systems, across a broad spectrum of utility circumstances. Methods that have not**
22 **had the benefit of that analysis and withstood the test of time must be viewed with**

1 skepticism. Proponents of such methods bear a special burden of proving that they
2 do a more accurate job of identifying cost-causation than do recognized methods,
3 and are not merely ad hoc creations designed simply to support a particular result
4 desired by the analyst.

5 OTHER ISSUES

6 Q HAVE YOU REVIEWED THE DIRECT TESTIMONY OF WITNESS JANE
7 LOHRAFF, WHO TESTIFIES ON BEHALF OF THE MISSOURI DEPARTMENT OF
8 ECONOMIC DEVELOPMENT, DIVISION OF ENERGY?

9 A Yes.

10 Q WHAT IS THE CENTRAL TENENT OF MS. LOHRAFF'S TESTIMONY?

11 A As stated on page 2 of her direct testimony, the central tenent is to recommend that
12 Ameren Missouri's Economic Development Rider ("EDRR") and Economic
13 Re-Development Rider ("ERR") be modified to require "active" participation in Ameren
14 Missouri's MEEIA program as a requirement for receiving EDRR or ERR benefits.

15 Q DO YOU AGREE WITH MS. LOHRAFF'S RECOMMENDATION?

16 A No, I do not. This recommendation is flawed for several reasons. First, it would
17 require mandatory participation in a program without any demonstration that the
18 energy efficiency measures offered by the utility are not already in place as a result of
19 the customer's investment, or that if they are not in place, the offered programs are
20 applicable to and would be cost-effective with respect to the particular customer
21 seeking to participate in the EDRR or ERR program.

1 Q WHY IS THIS A PROBLEM?

2 A It obviously is a problem because if the customer already has implemented and is
3 practicing energy efficiency to the extent cost-effective for the customer, forcing
4 participation in a program which does not provide additional benefits would only
5 burden the customer with excess cost, and reduce the attractiveness of the economic
6 development programs. In addition, even if the customer has not pursued all energy
7 efficiency programs which would be cost-effective for it, if the Ameren Missouri
8 program does not offer measures or other assistance that would be applicable to and
9 cost-effective for the customer, requiring such participation would be self-defeating,
10 and simply would amount to a "give-back" of part of the economic development
11 benefits for which the customer otherwise would be eligible.

12 Q DO YOU HAVE ANY OTHER COMMENTS WITH RESPECT TO MS. LOHRAFF'S
13 RECOMMENDATION OF MANDATORY PARTICIPATION IN AMEREN
14 MISSOURI'S MEEIA PROGRAMS?

15 A Yes. It is MIEC's position that the statutory language implementing MEEIA provides
16 the criteria for customers to "opt-out" of utility-sponsored energy efficiency programs,
17 and that the statutory authorization for the opt-outs trumps any potential "policy"
18 principles that DED or any other state government entity may attempt to impose.

1 Q ON PAGE 7 OF HER TESTIMONY, MS. LOHRAFF REFERENCES TARIFFS OF
2 NORTHERN INDIANA PUBLIC SERVICE COMPANY, WISCONSIN POWER AND
3 LIGHT COMPANY, AND PACIFIC GAS AND ELECTRIC COMPANY FOR THE
4 PROPOSITION THAT ENERGY EFFICIENCY INITIATIVES HAVE BEEN TIED TO
5 ECONOMIC DEVELOPMENT RIDERS IN OTHER STATES. HAVE YOU HAD AN
6 OPPORTUNITY TO REVIEW THIS TESTIMONY AND THE ATTACHED TARIFFS?

7 A Yes.

8 Q DO YOU BELIEVE THAT THE ATTACHED TARIFFS SUPPORT MS. LOHRAFF'S
9 RECOMMENDATION TO REQUIRE PARTICIPATION IN AMEREN MISSOURI'S
10 MEEIA PROGRAMS BY CUSTOMERS RECEIVING ECONOMIC DEVELOPMENT
11 INCENTIVES?

12 A No. These tariffs clearly do not support that view.

13 Q PLEASE EXPLAIN.

14 A First, the Northern Indiana Public Service Company tariff that is attached to her
15 testimony simply references "high-efficiency, end-use equipment and construction
16 technologies." No mention whatsoever is made of mandatory participation in any
17 energy efficiency program that may be conducted by Northern Indiana Public Service
18 Company. Accordingly, this tariff does not support Ms. Lohraff's recommendation.

19 Next, the Wisconsin Power and Light Company tariff attached to her testimony
20 simply states that the customer must meet with company representatives to identify
21 economically viable energy efficiency and demand-side management opportunities.
22 It also requires the customer to participate in or implement all economically viable
23 programs or projects with a projected payback of five years or less. However, it does

1 not require mandatory participation in Wisconsin Power and Light Company's energy
2 efficiency programs.

3 The attached Pacific Gas and Electric Company tariff is even further removed
4 from the issue at hand. It is a "Net energy Metering Service for City and County of
5 San Francisco Municipal Loads served by Hetch Hetchy At-Site Photovoltaic
6 Generating Facilities." This tariff simply relates to photovoltaic generating facilities
7 operated by Hetch Hetchy, which is a hydro electric facility owned by the City of San
8 Francisco, and is used to supply municipal loads. It does not even come close to
9 requiring what Ms. Lohraff states that it requires.

10 **Q WHAT IS YOUR RECOMMENDATION WITH RESPECT TO DED'S PROPOSALS?**

11 **A** My recommendation is that they be rejected because they are unsupported, and if
12 implemented could be counter-productive.

13 **Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

14 **A** Yes, it does.

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AMEREN MISSOURI

Case No. ER-2014-0258

**Customer Class Generation Capacity Costs Per kW
And Energy Costs Per kWh Under Traditional Methods
As Compared to OPC Proposal**

MIEC COST OF SERVICE STUDY

<u>Customer Class</u>	<u>Traditional Avg. & Excess CCOS</u>			
	<u>Capacity Rev Req.</u>		<u>Energy Rev Req.</u>	
	<u>Capacity Costs \$ per kW</u>	<u>% Difference From System Avg.</u>	<u>Energy Costs ¢ per kWh</u>	<u>% Difference From System Avg.</u>
Total	160		2.07	
Res	160	0%	2.07	0%
SGS	160	0%	2.07	0%
LGS/SPS	160	0%	2.07	0%
LPS	160	0%	2.07	0%
LTS	160	0%	2.07	0%
Lighting	160	0%	2.07	0%

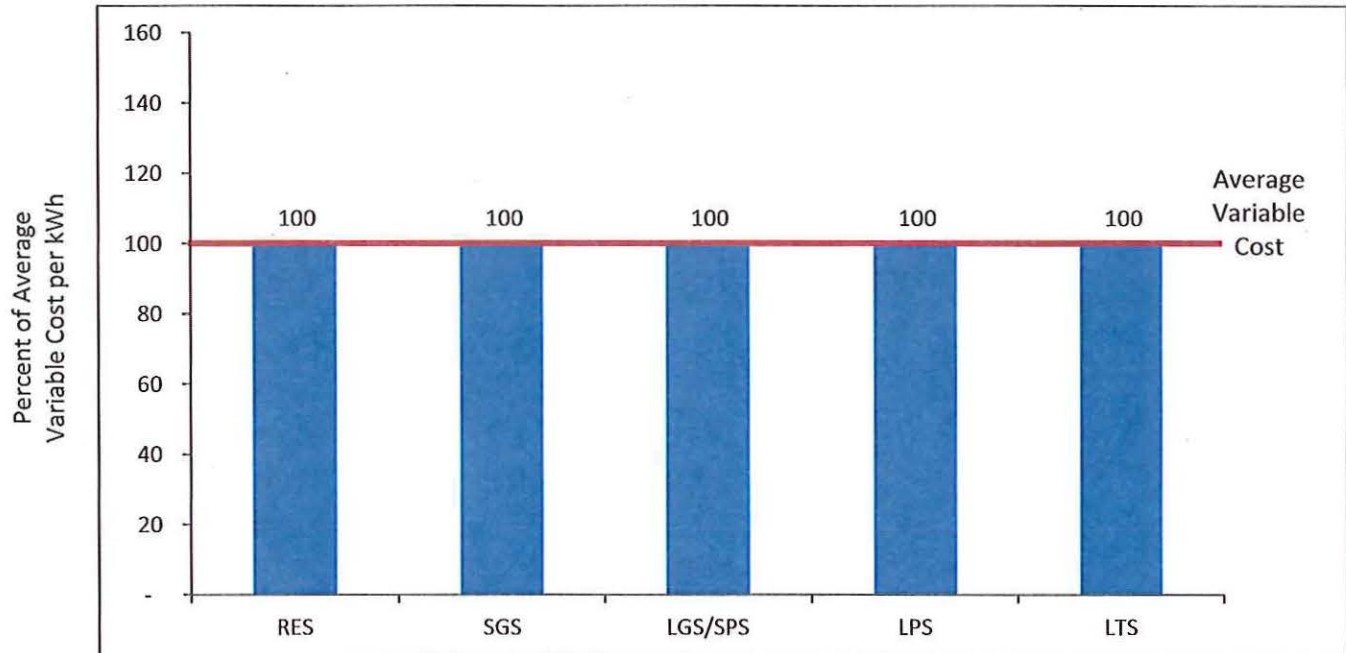
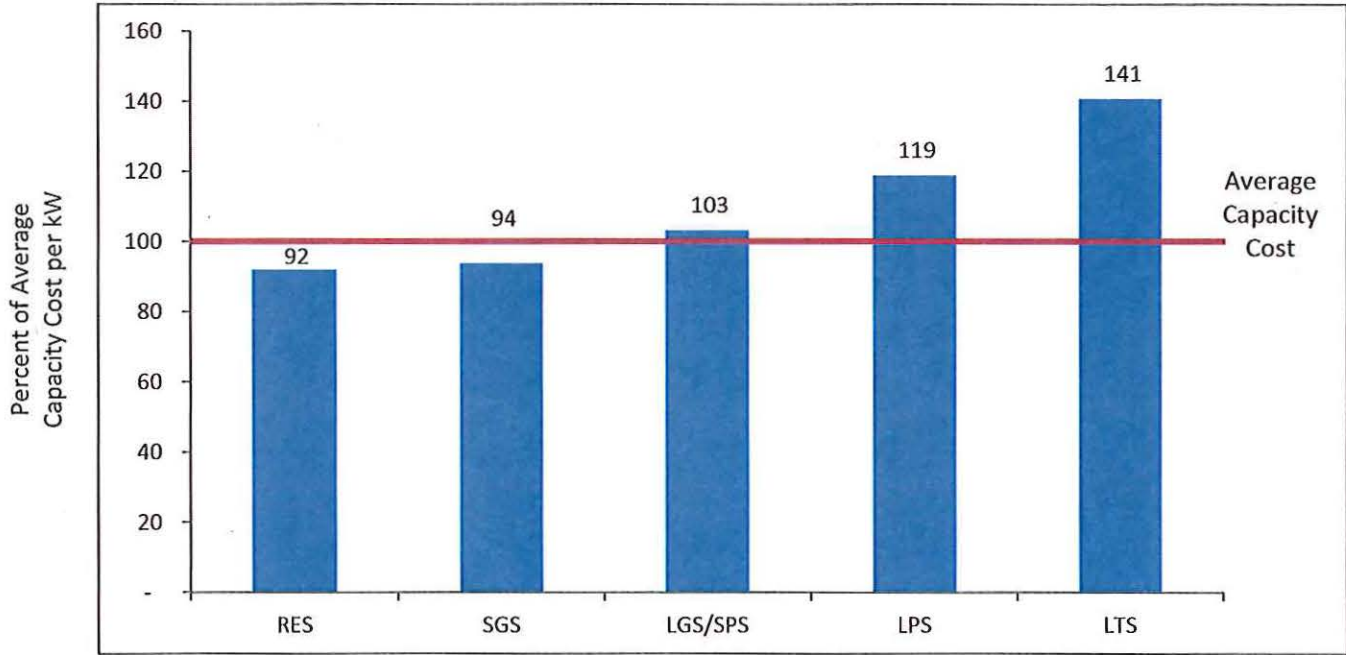
OFFICE OF PUBLIC COUNSEL COST OF SERVICE STUDY

<u>Customer Class</u>	<u>OPC Avg. and Peak CCOS</u>			
	<u>Capacity Rev Req.</u>		<u>Energy Rev Req.</u>	
	<u>Capacity Costs \$ per kW</u>	<u>% Difference From System Avg.</u>	<u>Energy Costs ¢ per kWh</u>	<u>% Difference From System Avg.</u>
Total	160		2.07	
Res	147	-8%	2.07	0%
SGS	150	-6%	2.07	0%
LGS/SPS	165	3%	2.07	0%
LPS	190	19%	2.07	0%
LTS	225	41%	2.07	0%
Lighting	83	-48%	2.07	0%

AMEREN MISSOURI

Case No. ER-2014-0258

Illustration of Skewed Allocation of Capital Costs and Energy Costs Under OPC's Allocation Proposal



ELECTRIC UTILITY COST ALLOCATION MANUAL

January, 1992



**NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
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CHAPTER 8

CLASSIFICATION AND ALLOCATION OF COMMON AND GENERAL PLANT INVESTMENTS AND ADMINISTRATIVE AND GENERAL EXPENSES

This chapter describes how general plant investments and administrative and general expenses are treated in a cost of service study. These accounts are listed in the general plant Accounts 389 through 399, and in the administrative and general Accounts 920 through 935.

I. GENERAL PLANT

General plant expenses include Accounts 389 through 399 and are that portion of the plant that are not included in production, transmission, or distribution accounts, but which are, nonetheless, necessary to provide electric service.

One approach to the functionalization, classification, and allocation of general plant is to assign the total dollar investment on the same basis as the sum of the allocated investments in production, transmission and distribution plant. This type of allocation rests on the theory that general plant supports the other plant functions.

Another method is more detailed. Each item of general plant or groups of general and common plant items is functionalized, classified, and allocated. For example, the investment in a general office building can be functionalized by estimating the space used in the building by the primary functions (production, transmission, distribution, customer accounting and customer information). This approach is more time-consuming and presents additional allocation questions such as how to allocate the common facilities such as the general corporate computer space, the Shareholder Relation Office space, etc.

Another suggested basis is the use of operating labor ratios. In performing the cost of service study, operation and maintenance expenses for production, transmission, distribution, customer accounting and customer information have already been functionalized, classified, and allocated. Consequently, the amount of labor, wages, and salaries assigned to each function is known, and a set of labor expense ratios is thus available for use in allocating accounts such as transportation equipment, communication equipment, investments or general office space.

II. ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include Accounts 920 through 935 and are allocated with an approach similar to that utilized for general plant. One methodology, the two-factor approach; allocates the administrative and general expense accounts on the basis of the sum of the other operating and maintenance expenses (excluding fuel and purchased power).

A more detailed methodology classifies the administrative and general expense accounts into three major components: those which are labor related; those which are plant related; and those which require special analysis for assignment or the application of the beneficiality criteria for assignment.

The following tabulation presents an example of the cost functionalization and allocation of administrative and general expenses using the three-factor approach and the two-factor approach.

Account Operation		Three-Factor Allocation Basis	Two-Factor Allocation Basis
920	A & G Salaries	Labor - Salary and Wages	Labor - Salary and Wages
921	Office Supplies	Labor - Salary and Wage	Labor - Salary and Wages
922	Administration Expenses Transferred-Credit	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
923	Outside Services Employed	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
924	Property Insurance	Plant - Total Plant ¹	Plant - Total Plant
925	Injuries and Damages	Labor - Salary and Wages ²	Labor - Salary and Wages
926	Pensions and Benefits	Labor - Salary and Wages	Labor - Salary and Wages
927	Franchise Requirements	Revenues or specific assignment	Revenues or specific assignment

¹ A utility that self-insures certain parts of its utility plant may require the adjustment of this allocator to only include that portion for which the expense is incurred.

² A detailed analysis of this account may be necessary to learn the nature and amount of the expenses being booked to it. Certain charges may be more closely related to certain plant accounts than to labor wages.

Account Operation		Three Factor Allocation Basis	Labor-Ratio Allocation Basis
928	Regulatory Commission Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
928	Duplicate Charge-Cr.	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.1	General Advertising Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.2	Miscellaneous General Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
931	Rents	Plant - Total Plant ³	Plant - Total Plant
Maintenance		Three Factor Allocation Basis	Labor-Ratio Allocation Basis
935	General Plant	Plant - Gross Plant	Labor - Salary and Wages

³A detailed analysis of rental payments may be necessary to determine the correct allocation bias. If the expenses booked are predominantly for the rental of office space, the use of labor, wage and salary allocators would be more appropriate.