Exhibit No.:	
Issues:	Cost of Service, Revenue Allocation, and Rate Design
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal Testimony
Sponsoring Party:	Missouri Industrial Energy Consumers
Case No.:	ER-2021-0240
Date Testimony Prepared:	October 15, 2021

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	**)))))**	**Case No. ER-2021-0240**

Rebuttal Testimony and Schedules of

Maurice Brubaker

on Cost of Service, Revenue Allocation and Rate Design

On behalf of

Missouri Industrial Energy Consumers

October 15, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11115

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	**)))))**	**Case No. ER-2021-0240**

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

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-2021-0240.

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

Maurice Brubaker

Subscribed and sworn to before me this 15th day of October, 2021.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2023
Commission # 15024862

Tammy S Klossner

Notary Public

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	**)))))**	**Case No. ER-2021-0240**

Rebuttal Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

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

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

A Yes. This information is included in Appendix A to my direct testimony filed on September 17, 2021.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Missouri Industrial Energy Consumers ("MIEC"), a non-profit corporation that represents the interests of large consumers in Missouri rate matters.

INTRODUCTION AND SUMMARY

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A The purpose of my rebuttal testimony is to respond to the direct testimony of the Commission Staff ("Staff") concerning the issues of class cost of service, revenue allocation and rate design. I will specifically address my response to the "Staff Report Class Cost of Service" ("Staff Report"). The second item I address is the criticisms that Staff levels at Ameren Missouri's allocations and assignments in the distribution plant category. Finally, I will comment on Staff's recommendation concerning Rider I, Rider B and Staff's recommendation for the overall allocation of any change in revenues approved by the Commission in this case.

Q PLEASE PROVIDE A HIGH LEVEL SUMMARY OF YOUR FINDINGS AND RECOMMENDATIONS.

A In general, I find that Staff has proposed allocations among customer classes that are not based on generally accepted cost allocation principles, and that would seriously over-allocate costs to large, high load factor customers, particularly those who take service under the Large Primary Service ("LPS") rate. Many of Staff's allocation methods are outside of the mainstream and/or use allocation parameters that have no reasonable relationship to cost-causation.

Staff's recommendation to allocate any revenue change as an equal percentage of existing revenues flows from use of these flawed cost allocations and therefore is flawed, and should be rejected. Instead, Ameren Missouri's cost of service study (as filed or as modified by me in my direct testimony) should be used to define class revenue requirements under conventional approaches. Those studies also should be used to determine an appropriate allocation of any change in revenues across customer classes. For reference, my recommendation from Schedule MEB-COS-5 of my direct testimony is included here as Schedule MEB-COS-R-1. The moderated allocation which moves all classes 50% toward cost of service which I recommended in Schedule MEB-COS-6 also is replicated here as Schedule MEB-COS-R-2.

Staff completely misunderstands the nature and purpose of Rider B. Its proposal to withdraw Rider B and deny customers the credits to which they are entitled should be flatly rejected.

Staff's recommendation with respect to the mandatory application of the provisions of Rider I are unnecessary because the billing provisions of both the Small Primary Service ("SPS") rate and the LPS rate already contain the same billing demand provision as Rider I.

I recommend that Rate 12 which is a large load, high load factor rate, be retained as part of Ameren Missouri's tariffs.

STAFF'S ALLOCATIONS

Q PLEASE DISCUSS THE METHOD BY WHICH STAFF ALLOCATED FIXED PRODUCTION COSTS.

A Staff segregated the various Ameren Missouri generating facilities into 10 categories: Nuclear; coal; combustion turbine; Taum Sauk; Osage; Keokuk; Wind; Landfill; General Solar; and Community Solar. Staff then calculated the revenue requirement associated with the fixed costs of each of these categories of generating units (see Staff Report, pages 37-39). Staff then considered a range of allocation methodologies, including variants of single peak; multiple peak; Average & Excess; and Peak & Average methodologies for the nuclear; coal; combustion turbine; Taum Sauk and Osage generation categories. For the other generation categories (Keokuk; Wind; Landfill; and General Solar), Staff relied only on the energy allocator under the misplaced premise that these generation facilities exist simply to provide Renewable Energy Certificates ("RECs") and energy and do not provide any capacity benefit (see Staff Report, page 42). Finally, Staff allocated the fixed costs associated with the Community Solar category entirely to the Community Solar customers. Ultimately, Staff presented 3 different studies which are summarized in the table on page 44 of the Staff Report. In Study 1, Staff claims to allocate the generation fixed costs (Gen Stable RR) on the basis of single coincident peak (1 CP). In Study 2, Staff claims to allocate these costs on the basis of Average & Peak - 4 NCP ("A&P 4NCP").[1] In Study 3, Staff claims to allocate these costs on the basis of Average and Excess - 4 NCP ("A&E 4NCP").

Q IS STAFF'S SUMMARY, AS PRESENTED ON PAGE 44, ACCURATE?

A No, it is very misleading.

Q IN WHAT RESPECTS IS IT MISLEADING?

A The first category for each study in this table refers to what Staff described as "Gen Stable RR" (Generation Stable Revenue Requirements), which essentially are the return, depreciation, labor and non-labor expenses (fixed costs) associated with each generation facility. The allocator shown in the table for each of the three studies is accurate only as to certain categories of generation – specifically nuclear, coal, combustion turbines, Taum Sauk; and Osage. While mentioned briefly in the Staff's Report, the table does not accurately indicate that fixed costs revenue requirements

[1]The "Average and Peak" method sometimes is referred to as "Peak and Average."

associated with Keokuk Hydro, Wind, Landfill Gas and Solar Generation (other than Community Solar) is actually allocated to customer classes on the basis of class energy (kWh) and not on the basis of a demand allocation factor. As I discuss later in more detail, Staff mistakenly assumes that Keokuk; Wind; Landfill Gas and Solar Generation do not provide any benefit towards meeting peak demand.

The second category for each study is labeled "Gen Variable RR" and generally refers to the fuel, market energy transactions and variable operation and maintenance expenses associated with all generation facilities. The table misleadingly states that these costs are allocated using a demand allocation factor, when in fact they are allocated on class kWh.

Finally, the table shows the methodology by which Staff allocated General Overhead and Plant In Service Accounting ("PISA")

Q ADDRESSING THE INDIVIDUAL STUDIES, WHAT IS YOUR ASSESSMENT OF STUDY 2?

A Study 2 claims to use an A&P allocation for generation and allocates General Overhead and PISA on kWh. As mentioned previously, however, Staff only used the A&P methodology for certain categories of generation facilities. The others are allocated using an energy allocator. Even then, the Commission has previously rejected A&P allocations because they double-count demand and behave essentially like an energy allocator.

> "Staff asserts that its Peak and Average Demand allocation method is superior to the Average and Excess method because it considers each class' contribution to the system's total peak rather than each class' excess demand at peak. However, what Staff describes as its method's strength is actually its downfall because the Peak and Average demand method double counts the average demand of the customer classes." (Case No. ER-2010-0036, Report and Order, page 84)

> "The Peak and Average method, in contrast, initially allocates average costs to each class, but then, instead of allocating just the excess of the peak usage period to the various classes to the cost causing classes, the method reallocates the entire peak usage to the classes that contribute to the peak. Thus, the classes that contribute a large amount to the average usage of the system but add little to the peak, have their average usage allocated to them a second time. Thus, the Peak and Average method double counts the average system usage, and for that reason is unreliable" (*Id*., page 85)

In addition to its faulty production allocator in Study 2, Staff used a faulty energy allocator for General Overhead and PISA. Allocating General Overhead and PISA on kWh (energy) sold rather than based on the underlying drivers of the incurrence of those costs has no claim to cost-causation and, as a result, Study 2 should be rejected in its entirety because of these inappropriate allocations.

Q WHAT IS YOUR ASSESSMENT OF STUDY 1?

A Study 1 states a single coincident peak allocator for what Staff describes as Gen Stable Revenue Requirements. Generally, as I mentioned at page 25 of my direct testimony, a coincident peak allocator for fixed production costs is appropriate. But as in Study 2, the fixed costs of some generation facilities are misallocated on class kWh. Staff actually allocates fixed costs of Landfill Gas, Wind, Solar and Keokuk Hydro on class energy consumption, and Study 1 should be rejected in its entirety.

Further, many of the "reallocations" of General Overhead, PISA, and Socialized Programs are on bases that are inappropriate and not cost-based.

Q PLEASE GIVE YOUR ASSESSMENT OF STUDY 3.

A Study 3 is described as using A&E 4NCP for generation. Generally, as reflected at pages 25-28 of my direct testimony, an A&E methodology is appropriate for allocating fixed production costs. That said, however, Staff omitted the fixed costs of Landfill Gas, Wind, Solar and Keokuk Hydro from the A&E allocator and, instead, allocated these costs on the basis of class kWh. Study 3, therefore, is inappropriate and should be rejected on that basis. In addition, Study 3 suffers from the same problems with respect to the allocation of General Overhead, PISA, and Socialized Programs as do Studies 1 and 2.

Q WHAT IS STAFF'S BASIS FOR ARGUING THAT THE ALLOCATION OF FIXED COSTS ASSOCIATED WITH RENEWABLE RESOURCES SHOULD BE ON THE BASIS OF KWH USAGE BY CUSTOMER CLASS?

A At the bottom of page 42 of the Staff Report, beginning on line 8, Staff states that this is because these resources are used "…for the generation of renewable energy certificates…", and that they are non-dispatchable.

Q IS STAFF'S EXPLANATION A VALID BASIS FOR ALLOCATING THE COSTS OF THESE RESOURCES TO CUSTOMER CLASSES ON KWH REQUIREMENTS, RATHER THAN THE MORE CONVENTIONAL ALLOCATION USED FOR OTHER GENERATION RESOURCES?

A No. All of these resources also have a capacity value and generate energy. The fact that the output receives RECs is incidental to the generation (for example, Keokuk Hydro has been in service well before anybody even thought of the term "renewable energy certificate"). The fixed costs associated with all of these resources should be allocated in the same way as the fixed costs associated with other resources in the generation portfolio.

Q PLEASE ELABORATE.

A To effectively and cost-efficiently serve the power requirements of its customers, electric utilities invest in and/or procure through purchased power agreements a variety of generation resources that have different characteristics. A generation resource portfolio typically includes baseload facilities that are designed to operate most of the time, and which have (in a relative sense) higher fixed costs, and lower variable cost. At the other end of the spectrum of characteristics are peaking plants (whose use is expected to be needed only infrequently for unexpected needs and for peaking capacity) that have (in a relative sense) relatively higher variable costs and relatively lower fixed costs. Other types and vintages of generating units fill roles in between those two.

In addition, generation portfolios often include a variety of renewable resources (such as Solar and Wind) that are intermittent in the sense that their output is available when the sun shines or the wind blows. The economics associated with these types of facilities are becoming even more cost-effective as technology improves and as additional resource providers enter the market.

Recognizing that all of these facilities are part of an overall generation resource portfolio designed to serve the overall power requirements of a utility's customers at the lowest overall reasonable cost, and that all provide capacity, the generally accepted method is to allocate the fixed costs associated with all of these facilities on the basis of an appropriate measure of customer demand, and to allocate all of the variable costs to customer classes on the basis of relative class kWh requirements.

Q DID STAFF PRESENT ANY OTHER ALLOCATION STUDIES?

A Yes. On page 46, Staff summarizes the "a" versions of each of these three studies. The only difference between the "a" version and the base study shown on page 45 is a slight change in the allocation of Transmission costs. The difference between these two sets of studies is very small, and for the reasons stated previously, should all be rejected.

Q TURNING BACK TO YOUR EARLIER STATEMENT, PLEASE EXPLAIN WHY STAFF'S ALLOCATIONS OF GENERAL OVERHEAD, PISA AND SOCIALIZED PROGRAMS ARE INAPPROPRIATE.

A Staff's broad based allocations ignore the more precise assignments and allocations that Ameren Missouri has made in its class cost of service study. In addition, in some instances, Staff has allocated these costs on class energy usage, which is entirely without support.

Q WHAT ARE SOME OF THE EXPENSE ITEMS THAT STAFF CLASSIFIES AS GENERAL OVERHEADS?

A In total, Staff designates about $284 million of expenses in this category. Some of the items included are Administrative and General ("A&G") salaries of $67 million, Office Supplies and Expenses of $32 million, General Plant Revenue Requirements of $65 million and $58 million related to Intangible Plant.

Q HOW ARE COSTS OF THIS NATURE GENERALLY HANDLED IN CLASS COST OF SERVICE ANALYSES?

A Traditionally, these kinds of expenses are allocated across functions (generation, transmission and distribution) and between demand-related, energy-related and customer-related costs on the basis of the relationship between these costs and the costs in the specific functional categories. For example, A&G labor and Pensions and Benefits would typically be allocated across generation, transmission, distribution and other functions based on the relative proportion of total salaries and wages included in each of those functions because the labor in those functions are what causes most of the A&G expenses to be incurred. Similar approaches would be applied for most of the other costs that Staff has placed into this category.

Q WHAT IS STAFF'S EXPLANATION FOR ITS BROAD BASED TREATMENT?

A Staff simply states that these costs are too general to be reasonably associated with other functions and therefore are generally allocated.

Q HOW DO YOU RESPOND TO THAT CLAIM?

A I would acknowledge that some of these investments and expenses do require allocation among functions because they are incurred on a general enterprise basis and support the activities being conducted within the different functional areas. The fact that they may not be "precisely" assignable does not justify a failure to make reasonable assignments and allocations, and instead lump everything into one bucket and arbitrarily allocate those costs to customer classes on the basis of class energy requirements or some other general basis. A reasonable allocation of these costs across the functions, even if not precisely accurate, is more cost-based and far better than the arbitrary and totally inaccurate allocation of all of these costs on the basis of class energy requirements or some other general basis.

Q HOW DID STAFF ALLOCATE COSTS RELATED TO PISA?

A In some cases (Study 2) Staff allocated PISA costs on the basis of class energy usage (which is totally inappropriate because these costs are not variable with energy usage). In other cases (Studies 1 and 3) Staff allocated PISA costs on rate base without bothering to functionalize those costs.

Q AT PAGES 41 AND 42 OF ITS COST OF SERVICE REPORT, STAFF REFERS TO A REGULATORY ASSISTANCE PROJECT ("RAP") "ELECTRIC COST ALLOCATION FOR A NEW ERA" MANUAL BY JIM LAZAR, PAUL CHERNICK AND WILLIAM MARCUS, AND EDITED BY MARK LEBEL. ARE YOU FAMILIAR WITH THAT DOCUMENT?

A Yes.

Q OTHER THAN THE REFERENCE IN STAFF'S COST OF SERVICE REPORT, ARE THERE OTHER INDICATIONS THAT STAFF RELIED UPON THIS DOCUMENT IN DEVELOPING ITS POSITIONS AND RECOMMENDATIONS?

A Yes. Staff also referred to this document in responding to a number of data requests that were submitted to it by Ameren Missouri, including 829, 830, 835, 842 and 843.

Q WHAT IS THE BASIC THESIS OF THIS MANUAL?

A As stated on page 14, the authors believe that because the electric system is different now than it was when NARUC published its seminal Electric Utility Cost Allocation

Manual that old methods must be discarded and new methods invented to accommodate the new systems.

Q DO YOU AGREE?

A No, I do not. The fundamental principles of cost-causation remain valid and can appropriately be applied to new generations of technology. At its very essence, the central feature of the recommendations in the RAP document is to increase the allocation of generation resources on the basis of class kWh, rather than on the cost-causative demands imposed by customers.

Q DO YOU HAVE ANY FURTHER COMMENTS WITH RESPECT TO THE RAP DOCUMENT?

A Yes. My firm has prepared a brief response to some of the key recommendations in that document. A copy of our report is attached as Schedule MEB-COS-R-3.

DISTRIBUTION SYSTEM ALLOCATION

Q STAFF SPENDS A CONSIDERABLE AMOUNT OF TIME IN THE STAFF REPORT COMMENTING ON AMEREN MISSOURI'S RECORDKEEPING AND ASSIGNMENTS WITHIN THE DISTRIBUTION FUNCTION. DO YOU HAVE ANY COMMENTS ON STAFF'S ISSUES WITH RESPECT TO DISTRIBUTION SYSTEM ALLOCATION?

A Staff levels significant criticisms against Ameren Missouri for its recordkeeping and inability to specifically identify costs associated with specific facilities. Staff seems to think that the inability to identify the costs associated with specific distribution lines and other delivery equipment makes Ameren Missouri's studies imprecise and unreliable.

Q WHAT IS YOUR REACTION TO STAFF'S CRITICISMS?

A While any set of records probably could be made more precise, the question is whether or not the added degree of precision would add useful or meaningful information and improve the accuracy of cost allocation studies. Knowing the exact cost (and depreciated value) of a specific 34 kV line running from Point A to Point B as compared to the <u>average</u> cost per mile of all 34 kV lines is not particularly meaningful when rates are set on the basis of general categories of customers and voltage level. Customers taking service at 34 kV are allocated a share of the costs of 34 kV and higher voltage equipment. Rates are designed to serve all 34 kV customers as a class, without regard to their specific geographic location, or the age of the facilities specifically providing service. In other words, unless rates were to be set separately for each individual customer, the added information would be of no value.

Q WHAT IS YOUR OVERALL ASSESSMENT OF THE LEVEL OF DETAIL BEHIND AMEREN MISSOURI'S CLASS COST OF SERVICE STUDY?

A I believe it is generally consistent with the level of detail and the practices of other electric utilities.

Q WHAT IS THE BASIS FOR THAT STATEMENT?

A It is based on 50 years of experience in reviewing class cost of service studies performed by numerous electric utilities in 34 different regulatory jurisdictions.

ALLOCATION OF ANY ALLOWED REVENUE CHANGE

Q HOW DOES STAFF RECOMMEND THAT ANY CHANGE IN REVENUE BE ALLOCATED AMONG CUSTOMER CLASSES?

A Staff recommends that any approved change in revenues be allocated amount customer classes on the basis of base rate revenues under current rates.

Q DO YOU AGREE WITH THIS RECOMMENDATION?

A No. Cost of service evidence (see Schedule MEB-COS-R-1) clearly indicates that the residential class is producing revenues far below the costs incurred to serve it. To the contrary, the rates being charged to all other major customer classes including the LGS/Primary class and the LPS class are producing revenues in excess of their cost of service and on a cost of service basis should see their current rates reduced by 10% to move them to their respective costs of service.

Q WHAT IS YOUR RECOMMENDATION?

A As explained in my direct testimony, I recommend making a movement toward class cost of service. My recommendation is shown on Schedule MEB-COS-R-2, and is to move 50% of the way from the current rate levels to cost of service.

For example, if at the end of the day Ameren Missouri is granted an increase of "X", class revenues should be adjusted first by applying the percentages in column 4 on Schedule MEB-COS-R-2 to make the movement toward cost of service and then to increase the resulting rate revenues by "X". This effectively provides an across-the-board allocation after an initial step toward class cost of service has been made.

RATE SCHEDULE ISSUES

Rider B

Q WHAT IS RIDER B?

A Rider B provides credits to customers who provide their own substations to reduce voltage from 34 kV or higher to the customer's receipt point voltage. It is titled "Discount Applicable for Service to Substations Owned by Customer in Lieu of Company Ownership." This appears on Sheet No. 75 of Ameren Missouri's electric tariff, and is provided here as Schedule MEB-COS-R-4. Note that it only is applicable to customers who actually own their own substations which provide this service link.

Q WHAT IS STAFF'S RECOMMENDATION?

A Staff's rather startling recommendation is stated on page 54:

> "Staff recommends that unless the costs of substation equipment that is dedicated to primary customer is specifically assigned to the bills of primary customers, that the discounts provided to primary customers under Rider B be suspended until Ameren Missouri provides the information necessary to include the cost of primary customer substations in the bills of primary customers (and such costs are so included)."

Q WHAT DO YOU THINK OF STAFF'S RECOMMENDATION?

A Candidly, it does not make sense. The substations that allow a customer to receive the Rider B credit are owned by the customer, not by Ameren Missouri. Since the rates provide service to customers who do not own their own substation, as well as those who do (Rider B customers), it is necessary to provide a credit to customers that own their own substation to recognize that they are not using the Ameren Missouri substation assets. Therefore, it is illogical for Staff to expect Ameren Missouri to "include the cost of primary [voltage] substations in the bills of primary [voltage] customers." This is the basis for the credit. Including the cost of substations (which are already owned by the customer) on the customer's bill, and then on top of that denying the customer the cost of service credit that arises because the customer, and not Ameren Missouri, actually owns that step-down substation defies logic. This recommendation reveals a fundamental misunderstanding by Staff and must be rejected.

Rider I

Q ON PAGE 4 OF THE STAFF REPORT, STAFF RECOMMENDS THAT AMEREN MISSOURI:

> **"…require, on a non-optional basis, that nonresidential customers participate in Rider I, which incorporates a time of use element to customers' billing as those customers obtain AMI metering equipment."**

WHAT IS YOUR REACTION TO THIS RECOMMENDATION?

A As it might pertain to SPS and LPS customers, the billing demand and time-of-use provisions contained in the LPS service, which are mandatory, are the same as those provisions included in Rider I. Accordingly, this recommendation is unnecessary and should not be made applicable to Rates SPS and LPS.

Rate 12

Q WHAT IS RATE 12?

A Rate 12 was designed for high load factor, large load customers taking service at the transmission level. It previously was used to provide service to Noranda Aluminum. Ameren Missouri proposes to eliminate that rate.

Q DO YOU AGREE?

A No. There is no reason to eliminate the rate. Although Ameren Missouri is not currently serving any load at the site, that could change. In addition, the rate could form the basis for service to other large, high load factor loads, such as data centers. There is no cost to maintain the rate, and I recommend that it not be eliminated.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes.

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AMEREN MISSOURI
Case No. ER-2021-0240

Class Cost of Service Study Results
and Revenue Adjustments to Move Each Class to Cost of Service
Using MIEC's Modified ECOS at Present Rates
(Dollars in Thousands)

Line	Rate Class	Base Revenues (1)	Current Rate Base (2)	Adjusted Operating Income (3)	Earned ROR (4)	Indexed ROR (5)	Income @ Equal ROR (6)	Difference in Income (7)	Revenue Change (8)	Percent Change (9)
1	Residential	$ 1,273,043	$ 5,600,934	$ 192,416	3.435%	72	$ 266,857	$ 74,440	$ 99,254	7.8%
2	Small GS	274,322	1,108,873	55,506	5.006%	105	52,832	(2,674)	(3,565)	-1.3%
3	Large GS/Primary	727,565	2,571,637	175,531	6.826%	143	122,526	(53,006)	(70,674)	-9.7%
4	Large Primary	188,576	609,255	44,317	7.274%	153	29,028	(15,289)	(20,385)	-10.8%
5	Company Owned Lighting	35,640	145,623	11,558	7.937%	167	6,938	(4,620)	(6,160)	-17.3%
6	Customer Owned Lighting	2,849	16,853	(345)	-2.045%	-43	803	1,148	1,530	53.7%
7	Total	$ 2,501,995	$ 10,053,175	$ 478,984	4.765%	100	$ 478,984	$ -	$ -	0.0%

Schedule MEB-COS-R-1

AMEREN MISSOURI
Case No. ER-2021-0240

Cost of Service Adjustments for
50% Movement Toward Cost of Service
Using Modified ECOS at Present Rates
($ in Millions)

Line	Rate Class	Current Revenues (1)	Move 50% Toward Cost Of Service[1] (2)	Adjusted Current Revenue (3)	Revenue-neutral Percent Change in Current Revenue (4)
1	Residential	$ 1,273.0	$ 49.6	$ 1,322.7	3.9 %
2	Small GS	274.3	(1.8)	272.5	(0.6)%
3	Large GS/Primary	727.6	(35.3)	692.2	(4.9)%
4	Large Primary	188.6	(10.2)	178.4	(5.4)%
5	Company Owned Lighting	35.6	(3.1)	32.6	(8.6)%
6	Customer Owned Lighting	2.8	0.8	3.6	26.9 %
7	Total	$ 2,502.0	$ -	$ 2,502.0	0.0 %

(1) Increase to equal cost of service from column 8 of Schedule MEB-COS-5, times 50%.

Rebuttal of the Key Recommendations in the Regulatory Assistance Project's Electric Cost Allocation Manual

Report

September 2021

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

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Abbreviations and Acronyms

A&E	Average and Excess
A&G	Administrative and General
BIP	Base-Intermediate-Peak
CP	Coincident Peak
Manual	Electric Cost Allocation for a New Era – A Manual
NARUC	National Association of Regulatory Utility Commissioners
POD	Probability of Dispatch
RAP	Regulatory Assistance Project

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Brubaker and Associates, Inc.
Rebuttal of the Key Recommendations in the
Regulatory Assistance Project's Electric Cost Allocation Manual
September 2021

Introduction

In January 2020, the Regulatory Assistance Project ("RAP") released an electric cost allocation manual entitled Electric Cost Allocation for a New Era ("Manual").[1] The authors of the Manual are Jim Lazar, Paul Chernick and William Marcus. Our report herein provides a high-level summary and critique of the Manual's major cost allocation recommendations.

The Manual offers numerous recommendations for electric cost allocation that, in the view of the Manual's authors, should be adopted to incorporate what they describe as "modern" cost of service methodologies that allegedly reflect changes in the electric industry such as expanded reliance on renewable resources and the increased deployment of storage technologies. The Manual is extensive and its cost allocation recommendations touch on virtually the entire range of utility cost categories, including generation, transmission and distribution fixed and variable costs, as well several categories of administrative and general ("A&G") expenses.

The Manual generally sets forth the traditional positions and arguments that small consumer advocates typically make in state regulatory proceedings with respect to the allocation of electricity costs. From a cost perspective, the most impactful recommendations in the Manual include 1) advocating for the Probability of Dispatch ("POD") and the Base-Intermediate-Peak ("BIP") allocation methods for generation fixed costs; 2) allocating a significant portion of transmission fixed costs on an energy basis; and 3) rejecting the Minimum System approach for classifying a portion of distribution fixed costs on a customer basis and instead allocating distribution investment on a demand and energy basis.

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[1]Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual*. Montpelier, VT: Regulatory Assistance Project.

The underlying premise of the Manual's cost allocation recommendations is that most electric utility system costs should be allocated on the basis of energy consumption and recovered on a kWh basis.[2] Moreover, the common theme among the Manual's recommended cost allocation approaches is that they would have the effect of shifting a greater share of costs to large, high load factor loads relative to more widely accepted cost allocation methods that typically rely on customer demands to allocate most, if not all, fixed system investment costs.

The balance of this report briefly summarizes the major electric cost allocation recommendations contained in the Manual and provides a high-level rebuttal of these recommendations. The report does not attempt to address each and every cost allocation recommendation in the Manual, nor does it attempt to rebut every argument that the Manual raises to support its cost allocation recommendations. Rather, the report focuses on the most impactful recommendations in the Manual in terms of their dollar impact on the allocation of costs to large high load factor customers and outlines the arguments that most effectively counter the Manual's main recommendations.

This report can provide a foundation for a more detailed and comprehensive electric cost allocation white paper that would provide a counter-weight to the Manual's recommendations. The report can also be used as a framework for developing testimony to rebut the key cost allocation arguments in the Manual, to the extent that witnesses for other parties rely on the Manual to develop cost allocation proposals in the context of an electric utility rate proceeding.

Allocation of Generation Fixed Costs

The Manual argues that the fixed cost of generation resources is in large part determined by energy requirements because the most expensive generating units from a capital cost perspective are used to provide energy during all hours of the year. Therefore, the Manual

[2]Manual at page 245.

argues that the POD and BIP allocation methods have the highest correlation to cost causality for such resources.[3]

Rebuttal

The POD and BIP allocation methods recommended in the Manual are not appropriate for the allocation of generation fixed costs. These allocation methods are inconsistent with cost causation because they rely on energy consumption throughout the year to allocate fixed generation costs that are in fact driven by customer class loads at the time of annual system peak demand.

The most appropriate approach for allocating generation fixed costs is the coincident peak ("CP") demand method. A CP demand allocation methodology allocates fixed generation costs to customer classes based on each class' demand at the time of the system peak demand interval(s). The CP allocation can be performed based on the forecasted or historical demand of the customer at annual system peak hour or interval (1 CP). Alternatively, the allocation can be based on a historical average of customer demand during the system peak hour or interval for several individual months during a calendar year (e.g., 3 CP or 4 CP) if the peak load profile of a utility system is such that there are several months of the year that are determined to be of near equal importance with respect to when the annual system peak demand will occur.

There are a number of considerations that make the CP allocation method the most appropriate method for allocating generation fixed costs. First, a CP allocation method is consistent with cost causation principles for the incurrence of fixed generation costs. Such an allocation method recognizes the fact that generation resource adequacy planning is based on ensuring that there are sufficient resources in place to meet the maximum simultaneous peak demand imposed by customers on the system. A CP allocation method properly recognizes this cost causative factor that gives rise to the incurrence of fixed production costs.

[3]Manual at pages 55-56 and 132.

Because energy cannot be economically stored in large quantities for significant periods of time, and customers expect their lights to go on when they turn on the switch, generating plants must be sized to meet the peak annual demand of the system, even if the actual system demand is much lower in most hours of the year. In addition, to address forecast uncertainty with respect to the magnitude of peak annual demand, generation resource and transmission outages and the availability of renewable resources, typically a generation reserve margin in excess of the projected system peak demand is carried in order to provide reliable service. This reserve margin, often referred to as planning reserve margin, is typically determined through probabilistic loss of load expectation studies that aim to keep the forecasted frequency of firm load curtailment due to resource unavailability to less than one day within in a specified number of years. Typically, the specified number of years is ten, but, for some utilities in unique situations, it can be as little as five years. This planning reserve margin is expressed as a percentage of the peak annual demand of the system and, in conjunction with annual system peak demand, is used to assess the need for incremental capacity.

A projection that the actual reserve margin during the forecasted planning horizon will fall below the level required to maintain reliability within loss of load expectation requirements provides the indication that additional generating capacity must be installed to preserve an adequate planning reserve margin. Therefore, it is clear that growth in system peak demand is the trigger for generation additions and dictates the size of such additions. This means that customer demand at the time of the system peak demand interval (the CP demand of those customers) is the driver for the incurrence of incremental fixed generation costs.

The CP allocation method also provides appropriate price signals to minimize the incurrence of incremental fixed generation costs. Given that the system peak demand is the driver for the incurrence of additional generation investment, the CP method sends a strong, cost-based price signal to discourage power use at the time of the system peak demand. This benefits all customers on the system by reducing the rate of growth in the system peak demand and thereby deferring the need to construct incremental generation plant.

In addition, the CP allocation method appropriately reflects the economic classification of costs by recognizing the fixed nature of generation capital investments. Once a generation investment decision is made, the costs associated with such capital investments are fixed and sunk because they can longer be avoided. Consequently, these generation capital costs do not vary with the amount of energy generated or consumed on the system or with the number of customers taking service. Therefore, it is appropriate to allocate these generation fixed costs on a CP demand basis. This means that state regulatory commissions should reject energy-based allocation methods for generation fixed costs, such as the BIP and POD methods proposed in the Manual.

The Manual contends that generation capital investments should be treated as variable costs based on the theory that all costs are variable over a very long time horizon of several years.[4] This argument is without merit. While a utility can retire generation and replace it with other generation sources or purchased power contracts, the capital costs of the generation units that are already in the utility's rate base remain fixed, sunk costs that cannot be avoided until the units are fully depreciated. Therefore, over the utility's rate and planning horizon, it is clear that generation capital costs are fixed costs that it cannot avoid once the investment is made, even if energy consumption levels on the utility's system change. This reality must be recognized by allocating generation capital costs on a demand rather than on an energy basis.

An electric utility system predominantly consists of fixed costs that must be accurately allocated to cost causers using a class cost of service study that recognizes the demand-related nature of these fixed costs. An appropriately designed class cost of service study can capture the cost-causative effects of differing customer class load shapes in a manner that properly

[4]Manual at pages 78-79.

reflects the differences in the coincidence of customer loads with the cost-causative utility system peaks.

In addition to being inconsistent with cost causation principles as outlined above, the BIP and POD methods suffer from critical conceptual flaws that undermine their validity. The POD method allocates generation capital costs to individual hours of the year based on the frequency with which each individual generating plant is dispatched to serve the utility's load. These hourly capacity costs for each generating plant are then summed and assigned to the customer classes based on the hourly class contributions to the total system load. The BIP method classifies and assigns individual generating assets based on their specific role in a utility's generation portfolio. Under the BIP method, typically "Base" load units are classified and allocated on energy, "Intermediate" units are classified and allocated as demand and energy based on their capacity factor, and "Peak" units are classified and allocated on peak demand.

The underlying premise of the POD and BIP methods is that load duration and the economic trade-off between capacity and energy costs are the driving forces behind generation investment decisions. This argument misrepresents the utility planning process. In reality, the most important consideration in the generation planning process is the need to preserve system reliability by ensuring that there is sufficient generation capacity to meet the utility's system peak demand requirements, plus a reasonable planning reserve margin.

By contrast, there is no clear cost-causation relationship between the duration of customer loads and resource planning. Utilities identify a need for new resources when generating capacity is needed to meet peak day demands and capacity reserves. These reserve margin requirements are tied to the utility's highest system peak demands in the year. Therefore, it is system peak demand, rather than the duration of resource use, that drives incremental resource additions.

The POD and BIP methods are also flawed because they oversimplify the utility generation planning process. Important factors such as fuel costs, technological innovations and environmental requirements can change significantly, distorting the dispatch order of a utility's generating resources over time. Changes in these factors can alter the frequency with which generating units are dispatched and can also impact the designation of units as Base, Intermediate or Peaking. Moreover, the dispatch order of generating units can be distorted by the addition of new plants that result in a different generation mix.

The POD and BIP methods ignore these significant factors that can alter the dispatch arrangement of generation units and that can impact the designation of Base, Intermediate or Peaking resources. Therefore, these allocation methods do not properly reflect the dynamic nature and the complexities of the utility system planning or dispatch processes.

Another flaw with the POD and BIP methods is that they frequently average fuel costs for all utility generating units and allocate these costs across customer classes based only on energy usage. However, to be consistent with the theory behind the POD and BIP method for allocating fixed costs, customer classes should receive a corresponding allocation of the fuel costs from the specific generation resources that are allocated to them using these methods. For example, customers that are allocated a larger percentage of baseload generating resource fixed costs should benefit from receiving a higher allocated share of the lower fuel costs associated with such baseload units. Customers who are allocated a higher percentage of peaking unit costs should pay the higher fuel costs of the peaking units because they pay a lower allocated share of baseload capacity costs. This is commonly known as the fuel symmetry issue.

This approach would reflect fuel symmetry by ensuring that customers that pay higher capital costs for baseload units under the POD and BIP methods benefit by receiving the lower energy costs produced by those units. Conversely, customers assigned the fixed costs for a less costly combination of Base, Intermediate and Peak units from a capital cost perspective should be assigned the higher fuel costs associated with this higher cost mix of resources. (It should be noted that Average and Excess ("A&E") cost allocation methods for production fixed costs do not suffer from the fuel symmetry problem.)

For all of the foregoing reasons, the POD and BIP allocation methods recommended in the Manual are fundamentally flawed and are inappropriate for the allocation of generation fixed costs. As discussed above, the driver for the incurrence of generation fixed costs is the contribution of customers to the system peak demand. Therefore, a CP allocation method for generation fixed costs is the most appropriate method that conforms to cost causation principles.

It should be noted that class cost of service studies that apportion generation fixed costs on the basis of the contribution of customer classes to the relevant system peaks are quite common in the electric utility industry. Indeed, customer class allocations of fixed costs based on the CP allocation method are similar in popularity to the A&E cost allocation methods that other parties have advocated for production fixed costs in utility rate proceedings. Moreover, for the major customer classes on many utility systems, an allocation of utility generation fixed costs using a 4CP allocation method would be relatively similar to the customer class allocation that results from applying the A&E-4NCP method for most classes.

A&E cost allocation methods allocate a portion of production fixed costs to the customer classes based on average demand (energy consumption) times the system load factor. The excess demand component above the average demand is allocate to the classes using some form of peak demand allocator.[5] By linking the energy component of the class allocation factors to the system load factor, the A&E method provides for a more reasonable energy weighting of fixed production and transmission costs that is more reflective of the actual operating

[5] A specific application of the A&E method is the A&E-4NCP methodology. Under this approach, a customer class's allocation factor for fixed production and transmission costs consists of two components. The first component (the average demand factor) is determined using average demand (energy consumption) times the system load factor. The second component of the class allocation factor (the excess demand factor) is determined as the proportion of the difference between the sum of the classes' 4 non-coincident peaks and the system average demand.

characteristics of the Company's system relative to other allocation methods such as POD and BIP. Therefore, the A&E method is a more reasonable and balanced allocation approach relative to the POD and BIP methods.

Allocation of Transmission Fixed Costs

The Manual categorizes the transmission system into various cost buckets and recommends different cost allocation methods for each category of costs. The proposed methods would generally classify a significant portion of transmission costs as energy-related and allocate such costs based on energy usage. For example, the Manual contends that all bulk transmission costs that are incurred to allow centralized generation and economic dispatch should be allocated on an energy basis. Any remaining bulk transmission costs would be deemed demand-related and allocated using a broad demand allocator that uses the highest 100 hours of usage in the year. This broad demand allocator is essentially another form of energy allocation that relies on a more targeted set of hours relative to a traditional energy allocator.

For local network transmission costs, the Manual recommends that any costs that are incurred to prevent overheating of conductors and related equipment[6] should be classified as energy-related and allocated using an on-peak energy allocator. Any remaining local transmission costs would be considered demand-related and allocated using a 4CP or 12CP demand allocator. Alternatively, the Manual suggests that all fixed transmission costs could be allocated in proportion to class energy usage in all of the hours in which the transmission facility is needed to provide service. The latter approach would essentially rely on a form of energy allocation for all generation fixed costs.[7]

[6]The Manual does not specify how conductor overheating costs would be determined.
[7]Manual at page 141.

Rebuttal

The Manual's suggestion that transmission capital investment should be allocated to customer classes primarily on an energy basis should be rejected because it is inconsistent with cost causation principles. The most appropriate method for allocating transmission capital costs is the CP allocation method.

Several considerations favor applying the CP allocation method to allocate and recover bulk transmission costs. First, a CP allocation method is consistent with cost causation principles for the incurrence of capacity costs. Such an allocation method recognizes the fact that transmission planning is based on ensuring that there is sufficient transmission capacity in place to meet the maximum simultaneous peak demand imposed by customers on the transmission system. A CP allocation method properly recognizes this cost causative factor that gives rise to the incurrence of fixed transmission costs.

In order to preserve system reliability, bulk transmission facilities must be sized to meet the annual system peak demand, even if the actual system demand is much lower in most hours of the year. Consistent with this reality, transmission planners principally conduct their bulk transmission planning for system reliability purposes using power flow models that assess power flows during system CP conditions. Therefore, growth in the system CP demand is the trigger for bulk transmission additions and dictates the size of such additions. This means that customer demands at the time of the system peak demand intervals are the driver for the incurrence of transmission investment costs.

The CP method also provides appropriate price signals to minimize the incurrence of incremental capacity costs. Given that growth in the system peak demand is the driver for the incurrence of additional bulk transmission investment, the CP method sends a strong, cost-based price signal to discourage power use at the time of the system peak demand. This benefits all customers on the system by reducing the rate of growth in the system peak demand and thereby deferring the need to construct additional transmission plant.

Finally, the CP allocation method appropriately reflects the economic classification of costs by recognizing the fixed nature of transmission capital investments. Once a transmission investment decision is made, the costs associated with such capital investments are fixed and sunk and cannot be avoided. Consequently, these capital costs do not vary with the amount of energy generated or consumed on the system or with the number of customers taking service. Therefore, it is appropriate to allocate these transmission fixed costs on a CP demand basis.

An allocation method for transmission capital investment that is based largely on energy consumption, as suggested in the Manual, is flawed for a number of reasons. First, an energy-based allocation method ignores the proper classification of electricity costs by using variable energy consumption levels to allocate fixed and sunk transmission costs that do not vary with energy consumption. From an economic standpoint, it is more efficient and more consistent with cost causation to classify and to allocate fixed capital costs on a demand basis.

Second, the Manual's proposed allocation approach would give weight to energy use during all hours of the year in determining the allocation of transmission costs. However, this approach ignores the fact that the incurrence of transmission costs is driven by customer demands at the time of the system peak demand intervals. Therefore, an energy-based allocation method violates principles of cost causation and results in a cost allocation that does not reflect customer contributions to the incurrence of transmission costs.

Finally, by focusing on consumption during all hours of the year, an energy-based allocation method fails to send a focused and efficient price signal to customers to reduce their demands at the time of the annual system peak demand intervals. By diluting the price signals that incentivize customers to reduce their electricity demands at the time of the system peaks, an energy-based method allocation method would contribute to the inefficient incurrence of incremental transmission costs that could have been avoided through proper, cost-based price signals that are focused on the system peak demand intervals.

One potential variation of an energy-based allocation method for transmission costs that the Manual proposes is to focus the energy-based cost allocation on a specific range of hours (such as on-peak hours). Another alternative would be to apply a weighted energy cost allocation method that assigns greater weight to the on-peak hours of the day and year in establishing cost responsibility for transmission costs, relative to off-peak hours. However, these allocation approach are sub-optimal and fail to send focused and efficient price signals that are consistent with cost causation principles. Specifically, these approaches send an inefficient price signal that is inconsistent with cost causation to the extent that they give any weight at all to the off-peak hours of the day or the year or to on-peak hours that are outside of the system peak demand intervals. Energy use during these hours should not influence the allocation of transmission investment because these hours have no relevance to the incurrence of bulk transmission costs that are driven by the need to plan the bulk transmission system to meet the CP demands.

Even a weighted energy consumption method that gives weight only to the on-peak hours of the day or year would be inconsistent with cost causation because it would assume that all on-peak hours are relevant to the establishment of the system peak demands that drive the incurrence of bulk transmission costs. In reality, only a handful of hours in the summer and/or winter seasons play a meaningful role in establishing the system peak demand. Weighting all on-peak hours equally in the allocation method would inappropriately dilute the strong price signals inherent in the CP allocation method and weaken the customer price response to these signals, making it more difficult to control the rate of growth in the system peak demand.

Allocation of Distribution Fixed Costs

The Manual argues that only meters and a portion of service drop costs should be considered customer-related and allocated on a customer basis, particularly in relatively densely populated service territories. The Manual also contends that all shared distribution network costs should be treated as demand-related or energy-related. Moreover, the Manual specifically rejects the Minimum System method that many regulatory commissions use to classify and to allocate a portion of distribution system costs on a customer basis. Instead, the Manual recommends that that distribution fixed costs be classified into demand and energy components. The demand-related costs would be allocated using a broad set of hours that encompasses both high-load hours and hours that are prior to the high-load hours. Alternatively, the Manual recommends what it characterizes as an ideal allocation method for distribution plant that would model and reflect the contribution of each class to the load on each individual substation, feeder or transformer during the hours when the class loads contribute to the potential for overloading of each distribution system element. While the Manual does not define precisely how this allocation would be accomplished, this is essentially a prescription for allocating all distribution plant using a form of energy allocator that relies on energy consumption during a fairly wide range of hours.[8]

Rebuttal

The Manual's suggestion that some distribution investment should be classified as energy-related is inappropriate and inconsistent with cost causation. For the reasons set forth above with respect to the allocation of transmission capital costs, an appropriate approach to the allocation of distribution capital costs must recognize the fixed nature of distribution system investments by allocating the cost of such investments using the customer demands imposed on the delivery system. These investments, and the associated customer class demands used to develop the demand allocator, should be differentiated by voltage level, such that customers who take service from the primary distribution system are not required to pay for secondary distribution system facilities that they do not use.

[8]Manual at pages 145-151.

In contrast to the use of CP demands to allocate transmission costs, distribution investments can be allocated based on the maximum localized (non-coincident peak) demands that customers impose on the utility system. This non-coincident peak demand approach acknowledges that the downstream, localized nature of distribution investments yields fewer demand diversity benefits relative to upstream transmission system investments that are more geographically distant from the end-use customer. Because distribution investments must be sized to meet the maximum localized demands that customers impose on these facilities, there is no cost causative link between customer energy consumption throughout the year and the level of distribution investment. Therefore, there is no basis for the Manual's suggestion that a portion of distribution investment should be allocated on an energy basis.

In the alternative, distribution investments can be allocated using a 1 CP allocation method based on the system peak demand for each voltage class of distribution facilities. This approach recognizes that there is a continuum ranging from individual customer NCP being the cost driver for distribution investments at the lowest voltage, least networked level of the distribution system (i.e., secondary voltage class) to customer demand at the system peak being the driver at the highest voltage, most networked part of the distribution system. It should be noted that, for some rate classes, the annual peak demand behavior of individual members of the class highly conforms to the annual peak demand of the system as a whole, such that NCP and CP demand are currently the same (e.g., residential class), though that may be changing as residential rooftop solar penetration increases.

Moreover, the Manual's argument that no portion of distribution investment is customer-related is fundamentally flawed and inconsistent with cost causation principles. The primary purpose of the distribution system is to deliver power from the transmission grid to the customer. Certain distribution investments, including investments in distribution poles and wires, must be made simply to connect a customer to the system and to meet the National Electric Safety Code. These investments are customer-related. A utility must incur costs to construct a distribution line to connect customers to its system, irrespective of the amount (i.e., energy) or rate (i.e., demand) of electricity usage on its system. Therefore, a portion of distribution line costs is properly classified and allocated as customer-related. The remaining distribution investment is needed to provide sufficient capacity to meet customers' demands when they arise. This remaining portion of the distribution investment is demand-related.

This customer/demand-related approach to classifying distribution line costs is widely accepted. On this topic, the National Association of Regulatory Utility Commissioners ("NARUC") Electric Utility Cost Allocation Manual, which is widely quoted in the electric utility industry, states that:

> "Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system."[9]

One of the methods that the NARUC Manual discusses for establishing the customer and demand components of distribution investment is the Minimum System method. The Minimum System method determines the minimum size distribution system that could be built to serve the minimum load requirements of customers on the system. This method involves determining the smallest size pole, conductor, cable and transformer that is currently installed by the utility. The cost of the smallest size facility is classified as customer-related. The demand-related cost is the difference between the total cost and the customer-related cost. Using this widely applied approach, the customer classification of distribution investment can be determined using current engineering cost data and characteristics that are specific to the utility's distribution system. Therefore, this approach is a conceptually sound and practical means of calculating the customer component of distribution investment.

[9]National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, page 90.

Allocation of Smart Meter Costs

The Manual contends that the benefits of smart metering are very broadly distributed because these meters enable improved peak load management and provide reliability benefits and distribution line loss savings. Therefore, the Manual argues that it is incorrect to allocate smart meter costs on a customer basis. Rather, the Manual asserts that such costs should be broadly functionalized and allocated to generation and distribution functions.[10]

Rebuttal

While advanced metering devices may be capable of providing some system benefits as discussed in the Manual, the bulk of the benefits from such meters accrue directly to the customers who install the device through more rapid identification of outages at their premises and by enabling these customers to better control their electricity consumption. Therefore, it is appropriate to directly assign these smart metering costs to the residential and small commercial classes that receive the benefits of utility smart meter rollouts. The cost of smart metering rollouts can run into the hundreds of millions of dollars. Large customers should not be required to subsidize the substantial cost of these smart meter rollouts when the bulk of the benefits from these meters will accrue to residential and small commercial customers.

Moreover, most large customers had advanced interval metering devices installed on their premises many years ago. These meters provide granular information regarding customer usage to the utility, and this information can be used to provide the same types of broader system benefits that the Manual identifies with respect to the smart meters that many utilities are now installing for residential and small commercial customers. Nevertheless, the Manual does not propose to broadly allocate the cost of advanced large customer meters in a manner that would require residential and small commercial customers to pay a large share of these

[10]Manual at pages 157-158.

metering costs. This asymmetrical approach to the allocation of metering costs as suggested in the Manual is inappropriate and should be rejected by state regulatory commissions.

Allocation of Uncollectible Accounts Expenses

The Manual rejects the more accepted method of allocating uncollectible costs on a customer basis. Instead, the Manual contends that uncollectible costs are related to class revenue and should therefore be allocated in proportion to class revenues.[11]

Rebuttal

A long established principle of cost allocation holds that costs should be directly assigned to customer classes where there is sufficient data to directly assign the costs in question. In the case of uncollectible costs, it is generally straightforward to track the source of customer payment defaults by customer account and by customer class. Therefore, it is typically not difficult to directly assign uncollectible costs that are associated with a specific customer class directly to that class, and this is the preferred method of recovering these costs from customers.

A broad allocation of uncollectible costs across all customer classes based on class revenues, as suggested in the Manual, would unfairly require large customers to pay a large share of uncollectible costs that are directly associated with residential accounts. Such an outcome would be inequitable and inconsistent with cost causation.

Allocation of Customer Service Costs

The Manual recommends that customer service costs should be allocated based on class energy consumption or class revenues rather than in proportion to customer numbers.[12]

[11] Manual at pages 162-163.
[12] Manual at pages 163-164.

Rebuttal

Clearly, there is a correlation between the number of customers and the costs that a utility incurs to field service calls and to provide customer assistance. Utilities must dedicate more personnel and resources to field the numerous customer service calls they receive from the large number of residential customers on their systems, relative to the service calls that receive from the smaller number of industrial customers that they support. By contrast, there is no clear cost causative link between customer energy consumption or revenues and the amount of customer service support that the utility must provide. Therefore, direct assignment of customer service costs by customer class or an allocation of such costs by customer count are the most appropriate treatment of these costs for ratemaking purposes.

Allocation of Sales and Marketing Costs

The Manual contends that marketing costs should be allocated using base rate revenues or another broad allocation factor such as rate base, rather than the more common method that relies on a customer allocator. The Manual alleges that a broader revenue or rate base allocator is justified because the Manual's authors contend that these marketing costs are incurred to increase electric loads.[13]

Rebuttal

It is clear that a utility's sales costs will increase in proportion to the number of customers that it targets through its sales activities. For example, the cost of distributing promotional materials via mail increases as the number of customers that are targeted by these mailing efforts increases. The same is the case for promotional sales calls via telephone. Therefore, the utility will incur higher sales costs to reach a large number of residential customers relative to a smaller number of large commercial or industrial customers. Accordingly, the use of a customer allocator for sales and marketing costs is consistent with

[13]Manual at page 164.

cost causation principles. A broader allocation of these costs using a revenue or rate base allocator, as proposed in the Manual, would inappropriately force large customers to subsidize costs that the utility incurs to target residential and small commercial customers with its marketing activities.

Analysis of Cost of Service Study Results

The traditional approach to evaluating the extent of inter-class subsidies in a utility rate case is to analyze the cost of service study results using a uniform rate of return applied to each customer class. The Manual suggests that it may be appropriate for regulators to deviate from this approach by assigning a higher required rate of return to industrial customers relative to residential customers to reflect what it characterizes as the higher risks of serving industrial loads through the economic cycle.[14]

Rebuttal

The Manual's suggestion that industrial customers should be assigned a higher required rate of return relative to other customer classes would be a significant and unwarranted departure from the widely accepted practice of evaluating class cost of service study results using a uniform rate of return. Moreover, the Manual's contention that industrial customers create higher financial risks to the utility due to the impacts of business cycles is severely flawed because it considers only one aspect of a utility's financial risk.

Other important customer and rate design characteristics suggest that industrial customers in fact pose a lower financial risk to the utility relative to residential customers. For example, the consumption levels of the residential class are very sensitive to weather fluctuations because much of residential customer energy consumption is associated with heating and cooling requirements that can vary significantly from year to year. By contrast, the

[14]Manual at page 231.

energy consumption levels of the industrial class are more closely linked to production processes that are much less weather sensitive.

Moreover, industrial customer rate designs generally utilize a three-part rate structure that includes a demand charge. This rate structure provides greater revenue stability and imposes less financial risk on the utility relative to the typical residential class rate design that contains no demand charge and relies on energy charges for the bulk of customer revenues. The heavy reliance on energy charges in residential rate design leads to wider swings in utility revenue from year to year based on weather and other factors that influence energy usage.

Based on the foregoing considerations, it is clear that there is no basis for the Manual's argument that utilities should assign a higher required rate of return to industrial classes relative to other customers on the utility's system.

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RIDER B

DISCOUNTS APPLICABLE FOR SERVICE TO SUBSTATIONS OWNED BY CUSTOMER IN LIEU OF COMPANY OWNERSHIP

Where a customer served under rate schedules 4(M) or 11 (M) takes delivery of power and energy at a delivery voltage of 34kV or higher, Company will allow discounts from its applicable rate schedule as follows:

*1. A monthly credit of $1.14/kW of billing demand for customers taking service at 34.5 or 69kV.

*2. A monthly credit of $1.35/kW of billing demand for customers taking service at 115kV or higher.

*Indicates Change.