BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

REBUTTAL TESTIMONY
OF
RONALD J. AMEN
WESTAR ENERGY

DOCKET NO. 18-WSEE-328-RTS

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS AFFILIATION.

A. Ronald J. Amen, Director with Black & Veatch Management Consulting, LLC ("Black & Veatch") and a member of the Advisory and Planning Practice of the Firm.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS CASE BEFORE THE STATE CORPORATION COMMISSION OF THE STATE OF KANSAS ("COMMISSION")?

A. Yes. I filed direct testimony in this case on behalf of Westar Energy ("Westar" or "the Company").

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony discusses the different opinions about cost of service studies contained in the testimony of witnesses in this proceeding. I discuss the areas of general agreement among the parties. Based on the areas of general agreement, I use those principles where parties agree to demonstrate that various cost study proposals fail to use those principles. I discuss each cost of service witness' conclusions related to the appropriate cost of service and show that the Westar AED/4CP methodology is the correct method for the classification and allocation of Production Plant that tracks cost causation closer than other methods for the Westar system. Based on the principle of cost causation, I provide empirical evidence that several components of the Staff cost of service study do not reflect cost causation. I will respond to the comments of witnesses representing

The Citizens' Utility Ratepayer Board ("CURB"), Kansas Industrial Consumers Group, Inc. ("KIC"), Department of Defense and all other Federal Executive Agencies ("DOD"), Walmart Inc. ("Walmart), and collectively, Sierra Club and Volt Solar ("SCVS").

Q. HOW IS THIS REBUTTAL TESTIMONY ORGANIZED?

A. My testimony is organized into sections ten sections as follows:

I. Introduction
II. Areas of General Agreement
III. Classification and Allocation of Production Plant
IV. Classification and Allocation of Distribution Plant
V. Review of Kansas Industrial Customers Group Comments
VI. Review of the Department of Defense Cost of Service Comments
VII. Review of Walmart Cost of Service Comments
VIII. Summary, Conclusions and Recommendations

Q. PLEASE BRIEFLY SUMMARIZE YOUR TESTIMONY.

A. My testimony demonstrates that other proposals related to cost of service do not reflect cost causation that all the parties support as a primary principle for cost allocation. The Westar preferred cost of service study reflects cost causation to the extent permitted by available data. The availability of more detailed data would permit further disaggregation of costs based on actual data rather than relying on practical assessments from the Company that permitted the study to show approximations for the disaggregated costs. Nevertheless, the Westar cost study provides the most reasonable basis available to the Commission for allocating revenue requirements and setting rates. My testimony also supports the logic of the cost study with empirical data that shows the planning and operating results mirror the preferred cost of service study and not any of the proposed alternatives. The data does not support the Staff's views related to the classification and allocation of both production and distribution plant. Rather the data solidifies the support for the AED/4CP proposed method for classifying and allocating production plant and the classification of a portion of distribution plant as customer-related.

II. AREAS OF GENERAL AGREEMENT

Q. ARE THERE AREAS OF BROAD AGREEMENT IN THE PROPOSED COST OF SERVICE STUDIES AND IN THE COMMENTS OF THE PARTIES?

A. Yes. There are consistent themes in all the testimony related to basic principles of cost of service. For example, all the parties agree that cost causation is a fundamental principle that should underlie the cost of service study. The parties agree that there is some capacity component of production plant and that some production plant costs need to be allocated on some measure of peak demand. Finally, the parties seem to recognize the existence of joint and common costs that necessitates the allocation of costs in the cost study.

Q. WHY THEN ARE THE RECOMMENDATIONS RELATED TO COST OF SERVICE DIVERGENT?

A. It appears that the agreement with the principle and the methodology that best represents the principle causes analysts to make recommendations consistent with the best interests of their constituents. That is, there is an inherent bias that arises in addressing the subjective areas of cost of service such as the development of a classification or allocation strategy for the cost of service study.

Q. PLEASE DISCUSS THE CONCEPT OF COST CAUSATION.

A. Cost causation is a critical component of the cost of service process. It is sufficiently important that I devoted a section of my direct testimony to the concept.[1] The fundamental problem in developing cost of service studies that reflect cost causation is that analysts do not typically take a comprehensive view of the concept. Care must be taken to analyze the underlying assumptions to see if they match the facts related not only to the accounting data to be classified and allocated but also to the planning and operation as reflected in the system. This latter concept is important because of the dynamic nature of power system operations as both total demand on capacity and the costs of inputs change over time.

Q. PLEASE DISCUSS THE CONCEPT OF CLASSIFYING AND ALLOCATING GENERATION PLANT USING A CAPACITY ALLOCATION FACTOR.

A. In this case, all the parties agree that some or all the production capacity should be classified as demand-related and allocated using a capacity allocation factor. There are differences related to how much capacity must be classified to demand and how that demand should be allocated. In general, the choice of classification and allocation factors selected by the analyst depends on the nature of the loads of the parties' constituents. High load factor and non-summer peaking loads, such as those customers represented by KIC, benefit from the use of peak demand allocation factor that has no average demand component because the result is a lower allocation of expensive base load plants to those groups. Low load factor, summer peaking classes, such as the residential customers represented by CURB,

[1] Amen Direct, at 8-9, and Appendix B, at 1-6.

tend to benefit from classifying some of the plant as energy that reduces the amount of baseload plant costs allocated to those classes. Nevertheless, in choosing a classification and allocation method, the analysts must rely on assumptions. It is important to test those assumptions against observable factors and whether reality matches the assumptions. If reality does not match the assumptions or the results of those assumptions produce outcomes that are not consistent with the facts, the resulting cost of service study is fundamentally flawed.

Q. PLEASE DISCUSS THE ISSUE OF JOINT AND COMMON COSTS.

A. I have discussed these two concepts in Appendix B to my testimony where I define the two concepts.[2] Indeed, it is the existence of common costs (the primary characteristic of utility costs) that requires the cost allocation study. For ratemaking the allocation is required. The need to allocate costs for ratemaking requires that cost studies be based on sound principles and that they reflect the planning and operating realities of the utility. Since no two utilities are exactly alike, there is no one best allocation methodology that may be applied as a one size fits all method. Further, systems are not static and the optimal allocation methodology may change over time as the system configuration, loads and markets change. Rather, there is a best cost allocation method for each application that reflects how the utility is planned and operated currently. That method must be chosen based on the underlying facts. Cost causation is one such basis for assessing the best cost study allocating common costs.

[2] Amen Direct, Appendix B, at 2.

III. <u>CLASSIFICATION AND ALLOCATION OF PRODUCTION COSTS</u>

Q. BASED ON YOUR REVIEW OF STAFF WITNESS MYRICK'S DIRECT TESTIMONY HAVE YOU REACHED ANY CONCLUSIONS RELATED TO COST CAUSATION FOR CLASSIFICATION AND ALLOCATION IN THAT STUDY?

A. I have concluded that the Staff cost of service study departs from sound theory of cost causation for the classification and allocation of both production and distribution plant. By not reflecting cost causation for these major plant items, the internal allocation factors are also not reflecting cost causation. I will discuss why this cost study cannot be relied on as a sound basis for allocating revenue requirements.

A. Staff's Hybrid Peak and Average Method

Q. PLEASE DESCRIBE STAFF'S "HYBRID PEAK AND AVERAGE" ("HP&A") METHOD FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT.

A. Staff witness Myrick states the peak and average method "weighs the fact that the system is sized to meet peak demand with the way the system is used on an average basis." The classification process followed by Staff is described by witness Myrick as the following:

> Traditionally, all production plant was classified as demand and energy related and allocated on the basis of 4CP and kWh at generation. Currently, we separate the types of production plant into steam, nuclear, combustion turbines and wind. Steam and nuclear are still considered base load units that are related to demand and energy. *However, combustion turbines and wind which were previously classified as demand and energy, respectively, are now treated in the same manner as other base load units*.[3]

[3] Myrick Direct, at 18:11-16 (italics original).

Ms. Myrick indicates that if production costs are considered 100% demand, large interruptible loads that use the system to supply energy would not be allocated a portion of production costs.[4]

Q. PLEASE EXPLAIN WHY STAFF'S METHOD FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT DOES NOT REFLECT COST CAUSATION.

A. First, no production plant costs should be classified as energy-related because energy is not the cause of the costs. The implicit assumption in classifying production plant on energy is that energy requirements caused the costs. However, plant is built to provide **capacity,** and if that capacity is adequate to meet peak load requirements, including all demand on capacity and adequate reserves, that plant will be able to provide all the system energy requirements regardless of the mix of generation. No production plant investment is caused by energy so all production plant costs must be classified as demand.

The focus of the analysis should be on how the cost study allocates the extra capacity costs incurred to provide a lower total energy cost. The answer that follows logically from the classification to demand is to use the Average and Excess demand allocation methodology to reflect that average demand properly treats the decision to build baseload units that produce energy cost savings and that capacity must be sufficient to meet peak loads measured by the sum of all demands on capacity not just native load.

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[4] Myrick Direct, at 20:6-11.

Second, the Staff's HP&A method, like other peak and average methods, double counts the average demand component of the allocator by using it for the energy classified component of production plant and then using it again as part of the demand classified component of production plant. In other words, the Staff methodology used average demand in the calculation of both the energy component of the allocation factor and the demand component of the allocation factor. The result is the HP&A method allocates too little costs to low load factor customers and too much to higher load factor customers. That does not occur under the AED/4CP methodology. Rather, it strikes a reasonable balance between peak demands and the system average demand.

Q. IS WITNESS MYRICK CORRECT IN THE STATEMENT YOU REFERENCED EARLIER WHEREBY LARGE INTERRUPTIBLE LOADS THAT USE THE SYSTEM TO ACCESS ENERGY WOULD NOT BE ALLOCATED A PORTION OF PRODUCTION COSTS UNDER THE COMPANY'S DEMAND CLASSIFICATION?

A. No. Under the Company's AED/4CP classification and allocation method, the Interruptible class ("INT") receives over $3 million of production plant[5] and $23.98 per MWh of average demand costs, in addition to $32.72 per MWh of energy-related fuel and steam expenses.[6]

Q. DOES CURB WITNESS KALCIC MISCHARACTERIZE THE AED/4CP METHODOLOGY AS IT RELATES TO RECOGNITION OF ENERGY IN THE ALLOCATION OF PRODUCTION PLANT?

[5] Amen Exhibit 2, Schedule RJA-1, at 2.
[6] Amen Exhibit 2, Schedule RJA-7, at 1.

A. Yes. Witness Kalcic states in his testimony, "the BIP methodology gives real weight to class energy use, while the AED/4CP methodology does not."[7] This statement is factually incorrect as the AED/4CP method makes use of energy in both the average component of the allocation factor, which is calculated as annual energy divided by hours in the year, and in weighting the cost between average demand and excess demand components based on load factor, which is defined as average demand divided by a measure of peak demand (1CP) in this application. Since both average demand and load factor are calculated using energy, the AED/4CP method correctly recognizes that energy plays a role in determining the allocation of production plant to rate classes.

B. CURB's Base – Intermediate – Peak Method

Q. PLEASE SUMMARIZE THE BASE – INTERMEDIATE – PEAK ("BIP") METHOD FOR CLASSIFIYING AND ALLOCATING PRODUCTION PLANT ADVOCATED BY CURB WITNESS KALCIC.

A. CURB witness Kalcic states that the BIP classification and allocation method "examines the design and operating characteristics of individual units, along with how those generation resources are used during the test period, and classifies production plant as either: a) base; b) intermediate; or c) peak-related."[8] Base classified costs are then allocated based on the class energy consumption during the month with the lowest total energy usage. Intermediate costs are allocated based on the classes' respective contributions to the system's twelve, monthly peaks ("12CP"), less the base use. Peak costs are usually allocated using the 4CP

[7] Kalcic Direct, at 7:3-4.
[8] Kalcic Direct at 5:15-18.

remaining demand, the classes' respective contributions to the 4CP, less the class loads served by the base and intermediate units.[9]

Q. DID WITNESS KALCIC PROVIDE THE RESULTS OF AN APPLICATION OF THE BIP METHOD OF CLASSIFICATION AND ALLLOCATION TO WESTAR'S GENERATION RESOURCES?

A. No. Witness Kalcic does not provide a cost of service study that applies the BIP methodology to the classification and allocation of production costs. Without preparing such a study, the results and implications of that methodology cannot be tested and no consideration can be given to the speculation that such a study would produce results consistent with the Staff's cost of service study, as witness Kalcic suggests.[10]

However, if one were to accept the representation that CURB's BIP proposal would provide results similar to the Staff's HP&A method, one could assume that all the evidence that demonstrates theoretically and empirically that Staff's method does not reflect cost causation, is unreliable and biased would also apply to the BIP method.

Q. PLEASE EXPLAIN WHY THE BIP METHOD FOR ALLOCATING PRODUCTION PLANT ADVOCATED BY CURB WITNESS KALCIC DOES NOT REFLECT COST CAUSATION.

A. The problem with this methodology is found in the underlying assumptions. First, it is important to recognize that **all capacity** is used to meet peak loads. But as I

[9] Kalcic Direct, at 6:12-21.
[10] Kalcic Direct, at 8:20-22.

explain in my direct testimony, peak loads are not the only loads relying on system capacity.[11] The total system demand on capacity plus the required reserve margins must be analyzed to determine the proper mix of capacity to meet load. In addition, over time the classification of units as baseload or peaking changes based on the vintage of the plant and its technology. With the advent of the Southwest Power Pool (SPP) IM (Integrated Market), the Company's plants are no longer dispatched solely to serve native load. This is an important consideration for cost allocation because it changes the pattern of use of plant assets. **Tables 1 and 2** below illustrates the changing nature of plant use over time. As steam plants age or have high heat rates the hours of use decline and they are no longer base loaded. This means that the arbitrary designation of steam as base load plants is not factually sound.

TABLE 1

UNIT OPERATING STATISTICS 2014[12]

Name	Type	Hours Connected to Load	Net generation	Cost per kW Installed $	Total Production Expenses	Expense per net kWh	Avg. BTU per kWh Net Generation (Heat rate)
Form 1	Line 1	Line 7	Line 12	Line 18	Line 34	Line 35	Line 44
Wolf Creek 47%	Nuclear	7,161	4,022,443,000	$3,038	125,310,567	$0.031	10,106
Hutchinson w/Diesel	Steam	1,194	33,908,000	$206	5,142,007	$0.152	18,394
Murray Gill	Steam	2,427	89,345,000	$198	13,304,906	$0.149	17,618
Gordon Evans w/Diesel	Steam	2,502	263,039,000	$202	23,841,855	$0.091	13,784
Tecumseh	Steam	8,760	1,328,608,000	$805	37,281,533	$0.028	11,111
LaCygne #2 (50%)	Steam	5,691	1,509,490,000	$372	62,351,622	$0.041	10,411
Jeffrey 20%	Steam	8,749	2,290,547,000	$1,062	58,612,936	$0.026	11,174
LaCygne #1 (50%)	Steam	7,666	2,447,026,000	$759	67,580,205	$0.028	10,382
Lawrence	Steam	8,760	3,673,824,000	$1,142	87,145,241	$0.024	10,847
Jeffrey (JEC) (72%)	Steam	8,749	8,245,979,000	$1,087	219,172,375	$0.027	11,174
Hutchinson	Gas Turbine	582	12,889,000	$104	2,228,074	$0.173	24,647
Spring Creek	Gas Turbine	201	23,383,000	$325	2,529,674	$0.108	13,236
Gordon Evans CTF	Gas Turbine	631	79,111,000	$335	9,873,329	$0.125	12,373
Emporia CTF	Gas Turbine	2,642	271,565,000	$422	23,827,712	$0.088	11,930
Flatridge	Wind	7,961	131,894,000	$1,904	353,614	$0.003	0
Central Plains	Wind	7,805	293,767,000	$1,834	4,822,184	$0.016	0

[11] Amen Appendix B, at 7-10.
[12] Westar Energy and Kansas Gas & Electric FERC Forms 1, 2014.

TABLE 2

UNIT OPERATING STATISTICS 2017[13]

Name	Type	Hours Connected to Load	Net generation	Cost per kW Installed $	Total Production Expenses	Expense per net kWh	Avg. BTU per kWh Net Generation (Heat rate)
Form 1	Line 1	Line 7	Line 12	Line 18	Line 34	Line 35	Line 44
Wolf Creek (47%)	Nuclear	8,760	5,004,571,000	$3,120	2,703,320	$0.023	9,988
Hutchinson w/Diesel	Steam	0	22,000	$1,520	33,116	$1.505	12,182
Murray Gill	Steam	1,499	56,786,000	$262	6,049,352	$0.107	17,745
Gordon Evans w/Diesel	Steam	2,525	254,891,000	$212	15,099,464	$0.059	13,341
Tecumseh	Steam	5,672	289,054,000	$1,593	11,220,285	$0.039	11,680
LaCygne #2 (50%)	Steam	3,520	726,989,000	$370	45,229,512	$0.062	10,926
Jeffrey (20%)	Steam	8,033	2,215,024,000	$1,124	58,807,386	$0.027	11,096
LaCygne #1 (50%)	Steam	4,398	1,127,516,000	$1,578	43,751,926	$0.037	10,515
Lawrence	Steam	7,900	2,477,673,000	$1,272	53,295,257	$0.022	11,291
Jeffrey (JEC) (72%)	Steam	8,033	7,974,111,000	$1,150	183,749,290	$0.023	11,096
Hutchinson	Gas Turbine	199	2,869,000	$158	1,408,116	$0.491	43,198
Spring Creek	Gas Turbine	69	9,096,000	$325	985,786	$0.108	16,112
Gordon Evans CTF	Gas Turbine	852	120,608,000	$344	7,998,379	$0.066	11,383
Emporia CTF	Gas Turbine	2,442	284,400,000	$423	17,042,651	$0.060	11,565
Flatridge	Wind	8,032	149,633,000	$2,183	2,959,462	$0.020	0
Central Plains	Wind	7,742	274,815,000	$1,538	4,074,380	$0.015	0
Western Plains	Wind	7,697	987,558,000	$1,886	9,313,318	$0.009	0

Several steam units in Tables 1 and 2 operate far less than baseload hours. These are older units with higher heat rates. The higher heat rate when coupled with fuel costs produces higher energy cost per MWh, certainly not low-cost energy associated with baseload plants.

Gas turbines are dispatched under many more conditions than a peak load period. Utility systems are dynamic and respond to changes in generation mix, load profile, and changes resulting from energy conservation that do not change the peak load demand by the same percentage as the energy reduction and relative fuel prices.

Therefore, as I explain in my direct testimony, a cost study that seeks to reflect cost causation for production plant must consider the total demand on capacity. This consideration is increasingly important as wind and solar PV

[13] Westar Energy and Kansas Gas & Electric Co. FERC Forms 1, 2017.

provide increasing amounts of energy for the system. These intermittent sources of power impact the generation mix that is optimal for the system and dramatically changes unit dispatch. The changes impact resources that were formerly strictly baseload plants or peaking units. The dispatch of gas turbines is no longer confined to peak periods as they run to match wind and solar output volatility. These factors demonstrate that the underlying assumptions about unit operations are incorrect under the BIP method.

Q. IS THE BIP METHOD FOR ALLOCATING PRODUCTION PLANT A THEORETICALLY SOUND METHOD?

A. No. There are several reasons that this methodology is not theoretically sound. First, as described earlier, the BIP method arbitrarily classifies production plant as both demand (Intermediate and Peak) and energy (Base). As I discussed with respect to the Staff's use of the HP&A method, production plant is properly classified as demand only. Energy cannot be a causal factor for production plant because production capacity is planned to meet peak demand including reserves. Once that plant capacity is in service the demand for energy up to the plant capacity is also available to serve load. The theoretically sound method for recognizing that extra capacity costs may be incurred to produce energy cost savings is found in the <u>average demand</u> component in the AED methodology. The AED methodology does not make an arbitrary classification of plants based on the type of fuel used, unlike witness Kalcic's designation of nuclear and coal as baseload plants.

Second, as described earlier, Mr. Kalcic classifies all baseload costs to energy and allocates those costs based on the customer class energy mix in the *lowest use month of the year*. Both these factors are problematic in theory and in practice.

As I discussed in my Direct testimony, the higher cost for a baseload unit is incurred to produce lower annual fuel costs and recognizes that some of the higher capacity cost is offset by fuel cost savings. Under these circumstances, a portion of the cost of a baseload unit is incurred for the purpose of lowering energy costs. Thus, some portion of the capital cost for baseload is related to energy. The AED method recognizes a portion of cost is related to energy and the excess cost is a pure demand related cost.[14]

Baseload plants are critical to meet the system peak day requirements and thus, must have some capacity component of costs. It is a fundamental principle of cost causation that all customers using the capacity of the plant at any time are equally responsible for the cost of that capacity. This is the case because the capacity was planned and built based on the need to provide peak capacity plus reserves. Classifying the plant as energy and allocating on total energy does not result in equal responsibility for plant costs among customers using the capacity.

Additionally, witness Kalcic departs from the NARUC BIP method and allocates the costs classified as energy on the class shares of energy in the lowest use month. (It is reasonable to note that in the lowest use month – typically a shoulder month like March, April or October (February, followed by April in the test

[14] Amen Direct, Appendix B, at 11.

period) – a major portion of the plant being allocated is not even operating because it is out of service for scheduled maintenance.) This has the effect of allocating more of the plant costs to loads of customers who may have more off-peak loads or who have steady loads throughout the year such as high load factor industrial customers. The BIP method also allocates the lowest share of costs to residential and other small customers whose low kWh use coincides with the low use month. These same low load factor customers also have the highest use in peak periods and therefore the highest impact on the need to build capacity. It is obvious that the BIP methodology cannot reflect cost causation but is designed to benefit a preferred class of customers at the expense of others.

As I have noted both in this rebuttal testimony and in direct testimony, reflecting cost causation relies on reviewing the total demand on capacity not just load. Scheduled maintenance, forced outages and unit deratings also put demand on capacity resources in the same way that load uses capacity. Understanding total demand is an important step in determining how system costs are incurred. As system load factor improves, it becomes more difficult to accommodate system maintenance. At some load factor, it may be necessary to add capacity just to accommodate the maintenance of units. The recommendations of witness Kalcic related to use of the BIP method should be rejected.

Q. CURB WITNESS KALCIC STATES THAT A 4CP ALLOCATION METHOD APPLIED TO PRODUCTION PLANT WOULD PRODUCE SIMILAR RESULTS TO THE AED/4CP METHOD. IS HE CORRECT?

A. No. Mr. Kalcic opines that because of the use of the 4CP in the AED/4CP allocation method, that the results would be mathematically identical to the 4CP method but for the Lighting class lack of contribution to Westar's coincident peak demands during summer months.[15] Presented in **Table 3** below are the side-by-side class percentage allocation results for the application of the 4CP and AED/4CP methods to Westar's production plant. The degree of similarity varies measurably by class and the differences are not impacted solely by the contribution of the Lighting class to summer coincident peaks.

TABLE 3
ALLOCATION OF PRODUCTION PLANT – 4CP V. AED/4CP

CLASS	4CP	AED4CP
RES	41.7%	42.2%
RES-DG	0.0%	0.0%
SGS	20.6%	20.6%
MGS	12.5%	12.4%
LGS	13.2%	12.8%
ILP	4.0%	3.9%
LTM	0.4%	0.4%
INT	0.2%	0.0%
SPL	3.2%	3.1%
RITOD	0.1%	0.1%
SCH	4.1%	4.2%
LIGHT	0.0%	0.3%
TOTAL	100.0%	100.0%

IV. CLASSIFICATION AND ALLOCATION OF DISTRIBUTION COSTS

[15] Kalcic Direct, at 4:14-18.

A. Staff's Cost of Service Study

Q. PLEASE EXPLAIN WHY THE STAFF COST STUDY DOES NOT REFLECT COST CAUSATION FOR DISTRIBUTION PLANT.

A. In classifying all the distribution plant in Accounts 364 through 368 (Poles and Towers, Overhead and Underground Conductor, Conduit, and Line Transformers) as demand-related and allocating those plant costs on non-coincident peak ("NCP"), Staff's study does not fairly allocate plant to customer classes for a variety of reasons.

To begin, the classification is inconsistent with public utility accounting theory. As Dr. James Suelflow writes in his treatise, *Public Utility Accounting: Theory and Practice*: "… distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."[16] Dr. Suelfow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer's premises.

Staff's fundamental error is not recognizing that there is far more diversity in load at the point where class NCP is measured (at the substation) than there is in local facilities to serve customers. That diversity can be seen by the fact that distribution transformer capacity is about 47 percent more than substation transformer capacity measured in MVA[17] and would be even greater if customer-owned transformer capacity was included in the calculation. By not classifying

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[16] *Public Utility Accounting: Theory and Practice,* Dr. James Suelflow, Institute of Public Utilities, Michigan State University, p. 241.

[17] MVA stands for Mega Volt Amp or Volts X Amp /1,000,000. If your total load requirement is 1,000 volts and 5,000 amps (1,000 x 5,000 = 5,000,000 VA) it can be expressed as 5MVA. This is called "apparent power" because it takes into consideration both the resistive load and the reactive load.

these distribution accounts as **customer and capacity**, the Staff incorrectly allocates more costs to larger customers who may not even use any of the facilities allocated to them. For example, the Staff cost of service study allocates about 17.0% of all transformer costs to the largest customers, many of whom own their own transformers. Further, as **Table 4** below shows, there are substantial economies of scale for all sizes of transformers and the per kVa cost of industrial transformers is less for industrial transformers than for every size of residential transformer, except for the largest and least used sizes of residential transformer.

TABLE 4

TRANSFORMER COST PER KVA

	Residential				Commercial 3 Phase				Industrial 3 Phase	
kVa	UG	Unit Cost	OH	Unit Cost	UG	Unit Cost	OH	Unit Cost	UG	Unit Cost
25	$2,723	$108.90	$2,297	$91.86						
50	$3,320	$66.40	$2,706	$54.13						
75	$3,633	$48.44	$3,419	$45.59	$8,317	$110.90	$7,694	$102.59		
100	$4,276	$42.76	$3,773	$37.73						
150					$9,876	$65.84	$9,576	$63.84		
167	$5,046	$30.21	$4,432	$26.54						
225							$12,063	$53.62		
250	$7,278	$29.11	$4,175	$16.70						
300					$12,257	$40.86	$13,791	$45.97		
500					$18,079	$36.16	$11,211	$22.42		
750									$21,638	$28.85
1000									$28,290	$28.29
1500									$27,546	$18.36
2000									$35,656	$17.83
2500									$35,263	$14.11

By allocating the cost of transformers on NCP, the Staff study allocates all the economies of scale in transformer costs to the residential class. As this data illustrates, there is no reasonable way that the Staff allocation of transformer costs reflects cost causation because it fails to account for economies of scale that are picked up in part by the minimum system allocation factor used in the Company study. Additionally, the Staff NCP methodology allocates an average of 5.0 residential customers to each transformer. The simple fact is that the two most common sizes of transformers, 25 kVa and 50 kVa, typically serve from one to three customers (25 kVa) and one to six customers (50 kVa). With a 70% 25 kVa and 30% 50 kVa mix of these transformers in the Westar distribution system, the maximum number of customers that could be served by this mix of transformers would be an average of 3.9 customers, an unrealistic expectation. It is therefore impossible for 5.0 residential customers to be served from each transformer allocated to the residential class. Finally, Company data shows that 213,555 transformers are used by residential customers. However, under the Staff method, only the cost of 122,898 transformers has been allocated to the residential class. Thus, by any empirical analysis, the use of NCP alone to allocate distribution Account 368 – Transformers is fundamentally wrong and cannot reflect the principle of cost causation.

As another example, the Staff cost of service study allocates only about 71 feet of conductor for each residential customer. Under the line extension policy of the Company, a residential customer is entitled to 1,320 feet of overhead conductor plus poles and a transformer, without being required to make a contribution in aid of construction ("CIAC"). Further, based on data provided by the Company, the typical new customer line extension is about 150 feet of conductor. It is unlikely that residential customers cause the Company to incur only the cost of 71 feet per customer for conductor based on these facts alone. By contrast, the Staff allocation allocates 81 *miles* of poles and conductor to the LTM rate class consisting of one customer. This is not a reasonable outcome. It results directly from the failure to classify distribution plant as both customer and demand in Staff's study. As with transformers there are economies of scale in all the distribution system accounts.

These same errors occur with respect to poles as well since the typical conductor span requires a pole every 200 feet. There are also economies of scale in poles relative to the size and class of pole used to carry larger loads. The result is that the Staff cost study is unreliable related to distribution costs. The Company uses a distribution design manual as a guide to select the optimal size of conductor, poles and transformers that includes the minimum system size and other common combinations of distribution facilities to meet the load of the customers served by a line extension.

B. CURB Comments on Distribution Plant Classification and Allocation

Q. CURB ALSO OPPOSES THE CLASSIFICATION OF DISTRIBUTION PLANT PROPOSED BY THE COMPANY. PLEASE COMMENT ON THAT OPPOSITION.

A. As with the Staff cost of service testimony, the CURB view is not consistent with cost causation. All the evidence demonstrates that the classification of distribution plant Accounts 364 – 368 on demand alone is not supported in theory or in fact. Allocating all distribution costs solely on class NCP does not reflect cost causation and produces biased and unreasonable results.

Q. CURB WITNESS KALCIC SUGGESTS THAT WESTAR'S AED/4CP METHOD

DIFFERS FROM THE BIP METHOD IN APPLICATION TO CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT AS WELL. IS THIS TRUE?

A. No. Mr. Kalcic states that the AED/4CP method classifies a portion of distribution plant and related expenses as both customer-related and demand-related, based on the minimum system analysis and that the BIP method does not.[18] This statement is both false as it applies to the AED/4CP method and misleading as it relates to the BIP method. The AED/4CP method was only employed in the Westar cost of service study for the purpose of classification and allocation of production costs. Likewise, the BIP method is strictly a production cost classification and allocation approach; it has no application to distribution plant, whether or not a minimum system analysis is employed for distribution plant classification. Mr. Kalcic is correct in his mention of the minimum system analysis as the basis for classification of distribution plant in the Westar cost of service study. However, the demand-related portion of distribution plant was allocated based on class non-coincident peak demands ("NCPs"), as differentiated by primary and secondary NCP levels, akin to the demand allocation method used in the KCPL cases cited by Mr. Kalcic.

Q. WITH RESPECT TO THE CURRENT WESTAR FILING HOW SHOULD THE COST OF SERVICE FOR DISTRIBUTION PLANT COSTS BE DETERMINED?

A. The Commission should accept the Westar study as a reasonable allocation methodology for both this case and future Westar cost of service studies. It is also likely that these same results would be found for other utilities in the state and the

[18] Kalcic Direct, at 7:12-14 and 18-20.

Commission should recognize the need to classify distribution plant Accounts 364 – 368 as both customer and demand.

C. Sierra Club – Vote Solar Comments on Distribution Plant Allocation

Q. PLEASE SUMMARIZE THE COMMENTS OF SCVS WITNESS MADELINE YOZWIAK REGARDING THE COMPANY'S COST OF SERVICE STUDY.

A. SCVS witness Yozwiak identified two primary issues within the Company's cost of service study, which she claims overstates the cost to serve the Residential Distributed Generation ("RS-DG") class. First, Ms. Yozwiak asserts that the NCP allocation factors were inappropriately developed based on the greater of the absolute value of the RS-DG class' exports to the utility and their purchased energy. Second, the cost of service study uses the RS-DG class' NCP demand to assign certain demand costs rather than the combined RS and RS-DG classes' NCP, which Ms. Yozwiak asserts does not reflect cost causation principles.[19]

Q. DO YOU FIND THE ISSUES RAISED BY MS. YOZWIAK TO BE CREDIBLE?

A. No. I will respond to the two issues individually.

Q. REGARDING THE FIRST ISSUE RAISED BY WITNESS YOZWIAK, WHAT IS WITNESS YOZWIAK'S VIEW OF THE RS-DG CLASS' EXPORT CONTRIBUTION TO THE LOCAL DISTRIBUTION SYSTEM DEMAND?

A. Ms. Yozwiak opines that at the time of the RS class' NCP, it is likely that some RS-DG customers were exporting energy that would have been consumed by the nearest load, thereby both reducing their own RS-DG demand and serving local load and reducing the cost to serve others at the time of the distributions system's

[19] Yozwiak Direct, at 23:11-19.

capacity constraint.[20] She provides this scenario to assert that the Westar cost of service study incorrectly denies RS-DG customers these benefits by using the RS-DG specific NCP and counting exports as cost-causing rather than cost-reducing.

Q. WHAT IS YOUR RESPONSE TO THIS ARGUMENT?

A. Exports of energy by RS-DG customers have almost no impact on distribution system loads. Ms. Yozwiak's scenario ignores the actual timing of customer NCP demands versus DG production demand. The distribution system must be designed to accommodate the higher of import or export demands; therefore, it is just as likely that distribution costs may increase as decrease due to DG production. In the Arizona proceeding example cited in Ms. Yozwiak's testimony, Tucson Electric Power treated DG customers as a separate rate class and prepared a cost of service study using the methodology accepted by the Arizona Corporation Commission in Phase I of that proceeding. The DG class NCP used for allocation of distribution costs was the maximum DG class use of the distribution system, which was based on the higher of energy consumption or DG exports. The Recommended Opinion and Order from the Hearing Division agreed with this approach and found that allocating distribution system capacity using the greater of the peak export or peak demand for the DG class was reasonable.

> The cost driver for the distribution system is capacity. Distribution circuit capacity is required for both delivery of energy to the customer and export of energy from the customer. Therefore, distribution circuits must be built to accommodate the combined maximum demand capacity for delivery and export usage. If DG export production occurs during the combined DG and non-DG NCP, it is appropriate and reasonable to include that usage of the grid for export or import in the allocation of costs because it impacts

[20] Yozwiak Direct, at 28:9-14.

> distribution system capacity. Thus, arguments by Vote Solar and TASC/EFCA[21] that DG export production should not be a basis for allocating distribution costs are invalid. [22]

Q. TURNING TO THE SECOND ISSUE RAISED BY MS. YOZWIAK, WHY IS IT APPROPRIATE TO ALLOCATE DISTRIBUTION DEMAND COSTS BASED ON THE RS-DG'S CLASS NCP VERSUS A COMBINED RS AND RS-DG NCP?

A In performing an electric cost of service study, a key cost causation factor is determined by when the respective customer classes reach their own peak usage, that is, the individual class NCP. Electric utility distribution costs have traditionally been allocated according to each individual class NCP. This is a widely accepted cost of service principle. The National Association of Regulatory Utility Commissioners ("NARUC") has weighed in on this issue as follows:

> Local area loads are the major factors in sizing distribution equipment. Consequently, customer class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.[23]

The Westar cost of service study followed this widely accepted cost of service principle by allocating distribution costs based on the separate and distinct class NCPs for the RS-DG and non-DG RS customer classes. Because the RS-DG customers are a separate class of customers from non-DG RS customers, no matter how large or small are the NCPs of either of the two classes or their respective locations on the distribution system, the evaluation of when the RS-DG class reaches its peak demand should occur independently of any other class.

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[21] TASC/EFCA = The Alliance for Solar Choice and the Energy Freedom Coalition of America.

[22] Recommended Opinion and Order (Phase II) from the Hearing Division, In the Matter of the Application of Tucson Electric Power Company, Arizona Corporation Commission Docket Nos. E-01933A-15-0239 and E-01933A-15-0322, p. 94 (Apr. 12, 2018).

[23] NARUC Electric Utility Cost Allocation Manual, January 1992, p 97.

Westar's distribution costs cannot be fairly allocated to a specific customer class using the NCP methodology suggested by Ms. Yozwiak, as it would be inconsistent with how distribution costs are allocated to the other non-residential customer classes. Clearly, the RS-DG class displayed unique usage characteristics, as the data provided by Westar[24] and presented as part of Ms. Yozwiak's testimony[25] demonstrates. As I described in my Direct testimony, when customers who have common or homogeneous load characteristics, they may warrant a separate class of service. This is particularly important to recognize that partial requirements customers require their own class of service because of the unique load characteristics of this type of customer.[26] Ms. Yozwiak's suggested NCP methodology would inequitably shift distribution costs associated with serving the RS-DG customers to other customer classes. This is contrary to commonly accepted cost allocation principles.

Q. MS. YOZWIAK ASSERTS THAT DUE TO ITS SIZE, THE RS CLASS' NCP, NOT THE PEAK OF THE RS-DG CLASS, DRIVES THEIR SIMULTANEOUS PEAK ON THE SYSTEM SERVING BOTH CLASSES. THEREFORE, RS-DG CUSTOMERS ONLY CAUSE COSTS WHEN CONTRIBUTING LOAD DURING THE RS CLASS' PEAK HOURS.[27] DO YOU AGREE?

A. No. Ms. Yozwiak's assertion either fails to recognize or accept the appropriate equitable sharing of the costs that result from the presence of joint costs and economies of scale, as referenced earlier in this testimony and in my Direct

[24] Westar Response to Sierra Club Request 1-27.
[25] Yozwiak Direct, Exhibit MY-5.
[26] Amen Direct, Appendix B, at 14.
[27] Yozwiak Direct, at 27:3-11.

testimony.[28] Each group or class of customers share in the benefits of the presence of joint costs and economies of scale in proportion to their contribution to scale economies based on their own relative costs on a stand-alone basis. In other words, for RS and RS-DG customers served from the same distribution circuits, the sum of the stand-alone costs of the respective groups would be higher than the joint costs of serving both RS and RS-DG customers. Proportionally, the smaller RS-DG class will be allocated less of the joint costs than the larger RS class, while allowing both to enjoy a lower total cost for the service being provided. While the larger RS class contributes more to the scale economies and will receive a relatively larger share of the total economies, the equitable cost sharing results from the application of the classes' respective NCPs in the cost allocation process throughout the cost of service study. It should be noted that the arguments provided by Ms. Yozwiak are not unique to the RS-DG class. Most SGS customers also share circuits with the RS and RS-DG classes and peak at a different time than these residential classes. Yet, it's a well-established practice to measure their NCP independent of other classes with which it shares distribution circuits.

V. <u>REVIEW OF KANSAS INDUSTRIAL CUSTOMERS GROUP COMMENTS</u>

Q. PLEASE SUMMARIZE KIC WITNESS BRIAN ANDREWS' COMMENTS REGARDING WESTAR'S FILED COST OF SERVICE STUDY.

A. KIC witness Andrews concluded that Westar's proposed cost of service study, with fixed production costs allocated using the AED/4CP method, is reasonable and should be approved by the Commission.[29] However, Mr. Andrews did identify an

[28] Amen Direct, Appendix B, at 2.
[29] Andrews Direct, at 2:12-14.

error in the energy allocation factors at the transmission and primary voltage levels that adversely impact the Industrial Large Power ("ILP") customer class by an over-allocation of approximately $426,000.[30]

Q. DO YOU AGREE WITH MR. ANDREWS' FINDING REGARDING THE ENERGY ALLOCATION FACTORS FOR THE ILP CLASS?

A. Yes. An inadvertent data entry error was made in the transfer of information from the cost of service input data sheet to the cost of service model. This resulted in 100% of the energy serving the ILP class to be treated as though it was provided at the primary voltage level. The correct apportionment of the ILP energy consumption would have been to reflect 60% delivered at the transmission voltage level and 40% at the primary voltage level.

Q. MR. ANDREWS PRESENTS REVISED CLASS COST OF SERVICE RESULTS AFTER CORRECTING FOR THE ENERGY ALLOCATOR.[31] DO YOU CONCUR WITH HIS COST OF SERVICE RESULTS?

A. No. While I agree with Mr. Andrews' adjustment of the energy allocators for the line loss factors, he overlooked an additional necessary adjustment to the NCP-Primary allocation factor and a small change to the Customer-Primary allocation factor from three ILP customers to one, which impacts the apportionment of distribution plant to the ILP class. In other words, the ILP class should receive a corresponding lower cost of the primary distribution system compared to the amount the class received under the Company's initial cost of service study results. I have prepared **Table 5** below to show a side-by-side comparison of the

[30] Andrews Direct, at 2:15-20.
[31] Andrews Direct, at 13, Table 2.

Company's initial summary class cost of service results, Mr. Andrews' corrected results,[32] and the Company's results with the complete correction for the ILP class from 100% Primary to 60% Transmission and 40% Primary.

TABLE 5
COMPARATIVE COST OF SERVICE RESULTS
WESTAR VERSUS KIC

	Company Proposed		KIC Corrected		BV Corrected	
Rate Class	Revenue Requirement	Return on Rate base	Revenue Requirement	Return on Rate base	Revenue Requirement	Return on Rate base
RES	$921,727,409	5.20%	$921,876,804	5.19%	$923,120,505	5.16%
RE-DG	217,688	-0.14%	217,714	-0.14%	218,774	-0.22%
SGS	399,942,708	7.44%	400,026,024	7.44%	400,653,622	7.39%
MGS	234,621,097	8.20%	234,681,404	8.19%	235,015,876	8.14%
LGS	279,957,267	10.67%	280,044,789	10.66%	280,367,495	10.61%
ILP	82,031,450	5.73%	81,605,678	5.95%	78,736,456	7.23%
LTM	8,426,569	8.71%	8,429,409	8.69%	8,429,408	8.69%
INT	1,739,524	-0.19%	1,739,930	-0.20%	1,754,104	-0.35%
SPL	70,949,188	0.86%	70,973,340	0.84%	71,075,094	0.80%
RITOD	2,736,662	-2.87%	2,737,027	-2.88%	2,746,480	-2.93%
SCH	75,150,781	0.76%	75,165,462	0.76%	75,364,198	0.70%
LIGHT	19,084,583	19.73%	19,087,346	19.72%	19,102,912	19.69%
Total $	2,096,584,926	6.46%	2,096,584,927	6.46%	2,096,584,926	6.46%

VI. REVIEW OF DEPARTMENT OF DEFENSE COST OF SERVICE COMMENTS

Q. DOES DOD WITNESS LARRY BLANK OPPOSE THE ALLOCATION METHODS USED IN THE WESTAR COST OF SERVICE STUDY?

A. No. Witness Blank states that the allocation methods employed by Westar generally followed accepted industry practices.[33]

Q. DID WITNESS BLANK HAVE CONCERNS REGARDING CERTAIN DETAILS OF THE WESTAR COST OF SERVICE STUDY?

[32] Andrews Direct, at 13, Table 2.
[33] Blank Direct, at 6:19-20.

A. Yes. Witness Blank raised three issues with the underlying distribution account-level functionalization between primary and secondary distribution and allocation of primary distribution costs.

Q. PLEASE RESPOND TO EACH OF MR. BLANK'S COMMENTS.

A. First, Mr. Blank is critical of the functionalization of certain distribution plant accounts (i.e. FERC Accounts 364 - Poles, 365 – Overhead Lines, 366 – Underground Conduit, and 367 – Underground Lines) between primary and secondary based on an estimate provided by Company personnel, which Mr. Blank deems to be arbitrary.[34] As I mentioned earlier in my introductory remarks, the Westar preferred cost of service study reflects cost causation to the extent permitted by available data. The availability of more detailed data would permit further disaggregation of costs based on actual data rather than relying on practical assessments from the Company that permitted the study to show approximations for the disaggregated costs. In this instance, estimates provided by Company personnel with direct knowledge of the configuration of the Westar distribution system is sufficient, absent verifiable information to the contrary.

Regarding the second issue, Mr. Blank believes that line transformer plant (Account 368) has been over-allocated to the LGS and ILP classes in an amount exceeding $2 million, due to the use of the NCP allocation factor at the transmission voltage level versus primary voltage.[35] However, transmission level demand in this NCP allocator has been reduced for classes that do not use transformers at primary voltage. Therefore, no line transformer plant cost has

[34] Blanc Direct, at 7:12-25
[35] Blank Direct, at 8:12-21

been allocated to the ILP class. Conversely, more than 90% of LGS customers receive service at primary voltage; the demands of these LGS customers are properly reflected in the NCP line transformer plant allocation employed in the Westar cost of service study.[36]

Finally, Mr. Blank has identified the same issue that I addressed in Section V of my rebuttal testimony concerning the proper allocation of Distribution plant to the ILP class under the composition of the NCP-Primary demand allocation factor. The correction of the inadvertent error discussed earlier, is reflected in Table 5.

VII. REVIEW OF WALMART COST OF SERVICE COMMENTS

Q. DOES WALMART WITNESS STEVE CHRISS OPPOSE THE USE OF WESTAR'S FILED COST OF SERVICE STUDY?

A. No. Walmart witness Chriss supports the use of the AED/4CP allocation as a reasonable method for allocating fixed production plant costs. Mr. Chriss does not take a position on the other elements of the Company's cost of service study.[37]

VIII. SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My testimony shows that of the proposed alternatives to the Westar AED/4CP classification and allocation methodology do not properly reflect cost causation. The analysis shows that on both theoretical and empirical grounds that the Staff methodology does not reflect the fundamental principle of cost causation. Further, since that principle is relied upon by all the witnesses who comment on principles, the data supports the use of the Company's proposed cost of service study as a

[36] Amen Direct, Exhibit 2, Schedule RJA-1, at page 3.
[37] Chriss Direct, at 4:15-20.

guide for allocating revenue requirements. The Commission should adopt the Westar proposed AED/4CP methodology for the classification and allocation of production plant. Since both average demand and load factor are calculated using energy, the AED/4CP method correctly recognizes that energy plays a role in determining the allocation of production plant to rate classes. The underlying operating assumptions that support the CURB preferred method are wrong in both theory and practice for the modern power system. The recommendations of witness Kalcic related to use of the BIP method should be rejected.

Q. WHY IS IT IMPORTANT TO REJECT THE PROPOSALS OF THE STAFF, CURB AND SIERRA CLUB – VOTE SOLAR AS THEY RELATED TO THE ALLOCATION OF DISTRIBUTION PLANT?

A. The detailed cost analysis in this testimony shows that classification of distribution plant costs strictly as demand-related does not produce reasonable results. In fact, the Staff methodology, which is supported by CURB, significantly under-allocates both the physical components of the system and the cost of those components to the residential customer class. Allocation on a demand basis also confers a disproportionate benefit of economies of scale on the residential customer class. Sierra Club – Vote Solar witness Yozwiak's suggested NCP methodology would inequitably shift distribution costs associated with serving the RS-DG customers to other customer classes. This is contrary to commonly accepted cost allocation principles.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS RELATED TO THE COST OF SERVICE STUDIES IN THIS CASE.

A. The Westar cost study – indeed any study – cannot be perfect in all respects because of data limitations, lumpy investment, economies of scale and other factors that impact the cost of service process. The fundamental question becomes: does the cost study provide a reasonable basis for allocating the revenue requirements? The Westar study meets that test. It reflects cost causation at an adequate level of detail. For the reasons found in both my Direct Testimony and this Rebuttal Testimony, the Commission should accept the Westar cost of service study, as corrected for the error in the Transmission and Primary voltage levels impacting the ILP class, as the preferred guide for allocating revenue requirements and establishing components of rate schedules.

Q. THANK YOU.

STATE OF KANSAS)
) ss:
COUNTY OF JOHNSON)

VERIFICATION

Ronald Amen, being duly sworn upon his oath deposes and states that he a Director with Black & Veatch Management Consulting, LLC, that he has read and is familiar with the foregoing Rebuttal Testimony, and attests that the statements contained therein are true and correct to the best of his knowledge, information and belief.

Ronald Amen

Ronald Amen

Subscribed and sworn to before me this 3rd day of July, 2018.

Notary Public

My Appointment Expires: 12/25/2019

Notary Public
State of Washington
JAEHYANG LEE
MY COMMISSION EXPIRES
December 25, 2019