BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of an Examination of the Class Cost of Service and Rate Design in the Missouri Jurisdictional Electric Service Operations of Aquila, Inc. (f/k/a UtiliCorp United Inc.)	))))))	**EO-2002-384** **[EO2002384xxx]**

PREHEARING BRIEF
OF SEDALIA INDUSTRIAL ENERGY USERS' ASSOCIATION

I. PROCEDURAL BACKGROUND.

In its Order of August 23, 2005, the Commission described the procedural background of this case as follows:

> Case No. EO-2002-384 was opened on February 21, 2002, as a "spin-off docket" in which to examine class-cost-of-service and rate design in the Missouri service areas of UtiliCorp United Inc., as Aquila was then known. At that time, UtiliCorp had only one Missouri service area and operated there as "Missouri Public Service." UtiliCorp has since changed its name to Aquila, purchased St. Joseph Light and Power Company, and now operates in two Missouri service areas. A subsequent rate case was filed, determined and closed, and now another rate case is pending, Case No. ER-2005-0436.[1/]

This summary, though succinct and sufficient for the purposes of that order, does not fully reveal that the case was initiated as a part of the Unanimous Stipulation and Agreement concluding the ER-2001-672 rate case, and was established to review, on a revenue-neutral basis, Aquila's class cost of service and

[1/] *Order Establishing Procedural Schedule*, Case No. EO-2002-384, August 23, 2005, pp. 1-2.

involved the collection of load research data. An analysis based upon fresh load research data, followed by class cost of service studies and then revenue-neutral class shift recommendations, was contemplated by the parties in that stipulation. The purpose was to allow a more detailed analysis of cost-causal factors so that out-of-balance rates could be identified and needed adjustments quantified, independent of the contentious issues and press of time that often accompanies a rate case and that tend to deflect attention from class cost issues and prevent full consideration of them.[2/]

The pertinent provision from that Unanimous Stipulation and Agreement provided as follows:

> 12. <u>Creation of Class Cost of Service and Rate Design Case</u>. The Parties agree that, as a part of this Stipulation and Agreement, the Commission establish in its order approving this Stipulation and Agreement a separate "EO" case ***for the purpose of examining customer class cost of service and rate design for UtiliCorp's MPS and SJLP electric operations*** and by said order to make the Parties to these proceedings parties to the "EO" case. ***The Parties contemplate that said "EO" case will utilize agreed-to load data and test year***. The Parties respectfully ask the Commission to set an early prehearing conference in said "EO" case for the purpose of discussing a procedural schedule and related matters.[3/]

In approving the Unanimous Stipulation and Agreement, the Commission's ordering paragraph 5 was no less succinct:

[2/] See footnote 1, *supra*.

[3/] Unanimous Stipulation and Agreement, Case No. ER-2001-672, pp. 5-6 (emphasis added).

> 5. That Case No. EO-2002-384 is hereby established for the purpose of examining class cost of service and rate design in UtiliCorp United Inc.'s Missouri jurisdictional electric service operations. All of the parties to the present case are hereby made parties to [*12] Case No. EO-2002-384 and the Commission's Data Center shall add them as such to the service list in Case No. EO-2002-384.[4]

Following that, several technical conferences were scheduled, initially to discuss and resolve data collection issues, sampling, sample size and the like, concerning the load research study that was desired. The overall objective of those conferences was to seek resolution of these data- and sample-related issues so that disputes about incorrect or inadequate data collection could be avoided. A load research study is, itself, not without significant expense for metering and processing, and no one desired to waste either time or money gathering data that would later be challenged.

While the data was being collected, there was no need for meetings of the technical folk. This process took over one full year. However, when the data was collected, analysis of it began and meetings again were scheduled. The process determined by the parties was for Aquila to initially submit a class cost of service study (CCOSS) which others would then critique and prepare their own, followed by another technical conference or

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[4] *In the Matter of the Tariff Filing of Missouri Public Service (MPS), a Division of UtiliCorp United Inc., to Implement a General Rate Increase for Retail Electric Service Provided to Customers in the Missouri Service Area of MPS*, 11 MoPSC3d 120 (February 21, 2002), pp. 131-32.

two so that the experts could resolve number "busts" and other technical issues, seeking to limit issues to matters of principle. Staff cooperated with this schedule, but OPC failed to even submit any CCOSS until required to do under a later-ordered procedural schedule.

During this process, one Aquila rate case involving both divisions was filed and resolved[5/] and new rates were developed using essentially a methodology that would not disturb the existing rate relationships and thus preserve the validity of the load research study results.

II. OBJECTIVE OF THE COST ALLOCATION PROCESS.

A. The Paradigm of a Competitive Market Results in Each Customer or Customer Group Being Served at No More Than Its Cost of Service.

Public utility regulation is intended to be a substitute for competition, instituted to avoid what was perceived to be wasteful expenditures in duplicate facilities by capital intensive enterprises.

Had regulation not stepped in, numerous service providers could have arisen, each offering service at the lowest cost with rational customers choosing the "lowest" cost provider. An aggressive competitor could try to "capture" a market share by offering a lower price forcing either a reduction in profit

[5/] Case No. ER-2004-0034.

margin or a recapturing price increase to other customers, thereby encouraging another competitor to restart the cycle.

Multiple iterations could result in a perfectly competitive environment presenting each customer with a price for their service that represented the cost to provide service to that customer. The customer that caused the cost paid the cost. In enacting the regulatory scheme, the General Assembly sought to preserve the benefits of competitive pricing for ratepayers without the downsides of duplicative facilities.

B. Determination of An Overall Revenue Requirement Is the Beginning Point.

The first step in this regulatory rate-setting process is typically the development of an overall revenue requirement. Once established, the overall revenue requirement is allocated to customers or customer groups using the cost allocation procedure through a cost allocation study. Consistent with the competitive market paradigm, of what would be the result of a competitive market for such services, the offering prices or "rates," should be designed to recover the costs from those customers or class of customers who cause them, plus a reasonable profit margin for the provider. In other words, as with the competitive model, the "cost causer" should be the "cost payer".

C. Grouping of Customers By Common Load and Usage Characteristics Is Permitted.

While ideal, requiring that each individual customer be charged the cost[6] that their individual service causes the utility to incur, such refinement would present insurmountable administrative difficulties. Accordingly, one of the long-recognized conventions in public utility regulation is that for ratemaking purposes, individual customers should be grouped or classed with other customers that have similar load, usage and cost characteristics. Missouri law recognizes this convention.[7] Thus, the pure principle of cost causation/cost payment is mitigated by the administrative practicality of dealing with smaller classes of customers whose characteristics are similar.[8]

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[6] Also typically, the "cost" of service is defined to include the reasonable profit margin allowed to the provider. We will hereafter generally follow that convention.

[7] Section 393.130.2 provides:

2. No gas corporation, electrical corporation, water corporation or sewer corporation shall directly or indirectly by any special rate, rebate, drawback or other device or method, charge, demand, collect or receive from any person or corporation a greater or less compensation for gas, electricity, water, sewer or for any service rendered or to be rendered or in connection therewith, except as authorized in this chapter, than it charges, demands, collects or receives from any other person or corporation for doing ***a like and contemporaneous service with respect thereto under the same or substantially similar circumstances or conditions.*** (Emphasis added).

[8] *State ex. rel. Laundry, Inc. v. Public Service Commission, 345 S.W.2d 37 (Mo. 1931)* remains one of the most useful judicial analyses of the topic of discrimination between utility customers that are similarly situated.

D. Cost Allocation Is the Next Step In the Process.

The next step in the process is cost allocation. A fully allocated cost of service study is necessary to determine the cost of service for each defined group or class of customer which in turn is then used to determine the design of the rates. Cost of service studies organize the cost and load information from the system in such a way that the costs can be assigned or allocated to various customers or classes of customer (the cost causers). These assigned costs are then compared to the revenues from those classes and rate base used to serve those classes, the relative contributions to system profitability are calculated and rates to recover those costs are designed for each class of customer (the cost payer). While there is often controversy or disagreement regarding the classification and allocation of joint and common costs, such a study is absolutely necessary to properly design rates with the least amount of discrimination between the classes of customer.

Discrimination is often a loaded term and implies differential treatment of persons or groups that should be treated equally.[9/] In utility regulation it refers to the circumstance where one customer is charged a different rate in relation to cost causation then another customer whose cost causal characteristics are materially similar. Were it administratively feasible to charge each customer precisely their own costs, there

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[9/] It is also implicitly prohibited by Section 393.130.2 quoted above.

could be no discrimination in a regulatory sense even though customers would be billed different amounts. But given the administrative need to have customer classes, the question becomes whether a customer class is being charged costs that vary from the costs that are caused by that customer class. This leads to the insertion of the word "undue" ahead of "discrimination" which serves to characterize or limit the degree of differential treatment that cannot be justified by the administrative necessity to group together customers with similar cost characteristics. Discrimination thus becomes "undue" when customer classes are charged rates that reflect cost causer/cost payer discrepancies that are not justified by the administrative necessity of customer grouping. Correspondingly, cost causer/cost payer discrepancies that can be remedied without substantial administrative impact should be regarded as "undue." In its earlier orders in this case, the Commission has recognized the need to avoid discrimination in utility rates and the utility of a cost allocation study to avoid that discrimination.[10/]

> [10/] A class-cost-of-service study is an equitable, mathematically-based method of determining the percentage of operating costs which each utility customer must pay through rates ***on the principle of matching costs to the customers who cause those costs.*** Utility customers are generally grouped into classes based on shared characteristics and the utility's operating costs are then either directly assigned to a class, where possible, or allocated ***using reasonable methods*** to reflect class responsibility.

Order Regarding Consolidation and Procedural Schedule, Case No. EO-2002-384, August 23, 2005, p. 7 (emphasis added).

Thus, when a customer or class of customer causes a cost to be incurred in rendering utility service, that customer or class of customer should pay rates that will allow the utility to recover those costs. A class cost of service study calculates the rate of return for the analyzed utility system and for each class of customer. The rate of return of a class is the contribution that the class of customer makes to the system rate of return. If the class rate of return is lower than the system rate of return, the contribution is less than average and the class is being subsidized by the other customers or classes of customer. If the class rate of return is higher than the system rate of return, that class is contributing more then the system average rate of return and, hence, subsidizing the other classes of customer.

Because the Aquila systems are used jointly by all of its customers, it is necessary to allocate those costs which cannot be directly assigned to the various types of services being rendered in order to determine customer class cost responsibility. This information is then used to design rates so as to avoid undue discrimination.

E. The Process of Cost Allocation.

There are three primary steps in conducting a cost of service study; 1) functionalization of costs, 2) classification of costs and 3) allocation of costs.

Functionalization of costs is the grouping or recording of costs by major function such as generation, transmission, distribution, and administrative and general. This is usually the easiest step since the utility investment and expense records are maintained in accordance with a FERC prescribed uniform accounting system. This uniform system of accounts classifies the costs according to primary operating functions.

Classification groups the costs into three basic categories; customer, energy, and demand or capacity. Customer costs vary with the number of customers served, energy costs vary with the quantity of energy delivered, and finally demand or capacity costs vary with the quantity or size of plant. Capacity costs are related to maximum system requirements for which the system is designed to serve during short intervals and are classified as demand-related, energy-related or customer-related.

Allocation, the final step, is the portioning out each of these classified costs to a particular customer or class of customers. Items that can be directly attributed to a particular customer or group of customers should first be segregated and directly assigned to the appropriate customers, exampled by a customer that makes use of unique transformation equipment.

F. Allocations Are Important In the Case of Electricity and Must Recognize Both Energy and Demand Components of Electric Service.

Such allocations are particularly important in the case of electricity as electricity differs from most other goods or services purchased by consumers. Electricity cannot be stored and must be delivered instantaneously to the customer’s home or place of business as it is produced. In addition, both the total quantity used (energy or kWh) by a customer and the rate of use (demand or kW) are important.

Further, electric utility services must be delivered at the place of consumption - homes, schools, businesses, factories - because this is where the lights, appliances, machines, air conditioning, and the like are located. Thus, every utility must provide a path through which electricity can be delivered regardless of the customer's demand and energy requirements at any point in time.

Even at the same location, electricity may be used in a variety of applications. Homeowners, for example, use electricity for lighting, space conditioning, and to operate various appliances. At any instant, several appliances may be operating (*e.g.*, lights, refrigerator, TV, air conditioning, and so on). Which appliances are used and when reflects the second dimension of utility service -- the rate of electricity use or ***demand***. The demand imposed by customers is an especially important characteristic because the maximum demands determine how much capacity the utility is obligated to provide.

Generating units, transmission lines and substations and distribution lines and substations are rated according to the maximum demand that can be safely imposed on them. They are not rated according to average annual demand; *i.e.*, the amount of energy consumed during the year divided by 8,760 hours. For example, on a hot summer afternoon when customers demand 2,000 megawatts (mW) of electricity, the utility must have at least

2,000 mW of generation, plus some additional capacity to provide adequate reserves, so that when a consumer flips the switch, the lights turn on, the machines operate and heating and air conditioning systems heat and cool homes, schools, offices, and factories.

Meeting the customers' combined demands is yet another dimension of utility cost analysis that must be addressed in a class cost of service study. Although many think of electricity simply in terms of kilowatthours, this is a one-sided picture. Mr. Brubaker provided an example of a commodity to help conceptualize the problem:

> The tomatoes we buy at the supermarket for about $2.00 a pound might originally come from Florida where they are bought for about 30¢ a pound. In addition to the cost of buying them at the point of production, there is the cost of bringing them to the state of Missouri and distributing them in bulk to local wholesalers. The cost of transportation, insurance, handling and warehousing must be added to the original 30¢ a pound. Then they are distributed to neighborhood stores, which adds more handling costs as well as the store's own costs of light, heat, personnel and rent. Shoppers can then purchase as many or few tomatoes as they desire at their convenience. In addition, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. What we are really paying for at the store is not only the vegetable itself, but the service of having it available in convenient amounts and locations. If we took the time and trouble (and expense) to go down to the wholesale produce distributor, the price would be less. If we could arrange to buy

them in bulk in Florida, they would be still cheaper.[11]

Unlike tomato producers and distributors, electric utilities are obliged by Missouri law to provide continuous, reliable and safe service.[12] This obligation of service corresponds to the utility's right to be the exclusive service provider within its territorial franchise. In addition to satisfying the energy (or kilowatthour) requirements of its customers, this obligation to serve means that the utility must also provide the necessary facilities to attach customers to the grid (so that service can be used at the point where it is to be consumed) and these facilities must be responsive to changes in the kilowatt demands whenever they occur.

G. Allocation Must Also Recognize Different Costs Associated with Different Voltage Levels.

As a graphical explanation of the provision of electric service, Mr. Brubaker provided Figure 1 in his testimony.[13] This illustration described generation as the first level. The next level is the extra high voltage transmission and subtransmission system (34,500 to 345,000 volts). Then the voltage is stepped down to primary voltage levels of distribution-4,160 to 12,000 volts. Finally, the voltage is stepped

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[11] Brubaker, Direct Testimony, p. 6.

[12] The statutory term is "safe and adequate" and is found in Section 393.130.1 RSMo 2005.

[13] Brubaker, Direct, p. 8.

down by pole transformers at the "secondary" level to 110/220 volts used to serve homes, barber shops and the like. Additional investment and expenses are required to serve customers at secondary voltages, compared to the cost of serving customers at higher voltage.

Each additional transformation, thus, requires additional investment, additional expenses and results in some additional electrical losses. To say that "a kilowatthour is a kilowatthour" is like saying that "a tomato is a tomato." The purchase of a kilowatthour at one's home includes not only the energy but also the service of having it delivered to your home. A customer who buys at the bulk or wholesale level such as large power service customers impose less cost (and should pay less) because some of the costs of that delivery from the utility are avoided.[14/]

H. The Production and Transmission Function of Electric Production is Also Critical.

Looking at the production function, the amount of production plant capacity required is primarily determined by the peak rate of usage during the year. If the utility anticipates a peak demand of 2,000 megawatts - it must install and/or contract for enough generating capacity to meet that anticipated demand (plus

[14/] In many cases the individual customer simply picks up these costs directly through the purchase and maintenance of its own step-down transformation facilities, its own switchgear, and its own personnel.

some reserve to compensate for variations in load and capacity that is temporarily unavailable).

There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment is usually classified to demand. Regardless of how production plant investment is classified, the associated capital costs (which include return on investment, depreciation, fixed operation and maintenance expenses, taxes and insurance) are fixed; that is, they do not vary with the amount of kilowatthours generated and sold. These fixed costs are determined by the amount of capacity (i.e., kilowatts) which the utility must install to satisfy its obligation-to-serve requirement.

On the other hand, it is easy to see that the amount of fuel burned-and therefore the amount of fuel expense-is closely related to the amount of energy (number of kilowatthours) that customers use. Therefore, fuel expense is an energy related cost.

Most other O&M expenses are fixed and therefore are classified as demand-related. Variable O&M expenses are classified as energy-related. Demand-related and energy-related types of operating costs are not impacted by the number of customers served.

I. The Appropriate Handling of Customer Costs is Another Important Characteristic of An Appropriate and Reasonable Allocation Methodology.

Customer-related costs are a third major category. Obvious examples of customer-related costs include the investment in meters and service drops (the line from the pole to the customer's facility or house). Along with meter reading, posting accounts and rendering bills, these "customer costs" may be several dollars per customer, per month. Less obvious examples of customer-related costs may include the investment in other distribution accounts.

A certain portion of the cost of the distribution system-poles, wires and transformers-is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

Mr. Brubaker also provided another illustration identified as Figure 2 in his direct testimony.[15/] This illustration, as an example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive

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[15/] Brubaker, Direct, p. 12.

distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), even though the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

J. Load Factor Must Also Be Considered.

Load factor is an expression of how uniformly a customer uses energy. Mathematically, load factor is the average rate of use divided by the peak rate of use. A customer with a higher load factor is less expensive to serve, on a per kilowatthour basis, than a customer with a low load factor, irrespective of size.

Mr. Brubaker offered an example of a rental car which costs $40/day and 20¢/mile. If Customer A drives only 20 miles a day, the average cost will be $2.20/mile. But for Customer B, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 40¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the average total cost per mile will differ depending on how consistently the car is used. Likewise, the average cost per kilowatthour will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industries generally have higher load factors than residential or general service customers, they are less costly to serve on a per-kilowatthour basis.

III. ISSUES PRESENTED IN THIS CASE.

This case has presented several issues that have been addressed in Mr. Brubaker's Direct, Rebuttal and Surrebuttal testimonies. Turning to those issues, one by one, results in the following analysis.

A. The Appropriate Method of Allocating Generation-related Costs to Customer Classes Is the Average and Excess Summer Non-coincident Peak.

Fixed generation costs should be allocated to customer classes on the basis of the average and excess summer non-coincident peak (A&E - summer NCP) method. Variable costs should be allocated on the basis of class energy adjusted for losses.

The A&E method is one of a family of methods that incorporate consideration of both the maximum rate of use and the duration of use. As the name implies, A&E makes a conceptual split of the system into an "average" component and an "excess" component. The "average" demand is simply the total kWh usage divided by the total number of hours in the year. This is the amount of capacity that would be required to produce the energy if it were taken at the same demand rate each hour. The system "excess" demand is the difference between the system peak demand and the system average demand.

Under the A&E method, the average demand is allocated to classes in proportion to their average demand (energy usage) and the difference between the system average demand and the system peak(s) is then allocated to customer classes on the basis of a measure that represents their "peaking" or variability in usage.

First, in order to reflect cost causation an appropriate methodology must give predominant weight to loads occurring during the summer months. Loads during these months (the peak loads) are the primary driver which has and continues to cause the utility to expand its generation and transmission capacity, and therefore should be given predominant weight in the allocation of capacity costs.

An analyst could use a coincident peak study, using the demands during the peak summer months, or a version of an average and excess cost of service study that uses peak loads occurring during the summer. These methods would be most appropriate to reflect these characteristics and the results should be similar as long as only summer period peak loads are used. Mr. Brubaker made his recommendations based on the A&E method because it takes into account the maximum class demands during the critical time periods, and is less susceptible to variations in the absolute hour in which peaks occur resulting in a somewhat more stable result over time.

In contradistinction, Office of the Public Counsel (OPC) witness Meisenheimer has used a method of allocation that she describes as "(1) 12-month non coincident (NCP) average and peak allocators, and (2) an energy (kWh) allocator." Her method is neither explained nor justified.[16/] Her method is not discussed in the NARUC Cost Allocation Manual nor in any other recognized reference manual.

The Commission's August 23, 2005 Order notes that "reasonable" methods are to be used.[17/] The absence of recognition of a cost allocation method, and in particular, the absence of recognition of the method used by OPC in this case, is significant. Cost of service studies for electric systems have been performed for well over 50 years. A significant amount of analysis by hundreds of different cost analysts has gone into the question of determining how best to ascertain cost-causation on electric systems across a broad spectrum of utility circumstances. Methods that have not had the benefit of that analysis and withstood the test of time should be viewed with skepticism. Proponents of such unproven and unrecognized methods bear a heavy burden of proving that they do a more accurate job of identifying cost-causation than recognized methods and are not *ad hoc* cre-

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[16/] Brubaker, Rebuttal, p. 4.

[17/] See footnote No. 1, *supra*.

ations devised simply to support a particular result desired by the analyst.

For example, OPC's method significantly underweights summer demands. OPC's study gives only 20% weighting to MPS summer demands and 13% weighting to L&P summer demands. Mr. Brubaker characterized these weightings as "fundamentally unreasonable" Given that it is summer peak demands that drive the need for the addition of generation capacity on both the MPS and L&P systems, an allocation methodology which only gives 13% to 20% weighting to summer peak demands is facially unreasonably and fundamentally flawed. The result of OPC's allocations is to skew the results such that high load factor customers are allocated costs that they do not cause and therefore should not pay.

Staff asserts that it has applied the "time of use" method.[18/] However, as Mr. Brubaker notes, there is no such method. In fact, there is no single "time of use" method.[19/] Unlike the terms "average and excess" and "coincident peak," the term "time-of-use" does not define a particular method or approach for analyzing or allocating costs. The method which Mr. Busch has used appears to be unique to the Missouri PSC Staff. Like OPC's method, this method is not described in the NARUC cost allocation manual, nor was Staff able through data requests to identify any other jurisdiction where it has been used.

[18/] Busch, Direct, p.10, l.4.

[19/] Brubaker, Rebuttal, p. 10.

Like OPC’s method, Staff’s method is fundamentally flawed. does not properly reflect cost causation. It allocates generation and transmission capacity costs across all hours of the year, even though many hours of the year are off-peak and loads are at such low levels that they would not cause the need for the addition of generation or transmission capacity.[20]

Unlike OPC, Staff at least attempts a justification of its method by attempting to argue that utilities can choose from different generation technologies. The method, however, does not properly reflect cost causation. Certainly, different generation technologies have different capital costs and different fuel costs, but this only states the obvious. But this claimed justification does not link Staff’s peculiar allocation method to these characteristics.[21]

In contrast, traditional and recognized cost allocation methods recognize that the utility’s generation "fleet" is built to serve the overall or combined load characteristics of ***all*** customer classes -- and not for the load characteristics of any particular customer class. These methods allocate energy costs equally across all customer classes, on an equal cents per kilowatthour basis, and allocate fixed costs equally across all customer classes on a uniform dollars per kilowatt of demand basis. This approach is reasonable, and avoids the needless complexity and speculation that would be required if one were to

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[20] Brubaker, Rebuttal, p. 10.

[21] Brubaker, Rebuttal, p. 11.

attempt to more precisely identify the specific mix of plants and the resulting separately determined capital and fuel costs on a class-by-class stand-alone basis.

The existence of different technologies does not justify allocating capacity costs to every hour of the year. As Mr. Brubaker explained:

> It is true that utilities select the mix of generation facilities that they expect to be able to produce power at the lowest overall total cost, which takes into account the combination of fixed costs and variable costs. Once that decision is made, the amount of fixed costs on the system is set, and does not vary with kilowatthour output or the number of hours that the facility is operated. These are truly fixed costs, which traditional allocation methods would treat as demand-related costs and allocate to customer classes based on a method such as average and excess or coincident peak. The types of fuel used are defined by the specific technology employed, but the total fuel cost varies as a function of total kilowatthour output-and thus is treated as a variable cost. Typically, the variable costs are allocated on the basis of the total annual kilowatthours required by the various customer classes.[22/]

Recognition of these technological differences is not relevant for class cost allocation purposes. Any distinction that would attempt to more precisely articulate costs by customer class would require an analysis to determine the technology or technologies that would be installed if a utility served each customer class ***independently***, at its lowest cost. Were this done, high load factor customers would have relatively more base load plant installed and less peaking plant would be installed

[22/] Brubaker, Rebuttal, p. 11.

with the converse true for lower load factor customers. But were such independent systems established, the high load factor class would be allocated more fixed costs, but much less variable costs; and the low load factor customer class would be allocated less capital costs but much more variable costs.

This type of analysis properly would reflect the trade-off between capital costs and fuel costs inherent in Mr. Busch's statement on page 10. Were this specific analysis done for each class on a ***stand-alone*** basis, then the results of this analysis would have to be analyzed to determine how to apply them to the actual fixed and variable costs which the utility has incurred in pursuit of its goal of selecting that combination of technologies which serves its total load at the lowest total (fixed plus variable) cost. But that is not what Mr. Busch has done and his analysis has not appropriately captured these considerations.[23/]

Further, Staff's analysis, while stating that it attempts to recognize technology differences, fails to recognize the break-even point that guides actual utility decision making regarding generation technology selection. In considering the different types of technologies available, the trade-off between variable costs and capital costs occurs at a specific number of hours of operation. Beyond the hours of operation where there is a "break-even" between the two different technologies, additional hours of operation of the more capital intensive plant does not change the decision of what type of technology to install. Thus,

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[23/] Brubaker, Rebuttal, p. 12.

it is only hours up to that point which could even arguably make a difference in technology choices. Mr. Brubaker illustrated this point at pages 13-14 of his Rebuttal testimony.

As a final proof, were Staff's method accurate, Staff's TOU allocation of energy costs would result in high load factor customers, and all customers who have an above-average percentage of their consumption during off-peak hours, receiving a below-average allocation of energy cost compared to an energy only allocator. Instead, Staff's method actually allocates more costs to a high load factor class than a method which does not even consider time-of-use.[24/] In response, Mr. Brubaker stated:

> This result is counter intuitive given the difference in load factors and percentage of energy consumption that occurs during off-peak hours. This is displayed on Schedule 3R. Note that the LPS class far and away has the highest load factor and the greatest percentage of consumption during off-peak hours of the major classes - yet it is allocated more energy costs than it would be allocated without regard to the time-of-use.[25/]

Indeed, Mr. Brubaker notes that Staff's method even assigned street lighting more energy costs than if "TOU" were not considered, despite street lighting being 70% off peak! These are not the results that would be associated with a recognized method of cost allocation; rather they are associated with a result driven allocation method.

[24/] Brubaker, Rebuttal, p. 15-16.

[25/] Brubaker, Rebuttal, p. 16.

Nor does Staff's method mimic competitive electricity markets. A superficial review of price behavior in the competitive wholesale market shows that summer period costs are significantly greater than costs during other periods because generation capacity is in tighter supply in the summer. The market also reveals that the energy component of price is much greater during summer periods of time when capacity is stressed because less efficient units are pressed into service, and that there are significant differences between on-peak and off-peak hours.

Staff's allocation methodology assigns capacity cost to every hour during which any generation unit operates. It doesn't matter that it is the middle of the night, it doesn't matter that it is during some other off-peak period, and it doesn't matter whether the load in that hour had any bearing on the decision to install capacity. While Staff says that the concept behind its allocations is to reflect "cost-causation," its allocation method does nothing of the kind. Staff's method is not an analysis of the causation of the costs of generation. Indeed, the phrase "capacity utilization" is very descriptive of the objective and mechanics of Staff's methodology and clearly reveals that Staff believes that it is appropriate for capacity costs to be allocated to every hour, regardless of whether loads in that hour have anything at all to do with the decision to install capacity. Stripped of the rhetoric, this looks more like an exercise in bookkeeping than in cost causation analysis.[26/]

[26/] Brubaker, Surrebuttal, pp. 2, 4.

Again, Staff's method, while purporting to be a "time of use" method, fails to capture these difference in costs over the "time of use." It is therefore false to its own representations and should not be used.

B. The A&E Summer Non-Coincident Method Is Also Appropriate For Allocating Transmission-Related Costs to Customer Classes.

For the same reasons, transmission costs should also be allocated to classes using the A&E - summer NCP method and not on some unexplained and apparently result-driven method.

C. The Appropriate Method For Allocating Distribution-related Costs to Customer Classes Depends On the Nature Of the Distribution Cost Being Allocated.

Distribution substations and feeder lines should be allocated based on class peaks at the primary voltage level, where each rate schedule is a separate class.

The costs in Accounts 364 through 368 should be addressed with recognition of whether they concern primary or secondary distribution costs and whether the costs are customer-related or demand-related. Regarding the primary distribution system, the customer component should be allocated to all customers on weighted customers (primary plus secondary customers) while the demand component of the primary distribution system should be allocated to all customers using class demands at the primary voltage level, with classes defined as rate schedules.

Regarding secondary distribution, the customer component of the secondary distribution system should be allocated on weighted secondary customers while the demand component of the secondary distribution system should be allocated using individual customer peaks at the secondary voltage level.

Again, OPC uses a non-conventional method and does not classify any portion of the primary network costs on a customer basis, but rather assumes that these costs are demand-related in their entirety. This is different from the treatment accorded these investments by Aquila, by MPSC Staff, and by Mr. Brubaker. The recognized methods for allocation of these costs include a customer component in the primary portion of the investment so as to recognize that the number of customers and the geographic dispersion over which they are located influences the amount of investment that must be made in the primary distribution network. I discuss this at significant length in my direct testimony, and will not repeat that discussion here. (Brubaker Rebuttal, p. 7-8).

D. The Appropriate Classification of Distribution Plant into the Categories of Primary Demand, Secondary Demand, Primary Customer-related and Secondary Customer-related Should Be as Recommended by Aquila Witnesses.

Aquila witness David Stowe explained the methodology used by Aquila to classify distribution plant into primary and secondary demand, and primary customer-related and secondary customer-related.

E. The Appropriate Method for Allocating Administrative and General Expenses to Customer Classes Should Be Allocated as Recommended by Mr. Brubaker and Aquila.

These expenses include such things as supervisory salaries, office supplies, rent and maintenance of general plant, and are related to the operation of properties and the supervision of employees. Accordingly, these costs should be allocated either on the basis of plant investment or on the basis of payroll. Account Nos. 920 (A&G Salaries), 921 (Office Suppliers), 922 (Administrative Expenses Transferred), 925 (Injuries & Damages), 926 (Employee Pensions and Benefits), and 931 (Rents) should be allocated on the lower component of the O&M expense in other functional categories allocated to customer classes. Account Nos. 924 (Property Insurance) and 935 (Maintenance of General Plant) should be allocated on gross plant from other functions as allocated to customer classes. Account Nos. 923 (Outside Services), 928 (Regulatory Commission Expenses), 929 (Duplicate Charges Credited), and 930 (Miscellaneous) should be allocated on total revenue.

OPC's study allocates these costs on the basis of "Total Cost of Service." Doing so effectively allocates a significant portion of these expenses on an energy-related basis, when they are in fact not energy-related but are, instead, related to salaries, supplies, maintenance and supervision of employees and even rental of plant. These costs simply bear no relationship to energy generation.

F. Inter-class Revenue Adjustments Should be Determined in this Case But Should be Implemented in Case No. ER-2005-0436.

A major but unlisted issue in this case is the claimed relationship between determining the class cost of service relationships in this case and implementing them in Aquila's now-pending rate case. Both OPC and Staff appear unable to apprehend this relationship. As was stated in prior Commission orders, this case is about determining where class rate relationships need to be moved -- in effect, determining your destination. It is another question entirely how one wishes to move to that destination. It is as though one engaged in a process to determine where to go on their vacation, resulting in a decision to visit Chicago. It is then a different question in determining whether one gets to Chicago by plane, car, bus or bicycle.

There is reasonable concern with impacts of adjustments to rate relationships, but this confuses the issue. The question of establishing the targets (*i.e.*, Chicago) is not the same as deciding how quickly one wishes to arrive at those destinations (*i.e.*, the mode or speed of travel). But just as certainly, the desired speed should not determine the destination. This would be like attempting to decide where to go on vacation by determining the length of time one wished to be on an airplane. What that would describe is not a destination but a circle within which thousands of potential destinations could exist.

G. The Appropriate Inter-class Revenue Adjustments Are Those Recommended by Mr. Brubaker and Are Determined Using the Methods He Recommends.

Mr. Brubaker has recommended the appropriate interclass revenue adjustments based on application of recognized and accepted methods of class cost allocation. These follow the results of his class cost of service study. This, in effect, determines the destination of the journey. However, he has proposed that this movement not be immediate by suggesting mitigation to the extent that no class would receive an increase of more than 4%-6% on a revenue neutral basis.

H. Large Power Tariffs of MPS and L&P Should Remain as Separate Tariffs.

Staff and Aquila have argued about whether certain rate schedules should be combined, eliminated or added. SIEUA does not take a position on this argument except to note that the large power tariffs of both divisions should remain as separate tariffs. As noted earlier in this Brief, the purpose of customer groupings for rate administration purposes is to group together customers that have common load and usage characteristics. These tariffs accomplish that objective. They group together customers that have common usage and load characteristics and in addition group customers whose load and usage characteristics distinguish them from other customers. It would be inappropriate to attempt to merge these tariffs with some other class or group with dissimilar load and usage characteristics.

I. The Rate Structures of the Large Power Tariffs of MPS and L&P Are Appropriate and Should Not Be Changed.

Again, Staff and Aquila are in disagreement over some of the internal components and relationships of certain of Aquila's tariffs. SIEUA believes, however, that with respect to the large power tariffs, those components are properly specified and related and we are not recommending that any changes be made to them.

J. The Appropriate Rate Values for Each Rate Schedule Should Be Determined as an Equal Percentage Change to Each Rate Block.

This issue addressed how, once the Commission determines the revenue shifts needed to bring rates into alignment with costs, that should be implemented with regard to the actual rate levels within a tariff. SIEUA believes that within the large power tariffs, these changes should be implemented by increasing each component by an equal percentage. This approach has the advantage of not introducing additional variations into the rate structure of the tariff and avoids the law of unintended consequences. Importantly it preserves the internal rate relationships within the tariff.

K. Income Taxes Should be Allocated to Classes Based on The Classes' Allocated Rate Base.

This new issue arose in this proceeding after the preliminary statement of issues was submitted. Most certainly treating income taxes on an energy basis or some other basis than rate base allocations introduces a disconnect into this component of cost causation. Tracking this element in accordance with rate base allocations keeps this element in line with causation. Under the *Hope* and *Bluefield* standards, the utility is entitled to a reasonable opportunity to earn a reasonable rate of return on the value of the investment that its shareholders have made in public utility property. It is therefore appropriate that the allocation of that rate base property to cost causing classes determines how income taxes are allocated to the same classes.

L. The Bottom Line -- The Indicated Cost Shifts.

Based on Mr. Brubaker's analysis, he recommended the target interclass shifts shown on the following two pages which are his Schedule 6 attached to his direct testimony.

AQUILA NETWORKS - L&P

Recommended Inter-Class Revenue Adjustments

Line	Rate Class	Present Rate Revenue ($'000)	Required Change	Recommended First Step Change: Capped at 4%	Recommended First Step Change: Capped at 6%
		(1)	(2)	(3)	(4)
1	RES	$ 41,106	12.14%	4.0%	6.0%
2	SGS	$ 7,576	-12.04%	-4.0%	-6.0%
3	LGS	$ 17,729	-12.69%	-4.2%	-6.3%
4	LP	$ 22,910	-7.98%	-2.6%	-3.9%

AQUILA NETWORKS - MPS

Recommended Inter-Class Revenue Adjustments

Line	Rate Class	Present Rate Revenue ($'000)	Required Change	Recommended First Step Change	
				Capped at 4%	Capped at 6%
		(1)	(2)	(3)	(4)
1	RES	$ 170,065	8.95%	4.0%	6.0%
2	SGS	$ 53,862	-9.78%	-4.4%	-6.6%
3	LGS	$ 44,189	-13.97%	-6.2%	-9.4%
4	LP	$ 51,095	-7.46%	-3.3%	-5.0%
4	SC	$ 256	15.45%	*	*

* SC will be folded into an existing rate schedule

IV. CONCLUSION.

WHEREFORE SIEUA respectfully urges the Commission to accept and adopt the recommendations offered by Mr. Brubaker.

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CERTIFICATE OF SERVICE

I hereby certify that I have sent true copies of the foregoing pleading either by United States Mail, facsimile or other electronic means, to the following on the date shown below.

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