Exhibit No.:	
Witness:	Maurice Brubaker
Type of Exhibit:	Rebuttal Testimony
Issue:	Cost of Service
Sponsoring Party:	Ag Processing, Inc. Federal Executive Agencies Sedalia Industrial Energy Users' Association
Case No.:	EO-2002-384

Before the Public Service Commission
of the State of Missouri

In the Matter of an Examination of Class Cost of Service and Rate Design in the Missouri Jurisdictional Electric Service Operations of Aquila, Inc., formerly known as UtiliCorp United Inc.) Case No. EO-2002-384

FILED[2]
DEC 07 2005
Missouri Public Service Commission

Rebuttal Testimony and Schedules of

Maurice Brubaker

On behalf of

Ag Processing, Inc.
Federal Executive Agencies
Sedalia Industrial Energy Users' Association

Project 7796
October 14, 2005

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

Exhibit No. 11
Case No(s). EO-2002-384
Date 11-07-05 Rptr KF

Before the Public Service Commission
of the State of Missouri

In the Matter of an Examination of Class Cost of Service and Rate Design in the Missouri Jurisdictional Electric Service Operations of Aquila, Inc., formerly known as UtiliCorp United Inc.	)))))	Case No. EO-2002-384

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

Affidavit of Maurice Brubaker

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

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by Ag Processing, Inc., Federal Executive Agencies and the Sedalia Industrial Energy Users' Association in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my rebuttal testimony and schedules which were prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. EO-2002-384.

3. I hereby swear and affirm that the testimony and schedules are true and correct and that they show the matters and things they purport to show.

M S Brubaker
Maurice Brubaker

Subscribed and sworn to before this 11th day of October 2005.

CAROL SCHULZ
Notary Public - Notary Seal
STATE OF MISSOURI
St. Louis County
My Commission Expires: Feb. 26, 2008

Carol Schulz
Notary Public

My Commission Expires February 26, 2008.

Before the Public Service Commission
of the State of Missouri

In the Matter of an Examination of Class Cost of Service and Rate Design in the Missouri Jurisdictional Electric Service Operations of Aquila, Inc., formerly known as UtiliCorp United Inc.	)	Case No. EO-2002-384

Rebuttal Testimony of Maurice Brubaker

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

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

A Yes.

Q ARE YOUR QUALIFICATIONS SET FORTH IN YOUR DIRECT TESTIMONY?

A Yes.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A First, I update the cost of service results that were filed with my direct testimony. The update is based on the results of the technical conferences conducted subsequent to the filing of direct testimony. Second, I respond to the positions on cost of service taken by MPSC Staff and OPC witnesses.

COST OF SERVICE STUDY UPDATES

Q PLEASE DESCRIBE GENERALLY THE NATURE OF THE MODIFICATIONS WHICH YOU HAVE MADE IN YOUR UPDATED COST OF SERVICE STUDIES.

A I have modified the allocations of some of the distribution system accounts based on the aforementioned discussions among the parties at the technical conference conducted during the week of September 26, 2005.

Q HAVE YOU PREPARED SCHEDULES WHICH DISPLAY THE UPDATED RESULTS?

A Yes, I have. Schedule 1R presents the updated results for L&P. It may be compared to Schedule 4 attached to my direct testimony.

Q CAN YOU COMPARE THE RESULTS OF THE UPDATE WITH THE ORIGINAL FILING?

A Yes. Perhaps the easiest way to do this is to compare the last line, labeled "% Change" on page 2 of each Schedule. This comparison shows that with the update, the percentage increase required to move the residential class to cost of service is slightly more than it was originally, and the percentage decreases to move all other classes to cost of service are slightly more than they were originally. Overall, the results fundamentally have not changed.

Q WHERE ARE THE RESULTS FOR THE UPDATE FOR MPS SHOWN?

A They are shown on Schedule 2R attached to my rebuttal testimony.

Q HOW DO THE RESULTS COMPARE WITH WHAT YOU ORIGINALLY FILED?

A They can be compared to what was presented as Schedule 5 of my direct testimony. Looking at the last line of page 2 of each Schedule, labeled "% Change", it can be seen that the increase required to move the residential class to cost of service is slightly higher than it was originally, and that the decreases required to move other classes closer to cost of service are slightly larger than they were initially. The results fundamentally have not changed.

RESPONSE TO OPC TESTIMONY

Q HAVE YOU REVIEWED THE DIRECT TESTIMONY OF OPC WITNESS BARBARA MEISENHEIMER?

A Yes, I have. She presents cost of service study results for L&P and for MPS.

Q DO YOU TAKE EXCEPTION TO ANY OF THE METHODOLOGIES EMPLOYED IN OPC'S COST OF SERVICE STUDIES?

A Yes. As a general matter, the cost of service methodology offered by OPC is unusual and not generally consistent with accepted cost allocation procedures. I will not attempt to detail every aspect of the studies with which I take exception, but will focus instead on the elements of the study that are most determinative of the overall results. These are the allocation methodology applied to generation and transmission investment, the classification of production system expenses, the classification of distribution investment, and the allocation of administrative and general expenses.

Q PLEASE ADDRESS OPC'S ALLOCATION METHODOLOGY FOR GENERATION AND TRANSMISSION FACILITIES.

A At page 5 of her testimony, Ms. Meisenheimer says that she uses the "(1) 12-month non-coincident (NCP) average and peak allocators, and (2) an energy (kWh) allocator."

Q DOES SHE EXPLAIN HER BASIS FOR THIS ALLOCATION METHODOLOGY?

A No, she does not. There is only a short paragraph at pages 5 and 6 that simply states that this is the methodology used. Nowhere is the methodology explained, nor is there any justification presented for using it.

In almost an aside, she claims that the allocator is ". . . a reasonably close approximation to a TOU method which the Commission has previously determined reasonable." She does not explain what TOU method she is referring to, nor does she state what Commission determined it to be reasonable, when it did so, or the factual circumstances at the time.

Q **DID YOU ASK ANY DATA REQUESTS OF OPC?**

A Yes. Data requests were served on October 4, 2005 but as of the time of completion of this testimony no responses have been received.

Q **HAVE YOU REVIEWED OPC'S ALLOCATION METHOD FOR GENERATION AND TRANSMISSION PLANT?**

A **Yes, I have. The methodology is not one that I have ever seen used outside the State of Missouri. It is not discussed in the NARUC Cost Allocation Manual, or in any other reference manual of which I am aware.**

Q **WHAT IS THE SIGNIFICANCE OF THE FACT THAT THIS METHODOLOGY IS NOT USED IN OTHER JURISDICTIONS?**

A Cost of service studies for electric systems have been performed for well over 50 years. This means that there has been a significant amount of analysis that 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 must be viewed with skepticism, and proponents of such methods bear a special burden of proving that they do a more accurate job of identifying cost-causation than recognized methods and are not ad hoc creations simply to support a particular result desired by the analyst.

Q HOW MUCH WEIGHTING DOES OPC'S ALLOCATION METHODOLOGY GIVE TO SUMMER DEMANDS?

A Based on the percentages shown on page 3 of Schedule BAM, Direct MPS, the weighting given to demands during the three summer months is only about 20%, and according to the corresponding page 3 for L&P, it is only about 13%.

Q ARE THESE REASONABLE WEIGHTINGS FOR SUMMER PEAK DEMANDS?

A No. These are fundamentally unreasonable. It is summer peak demands that drive the need for the addition of generation capacity on both the MPS and L&P systems, and an allocation methodology which only gives 13% to 20% weighting to summer peak demands cannot be regarded as reasonable. 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.

Q TURNING TO THE CLASSIFICATION AND ALLOCATION OF GENERATION PLANT AND RELATED EXPENSES, HOW DID OPC ALLOCATE FUEL COSTS AND THE ENERGY COMPONENT OF PURCHASED POWER?

A On class energy requirements, adjusted for losses.

Q DO YOU HAVE ANY DISAGREEMENT WITH THIS TREATMENT OF THESE PARTICULAR ITEMS?

A No. That is generally consistent with accepted practices.

Q **WITH RESPECT TO OTHER PRODUCTION SYSTEM O&M EXPENSE ACCOUNTS, DO YOU AGREE WITH OPC'S ALLOCATIONS?**

A No. In the case of a number of these accounts, OPC used an energy allocation rather than a demand allocation. The accounts in questions are Accounts 502, 504, 505, 506, 509, 512, 513, 514, 553, 556, and 557.

OPC allocated expenses in these accounts on the basis of class energy, rather than class demands or the previously allocated investment in generation plant. Costs in these accounts are related to the operation and maintenance of the facilities and are caused by the existence of the facilities and the passage of time (maintenance intervals), not the numbers of kWh generated. Accordingly, they typically are treated as being related to plant in service and the procedure or concept that "expenses follow plant" is usually applied. This is the methodology that was used by Aquila, by Staff and by me in this case. OPC provides no rationale for assigning these expenses to the energy component and allocating them to classes on energy.

Q **WHAT ISSUE TO YOU TAKE WITH OPC'S TREATMENT OF DISTRIBUTION PLANT?**

A While there may be others, the main areas of disagreement surround the classification of Account 364 (Poles, Towers and Fixtures), Account 365 (Overhead Conductors and Devices), Account 366 (Underground Conduit), and Account 367 (Underground Conductors and Devices).

Q **WHAT IS THE ISSUE HERE?**

A OPC 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 me. Recognized methods include a customer component in the primary portion of the investment in these facilities in order 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.

Q HOW DOES OPC ALLOCATE ADMINISTRATIVE AND GENERAL EXPENSES OTHER THAN PROPERTY INSURANCE, PENSIONS AND BENEFITS, AND INJURIES AND DAMAGES EXPENSES?

A OPC allocates the remaining A&G expenses on the basis of the "Total Cost of Service" allocated to each class.

Q IS THIS THE CONVENTIONAL TREATMENT FOR THESE EXPENSES?

A No. These other expenses, which include such things as supervisory salaries, office supplies, rent and maintenance of general plant, are related to the operation of properties and the supervision of employees. Accordingly, these remaining costs are typically allocated either on the basis of plant investment or on the basis of payroll. By allocating on the basis of "Total Cost of Service," OPC effectively allocates a significant portion of these expenses on an energy-related basis, when they are in fact not energy-related.

Q **HAVE YOU REVIEWED OPC'S PROPOSED INTERCLASS ALLOCATIONS OF REVENUES?**

A Yes. Because OPC's proposal is based on its flawed cost of service study, its interclass allocation proposals should not be accepted.

RESPONSE TO COMMISSION STAFF

Q **HAVE YOU REVIEWED THE COST OF SERVICE STUDY PRESENTED BY MPSC STAFF?**

A Yes. The study is sponsored by Mr. Bush, with input by Mr. Watkins.

Q **AT PAGE 10, LINE 4 OF HIS DIRECT TESTIMONY, MR. BUSCH STATES THAT HE ALLOCATED PRODUCTION CAPACITY COSTS TO CUSTOMER CLASSES BY USING A TIME-OF-USE METHOD. IS THERE A SINGLE TIME-OF-USE METHOD?**

A No. 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 is, as far as I can tell, unique to the Missouri PSC Staff. **The method which Mr. Busch used is not described in the NARUC cost allocation manual, nor have I seen this particular method used in any other jurisdiction.**

Q **DID YOU ASK ANY DATA REQUESTS OF STAFF?**

A Yes. Data requests were served on September 27, 2005 but as of the time of completion of this testimony no responses have been received.

Q **WHAT IS YOUR OVERALL ASSESSMENT OF THIS METHODOLOGY?**

A In my opinion, it 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.

Q **AT PAGE 10 OF HIS TESTIMONY, MR. BUSCH GIVES AS A JUSTIFICATION FOR HIS ALLOCATION METHOD THE FACT THAT UTILITIES CAN CHOOSE FROM DIFFERENT TYPES OF GENERATING UNITS THAT HAVE DIFFERENT COST CHARACTERISTICS. DOES THIS JUSTIFY HIS ALLOCATION APPROACH?**

A No. Mr. Busch references the fact that there are several available generation technologies, which he summarizes into the categories of base, intermediate and peaking. Clearly, these facilities have different capital costs and different fuel costs. But, he does not provide a justification which links his particular allocation method to these characteristics. The existence of different technologies does not justify allocating capacity costs to every hour of the year.

Q **PLEASE EXPLAIN.**

A It is true that utilities select the mix of generation facilities that they expect to be able to produce power at the lowest overall <u>total</u> 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.

Q **IS THIS TECHNOLOGY DISTINCTION IMPORTANT FOR PURPOSES OF PERFORMING CLASS COST ALLOCATION STUDIES?**

A No, it is not. While it is recognized that the different technologies have different combinations of fixed and variable costs, 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. The result would be that for high load factor customer classes relatively more base load plant would be installed, and relatively less peaking plant would be installed. The converse would be true for lower load factor customers. If this were done, then the high load factor class would be allocated more fixed costs, but less variable costs; and the low load factor customer class would be allocated less capital costs but more variable costs.

This analysis properly would reflect the trade-off between capital costs and fuel costs inherent in Mr. Busch's statement on page 10. If this specific analysis were 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. If the desire is to more specifically reflect these technology tradeoffs, then this type of analysis would be required. The type of analysis that Mr. Busch performed has not appropriately captured these considerations.

Q HOW DO TRADITIONAL COST ALLOCATION STUDIES RECOGNIZE THIS MIX OF TECHNOLOGIES?

A Traditional cost allocation studies recognize that the mix or combination of plants 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. They, therefore, 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 a lot of complexity and speculation that would be required if one were to attempt to more precisely identify the specific mix of plants and the resulting separately determined capital and fuel costs.

Q ARE THERE OTHER REASONS WHY IT IS INAPPROPRIATE TO INCLUDE CAPITAL COSTS IN ALL HOURS OF THE YEAR?

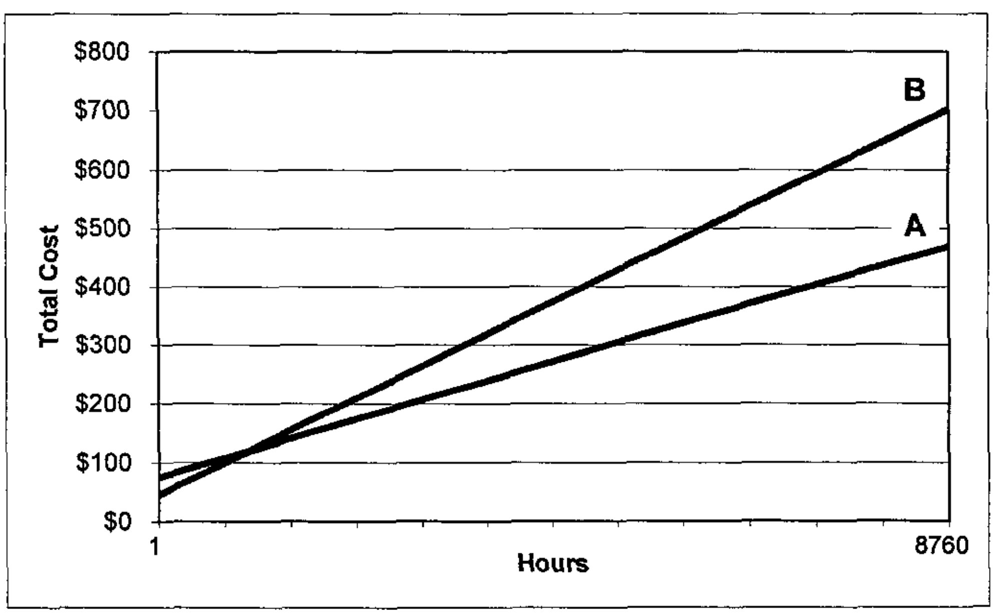
A Yes. In considering the different types of technologies available, the trade-off between variable costs and capital costs occurs at some specific number of hours of operation. Beyond the hours of operation where there is a "break-even" between the two different technologies, additional hours of operation of the more capital intensive plant does not change the decision of what type of technology to install. Thus, it is only hours up to that point which could even arguably make a difference in technology choices.

Q CAN YOU ILLUSTRATE?

A Yes. Assume Technology A has a capital cost of $500 per kilowatt, a heat rate of 7,000 Btu per kilowatthour, O&M expense of 0.3¢ per kilowatthour, and that it is fired with natural gas at a delivered cost of \$6.00 per MMBtu. The total of fuel and O&M expenses would be 4.5¢ per kilowatthour.

Assume that a second technology, B, has a capital cost of \$300 per kilowatt, a heat rate of 12,000 Btu per kilowatthour and O&M expenses of 0.3¢ per kilowatthour. With the same fuel price, the total variable cost of this unit would be 7.5¢ per kilowatthour. The difference in variable cost is, therefore, 3.0¢ per kilowatthour (7.5¢ - 4.5¢). Assuming a carrying charge rate of 15%, the difference in capital cost is \$30 per kW (the \$200 per kW difference in capital cost times 15%). The break-even point (the hours of operation required for the lower fuel cost to out weigh the higher capital cost) is 1,000 hours (\$30 ÷ \$0.03). This illustrates that only slightly more than 11% of the hours in the year (1,000 out of 8,760) are arguably important in the technology choice question. This is illustrated below.

Break-Even Analysis



Since the additional hours are not relevant in this decision because those loads had nothing to do with the incurrence of the capital cost, it is wrong to include loads in those additional hours in the cost allocation process. The cost allocation methodology used by Staff suffers heavily from this problem because capital costs are assigned to all hours of the year.

Q **BASED ON STAFF'S OBSERVATIONS WITH RESPECT TO THE ALLOCATION OF ENERGY COST, WOULD YOU EXPECT THAT HIGH LOAD FACTOR CUSTOMERS WHO HAVE AN ABOVE-AVERAGE PERCENTAGE OF THEIR LOAD DURING OFF-PEAK HOURS WOULD BE ALLOCATED MORE ENERGY COSTS OR LESS ENERGY COSTS WITH STAFF'S METHOD?**

A As compared to the traditional method of allocating energy costs on the basis of annual kWh, I would expect that Staff's TOU allocation of energy costs would produce the result that high load factor customers, and all customers who have an above-average percentage of their consumption during off-peak hours, would receive a below-average allocation of energy cost.

Q **DOES STAFF'S ALLOCATION METHOD PRODUCE THAT RESULT?**

A No. Please see Schedule 3R. This displays the result of Staff's TOU allocations for the L&P system. Please note that for the LPS class, the annual energy allocation factor is 33.70%, whereas under Staff's approach, the LPS class is allocated 33.78% of energy costs.

Q **IS THERE REALLY A BIG DIFFERENCE BETWEEN THESE TWO ALLOCATION PERCENTAGES?**

A No, the difference is not large. What is important is that Staff's approach, which is supposed to be more reflective of time-of-use, and the resulting cost differences, actually allocates more costs to a high load factor class than a method which does not even consider time-of-use.

Q WHAT DO YOU CONCLUDE FROM THIS?

A 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.

Q IS THE SAME TRUE FOR STREET LIGHTING?

A Yes. Street lighting is nearly 70% off-peak, yet Staff's TOU energy allocation assigns it more energy costs than if time-of-use is not considered!

Q DO YOU HAVE ANY OTHER COMMENTS WITH RESPECT TO STAFF'S ALLOCATION METHODOLOGY?

A Yes. At page 12 of his testimony, Mr. Busch, at lines 16 through 18, claims that Staff's TOU allocations "mimic a truly competitive retail electricity market." Nothing could be further from the truth. Even a cursory examination of the behavior of prices in the competitive wholesale market reveals that costs during the summer period are significantly greater than costs during other periods of the year because generation capacity is in tighter supply. The market also reveals that the energy component of price is much greater during 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.

If Staff's TOU method mimicked the competitive market, it clearly would not produce the results where above-average load factor customers whose loads are less seasonal and more off-peak than average are allocated above-average energy costs. It also would not produce a result where the energy allocation factors and demand allocation factors are so close to each other, indicating a lack of appropriate distinction between energy costs and capacity costs.

Q WHAT IS YOUR CONCLUSION FROM THESE RESULTS?

A This reinforces my conclusion that the Staff "TOU" allocator has no basis in fact or theory, and produces erroneous results.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

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BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP
RATE OF RETURN FORMAT ($000)
AQUILA NETWORKS - L&P
CASE NO. EO-2002-384

Line	Description	Residential	SGS	LGS	LP	TOTAL
		(1)	(2)	(3)	(4)	(5)
1	Revenue [1]	$ 44,702	$ 8,115	$ 19,218	$ 24,850	$ 96,885
2	Expense	41,832	5,793	14,407	19,931	81,964
3	Return	2,870	2,322	4,810	4,919	14,921
4	Rate Base	$ 98,313	$ 14,079	$ 27,827	$ 33,646	$ 173,865
5	Rate of Return	2.92%	16.49%	17.29%	14.62%	8.58%
6	Allowed Rate of Return	8.58%				
7	Return at Cost of Service [2]	$ 8,437	$ 1,208	$ 2,388	$ 2,887	$ 14,921
8	Required Increase or (Decrease)	$ 5,567	$ (1,114)	$ (2,422)	$ (2,032)	$ 0
9	Required Increase or (Decrease) Adjusted For Rounding	$ 5,573	$ (1,113)	$ (2,424)	$ (2,037)	$ (0)

Notes:

[1] Rate Revenue plus allocated other revenue.

[2] Revenue Neutral Rate of Return times Rate Base

BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP

FUNCTIONAL COST FORMAT - AQUILA NETWORKS - L&P

CASE NO. EO-2002-384

FUNCTIONAL CATEGORY			RES	SGS	LGS	LP		Other	TOTAL
PRODUCTION	CAPACITY		$15,631,185	$2,226,111	$6,713,490	$9,124,514	$0	$0	$33,695,300
PRODUCTION	ENERGY		$10,218,001	$1,478,183	$5,243,474	$8,764,138	$0	$0	$25,703,796
TRANSMISSION	CAPACITY		$3,495,329	$497,786	$1,501,221	$2,040,356	$0	$0	$7,534,692
DISTRIBUTION	SUBSTATIONS	DEMAND	$2,626,619	$285,743	$824,460	$1,077,840	$0	$0	$4,814,661
DISTRIBUTION	POLES AND CONDUCTORS	PRI. FEEDER - DEMAND	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP -CUSTOMER	$1,397,045	$254,131	$115,474	$7,281	$0	$0	$1,773,930
DISTRIBUTION	POLES AND CONDUCTORS	SEC. CUSTOMER	$1,382,463	$251,478	$112,153	$5,512	$0	$0	$1,751,607
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP - DEMAND	$3,258,440	$354,478	$1,022,780	$1,337,109	$0	$0	$5,972,806
DISTRIBUTION	POLES AND CONDUCTORS	SEC. DEMAND	$883,878	$96,286	$208,933	$187,781	$0	$0	$1,376,877
DISTRIBUTION	TRANSFORMERS	SECONDARY	$2,343,618	$355,746	$340,280	$210,955	$0	$0	$3,250,599
DISTRIBUTION	TRANSFORMERS	PRIMARY	$125,313	$19,365	$21,206	$19,660	$0	$0	$185,543
DISTRIBUTION	CUSTOMER INSTALLATIONS		$303,146	$55,144	$24,593	$1,209	$0	$0	$384,091
DISTRIBUTION	SERVICES		$1,329,250	$241,798	$109,870	$6,928	$0	$0	$1,687,846
DISTRIBUTION	METERS		$1,086,708	$197,679	$89,823	$5,664	$0	$0	$1,379,873
	CUSTOMER DEPOSITS		($32,584)	($3,472)	($630)	($33)	$0	$0	($36,719)
	METER READING		$380,618	$69,349	$31,433	$1,982	$0	$0	$483,381
	BILLING, SALES, SERVICE		$3,062,984	$326,360	$59,239	$3,115	$0	$0	$3,451,697
	ASSIGNED LGS/LPS/SC		$0	$0	$376,216	$19,783	$0	$0	$395,998
	ASSIGNED RES/SGS		$2,782,228	$296,445	$0	$0	$0	$0	$3,078,673
	EXCESS FACILITY		$0	$0	$0	$0	$0	$0	$0
	TOTAL		$50,274,240	$7,002,610	$16,794,012	$22,813,792	$0	$0	$96,884,654
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	$0
	TOTAL COST OF SERVICE		$50,274,240	$7,002,610	$16,794,012	$22,813,792	$0	$0	$96,884,654
	%		51.89%	7.23%	17.33%	23.55%	0.00%	0.00%	100%
	RATE REVENUE		$41,106,120	$7,575,521	$17,728,841	$22,910,401	$0	$2,238,976	$91,559,859
	Allocate Rate Revenues for Others		$1,161,823	$161,828	$388,105	$527,220	$0	($2,238,976)	$0
	NON RATE REVENUE		$746,413	$137,558	$382,853	$442,966	$0	$40,656	$1,750,446
	Interruptible Credit		$0	$0	($4,927)	($12,317)	$0	$0	($17,244)
	OffSystem Revenue		$1,666,133	$237,282	$715,593	$972,585	$0	$0	$3,591,593
	Excess Facility Revenue		$0	$0	$0	$0	$0	$0	$0
	Sale of Emission		$0	$0	$0	$0	$0	$0	$0
	Allocate Non Rate Rev for Others		$21,097	$2,939	$7,047	$9,573	$0	($40,656)	$0
	TOTAL REVENUE		$44,701,586	$8,115,128	$19,217,512	$24,850,428	$0	$0	$96,884,654
	%		46.14%	8.38%	19.84%	25.65%	0.00%	0.00%	100%
	REVENUE DEFICIENCY		$5,572,654	($1,112,518)	($2,423,500)	($2,036,637)	$0	$0	$0
	% CHANGE		13.56%	-14.69%	-13.67%	-8.89%		0.00%	0.00%

AQUILA NETWORKS - L&P

Cost-of-Service Allocation Methods

Line	Functionalization Category	Allocation Method
1	**Production:**	
2	Capacity	A&E Summer NCP
3	Energy	Total Year Sales
4	**Transmission:**	A&E Summer NCP
5	**Distribution:**	
6	Substations	Class Peak at Primary Voltage Level
7	Feeder Lines	Class Peak at Primary Voltage Level
8	**#364 Poles, Towers & Fixtures**	
9	Primary Customer	All Customers - Weighted
10	Primary Demand	Class Peak at Primary Voltage Level
11	Secondary Customer	Secondary Customers - Weighted
12	Secondary Demand	Customer Peak at Secondary Voltage Level
13	**#365 Overhead Conductors & Devices**	
14	Primary Customer	All Customers - Weighted
15	Primary Demand	Class Peak at Primary Voltage Level
16	Secondary Customer	Secondary Customers - Weighted
17	Secondary Demand	Customer Peak at Secondary Voltage Level
18	**#366 Underground Conduit**	
19	Primary Customer	All Customers - Weighted
20	Primary Demand	Class Peak at Primary Voltage Level
21	Secondary Customer	Secondary Customers - Weighted
22	Secondary Demand	Customer Peak at Secondary Voltage Level
23	**#367 Underground Conductors & Devices**	
24	Primary Customer	All Customers - Weighted
25	Primary Demand	Class Peak at Primary Voltage Level
26	Secondary Customer	Secondary Customers - Weighted
27	Secondary Demand	Customer Peak at Secondary Voltage Level
28	**#368 Line Transformers**	
29	Primary Customer	All Customers - Weighted
30	Primary Demand	Class Peak at Primary Voltage Level
31	Secondary Customer	Secondary Customers - Weighted
32	Secondary Demand	Customer Peak at Secondary Voltage Level
33	Customer Installations	Secondary Customers - Weighted
34	Services	All Customers - Weighted
35	Meters	All Customers - Weighted
36	***Other:***	
37	*Customer Deposit*	All Customers
38	Meter Reading	All Customers - Weighted Customers
39	Billing & Sales	All Customers
40	Assigned - LGS/LPS/SC	All Customers - LGS/LPS/SC
41	Assigned - RES/SGS	All Customers - RES/SGS

BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP
RATE OF RETURN FORMAT ($000)
AQUILA NETWORKS - MPS
CASE NO. EO-2002-384

Line	Description	Residential (1)	SGS (2)	LGS (3)	LP (4)	SC (5)	TOTAL (6)
1	Revenue [1]	$ 183,403	$ 57,787	$ 47,362	$ 54,894	$ 281	$ 343,726
2	Expense	162,786	43,672	35,573	44,271	272	286,574
3	Return	20,617	14,115	11,788	10,623	9	57,152
4	Rate Base	$ 422,302	$ 100,473	$ 67,479	$ 72,455	$ 527	$ 663,236
5	Rate of Return	4.88%	14.05%	17.47%	14.66%	1.74%	8.62%
6	Allowed Rate of Return	8.62%					
7	Return at Cost of Service [2]	$ 36,390	$ 8,658	$ 5,815	$ 6,244	$ 45	$ 57,152
8	Required Increase or (Decrease)	$ 15,774	$ (5,457)	$ (5,974)	$ (4,379)	$ 36	$ 0
9	Required Increase or (Decrease) Adjusted For Rounding	$ 15,767	$ (5,457)	$ (5,971)	$ (4,375)	$ 36	$ (0)

Notes:

[1] Rate Revenue plus allocated other revenue

[2] Revenue Neutral Rate of Return times Rate Base

BAI COST-OF-SERVICE RESULTS - A&E SUMMER NCP

FUNCTIONAL COST FORMAT - AQUILA NETWORKS - MPS

CASE NO. EO-2002-384

FUNCTIONAL CATEGORY			RES	SGS	LGS	LP	SC	Other	TOTAL
PRODUCTION	CAPACITY		$57,948,618	$17,454,324	$14,156,481	$16,990,556	$118,368	$0	$106,668,348
PRODUCTION	ENERGY		$47,644,607	$15,984,496	$16,278,827	$23,778,202	$124,464	$0	$103,810,596
TRANSMISSION	CAPACITY		$15,692,078	$4,726,508	$3,833,475	$4,600,923	$32,053	$0	$28,885,038
DISTRIBUTION	SUBSTATIONS	DEMAND	$6,376,581	$1,645,350	$1,307,488	$1,485,206	$10,977	$0	$10,825,603
DISTRIBUTION	POLES AND CONDUCTORS	PRI. FEED - DEMAND	$0	$0	$0	$0	$0	$0	$0
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP-CUSTOMER	$8,713,659	$1,342,641	$273,759	$59,275	$241	$0	$10,389,575
DISTRIBUTION	POLES AND CONDUCTORS	SEC. CUSTOMER	$7,123,891	$1,097,147	$205,577	$21,181	$197	$0	$8,447,994
DISTRIBUTION	POLES AND CONDUCTORS	PRI. TAP - DEMAND	$11,107,703	$2,866,123	$2,277,582	$2,587,159	$19,122	$0	$18,857,690
DISTRIBUTION	POLES AND CONDUCTORS	SEC. DEMAND	$5,710,435	$1,136,418	$723,625	$378,708	$5,390	$0	$7,954,575
DISTRIBUTION	TRANSFORMERS	SECONDARY	$11,729,630	$2,017,756	$797,989	$332,306	$4,626	$0	$14,882,307
DISTRIBUTION	TRANSFORMERS	PRIMARY	$662,505	$126,537	$61,663	$57,704	$417	$0	$908,827
DISTRIBUTION	CUSTOMER INSTALLATIONS		$1,473,507	$226,934	$42,522	$4,381	$41	$0	$1,747,384
DISTRIBUTION	SERVICES		$6,141,813	$946,359	$192,959	$41,780	$170	$0	$7,323,081
DISTRIBUTION	METERS		$4,165,713	$641,873	$130,875	$28,338	$115	$0	$4,966,913
	CUSTOMER DEPOSITS		($274,442)	($39,589)	($1,592)	($211)	($1)	$0	($315,835)
	METER READING		$1,547,158	$223,179	$30,882	$10,540	$43	$0	$1,811,802
	BILLING, SALES, SERVICE		$6,006,829	$866,491	$34,854	$4,608	$32	$0	$6,912,815
	ASSIGNED LGS/LPS/SC		$0	$0	$1,043,299	$137,941	$971	$0	$1,182,211
	ASSIGNED RES/SGS		$7,399,689	$1,067,413	$0	$0	$0	$0	$8,467,102
			$0	$0	$0	$0	$0	$0	$0
	TOTAL		$199,169,975	$52,329,961	$41,390,266	$50,518,599	$317,227	$0	$343,726,028
	Allocate Cost of Service for Others		$0	$0	$0	$0	$0	$0	$0
	TOTAL COST OF SERVICE		$199,169,975	$52,329,961	$41,390,266	$50,518,599	$317,227	$0	$343,726,028
	%		57.94%	15.22%	12.04%	14.70%	0.09%	0.00%	100%
	RATE REVENUE		$170,064,667	$53,861,537	$44,188,703	$51,095,135	$256,249	$5,475,023	$324,941,314
	Allocate Rate Revenues for Others		$3,172,469	$833,535	$659,283	$804,683	$5,053	($5,475,023)	$0
	NON RATE REVENUE		$2,034,732	$644,424	$528,694	$611,326	$3,066	$65,506	$3,887,748
	Interruptible Credit		$0	$0	$0	$0	$0	$0	$0
	OffSystem Revenue		$8,085,989	$2,435,528	$1,975,356	$2,370,815	$16,517	$0	$14,884,205
	Excess Facility Revenue		$0	$0	$0	$0	$0	$0	$0
	Interdepartmental Sales		$6,679	$2,115	$1,735	$2,007	$10	$215	$12,761
	Allocate Non Rate Rev for Others		$38,081	$10,006	$7,914	$9,659	$61	($65,721)	$0
	TOTAL REVENUE		$183,402,618	$57,787,145	$47,361,685	$54,893,625	$280,955	$0	$343,726,028
	%		53.36%	16.81%	13.78%	15.97%	0.08%	0.00%	100%
	REVENUE DEFICIENCY		$15,767,357	($5,457,184)	($5,971,419)	($4,375,026)	$36,272	$0	$0
	% CHANGE		9.27%	-10.13%	-13.51%	-8.56%	14.16%	0.00%	0.00%

AQUILA NETWORKS - MPS

Cost-of-Service Allocation Methods

Line	Functionalization Category	Allocation Method
1	**Production:**	
2	Capacity	A&E Summer NCP
3	Energy	Total Year Sales
4	**Transmission:**	A&E Summer NCP
5	**Distribution:**	
6	Substations	Class Peak at Primary Voltage Level
7	Feeder Lines	Class Peak at Primary Voltage Level
8	**#364 Poles, Towers & Fixtures**	
9	Primary Customer	All Customers - Weighted
10	Primary Demand	Class Peak at Primary Voltage Level
11	Secondary Customer	Secondary Customers - Weighted
12	Secondary Demand	Customer Peak at Secondary Voltage Level
13	**#365 Overhead Conductors & Devices**	
14	Primary Customer	All Customers - Weighted
15	Primary Demand	Class Peak at Primary Voltage Level
16	Secondary Customer	Secondary Customers - Weighted
17	Secondary Demand	Customer Peak at Secondary Voltage Level
18	**#366 Underground Conduit**	
19	Primary Customer	All Customers - Weighted
20	Primary Demand	Class Peak at Primary Voltage Level
21	Secondary Customer	Secondary Customers - Weighted
22	Secondary Demand	Customer Peak at Secondary Voltage Level
23	**#367 Underground Conductors & Devices**	
24	Primary Customer	All Customers - Weighted
25	Primary Demand	Class Peak at Primary Voltage Level
26	Secondary Customer	Secondary Customers - Weighted
27	Secondary Demand	Customer Peak at Secondary Voltage Level
28	**#368 Line Transformers**	
29	Primary Customer	All Customers - Weighted
30	Primary Demand	Class Peak at Primary Voltage Level
31	Secondary Customer	Secondary Customers - Weighted
32	Secondary Demand	Customer Peak at Secondary Voltage Level
33	Customer Installations	Secondary Customers - Weighted
34	Services	All Customers - Weighted
35	Meters	All Customers - Weighted
36	**Other:**	
37	Customer Deposit	All Customers
38	Meter Reading	All Customers - Weighted Customers
39	Billing & Sales	All Customers
40	Assigned - LGS/LPS/SC	All Customers - LGS/LPS/SC
41	Assigned - RES/SGS	All Customers - RES/SGS

AQUILA NETWORKS - L&P

ANALYSIS OF STAFF ALLOCATION FACTORS

Line	Class	Energy @ Generator KWh (1)	Annual Energy Allocation (2)	Staff TOU Allocators: Production Energy Allocator (3)	Staff TOU Allocators: Production Capacity Allocator (4)	Staff TOU Allocators: Transmission Capacity Allocator (5)	Class Load Factor [1] (6)	% of Energy Used During Off-Peak Hours [2] (7)
1	RES GEN	345,566,151	17.64%	17.62%	20.38%	20.38%	35%	31.2%
2	RES WH	108,415,764	5.53%	5.53%	5.99%	5.99%	40%	29.8%
3	RES SH	315,724,127	16.12%	16.07%	15.38%	15.38%	76%	34.7%
4	TOTAL RES	769,706,042	39.29%	39.22%	41.75%	41.75%	46%	32.5%
5	SGS	111,349,188	5.68%	5.67%	5.92%	5.92%	47%	28.3%
6	LGS	394,982,693	20.16%	20.14%	19.95%	19.95%	56%	28.9%
7	LPS	660,188,838	33.70%	33.78%	31.54%	31.54%	72%	35.6%
8	LIGHTING	22,896,803	1.17%	1.18%	0.84%	0.84%	49%	68.6%
9	TOTAL	1,959,123,564	100.00%	100.00%	100.00%	100.00%	55%	33.0%

Notes:

[1] Max Demand is based on the average of maximum demands in the months of July, August & September.

[2] Off-Peak Time Period = All months - Weekdays, weekends & holidays 10 p.m. - 7 a.m.