EXECUTIVE SUMMARY
DIRECT TESTIMONY OF DAVID L. STOWE
DOCKET NO. EO-2002-384

Every meaningful rate design begins with a class cost-of-service ("COS") study. This is because the purpose of the COS study is to distribute a utility's total cost of providing service to its customers. When performed properly a COS will show the revenue that must be recovered from each customer class.

In his testimony, Aquila witness David L. Stowe describes the Company's COS studies; explaining the source of input data, the special studies which enhanced the COS, and describing the logic and assumption of both. Stowe concludes his testimony with the recommendation that the Commission endorse Aquila's COS methods and approve the COS results for use in Aquila's rate design.

Cost of Service Inputs

This section explains the source of the revenue and expense account data which were used in the COS studies. The revenue and expense data came from Accounting schedules based on the Settlement Agreement approved by the Commission in Docket No. ER-2004-034.

Customer Classes

The COS customer classes were identified by Aquila's Load Research department based on each class' load shape. The class load data is described in this section.

Effects of adding Line Losses

This section explains why and how the class load data was increased to reflect line losses. The section explains that the line loss values came from a joint project by Aquila's transmission and distribution engineers in 2002. This section contains two summary tables, the first showing how current tariff rates are combined into COS classes and the second showing how those classes are combined into rate groups.

The Test Year

This section describes the test period for Aquila's COS study and explains the supplemental class data that was developed as input to the COS study.

Method of developing a COS study.

This section describes the logic and method of developing a COS study. The section also describes specifics of Aquila's COS. It explains when and where certain allocation factors might be used, and describes which allocation factors *were* used in Aquila's COS studies. The section also demonstrates Aquila's understanding of the techniques and methods of COS studies.

Distribution Study and the Zero Intercept Method.

This portion of testimony is a detailed description of two lengthy studies completed to enhance the COS studies.

The Distribution Study was completed to distinguish primary distribution costs from secondary distribution costs.

The Zero Intercept study was completed to identify the customer costs and demand costs of certain distribution components.

Distribution Study Results

This section describes the results of the distribution studies contained in Schedules DLS-1 and DLS-2. Aquila recommends that the Commission endorse the separation of primary distribution costs from secondary distribution costs and the use of the Zero Intercept method to classify certain distribution costs as demand and customer.

COS Study Results:

This section describes the results of the COS studies contained in Schedules DLS-3 through DLS-10. Aquila recommends the Commission endorse Aquila's COS studies.

Billing Units:

This final section describes the calculation of billing determinants for use in the proposed rate structure. Adjustment factors provided by Staff witness Janice Pyatte were used to develop billing units that best produce the revenues by class from the previous rate case.

Exhibit No.:	
Issues:	Cost-of-Service, Distribution Study, Billing Units
Witness:	David L. Stowe
Sponsoring Party:	Aquila Networks – L&P Aquila Networks – MPS
Case No.:	EO-2002-384

Before the Public Service Commission
Of the State of Missouri

Direct Testimony

Of

David L. Stowe

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI
DIRECT TESTIMONY OF DAVID STOWE
ON BEHALF OF AQUILA INC.
DOCKET NO. ER-2002-384

Q. Please state your name and business address.

A. My name is David Stowe and my business address is 10700 East 350 Highway, Kansas City, Missouri.

Q. By whom are you employed and in what capacity?

A. I am employed by Aquila, Inc. ("Aquila") in the Regulatory Services group as a Senior Regulatory Analyst.

Q. What are your duties and responsibilities at Aquila?

A. I am responsible for the analysis and preparation of cost-of-service ("COS") studies, cost allocation studies, and rate design. I also prepare analyses, work papers and other supporting documents for various filings with regulatory agencies and reports, both internal and external.

Q. Please describe your educational and professional background.

A. I am a graduate of Kansas State University with a B.S. in Electrical and Computer Engineering. From 1987 to 1993, I was employed by the Kansas Corporation Commission as a Regulatory Engineer. From 1993 through 1995, I was employed by the Missouri Public Service Commission ("Commission") as a Senior Regulatory Engineer. In late 1995, I left the Commission and moved my family to Kansas City, where, while working with the Kansas City Power & Light Company, I completed the requirements for my Professional Engineering license. In January of 2001, I was employed by Aquila as a Senior Regulatory Analyst for Aquila's Regulatory Services Department.

Q. What is the purpose of your testimony?

A. I will present testimony explaining the methods used in preparing the COS studies of Aquila Networks – MPS's and Aquila Networks - L&P's ("MPS" and "L&P") electrical systems. I will describe the distribution studies which I performed on MPS and L&P service territories to determine secondary and primary distribution system percentages, and customer and demand category percentages.

Q. Are you sponsoring any schedules in this proceeding?

A. Yes, I am sponsoring Schedules DLS-1 through DLS-10.

Q. Please explain the purpose of these Schedules.

A. DLS-1 and DLS-2 show the results of my distribution and zero intercept studies for MPS and L&P. DLS-3 through DLS-10 show the results of the COS studies for MPS and L&P. These schedules show the Income Statement, classification and allocation of rate base and expense accounts, and the calculation of customer, demand, and energy charges that served as a starting point for Aquila's proposed rate schedules

Q. What recommendations are you making to the Commission?

A. I recommend that the Commission endorse Aquila's COS studies and approve the results for use in Aquila's proposed rate design.

CLASS COST OF SERVICE

Q. Were the COS studies for MPS and L&P performed by you?

A. Yes. I worked with Aquila Regulatory Manager Matt Tracy in preparing both studies.

Q. What is the purpose of a COS study?

A. A class COS study is performed to distribute a utility's total COS among its customers. Customers with similar service requirements and usage characteristics are grouped into classes, and costs are assigned or allocated, as appropriate, to those classes.

Q. When are costs assigned and when are they allocated?

A. Where a customer class is directly responsible for a cost, the cost is assigned to that class. If the costs are joint or common costs, they must be allocated to the classes based on some allocation factor. The fact that COS studies allocate costs to broad customer classes recognizes the impracticality of assigning costs separately down to individual customers. The goal is to reasonably evaluate the appropriate similar groups of customers for the costs incurred by a utility in providing service to them; it is not to make a precise assignment of costs. The resulting class cost determinations provides revenue targets in establishing customer class rate levels.

COST OF SERVICE INPUTS

Q. Please describe the process used to develop the inputs to the COS studies for MPS and L&P.

A. Aquila's Regulatory Services Department held multiple meetings and technical conferences with members of the Commission Staff ("Staff"), members of the Office of the Public Counsel ("OPC") and representatives of the Sedalia

Industrial Energy Users' Association ("SIEUA") and the Federal Executive Agencies ("FEA") wherein all of the major cost-of-service issues were discussed. From the discussions in those meetings, and from months of cooperation with the other parties, Aquila's Regulatory Services department developed the data that now serves as the input to the class COS studies I am sponsoring today.

Q. What is the source of the financial information you used in performing the class COS studies?

A. The cost and revenue information was taken from Accounting Schedules provided by the Staff. These Accounting schedules were derived from a previous Settlement Agreement approved by the Missouri Public Service Commission in Docket No. ER-2004-034.

<u>Customer Classes</u>

Q. What customer classes did you use in your class COS study?

A. My COS studies separate fourteen distinct rate classes in MPS's territory and nine distinct rate classes in L&P's territory. The MPS classes are: 1. RES-GEN, 2. RES-SH, 3. SGS-S, 4. SGS-P, 5. LGS-S, 6. LGS-P, 7. LGS-SF, 8. LPS-S, 9. LPS-P, 10. S&C, 11. MUNI-WPR, 12. MODINE, 13. LIGHTS, and 14. THERM. The classes used in the L&P class COS study are: 1. RES-GEN, 2. RES-H20, 3. RES-HEAT, 4. SGS, 5. LGS-S, 6. LGS-P, 7. LPS-S, 8. LPS-P, and 9. LIGHTS. In general, these rate classes follow Aquila's tariffs for Residential, Small General Service, Large General Service, Large Power Service, Lights, and Special Contracts. I have created certain sub-classes to distinguish residential space heating from general residential, secondary service from primary service, etc.

Q. How were these rate classes identified?

A. Aquila's load research group, managed by Matt Tracy, identified the classes based on customer load shapes. Mr. Tracy provided the class load information that included; 1) Monthly and Annual Energy, 2) Monthly Peak Demand, 3) Coincident Peak information, 4) Class non-coincident peak information, 5) the calculation of the A&E-3CP, Average Energy, Class NCP, and Customer NCP allocation factors.

Q. Were these the same allocation factors that you used in your COS studies?

A. Yes.

Q. Did you use allocation factors besides the demand and energy factors mention above?

A. Yes.

Q. What other allocation factors did you use?

A. I used weighted, customer allocation factors to distribute customer related costs to the classes. I also used revenue allocation factors as a technique to assign the adjusted class revenues, from Case No. ER-2004-034, to the classes. The adjusted revenues were separated by tariff rate, but I knew how the tariff rates were related to the COS classes, and was able to calculate the revenue allocation factors.

Q. How do the COS classes relate to Aquila's current tariff rates?

A. The relationship is shown in Table 1 below.

Table 1, Customer Classes

MPS		L&P	
COS Class	Tariff Rate	COS Class	Tariff Rate
RES-GEN; Residential Non-General.	MO860	REG-GEN; Residential Service – General.	MO910, MO911, MO915
RES-SH; Residential – Space Heating	MO870	RES-H20; Residential Service – Water Heating.	MO913, MO914
SGS-S; Small General Service – Secondary.	MO710, MO711	RES-HEAT; Residential Service – Space Heating.	MO920, MO921, MO922
SGS-P; Small General Service – Primary.	MO716, MO745	SGS; Small General Service.	MO930, MO931, MO932, MO933, MO940, MO941
LGS-S; Large General Service – Secondary.	MO720, MO721	LGS-S; Large General Service – Secondary.	MO940 subset
LGS-P; Large General Service: - Primary.	MO25 subset	LGS-P; Large General Service – Primary.	MO940 subset
LGS-SF; Large General Service – Mo. State Fair.	MO25 subset	LPS-S; Large Power Service – Secondary.	MO944 subset
LPS-S; Large Power Service – Secondary.	MO730, MO731	LPS-P; Large Power Service – Primary.	MO944 subset
LPS-P; Large Power Service – Primary.	MO735, MO737	LIGHTS; PAL, Street Lighting and Signals.	All Lighting Rates
S&C; Schools and Churches	MO740		
MUNI-WPR; Muni Water Pumping, Parks & Rec.	MO800, MO810, MO811		
MODINE	MO919		
LIGHTS; PAL, Street Lighting, and Signals.	All Lighting Rates		
THERM; Thermal Energy Storage.	MO650		

Q. Are these classes the only grouping of rates used in your COS model?

A. No. Besides combining similar tariff rates into the classes discussed above, I also combined rate classes into rate groups.

Q. What is a rate group?

A. A rate group is a technique used by Aquila's COS software to make the distribution of costs to rate classes easier.

Q. Please explain.

A. Combining rate classes into groups allows the COS software to allocate costs to every class in the group in one step; making the model easier to build, understand, and troubleshoot. In Aquila's COS study, every class of customers that is served at secondary voltage is included in a group called SEC_DIST. Various Federal Energy Regulatory Commission ("FERC") accounts which contain the plant, maintenance, and operational costs for the secondary distribution system, are associated with this group. Primary customers, who do not incur these secondary distribution costs and who are not part of the SEC_DIST group, will not be allocated any of these costs. Direct assignments of costs to classes are also accomplished by using a rate group.

These processes can be accomplished without the use of rate groups, but the technique is more complicated and prone to error.

Q. What rate groups did you use in the COS studies?

A. I used four groups in my COS studies. A group called ALL includes every class in the study. SEC_DIST includes only the secondary customers. PRIM_DIST is a super-set of classes; containing all the classes in SEC_DIST, but also the classes connected to the primary distribution system. Finally, a LIGHTS group was created to directly assign costs to the Lights class. The rate groups, and the customer classes in those groups, are shown in Table 2 below.

Table 2, MPS Group Membership

	Groups			
Customer Class	**ALL**	**PRIM_DIST**	**SEC_DIST**	**Directly Assigned**
RES-GEN	X	X	X	
RES-SH	X	X	X	
SGS-S	X	X	X	
SGS-P	X	X		
LGS-S	X	X	X	
LGS-P	X	X		
LGS-SH	X	X		
LPS-S	X	X	X	
LPS-P	X	X		
S&C	X	X	X	
MUNI-WPR	X	X	X	
MODINE	X	X	X	
LIGHTS	X	X		X

L&P Group Membership

	Groups			
Customer Class	**ALL**	**PRIM_DIST**	**SEC_DIST**	**Directly Assigned**
RES-GEN	X	X	X	
RES-H2O	X	X	X	
RES-HEAT	X	X	X	
SGS	X	X	X	
LGS-S	X	X	X	
LGS-P	X	X		
LPS-S	X	X	X	
LPS-P	X	X		
LIGHTS	X	X		X

<u>Line Losses</u>

Q. Did you modify the allocation factors prior to using them in your COS studies?

A. Yes. I increased each class' monthly energy and demand to account for line losses.

Q. What are line losses?

A. Line losses are the amount of energy lost during transmission and distribution of electricity, and are primarily due to electrical resistance in the conductors and to inefficiencies within transformers.

Q. Why do line losses affect the class energy and demand values?

A. When a certain amount of energy is needed at the customer's meter, the utility must generate enough energy to meet that need, plus the line losses. The further the energy travels from the generator, the greater the losses. Thus, secondary customers impose more losses on the system than primary customers because their energy must be carried over more wire and through more transformers. In order to model this in the COS studies, it was necessary to apply a larger loss factor to the secondary customers than the primary customers.

Q. Where did the line loss factors come from?

A. In 2002, Aquila's transmission and distribution engineers completed a loss study for each of Aquila's service territories. The study used peak and average demand values for the summer and winter of 2001 to derive peak and average loss factors. The final report listed the total peak and average losses for the transmission system, primary substations, primary taps and feeders, line transformers, and secondary lines and services.

Using the results of that study, I calculated the peak and average losses to apply to the primary and secondary classes. I applied the peak losses to the class demand, and average losses to the class energy.

Q. What effect did the addition of losses have on the allocation factors?

A. The addition of losses had no effect on the way the allocation factors were calculated, but they did affect the final allocation factor values. The weighted, demand and energy allocation factors for secondary customers increased slightly when compared to those same allocation factors for primary customers.

The Test Year

Q. What test year did you use for your COS study?

A. The historical time period that I used was the twelve month period ending on December 31, 2002, and updated for known and measurable adjustments to September 30, 2003.

Q. What class data was developed for the class COS study in this case?

A. The class data developed for this case were: 1) hourly demand (KW) data by class, 2) monthly and annual demand (KW) data by class, 3) monthly and annual energy (KWh) data by class, 4) monthly and annual revenue data by class, 5) customer number data by class, and 6) the primary and secondary cost percentages for FERC accounts 364 through 368, 7) and the zero intercept percentage for FERC accounts 364 through 368.

Explanation of the Method

Q. Please describe the method of creating a COS study.

A. A COS study involves a three-step process in which rate base investment, operation and maintenance expenses, depreciation expense, and income taxes are assigned or allocated to the customer classes. The first step involves the 'functionalization' of costs, the second requires the analyst to classify of the functionalized costs, and the last step entails the assignment or allocation of costs to the customer classes.

Functionalization

Functionalization is possible because the Uniform System of Accounts ("USOA") prescribed by the FERC separates costs according to their functional use. The functions used for *plant* accounts are: intangible, production, transmission, distribution, and general, while the functions used for operating and maintenance *expense* accounts are: production, transmission, distribution, customer accounts, customer service and information, sales, and administrative and general.

Classification

Classification of functionalized costs is performed for the purpose of allocating those costs among the customer classes. Costs are divided into three major classifications: commodity costs, demand costs, and customer costs. Commodity costs are a function of the volume of *energy* (KWh) delivered on the system. An example of commodity costs is the cost of fuel used to generate electricity by a power plant. It is intuitively obvious that more fuel will produce more energy. Thus, fuel costs are classified as commodity costs. Demand costs are a function of the load on, or *power* (KW) delivered to, the electric system. An excellent example of demand costs is found in FERC Account 356: Overhead Transmission Conductors and Devices. Like the example of the fuel costs, it is obvious that the transmission lines, which carry the enormous power from the generating stations to the cities and communities, must be designed and constructed to meet the maximum demand those cities and communities will place on them.

Customer costs are those which are a function of the number of customers on the system. An example of customer costs are those found in FERC Account 370: Distribution Meters. Since every customer on the system requires their own meter, there is a direct relationship between the number of customers and meter costs.

Q. Are there costs that do not fall into one of these three classifications?

A. Yes. It is quite common to encounter costs that do not fall neatly into a single category. For example, while the costs in Account 356; "Overhead Transmission Conductors and Devices" are incurred to meet the demand on the conductors, it is equally obvious that the costs to purchase the land or right-of-way for that transmission line (Account 350) are *not*. Neither are they incurred by the energy carried by that line in an hour or month or by the number of customers.

Q. How are the costs in Account 350 classified?

A. In the case of Account 350, history and tradition play a role in determining how the costs are classified. The National Association of Regulatory Utility Commissions published a manual titled, "Electric Utility Cost Allocation Manual", (" NARUC Manual") that defines the transmission system '... for ratemaking purposes as a group of highly integrated bulk power supply facilities consisting of high voltage power lines and substations.'[1]

The NARUC manual also indicates that the FERC "defines a transmission system to include: (1) all land, conversion structures, and equipment employed at a primary source of supply... (2) all land, structures, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point..."[2]

In light of these definitions by the FERC and NARUC (i.e., wherein land, structures, and conductors, etc. are combined), the costs in all of the transmission accounts have traditionally been classified as demand costs. I would be quick to add, however, that history and tradition are not the only justification for classifying every transmission plant account as demand

Q. What other justification is there?

A. Much of the cost of transmission system, while not directly related to the number of kilowatts flowing through the lines, can be shown to be indirectly related to that demand.

Q. Please explain.

A. Consider that the power (KW) flowing though a transmission line is equal to the amount of current flowing though the wires times the voltage. This relationship, in a somewhat simplified form, is shown as:

$$P = V \times I$$

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[1] The National Association of Utility Regulatory Commission's Electric Utility Cost Allocation Manual (Chapter 5, page 69).

Where P is the power,

V is the voltage,

And I is the current.

This equation shows that for a given power the equation can be balanced either by increasing the voltage and lowering the current, or by lowering the voltage and increasing the current. Over a century of experience has proven that increasing voltage and lowering current is the most cost effective and efficient way to balance the cost and performance of the transmission system

Yet, while higher voltages increase the efficiency of transmitting power over long distances, higher voltages also require greater distances between conductors and other structures such as towers, other conductors, trees, buildings, and the ground to prevent arcing.

Higher demand on utility transmission systems has led to higher voltages. Higher transmission voltages, in turn, have led to taller towers, larger insulators, wider cross-arms, wider right-of-ways, etc., and the net result has been an increase in cost for all these components.

Q. Is it true that these costs, in much the same way as you describe above, are indirectly related to the *energy* on the system. Couldn't they just as easily be classified as commodity costs?

A. In my opinion, no.

Q. Why not?

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[2] Ibid.

A. The difference between demand and energy needs to be understood. As I have said, power is equal to the voltage times the current. Energy is power delivered over time. Mathematically, energy equals power multiplied by time or ($E = P \times T$). While it can be shown that an increase in power has led to an increase in voltage and thereby and increase in cost; there is simply no analogous way to show that an increase in energy will also lead to an increase in cost. That is to say, moving a certain amount power over the line for three hours does not require taller towers, larger conductors, or more land than moving that same power for two hours. It is unreasonable to classify costs which are incurred to transmit power on the electric system as commodity costs.

Allocation

Q. What is done with the classified costs in the COS study?

A. Wherever possible, the commodity, demand, and customer costs are assigned directly to the class which incurred them. However, when a cost cannot be assigned, it is allocated among the classes using an appropriate allocation factor. Weighted allocation factors are generally used to recognize certain cost differentials among classes.

Q. What weighted allocation factors did you use in your COS study?

A. I used eleven different weighted allocation factors in each COS study. Because commodity costs are based on the volume of energy supplied, all commodity costs were distributed among the classes using *Average Energy* weighted allocators.

Demand costs were distributed using one of a number of demand allocators. Transmission demand costs were distributed to the classes using Average and Excess Demand allocators that made use of the systems' three coincident peaks ("*A&E-3CP*"). Primary distribution demand costs are allocated using the weighted, class, non-coincident peak ("*CLASS*"). Secondary distribution demand costs are allocated using the weighted, customer non-coincident peak ("*NCP*") allocators.

Customer costs were distributed to the classes using a weighted, customer allocation factor calculated as the number of customers multiplied by the average installed meter cost ("CUST").

The demand and customer allocation factors were also calculated for the primary and secondary groups; PRIM_DIST and SEC_DIST. These distinct primary and secondary demand and customer allocation factors were used in the COS studies where appropriate.

DISTRIBUTION STUDY AND THE ZERO INTERCEPT METHOD

The Distribution Study

Q. If you used one demand allocation factor for primary demand costs and different demand allocation for secondary costs, how were you able to separate the primary and secondary costs?

A. I have completed a thorough analysis of MPS and L&P distribution systems for the purpose of identifying and separating the primary and secondary distribution costs, and to determine the zero intercept value for certain accounts. The study included seventeen FERC accounts, but I quickly narrow my focus to the few FERC accounts that shared a primary and secondary distribution function. The result of the study was a set of primary and secondary percentages, and a set of customer and demand percentages for FERC accounts 364 through 368. I used the primary and secondary percentages to separate primary costs from secondary costs, and the customer and demand percentage to classify those separated costs.

Q. Which FERC accounts did you analyze as part of your distribution study?

A. Table 3 lists the seventeen FERC accounts that were included in the distribution study.

TABLE 3. Cost Allocation Study Accounts

Account	Description
360001	Elect. Dist. - Land
360002	Electric Distribution: - Land Rights/ROW
361000	Electric Distribution: Substation Structures & Improvements
362000	Electric Distribution: Substation Equip.
364000	Electric Distribution: - Pole/Tower/Fixture
365000	Electric Distribution: - Overhead Conductors
366000	Electric Distribution: - Underground Conduit
367000	Electric Distribution: - Underground Conductors
368001	Electric Distribution: Line Transformer - Other Equip.
368002	Electric Distribution: Line Transformer - Conventional
368003	Electric Distribution: Line Transformer - Pad mount
369001	Electric Distribution: - Overhead Services
369002	Electric Distribution: - Underground Services
370001	Electric Distribution: - Meters Other
370002	Electric Distribution: - Meters PURPA
371000	Electric Distribution: - Installation Cust Premise
373000	Electric Distribution: - Street Lighting

Q. Is a complete distribution study necessary to classify the costs shown in the Table 3?

A. Not in every case. As I have already stated, certain FERC account costs can be easily classified as commodity, demand, or customer because it is intuitively obvious that the costs are a function of energy, demand, or the number of customers. Therefore, account 371, which contains the cost of installing service to the customer's premises, would be classified as "customer" and would be recovered through a "customer" charge. Similarly, account 362, which contains the cost ofsubstation equipment on the primary distribution system, are not impacted by the number of customers served but by the demand (KW) placed on the equipment by those customers. These costs are appropriately classified as demand.

Q. How are costs classified if a distribution study is not available?

A. In situations where the necessary data is unavailable or when time will not allow a full distribution study, the analyst may simply classify the costs in FERC accounts 360, 361, 362, 364, 365, 366, and 367 as demand, and the costs in FERC accounts 368, 369, 370 as customer.

Q. With regard to all the accounts 360 through 371, did you classify the costs in these accounts this way?

A. No.

Q. If it is not necessary to analyze the distribution system at all: if you can simply group large numbers of accounts and classify them in bulk, why make the effort to perform such a detailed study?

A. Aquila has invested hundreds of millions of dollars to construct and maintain distribution plant in the Missouri service territories. These costs are accounted for in FERC accounts 360 through 372 and are, after the rate-setting process, recovered in Aquila's approved rates. Aquila, like other utilities, is aware of the importance of thoroughly understanding these costs since our revenues are so closely tied to them.

Q. As you performed the distribution study, did you encounter anything unexpected or surprising?

A. Yes.

Q. Please explain.

A. In the process of analyzing these distribution systems, I began to realize the need to rethink my preconceived ideas about their design and construction. Many primary and secondary distribution components (Accounts 364 through 368), which I had previously assumed to be designed to meet the demand of the customer, were actually designed to meet National Electrical Safety Code ("NESC") requirements. I learned that the NESC sets the minimum requirements of these components many times above the typical customer's demand. I knew that the costs of electrical system components were higher for those capable of withstanding higher demand, and I had expected this to be true throughout my study. But I found was a leveling off of costs as I moved closer to the point of delivery to the customer. It seemed that there is a disconnect between the electrical demand which is placed on the system, and the cost of the system.

Q. Please give an example of this 'disconnect'.

A. Consider the point on a distribution system where the last length of power line comes to the customer's premises. This segment of cable is referred to as the "service drop" and is accounted for in FERC Account 369. According to the NESC, the minimum size of cable that can be used is a #4 AWG line. The NESC sets this minimum size standard based, not on the capacity, or demand handling capability, of the line, but on safety issues associated with the line; how much ice or wind load the line can handle without breaking.

To better see the disconnect I'm describing, consider that the electric industry commonly uses ACSR (Aluminum Conductor with Steel Reinforcing) cable and that the capacity of a #4 ACSR line is about 140 amps. For residential customers this line will operate at about 120 volts. Aquila's distribution engineers estimate that the typical residential customer will draw about 20 to 30 amps at this same 120 volts. Thus, the typical residential demand is between one-seventh and one-fifth of the capacity of the smallest conductor we are allowed by the NESC to install.

Clearly, the demand on these lines is not the deciding factor when designing them. The NESC requirements are more than adequate to meet the load, and much of the cost for these lines is incurred to meet those requirements rather than the demand.

Q. How should the cost for services be recovered in rates?

A. The costs for Account 369 are generally classified as customer and are recovered in the monthly customer charge.

Q. Please give a specific example of costs that are more appropriately classified as both demand and customer?

A. It is appropriately to split the cost of Account 365, Secondary Overhead Conductors, into demand and customer percentages. To illustrate this, I can build off of what I have just explained about Account 369, because the secondary overhead conductors are that portion of the distribution system connecting the service drops to the transformers.

Just like the service conductors, the secondary conductors are required by the NESC to be no less than a #4 AWG and operate at the same voltage. The sole difference between the secondary conductor and the service drop is that two or more customers *may* be connected to the secondary system, whereas every customer gets their own service drop.

Therefore, the secondary overhead conductors do not have the one-to-one correspondence to the customer that the services have, yet must be sized with capacity far above the expected demand to meet the safety requirements of the NESC. The costs of Account 365 are not a function of customer *or* demand, but of customer *and* demand. It is reasonable, therefore, to classify a percentage of these costs as customer, and the remainder of them as demand.

Q. How should the cost of secondary overhead conductors be recovered in rates?

A. The portion of the costs which are classified as customer should be recovered in the monthly customer charge. The remainder should be recovered in the demand charge. Where the customer is not charged a demand charge, the demand portion is generally included in the energy charge.

Q. Are there other distribution costs that should be classified as both customer and demand?

A. Yes. Between the service drops (Account 369) and the primary substation (Account 362) Aquila has installed millions of dollars in equipment that are appropriately classified as both customer and demand.

Q. How are you proposing the distribution account costs be recovered?

A. The costs in FERC accounts 360 through 362 should be considered demand related and recovered through a demand charge. Likewise, the costs in Accounts 369 through 372 should be classified as customer related and recovered through a customer charge. Finally, the zero intercept method should be used to determine the customer and demand percentages for the costs in FERC accounts 364 through 368 with the customer portion recovered in the customer charge, and the demand portion recovered in the demand or energy charge.

<u>The Zero Intercept Method</u>

Q. What is the Zero Intercept method?

A. The zero intercept method refers to a technique or process used to estimate the percentage of the system that is "non-demand" related.

Q. Are there techniques, other than the zero intercept method, that will estimate this same percentage?

A. Yes.

Q. Why did you use the zero intercept method in your COS study?

A. I believe the zero intercept method creates a more realistic and accurate COS model and does so by using the most accurate data available. Like many of my colleagues, I aim constantly at improving the COS models I have developed for my company. The zero intercept method is a recognized technique that accurately simulates the real world, and leads to a better COS study. That the zero intercept method is valid and useful is seen in the fact that the NARUC manual devotes considerable attention to it.

Q. How does the zero intercept method more realistically reflect the costs of actual distribution systems?

A. The zero intercept study that I performed used distribution component data from Aquila's PowerPlant™ Database. This database contains up-do-date property records for every pole, conductor, transformer, insulator, etc. installed in each of Aquila's electric divisions. Using this source of data for the study ensured the analysis would contain accurate, reliable data that describes the actual equipment in the field.

Also, the process of calculating the zero intercept required me to interact with Aquila's field engineers and linemen, study the latest construction standards, interview our supply purchasing personnel, and contact equipment vendors. All of this fieldwork was crucial because it allowed me to identify and track the costs from the point of the design and installation of the equipment, to the entry of the job ticket information into the PowerPlant™ Database

Q. Please explain the process of calculating the zero intercept.

A. In order to calculate the zero intercept cost, I queried millions of records from the PowerPlant™ Database and developed a specialized database which contained current property data. From that data, I determined the cost-per-foot or cost-per-item necessary to install each major distribution component. By the end of the study, I had calculated the "per item" cost for poles of every height and type that Aquila purchases, transformers of every size listed in the current property records, conductors of various diameter and composition, steel and plastic conduit, and installation estimates for trenching and burying underground conductor and conduit, setting poles, stringing wire, and setting transformers.

Q. What did you do with the per-foot and per-item costs?

A. I charted the per-foot or per-item costs of each component on an Excel graph from which I was able to calculate the zero intercept point.

Q Please explain what you mean.

A. Consider the process of calculating the zero intercept point for a component such as conductor. In this example, the actual current property records, for every foot of conductor in the territory, were downloaded into a special database. Then the conductors are separated from all the other components in the database, and further separated by conductor type, diameter, and whether the conductor was insulated or not. The resulting information is then input to an Excel spreadsheet where installation costs are added and the installed price-per-foot of each size and type of conductor is determined and graphed. For instance, the price per foot for #6 AWG wire might be plotted as point W_1, #4

AWG might be point W_2, #2 AWG is W_3 and so on. This same process was followed for every major component in accounts 364 through 368. On the graph, these data points increase in value (farther from the horizontal axis) as I moved from the origin of the axes toward the right. This means that if I drew a rough line through the data points toward the y-axis, the line would drop toward the origin of the graph. This is precisely the next step in determining the zero intercept. Using linear, exponential, or polynomial regression techniques, a 'best fit' line is extrapolated through the data points and back to the y-axis (the vertical axis) of the graph. The point at which the extrapolated line crosses the y-axis is the y-intercept or the zero intercept value.

Q. If you inflated the per-foot or per-item cost prior to charting the costs, would you get an inflated zero intercepts?

A. It is possible that you would.

Q. What precautions did you take to insure the zero intercept value could not be arbitrarily increased or inflated?

A. In the final step of the process, I expressed the zero intercept value as a percentage of replacement cost.

Q. Please explain.

A. The y-intercept value has the same units (e.g., dollars per foot) as the other data points on the chart. This means that if the data points W_1, W_2, and W_3 are inflated because I used replacement costs rather than embedded costs, the intercept value will also be inflated to the same degree. Similarly, if I inflated W_1, W_2, and W_3 by a factor of ten, again the zero intercept value would also be inflated by the same factor. In other words, the input (replacement cost) and the output (zero intercept value) are at the same "scale".

Here is the critical step that must be understood. The zero intercept cost (zero intercept value) multiplied by the quantity (feet of conductor, for example) is then divided by the total cost (replacement value multiplied by the quantity). The result is a zero intercept *percentage* between 0% and 100%. Due to this last step, inflating or deflating the costs has no net effect on the results. I used the resultant zero intercept percentage to classify the customer and demand portion of Accounts 364 through 368.

Q. You have said that you used the Zero Intercept Method as described in the NARUC manual did you follow the procedures in the manual precisely?

A. No.

Q. Why not?

A. The NARUC manual serves as an excellent tool in that it gives a detailed description of a zero intercept study. However, the NARUC manual was developed using data, or assumptions about that data, that was quite different from what I had available. The NARUC manual states that while calculating the zero intercept for account 365: Distribution, Overhead Conductors and Devices, the zero intercept cost should be multiplied by the total number of circuit feet times two. A note explains that the 'circuit feet', not the 'conductor feet' were used to get their customer component. Apparently, the authors of the NARUC manual were working with data wherein the conductor costs were given in dollars-per-*circuit*-foot. The authors needed to convert this value into the equivalent 'conductor feet', and they did so by multiplying the circuit feet by two. This is a reasonable assumption since every circuit must have at least two conductors to operate: the phase conductor and the ground conductor. The Account 365 data within PowerPlant™, however, was already given in dollars-per-foot of conductor. No conversion was necessary. I deviated from the NARUC manual with respect to other accounts as well, but generally for similar reasons.

DISTRIBUTION AND ZERO INTERCEPT STUDY RESULTS

Q. Please describe the results of your distribution and zero intercept studies.

A. These studies are summarized in two tables on the Distribution Study Reports, attached as Schedules DLS-1 and DLS-2. These tables show the total account costs with the primary and secondary percentages, in total dollars as well as in percentages of total account cost. The also show the customer and demand classifications as percentages of total account cost.

Q. Why did you allocate a portion of Account 368 (Line Transformers) to the primary distribution system?

A. According to FERC's Code of Federal Regulations, Account 368 is used to track the costs of capacitors used for voltage regulation. These devices are used to benefit the entire distribution system and not just the secondary, and should be allocated to the primary system.

Q. What impact did your zero intercept study have on the COS study?

A. The results of the zero intercept study were used to assign the costs in accounts 364 through 368 to the appropriate cost classifications. Once appropriately classified, these costs were distributed to the classes using the proper allocation factors. Therefore, when the results were used in the COS studies, the costs classified as customer were distributed using the weighted, customer allocation factors, and those classified as demand were distributed using weighted, demand allocation factors.

COS STUDY RESULTS

Q. Please describe the results of your class COS study.

A. The class COS results for MPS is summarized in the tables of Schedules DLS-3, DLS-4, DLS-5, and DLS-6, and for L&P in the tables of Schedules DLS-7, DLS-8, DLS-9, and DLS-10. Because the schedules for MPS are so similar to the schedules for L&P, I will explain the content of 'pairs' of schedules.

Schedules DLS-3 and DLS-7 are the Income Statement reports for MPS and L&P respectively. These schedules show the assignment and allocation of operating revenues, operating expenses, Net Operating Income. The schedules also show a calculation ofthe shift in revenue into or out of the classes to bring all classes to the return approved by the Commission in Docket No. ER-04-034.

Schedules DLS-4 and DLS-8 are Rate Base by Category reports for MPS and L&P respectively. These schedules show byclass, the classified cost (i.e., energy, demand, or customer) for each *rate base plant* account.

Schedules DLS-5 and DLS-9 are the O&M Expenses by Category reports for MPS and L&P respectively. These schedules show byclass, the classified cost (i.e., energy, demand, or customer) for each *expense* account. This report shows in great detail the classifed, operating expenses by function (i.e., intangible, production, transmission, distribution, etc.). These classified expenses, totaled by function, match exactly the expenses shown in the income statement reports (DLS-3 and DLS-7).

Schedules DLS-6 and DLS-10 are the Customer, Demand, and Energy Charge reports for MPS and L&P respectively. These schedules show the steps taken to calculate the customer, demand and energy charges; used as starting points for Aquila's rate design efforts.

BILLING UNITS

Q. How do the results of your COS help Aquila determine rates?

A. The results of the COS studies serve as a foundation upon which the rate designers can build.

Q. Were you also involved in the rate design efforts beyond providing the COS studies?

A. Yes. I provided test year billing units for the proposed rate structure to Aquila witness Charles Gray.

Q. Please explain.

A. Aquila developed customer impact software which can analyze historical billing data, from Aquila's Customer Information System ("CIS"), and reproduce a sample bill. Essentially, this software answers the question, "what would the customer have paid with a different rate structure, with different rate prices, or with both?"

The software can generate a report showing the original bill with the individual customer, energy, and demand charges. It is also able to identify and report such items as seasonal energy blocks, seasonal demand blocks, separate customer charges, facility charges, etc. Collectively, these are called the billing units.

After Aquila's Regulatory Service department had determined the new rate structures that are being proposed in this case, I used the customer impact software to determine the billing units (i.e., kilowatt hours in each energy block, summer demand, winter demand, etc.), under that proposed structure.

Q. Were these the billing units you provided to Mr. Gray?

A. No. Recall that these billing units are based on the underlying CIS data. These units represent the actual billing units from the test year, but restructured to match our proposed rate. Also recall that the COS studies serve as a foundation upon which the new rates are constructed. Therefore, what we still needed were billing units which reflected the adjustments and normalizations that were made to the COS study inputs.

Q. What adjustments and normalizations were made to the COS study inputs?

A. The COS studies used KWh sales (energy) data that had been weather normalized, annualized for 365 days, adjusted to account for rate switchers, adjusted for customer growth, and annualized for large customer load changes. All of these adjustments and normalizations are explained in detail in Staff's testimony in Case No. ER-2004-0034.

Q. Did you modify the billing units that the customer impact software produced?

A. Yes. The Regulatory Services department worked closely with Staff to develop the billing units. Staff witness Janice Pyatte provided Aquila with a set of adjustment factors to apply to the billing units produced by the customer impact software.

Q. How did you apply those adjustment factors?

A. Aquila modified the software slightly so that it would apply the adjustment factor to every customer in the database. Since the adjustment factors provided by Staff witness Pyatte were distinguished by rate and by month, the software was modified to identify the rate id for every customer and apply the adjustment factor for the appropriate month to the billing units.

We worked with Staff to determine a final correction to account for the customer adjustment, and to force the revenue generated by the billing units to equal the revenue from Staff's final position in the revenue requirements case. Those adjusted billing units were used by Aquila witness Gray.

Q. What recommendations are you making to the Commission?

A. I am recommending that the Commission endorse Aquila's COS studies and approve the results to be used in designing Aquila's proposed rates.

Q. Does this conclude your direct testimony?

A. Yes.

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

County of Jackson)
) ss
State of Missouri)

AFFIDAVIT OF DAVID L. STOWE

David L. Stowe, being first duly sworn, deposes and says that he is the witness who sponsors the accompanying testimony entitled "Direct Testimony of David L. Stowe;" that said testimony was prepared by him and under his direction and supervision; that if inquiries were made as to the facts in said testimony and schedules, he would respond as therein set forth; and that the aforesaid testimony and schedules are true and correct to the best of his knowledge, information, and belief.

David L. Stowe

David L. Stowe

Subscribed and sworn to before me this 16TH day of SEPTEMBER, 2005.

Marvin L. Friedrich

Notary Public
MARVIN L. FRIEDRICH

My Commission expires:

March 10, 2007