BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF KIT CARSON ELECTRIC COOPERATIVE, INC.'S ADVICE NOTICE NO. 57,	)	
KIT CARSON ELECTRIC COOPERATIVE, INC.,	)	**Case No. 10-00379-UT**
APPLICANT.	)	

PREPARED DIRECT TESTIMONY AND EXHIBITS
OF
DR. MARTIN J. BLAKE

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Martin J. Blake. My business address is 6001 Claymont Village Drive, Suite 8, Crestwood, Kentucky 40014.

Q: BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A: I am a Member and Principal of The Prime Group, LLC. The Prime Group provides consulting services in the areas of strategic planning, cost of service, rate and regulatory support, and training for energy industry clients.

Professional Qualifications & Experience

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A: I received my Ph.D. in Agricultural Economics in 1976 from the University of Missouri, Columbia. My doctoral work centered on the areas of marketing and econometrics. I also hold a Master of Arts in Economics from the University of Missouri, Columbia, which I received in 1972. In addition, I received a Bachelor of Arts degree in Economics from Illinois Benedictine College in 1970.

Q: IN WHAT AREAS DOES YOUR PRACTICE CONCENTRATE?

A: As a member of The Prime Group, I have provided utility clients with assistance regarding rate design for both wholesale and retail rates; the development of rates to achieve strategic objectives; the unbundling of rates and the development of menus of rate alternatives for use by customers; performance-based rate and incentive rate development; state and federal regulatory filing development, testimony and support; cost of service development and support; and strategic planning. I have also been involved in the development of the Midwest ISO and represent Southern Illinois Power Cooperative and Hoosier Energy on the

Midwest ISO Transmission Owners Committee, the Transmission Owners Tariff Working Group, the Finance Subcommittee and the Demand Response Working Group. I served a three year term as Chairman of the Transmission Owners Tariff Working Group. I have made presentations to train utility personnel in cost of service, rate making, utility finance, and utility marketing. I have provided marketing and marketing support services for utility clients and have assisted them in assessing their marketing capabilities and processes.

Q: PLEASE BRIEFLY SUMMARIZE YOUR AREAS OF PROFESSIONAL EXPERIENCE PRIOR TO JOINING THE PRIME GROUP.

A: I have professional experience as an economist and professor of economics, as a utility regulator, as a utility manager and executive and as a consultant.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS AN ECONOMIST.

A: From January 1977 to December 1986, I was employed first as an Assistant Professor, then as an Associate Professor, and finally as a Professor of Agricultural Economics at New Mexico State University in Las Cruces, New Mexico ("NMSU"). I was the head of the undergraduate program and taught agricultural economics and econometrics. While at NMSU, I also worked as a consultant for various clients, providing price forecasting, load forecasting, and marketing services. From 1992 through 1994, I taught mathematical economics and econometrics as an Adjunct Professor in the Economics Department at the University of Louisville. Prior to my joining the faculty at NMSU, I served in the U. S. Army as an instructor of economics, statistics, and accounting at the U. S.

Army Institute of Administration at Fort Benjamin Harrison, Indianapolis, Indiana.

I also have a variety of experience with the application of economics to utility public policy issues. In addition to my experience as a utility regulator and executive, which I describe below, I taught retail and wholesale pricing for electric utilities at the NARUC Annual Regulatory Studies Program at Michigan State University for thirteen years. From May 1983 to August 1983, while on a sabbatical leave from NMSU, I served as a Policy Analyst for the Assistant Secretary for Land and Water at the U. S. Department of Interior.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY REGULATOR.

A: From January 1987 to November 1990, I served as a Commissioner and as the Chairman of the New Mexico Public Service Commission. As a Commissioner, my duties included making policy and adjudicatory decisions regarding rates, terms of service, financing, certificates of public convenience and necessity, and complaints for electric, natural gas, water, and sewer utilities. As Chairman, I supervised a staff of 32 professionals and 16 support staff. During my tenure on the New Mexico Commission, I also served as Chairman of the Western Conference of Public Service Commissioners Electric Committee and as Chairman of the Committee on Regional Electric Power Cooperation, a group composed of state public service commissioners and representatives from the state energy offices of the 13 western states.

As a Commissioner, I interpreted legislation, reviewed prior Commission cases to determine the precedents that they provided, drafted rules and regulations, wrote orders, and served as an arbitrator in alternative dispute resolution proceedings. I performed adjudicatory and regulatory functions for the four years that I served on the Commission.

Q: PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AS A UTILITY MANAGER.

A: From December, 1990 to June 1996, I was employed by Louisville Gas and Electric Company ("LG&E"). Initially, I served as LG&E's Director of Regulatory Planning. In this position, I was responsible for coordinating all of LG&E's state and federal regulatory efforts, and prepared and presented testimony to regulators.

My areas of responsibility were expanded in April 1994 to include marketing and strategic planning. As the Director, Marketing, Planning and Regulatory Affairs, I was responsible for coordinating LG&E's retail gas and electric marketing, strategic planning, and state and federal regulatory efforts. I continued to be employed in that capacity at LG&E until June 1996, when I joined the Prime Group as one of its Principals.

Q: PLEASE DESCRIBE THE INDUSTRY GROUPS IN WHICH YOU HAVE PARTICIPATED.

A: I have served on several regional transmission coordination groups such as the Interregional Transmission Coordination Forum, and the General Agreement on Parallel Paths, as well as the following committees of the Edison Electric Institute

("EEI") -- Economics and Public Policy Executive Advisory Committee, Strategic Planning Executive Advisory Committee, Transmission Task Force, and Power Supply Policy Technical Task Force.

Q: HAVE YOU TAUGHT ANY COURSES OR SEMINARS IN THE UTILITY AREA?

A: Yes. I have taught the following courses at the NARUC Annual Regulatory Studies Program at Michigan State University: 1) retail ratemaking, 2) wholesale pricing, 3) rate of return regulation, 4) competitive market fundamentals, 5) electric industry overview, 6) the economics of power production and delivery, 7) electric system technologies, and 8) the institutions and organizations of the new electric utility industry. Each year, I also teach and conduct numerous workshops and programs and deliver invited presentations to utility managers and regulators on a variety of subjects.

Q. IN WHAT CASES HAVE YOU PREVIOUSLY TESTIFIED?

A. I have testified in numerous proceedings before the Federal Energy Regulatory Commission and various state regulatory bodies. KCEC Exhibit No. __ (MJB-1) is a summary of the testimony that I have presented in other regulatory proceedings.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to sponsor the fully allocated class cost of service study based on Kit Carson's embedded cost of providing electric service for the 12 months ended December 31, 2009, to explain the rate design for the proposed

rates and to respond to complaints and protests raised by Kit Carson's members that were filed with the Commission.

Q. **PLEASE SUMMARIZE YOUR TESTIMONY.**

A. In developing its proposed rates in this proceeding, Kit Carson relied heavily on the results of the cost of service study. The Cooperative's fully allocated, embedded cost of service study was prepared using industry standard cost of service methodologies similar to those used by other regulated utilities in the United States. The purpose of this study is to determine the contribution that each customer class is making toward Kit Carson's overall rate of return. Rates of return on rate base are calculated for each rate class. Based on the results of the cost of service study, Kit Carson is proposing to allocate its overall rate increase to rate classes so that the increase is both equitable and mitigates in part the rate subsidies that exist with the current rate structure. I also describe the rate design that was utilized in this proceeding. The individual rate components are designed to more closely track the cost of service results than does the current rate design. The proposed Customer Charge is designed to more accurately reflect the fixed costs of providing electric service to each rate class.

Cost of Service Study

Q. DID YOU PREPARE A COST OF SERVICE STUDY FOR KIT CARSON'S ELECTRIC OPERATIONS BASED ON THE FINANCIAL AND OPERATING RESULTS FOR THE 12 MONTHS ENDED DECEMBER 31, 2009?

A. Yes. I supervised the preparation of a fully allocated, embedded cost of service study for Kit Carson's electric operations. The objective in performing the cost of service study is to fairly allocate Kit Carson's costs to the various customer classes based on actual usage patterns and to determine the contribution to Kit Carson's margins from each customer class, which provides an indication as to whether Kit Carson's electric service rates reflect the cost of providing service to each customer class. The allocation methodology used in the cost of service study ensures that a customer class is allocated costs only if the class actually uses the resources used to provide electric service as indicated by the relevant cost driver. Thus, customers only have to pay for what they actually use and are not allocated costs if they do not use the resources used to provide electric service. I have included a copy of the Executive Summary from the cost of service study as KCEC Exhibit No. __ (MJB-2), attached to my testimony.

Q. ARE ANY DATA FROM KIT CARSON'S UNREGULATED OPERATIONS OR AFFILIATE OPERATIONS INCLUDED IN THE COST OF SERVICE RESULTS?

A. No. The data used in preparing the cost of service study reflect only data from Kit Carson's electric operations and do not include data from Kit Carson's unregulated operations or affiliate operations. This was accomplished by utilizing only those accounts associated with providing electric utility service pursuant to the FERC Uniform System of Accounts and checking to ensure that the data included in these accounts did not relate to any of Kit Carson's diversified businesses. This was done to ensure that the rates developed from the cost of

service study do not subsidize unregulated activities, such as broadband internet or the propane business.

Q. DID THE PRIME GROUP DEVELOP THE MODEL USED TO PERFORM THE COST OF SERVICE STUDY?

A. Yes. The Prime Group developed the spreadsheet model used to perform the cost of service study submitted in this proceeding. The cost of service study results are attached as KCEC Exhibit Nos. __ (MJB-3) and __ (MJB-4) to my Direct Testimony.

Q. WHAT PROCEDURE WAS USED IN PERFORMING THE COST OF SERVICE STUDY?

A. The three traditional steps of an embedded cost of service study are functional assignment, classification, and allocation. The cost of service study was prepared using the following procedure: (1) costs were functionally assigned (functionalized) to the major functional groups; (2) costs were then classified by relevant cost driver as commodity-related, demand-related, or customer-related; and (3) costs were allocated to the rate classes based on each customer classes' pro rata share of the relevant cost driver. This three step process is depicted in the following diagram (Figure 1).

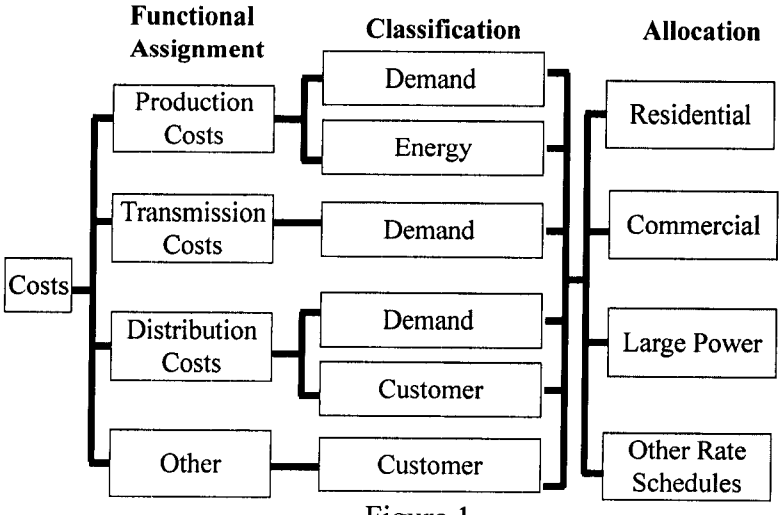

Figure 1

The following functional groups were identified in the cost of service study: (1) Production Plant, (2) Purchased Power, (3) Transmission, (4) Distribution Substation (4) Primary and Secondary Distribution Lines, (5) Customer Services, (6) Distribution Meters, (7) Distribution Street and Customer Lighting, (8) Meter Reading, Billing and Customer Service and (9) Load Management.

Q. HOW WERE COSTS CLASSIFIED AS ENERGY RELATED, DEMAND RELATED OR CUSTOMER RELATED?

A. Classification provides a method of arranging costs so that the service characteristics that give rise to the costs can serve as a basis for allocation. Costs classified as *energy related* tend to vary with the amount of kilowatt-hours consumed. Costs classified as *demand related* tend to vary with the capacity needs of customers, such as the amount of transmission or distribution equipment necessary to meet a customer's needs. Transmission lines and distribution substations are examples of costs typically classified as demand costs. Costs

classified as *customer related* include costs incurred to serve customers regardless of the quantity of electric energy purchased or the peak requirements of the customers and include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in my testimony, costs related to Distribution Lines and Distribution Line Transformers were classified as demand-related and customer-related using the zero-intercept methodology. Distribution Services, Distribution Meters, Distribution Street and Customer Lighting, Meter Reading, Billing and Customer Service and Load Management were classified as customer-related.

Q. PLEASE EXPLAIN WHY THE FIXED COST OF THE COOPERATIVE'S DISTRIBUTION SYSTEM IS CLASSIFIED INTO A CUSTOMER-RELATED COMPONENT AND A DEMAND-RELATED COMPONENT.

A. In order to be as fair as possible to all customers, the fixed costs of the Cooperative's distribution system are classified into two components: 1) customer-related costs and 2) demand-related costs. The portion classified as customer-related cost is the portion of the fixed costs of the distribution system that is size invariant and represents the minimum amount of equipment that is necessary for any customer to access the electric grid.

Costs that do not vary with the load carrying capability of the distribution facilities are fixed costs that exist irrespective of what size of facility is installed. These costs are present due to the fact that a customer is being served and will not increase or decrease with the load requirements of that customer. Using conductor as an example, there is a level of fixed production cost associated with every

conductor size. That fixed cost is best allocated on the basis of customer months because it is caused by the existence of a customer, not by the existence of demand. These costs that do not vary with the size of the equipment are properly classified as customer costs and allocated based on the number of customers in a class. This size invariant or non-volumetric portion of the costs is usually determined using the zero intercept approach, which is discussed later in my testimony.

Costs that vary with the load carrying capability of the distribution facilities are volumetric fixed costs that are allocated based on customer usage. The split between customer-related and demand-related distribution costs is made so that customers only have to pay for what they are actually using. All customers need at least the minimum amount of equipment necessary to access the electric grid and pay for this through the customer charge. However, many customers cannot get by with just the minimum system and they pay for the size related portion of the cooperative's distribution system through the distribution charge that is assessed on customer usage. This split of the cooperative's distribution system costs into demand-related and customer-related components ensures that customers only have to pay for what they are actually using, which is a concept that I believe most customers will regard as fair.

Q. HAVE YOU PREPARED EXHIBITS SHOWING THE RESULTS OF THE FUNCTIONAL ASSIGNMENT AND CLASSIFICATION STEPS OF THE COST OF SERVICE STUDY?

A. Yes. KCEC Exhibit No. __ (MJB-3) shows the results of the functional assignment and classification steps of the cost of service study. As discussed later in my testimony, once costs are functionally assigned and classified, they are then allocated to the rate classes based on each class' pro rata share of the relevant cost driver. KCEC Exhibit No. __ (MJB-4) shows the results of the allocation step in the cost service study.

Q. WHAT METHODOLOGIES ARE COMMONLY USED TO CLASSIFY DISTRIBUTION PLANT?

A. Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero-intercept" methodology. In the minimum system approach, "minimum" standard poles, conductor, and line transformers are selected and the cost of the minimum system is obtained by pricing all of the applicable distribution facilities at the unit cost of the minimum size plant. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. The theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero-intercept" methodology was used to determine the customer-related components of overhead conductor, underground conductor, and line transformers. Because the zero-intercept methodology is less subjective than the minimum system approach, the zero-intercept methodology is strongly preferred over the minimum system methodology when the necessary data are available. With the zero-intercept methodology, one is not forced to choose a minimum size conductor or line transformer to determine the customer component. In the zero-intercept methodology, a zero-size conductor or line transformer is the absolute minimum system.

Q. WHAT IS THE THEORY BEHIND THE ZERO-INTERCEPT METHODOLOGY?

A. The theory behind the zero-intercept methodology is that there is a linear relationship between the unit cost ($/ft or $/transformer) of conductor or line transformers and the load flow capability of the plant, which is proportionate to the cross-sectional area of the conductor or the kVA rating of the transformer. After establishing a linear relation, which is given by the equation:

$$y = a + bx$$

where:

y is the unit cost of the conductor or transformer,

x is the size of the conductor (MCM) or transformer (kVA), and

a, **b** are the coefficients representing the intercept and slope, respectively

it can be determined that, theoretically, the unit cost of a foot of conductor or transformer with zero size (or conductor or transformer with zero load carrying capability) is **a**, the zero-intercept. The zero-intercept is essentially the cost component of conductor or transformers that is invariant to the size and load carrying capability of the plant.

Like most electric utilities, the feet of conductor and number of transformers on Kit Carson's system are not uniformly distributed over all sizes of wire and transformer. For this reason, it was necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the determination of the zero intercept. Without performing a weighted regression analysis, all types of conductor and transformers would have the same impact on the analyses, even though the quantity of conductor and transformers are not the same for each size and type.

Using a weighted regression analysis, the cost and size of each type of conductor or transformer is weighted by the number of feet of installed conductor or the number of transformers. In a weighted regression analysis, the following weighted sum of squared differences is minimized, where **w** is the weighting factor for each size of conductor or transformer, and **y** is the observed value and $\hat{\mathbf{y}}$ is the predicted value of the dependent variable:

$$\sum_i w_i (y_i - \hat{y}_i)^2$$

Q. IS THE ZERO-INTERCEPT METHODOLOGY A STANDARD APPROACH GENERALLY ACCEPTED WITHIN THE ELECTRIC UTILITY INDUSTRY?

A. Yes. The Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC"), January, 1992, identifies the zero-intercept (or "minimum intercept") as one of two standard methodologies for classifying distribution fixed costs. NARUC's Electric Utility Cost Allocation Manual states that the zero-intercept method "requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small." (Id. at p. 92) The Electric Utility Cost Allocation Manual provides the following instructions for overhead conductor, underground conductor and transformers:

> **Account 365 – Overhead Conductors and Devices**
>
> Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
>
> **Account 366 and 367 – Underground Conduit, and Underground Conductors and Devices**
>
> Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

Account 368 – Line Transformers

Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

(Id. at pp. 92-94.)

A recent text book on electric ratemaking written by Lawrence J. Vogt, P.E. titled Electric Pricing: Engineering Principles and Methodologies (CRC Press, Taylor & Francis Group, 2009) also identifies the zero-intercept methodology as a standard approach for classifying distribution fixed costs as customer-related or demand-related. Mr. Vogt states that "The minimum intercept or zero-intercept methodology provides a rational basis for separating the cost of a device between its customer and demand components." (Id. at p. 500.)

Q. HAVE YOU PREPARED EXHIBITS SHOWING THE RESULTS OF THE ZERO-INTERCEPT ANALYSIS?

A. Yes. The zero-intercept analysis for overhead conductor, underground conductor, and line transformers are included in KCEC Exhibit Nos. __ (MJB-5), __ (MJB-6) and __ (MJB-7).

Q. IN YOUR COST OF SERVICE MODEL, ONCE COSTS ARE FUNCTIONALLY ASSIGNED AND CLASSIFIED, HOW ARE THESE COSTS ALLOCATED TO THE CUSTOMER CLASSES?

A. In the cost of service model used in this study, Kit Carson's costs are functionally assigned and classified using what are referred to in the model as "functional vectors." These vectors are multiplied (using scalar multiplication) by the various accounts in order to simultaneously assign costs to the functional groups and classify costs. Therefore, in the portion of the cost of service model included in KCEC Exhibit No. __ (MJB-3), Kit Carson's accounting costs are functionally assigned and classified using the explicitly determined functional vectors of the analysis and using internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on pages A-31 through A-33. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. The internally generated functional vectors that are used to allocate a particular cost are shown on pages A-1 through A-30 of KCEC Exhibit No. __ (MJB-3) in the column labeled "Functional Vector". An example of the development and use of an internally generated functional vector is the use of Total Production, Transmission and Distribution Plant (PT&D) to functionally assign and classify the intangible plant found in FERC accounts 301 and 303 on page A-1 of KCEC Exhibit No. __ (MJB-3). The functional vector that is used to allocate a specific cost is identified by the column in the model labeled "Functional Vector" and refers to a vector that is calculated using data from a row and identified by the column labeled "Name".

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors". This process is illustrated in Figure 2 below.

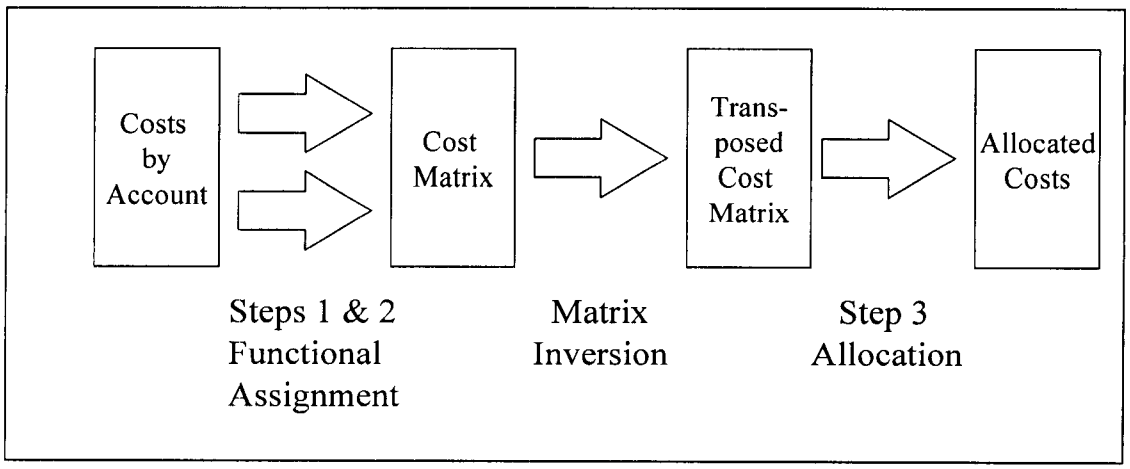

Figure 2

The results of the class allocation step of the cost of service study are included in KCEC Exhibit No. __ (MJB-4). The costs shown in the column labeled "Total System" in KCEC Exhibit No. __ (MJB-4) were carried forward from the functionally assigned and classified costs shown in KCEC Exhibit No. __ (MJB-3).

Q. PLEASE DESCRIBE THE ALLOCATION FACTORS USED IN THE COST OF SERVICE STUDY.

A. The following allocation factors were used in the cost of service study:

- **NCPP** – The demand cost component is allocated on the basis of the maximum class demands for primary and secondary voltage customers.
- **SICD** – The demand cost component is allocated on the basis of the sum of individual customer demands for secondary voltage customers.
- **C02** – The customer cost component of customer services is allocated on the basis of the average number of customers for the test year.
- **C03** – Meter costs were specifically assigned by relating the costs associated with various types of meters to the class of customers for whom these meters were installed.
- **YECust04** – Costs associated with lighting systems were specifically assigned to the lighting class of customers.
- **YECust05 and YECust06** – Meter reading, billing costs and customer service expenses were allocated on the basis of a customer weighting factor based on discussions with Kit Carson's meter reading, billing and customer service departments.
- **Cust05** – The customer cost component is allocated on the basis of the average number of customers for the test year.
- **YECust07** – The customer cost component is allocated on the basis of the year-end number of customers using line

transformers and secondary voltage conductor.

- **YECust08** – The customer cost component is allocated on the basis of the year-end number of customers using primary voltage conductor.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COST OF SERVICE STUDY.

A. The following table (Table 1) summarizes the pro forma revenues, operating expenses, operating margin, rate base and rates of return on rate base for each customer class:

	Revenue	Operating Expenses	Operating Margin	Rate Base	Rate of Return on Rate Base
Residential Service	$ 15,311,669	$ 15,604,712	$ (293,043)	$ 47,227,703	-0.62%
Residential Seasonal Service	$ 1,959,765	$ 2,053,834	$ (94,069)	$ 6,569,698	-1.43%
Commercial Service	$ 5,600,130	$ 5,487,110	$ 113,020	$ 14,254,166	0.79%
Power Service	$ 7,060,832	$ 5,567,254	$ 1,493,578	$ 7,876,983	18.96%
Security Lighting Service	$ 363,858	$ 298,847	$ 65,011	$ 971,991	6.69%
Interruptible Power Service	$ 112,683	$ 67,868	$ 44,815	$ 422,804	10.60%
Power Service Time-of-Use	$ 168,835	$ 149,487	$ 19,348	$ 236,880	8.17%
Residential Service Time-of-Use	$ 453,931	$ 473,676	$ (19,745)	$ 1,225,233	-1.61%
Residential Seasonal Service Time-of-Use	$ 14,109	$ 15,812	$ (1,704)	$ 48,960	-3.48%
Commercial Service Time-of-Use	$ 215,270	$ 210,721	$ 4,549	$ 513,849	0.89%
Irrigation Power Service Time-of-Use	$ -	$ -	$ -	$ -	
Irrigation Power Service	$ 5,777	$ 8,482	$ (2,705)	$ 28,632	-9.45%
MolyCorp - Special Contract	$ 3,778,702	$ 3,575,001	$ 203,701	$ 2,685,151	7.59%
Total	35,045,563	33,512,806	1,532,757	82,062,050	1.87%

Table 1

Determination of the test year and pro forma rates of return on rate base are detailed in KCEC Exhibit No. __ (MJB-4), pages B-25 through B-30.

Q. DOES THE COST OF SERVICE STUDY PROVIDE INFORMATION CONCERNING THE UNIT COSTS INCURRED BY KIT CARSON TO PROVIDE SERVICE UNDER EACH RATE SCHEDULE?

A. Yes. Customer-related, demand-related and energy-related unit costs for each rate class are shown on pages B-43 through B-48 of KCEC Exhibit No. __ (MJB-4). The top half of pages B-43 through B-45 show unit costs with margins that provide the same rate of return as the class generated in the pro forma cost of service results on pages B-25 through B-27. The bottom half of pages B-43 through B-45 show unit costs with margins that provide the equalized rates of return at the overall 1.87% return on rate base for Kit Carson as a whole indicated by the pro forma cost of service results on page B-25. Pages B-46 through B-48 show unit costs with margins that provide the equalized rates of return at a 5.16% overall return on rate base for Kit Carson. Customer-related costs are stated as a cost per customer per month. Energy-related costs are stated as a cost per kWh. For customers metered predominantly on a per kWh basis, such as Residential customers in Rate 1, demand-related costs are stated as a cost per kWh. For demand-metered customer classes such Power Service customers in Rate 4, demand-related costs are stated as a cost per kW per month.

Q. WERE THESE UNIT COSTS USED TO DEVELOP THE CUSTOMER CHARGES IN KIT CARSON'S PROPOSED RATES?

A. Yes. In this filing, Kit Carson is proposing to increase the revenues that it collects from its customers by 13.11% which will generate additional revenue of $4,331,149 as shown as shown on page 1 of KCEC Exhibit No. __ (MJB-8). The proposed rates apportion this revenue increase among the various customer classes served by Kit Carson. As shown on pages 2 through 13 of KCEC Exhibit No. __ (MJB-8), the increase in revenues for each rate class was determined by

applying both the current and proposed charges to the adjusted billing determinants for each rate class and calculating the difference. The individual rate components and the revenue generated by each rate component for both the test year and for the proposed rates are provided on pages 2 through 13 of KCEC Exhibit No. __ (MJB-8). The proposed rates move in the direction of the unit costs indicated by the cost of service study, but do not fully reflect these unit costs. Kit Carson chose to move toward the unit costs indicated in the cost of service study in phases rather than in a single jump and plans to continue the move in the direction of the unit costs indicated by the cost of service study in future rate cases.

Q. WHAT WAS THE BASIC UNDERLYING INFORMATION THAT SUPPORTED THE PROPOSED ALLOCATION OF THE REVENUE REQUIREMENT AMONG KIT CARSON'S RATE CLASSES?

A. The cost of service study provided information measuring the extent to which the revenues generated by each customer class contribute to the overall margin earned by Kit Carson as well as the cost based unit charges that would be appropriate for each rate component. As shown on KCEC Exhibit No. __ (MJB-4), pages B-28 through B-30, the cost of service study indicated that the pro forma rate of return on rate base for Kit Carson as a whole was 1.87% with rates of return on rate base for the individual classes ranging between -9.45% for the Irrigation Power Service class to 18.96% for the Power Service class. This indicates a need to increase the revenues and margins collected from some classes more than others. The rate components for all classes of customers were redesigned to more accurately

reflect cost causation. However, less, or in some cases none, of the rate increase was collected from classes of customers that had a pro forma rate of return on rate base significantly higher than the average. Although classes with a relatively high pro forma rate of return on rate base received either no or relatively small increases, customers within these classes may experience a larger increase in their energy bills than the class as a whole because of their usage patterns.

Q. WHAT WERE THE RATEMAKING OBJECTIVES IN DEVELOPING THE PROPOSED RATES?

A. One of our key objectives was to bring the pro forma rates of return on rate base for the various classes more in line by allocating relatively more of the revenue increase to the customer classes with low pro forma rates of return on rate base and allocating relatively less or none of the revenue increase to customer classes with high pro forma rates of return on rate base. We chose not to decrease the revenue collected from any class, even though a decrease could be justified for customer classes with high pro forma rates of return on rate base. This allowed mitigation with respect to the level of increases to the Residential class when a higher increase could have been supported for this class, as shown on page 1 of KCEC Exhibit No. __ (MJB-8).

Another key objective was to bring the unit charges for the individual rate components more in line with the unit costs derived from the cost of service study. Kit Carson's rates include both two-part rates, consisting of a customer charge and energy charge, and three-part rates, consisting of a customer charge,

energy charge and demand charge. We worked to develop rates that moved these various charges toward the unit costs indicated by the cost of service study.

Q. WHAT IS THE PROPOSED REVENUE INCREASE FOR SCHEDULE R, RESIDENTIAL SERVICE?

A. Kit Carson is proposing a revenue increase of $1,297,429 for the Residential rate class, which will be collected through an Energy Charge of $0.09079 per kWh and a Customer Charge of $20.50 per customer meter per month, as shown on page 2 of KCEC Exhibit No. __ (MJB-8). The Residential class has a pro forma return on rate base of -0.62% in the cost of service study. Thus, a significant portion of the increase that Kit Carson is requesting is allocated to the residential class, although the cost of service study would support more than double the requested amount being allocated to the residential class.

Q. IS KIT CARSON PROPOSING TO BRING THE RESIDENTIAL CUSTOMER CHARGE MORE IN LINE WITH THE UNIT COSTS SHOWN IN THE COST OF SERVICE STUDY?

A. Yes. Kit Carson is proposing to increase the monthly Residential Customer Charge from $10.00 to $20.50 to bring it more in line with a rate that fully reflects the cost of providing service. This charge is still lower than the full cost of providing the minimum amount of equipment that each customer needs in order to access the electric grid. As shown in the cost of service study on page B-46 of KCEC Exhibit No. __ (MJB-4), a full cost based Customer Charge for the Residential class would be $23.76 per customer per month at a 5.16% rate of return on rate base. Therefore, Kit Carson is proposing to move the Customer

Charge toward one that fully reflects cost of service but still has a way to go toward meeting this goal.

Q. PLEASE EXPLAIN THE COSTS THAT ARE RECOVERED THROUGH THE CUSTOMER CHARGE.

A. The customer charge recovers the minimum system that each customer must have in place to have access to the electric grid and the cost of operating and maintaining this minimum system. The minimum system is comprised of the meter, service drop from the transformer, the transformer, the minimum size of wire, and poles extending to the distribution substation that is necessary to provide a customer with access to the electric grid. Once the cost of this minimum system is determined using the zero-intercept methodology, each customer needs at least the minimum system to receive service from the Cooperative. Many customers need more equipment in place than this minimum system in order to receive adequate service. The cost of this equipment above the minimum is related to the customer's usage level and is a volumetric demand-related fixed cost that is recovered through either a demand or energy charge. A cost of service study is performed for the purpose of allocating costs as accurately as possible based on cost causation. In a cost of service study, it is important to distinguish the distribution system costs that are related to usage from the distribution system costs that are related to the minimum system which are non-volumetric and are not related to usage, as discussed in the NARUC Electric Utility Cost Allocation Manual. By becoming a customer, the customer has caused the cooperative to provide the minimum amount of equipment necessary to provide access to the

electric grid, and each customer must have that minimum amount of equipment in place in order to obtain electric service. The customer caused these non-volumetric fixed distribution costs that are classified as customer-related by becoming a customer and should be responsible for paying these costs through a fixed the customer charge regardless of the customer's usage. The remainder of the distribution costs, which are related to volume, are classified as demand-related and are collected through a kWh energy charge for the Residential class or through a kW charge for customer classes billed on a demand basis. This split of distribution system costs between volumetric and non-volumetric assures that customers only have to pay for what they are actually using, namely the basic minimum system that all customers require plus as much size as customers require to meet their needs.

Q. PLEASE EXPLAIN HOW THE FULL COST-BASED CUSTOMER CHARGE WAS CALCULATED FOR RESIDENTIAL SERVICE.

A. The full cost-based Customer Charge for Residential Service was calculated by dividing the sum of customer-related costs and customer-related margins, which together I will refer to hereafter as "fixed costs," by the number of monthly customer charges collected by Kit Carson from Residential Service customers during in the test year. The margins assigned for collection through the monthly Customer Charge were calculated by allocating the total margins assigned to the Residential Service class into distribution demand-related and customer-related components, based on the percentage of the net cost rate base that was customer related or demand related for the Residential Service class. The result was a

monthly customer-related unit cost of $23.76 per customer per month at a 5.16% rate of return for the Residential Service class, as shown on page 2 of KCEC Exhibit No. __ (MJB-8).

Q. DOES THE CURRENT CUSTOMER CHARGE OF $10.00 RECOVER CUSTOMER-RELATED COSTS FOR THE RESIDENTIAL CLASS?

A. No. The current Customer Charge of $10.00 per customer per month does not recover all of the customer-related, non-volumetric fixed costs of $18.46 let alone any of the $5.30 of margins, as shown on page B-46 of KCEC Exhibit No. __ (MJB-4). Based on calculations from the cost of service study, there are $13.76 in non-volumetric fixed costs per customer per month (calculated as $23.76 - $10.00 = $13.76) that are not being collected through the Customer Charge. When this under-recovery of $13.76 per customer per month is multiplied by the billing units of 261,860 customer months for the Residential Service class during the test year, the result is $3,603,193 in non-volumetric fixed costs that are not being recovered through the Customer Charge under the current rate design. When these non-volumetric fixed costs are recovered through the Energy Charge instead, the result is about 3.0 cents per kWh of non-volumetric fixed cost collected through the Energy Charge (calculated as $3,603,193 / 120,299,391 kWh = $0.02995/kWh). Thus, the current Customer Charge is $13.76 per customer meter per month too low and the Energy Charge is 3 cents per kWh too high based on data provided in the cost of service study. This recovery of non-volumetric fixed costs through the energy charge assessed on a kWh basis results in intra-class

subsidies and in unrecovered fixed costs if kWh usage declines due to energy efficiency, conservation or mild weather.

Q. PLEASE EXPLAIN THE INTRA-CLASS SUBSIDIES THAT RESULT FROM THE CUSTOMER CHARGE NOT ADEQUATELY RECOVERING THE COOPERATIVE'S FIXED COSTS AND MARGINS.

A. The rate making principle that should be followed to avoid intra-class subsidies is that fixed costs should be recovered through fixed charges (such as the customer charge and demand charge) and variable costs should be recovered through variable charges (such as the energy charge and the wholesale power cost adjustment charge). If fixed costs are recovered through variable charges, such as the energy charge assessed on a kWh basis, each kWh contains a component of fixed costs and customers using more energy than the average customer in the class are paying more than their fair share of the cooperative's fixed costs, while customers using less energy than the average customer in the class are paying less than their fair share of the cooperative's fixed costs. These fixed costs should be collected through the billing units associated with the appropriate cost driver, and energy usage clearly is not the correct cost driver for collecting fixed costs.

The collection of fixed costs through the energy charge typically results in customers with above-average usage subsidizing customers with below-average usage. In order to eliminate this source of intra-class subsidies, Kit Carson proposes a rate design that more closely follows the ratemaking principle of recovering fixed costs through fixed charges and variable costs through variable charges than does its current rate design.

Q. TYPICALLY, WHO ARE THE LOW-USAGE CUSTOMERS WHO WOULD BE PAYING HIGHER ENERGY BILLS ONCE THE SUBSIDIES ARE REMOVED?

A. For Kit Carson, low-usage customers are loads such as hunting camps, fishing camps, garages, vacation homes, services run to barns or shops, stock tanks and electric fences. These loads typically consume very few kilowatt hours during the course of a year and the usage is sporadic. However, the cooperative often incurs significant fixed costs to install the minimum system requirements necessary to serve these loads. Further, these loads are seldom located near roads and existing distribution lines. A rate design with a customer charge that does not recover a large portion of non-volumetric fixed costs, and with a significant portion of non-volumetric fixed cost recovered through the energy charge, would result in revenue that was insufficient to support the investment in the minimum amount of equipment necessary to serve loads such as vacation homes, hunting camps, barns, and other similar loads. Such a rate design would result in these customers being subsidized by the other cooperative customers who have above-average usage.

Kit Carson's Board, which is comprised of individuals who are both members and customers of the Cooperative, does not believe that this is appropriate. A rate design that recovers a significant portion of the Cooperative's non-volumetric fixed cost through the energy charge sends improper economic signals to customers. It sends a signal that it is relatively inexpensive to provide

the minimum amount of physical equipment necessary to provide service to customers, and this is definitely not the case for Kit Carson.

Q. WHAT WOULD BE THE IMPACT OF A HIGHER CUSTOMER CHARGE AND A REDUCED ENERGY CHARGE ON FIXED AND LOW INCOME CUSTOMERS?

A. For fixed and low income customers to significantly benefit from a rate design with a lower customer charge and higher energy charge than the cost of service study indicates is appropriate, these customers would need to have an energy usage that is much lower than the class average. Generally, this is not the case for low income customers, and it does not appear to be the case for Kit Carson's low-income customers based on 2009 usage data for LIHEAP customers. Based on 2009 usage data, Kit Cason's LIHEAP customers used an average of 633 kWh per month while the average usage for the residential class as a whole was 487 kWh. Thus, based on average monthly usage of 633 kWh per month, Kit Carson's low income customers would pay an additional $1.38 per month under the proposed rates, which represents a 1.8% increase even though the residential lass as a whole is receiving an 8.65% increase. Low income customers with above average usage would benefit from the proposed change in rate design because they would no longer subsidize the low usage customers, such as those with vacation homes, hunting camps or barns. In addition, it is my experience that, because they have a stock of appliances similar to other customers and are frequently home all day, fixed income customers generally have usage levels in the neighborhood of the

class average and also would not differ significantly from the impacts experienced by residential customers as a whole.

Q. IN YOUR EXPERIENCE, DO LOW INCOME CUSTOMERS IN OTHER STATES ALSO USE LESS ELECTRICITY THAN THE AVERAGE RESIDENTIAL CUSTOMER?

Yes. In fact, it has been my experience that the housing stock in which many low income customers are living is relatively inefficient from an energy usage standpoint, so their energy usage is frequently above the class average. This was the case in Virginia, where I recently testified on behalf of Northern Neck Electric Cooperative ("NNEC") that:

> NNEC collected load research data on customers who meet the state standards for participating in low income energy assistance programs. The average annual usage for NNEC's Residential customers is 13,969 kWh per year while the annual average usage for low income customers is 14,871 kWh per year. (Case No. PUE-2008-00076 before the Virginia State Corporation Commission.)

This was also the case in Indiana, where I testified on behalf of Jackson County Rural Electric membership Cooperative that:

> Jackson County calculated that the average usage for LIHEAP customers, who are used as the proxy for low income customers, was 16,606 kWh per year, while the average annual usage for the Basic Service class as a whole was 15,984 kWh per year. This indicates that low income customers would not be significantly harmed or burdened by the increase in the facilities charge that Jackson County is seeking. (Cause No. 43861 before the Indiana Utility Regulatory Commission)

The inefficient energy usage of the dwelling in which many low income customers live has typically resulted in the price of the dwelling being discounted to a level that low income customers can afford. The tradeoff is a lower initial

purchase price in exchange for higher monthly energy bills than if a more energy efficient home were purchased. In these cases, typical low income customers would actually benefit from a rate design that had a higher customer charge and a lower energy charge, as these customers, because of their higher usage, would no longer be required to subsidize low usage customers.

Q. WOULD A HIGHER CUSTOMER CHARGE AND A REDUCED DISTRIBUTION CHARGE STABILIZE KIT CARSON'S REVENUES?

A. Yes. When fixed costs are recovered through variable charges, such as an energy charge per kWh, a cooperative's fixed cost recovery is impacted by sales fluctuations due to weather, energy efficiency, conservation or self-generation. If fixed costs are loaded in every kWh that the cooperative sells, then increased sales due to extreme weather, either hot or cold, result in over recovery of fixed costs. Similarly, mild weather, conservation, energy efficiency or self generation would result in both reduced sales and under recovery of fixed cost by the cooperative. The result is a rollercoaster effect for cooperative revenue and margin recovery. This rollercoaster effect can be eliminated if the cooperative is permitted to follow the principle of recovering fixed cost through fixed charges, such as the Customer Charge. Recovering fixed costs through fixed charges aligns the interests of customers and the Cooperative by allowing the Cooperative to recover its fixed costs regardless of sales, thus freeing the Cooperative to work closely with its customers in reducing the costs that the Cooperative pays to its supplier and reducing customer energy bills.

An additional benefit to stabilizing the Cooperative's revenues is that the Cooperative may not need to file rate cases as frequently to address the revenue fluctuations. A cooperative is required to maintain certain levels of revenue to remain eligible for loans though the Rural Development Utilities Program (RDUP), and consequently, it has no choice but to seek a rate increase if it falls below these levels over time. Therefore, all member customers benefit if the Cooperative has a more stable revenue stream by avoiding costly and time consuming rate cases.

Q. WOULD A HIGHER CUSTOMER CHARGE AND A REDUCED DISTRIBUTION CHARGE STABILIZE A CUSTOMER'S BILLS AS WELL?

A. Yes. This rollercoaster effect on cooperative revenues with fixed cost recovery higher than necessary in periods of high sales and lower than necessary in periods of low sales also has the impact of customers paying more fixed cost than the cooperative requires when sales are high and paying less fixed cost than the cooperative requires when sales are low. The result is unnecessary customer energy bill volatility. If Kit Carson is permitted to implement a Customer Charge that more fully reflects fixed cost recovery, with the energy charge correspondingly reduced, customers' energy bills will not be as high when weather is extreme and sales are high and will not be as low when weather is mild and sales are low. In my opinion this reduction in bill volatility is a benefit to customers. It will allow customers greater bill stability and less volatility, which

should help all residential customers, especially low income customers, with paying their bills in a timely fashion.

Q. ARE YOU AWARE OF ANY OTHER RURL ELECTRIC COOPERATIVES THAT HAVE INCREASED THEIR CUSTOMER CHARGES TO MORE ACCURATELY REFLECT COST CAUSATION?

A. Yes. I am aware of fifty-five other cooperatives for who The Prime Group has worked that have adopted costs based customer charges similar to the one that Kit Carson is proposing for Residential Service in this proceeding. This list of fifty-five cooperatives and their respective customer charges is provided as KCEC Exhibit No. __ (MJB-9). It is significant to note that the average of the customer charges for these fifty-five cooperatives is $27.24, which is well above the $20.50 that Kit Carson is requesting in this proceeding.

Q. DOES THE CURRENT RATE DESIGN PROVIDE THE RIGHT RETAIL RATE ENVIRONMENT FOR KIT CARSON TO PURSE ENERGY EFFICIENCY AND CONSERVATION?

A. No. With a significant portion of fixed cost recovered through the energy charge assessed on a kWh basis, Kit Carson foregoes about 3 cents of non-volumetric fixed cost recovery for each kWh that it helps a customer save. This creates a win/lose scenario where the cooperative would forego fixed cost recovery whenever it helped a customer to conserve energy or use energy more efficiently.

Q. WOULD THE PROPOSED RATE DESIGN PROVIDE THE RIGHT RETAIL RATE ENVIRONMENT FOR KIT CARSON TO ENHANCE ITS PURSUIT OF ENERGY EFFICIENCY AND CONSERVATION?

A. Yes. With a much larger portion of Kit Carson's fixed costs and margins recovered regularly through a monthly Customer Charge and not subject to variations due to customer energy usage, Kit Carson would be in a much better position to aggressively pursue energy efficiency and conservation programs. The proposed rate design would more accurately reflect cost causation and create a much better environment for Kit Carson to pursue energy efficiency and conservation than the current rate design. Allowing the cooperative to recover its fixed costs and margins regardless of how much energy the customer consumes, or perhaps more to the point, does not consume creates a win/win environment in which the cooperative can actively promote energy conservation and energy efficiency.

Q. WHY IS THE CUSTOMER CHARGE THAT KIT CARSON IS PROPOSING MUCH HIGHER THAN THE CURRENT CUSTOMER CHARGE?

A. The answer is because the cost of installing, operating and maintaining the physical facilities that the cooperative recovers through this charge are high and the current rate design does not reflect this. The customer charge recovers the cost of the minimum amount of equipment that the cooperative must install to provide a customer with access to the electric grid. This includes the meter, service drop, transformer and a portion of the poles and wire connecting to the nearest distribution substation. Without this minimum amount of equipment, customers would not be able to receive electric service. Unfortunately, the costs of the poles,

wire, transformers, service drops, and meters necessary to provide a customer with access to the electric grid are not cheap. For example, the 15 kVa transformer that is used for most residential customers costs about $600 installed. A mile of single phase distribution line costs about $30,000 per mile, which includes both the poles and the wire. These represent fixed costs to the cooperative; that is costs that do not change regardless of the amount of electric energy purchased by customers. So if customers use less electricity, either because they have taken steps to conserve energy or because they left on vacation, these costs to the cooperative do not change and must be recovered for the cooperative to remain financially sound. The problem for cooperatives is that they cannot spread their fixed cost over as many customers per mile as an investor-owned utility, resulting in higher customer charges for cooperatives compared to investor owned utilities.

Q. UPON REVIEW OF THE PROTESTS FILED BY KIT CARSON'S CUSTOMERS, WHAT ISSUES DID THE COMMISSION FIND THAT COULD RAISE THE QUESTION OF WHETHER KIT CARSON'S RATES ARE JUST AND REASONABLE.

A. The Commission found that the following issues were raised by protestors:

1. Whether it is just and reasonable for Kit Carson to increase the fixed service charges, in some classes by more than 50%, while reducing the customer's energy charge.
2. Whether the proposed rate increases will impose a hardship on customers living on fixed incomes.

3. Whether the proposed rate increases will cause undue hardship for local businesses, such that some may need to close.
4. Whether the proposed new rate design unfairly penalizes low-end users and discourages conservation.
5. Whether Kit Carson should not be required to reduce its internal costs and operational expenses before attempting to recover these costs and expenses through a rate increase.

Q. WHAT ARE THE CRITERIA THAT ARE GENERALLY USED FOR ASSESSING WHETHER PROPOSED RATES ARE FAIR, JUST AND RESONABLE?

A. It is my understanding that "fair, just and reasonable" rates are rates that accurately reflect the cost of providing service to customers and that are based on cost causation. This approach to developing fair, just and reasonable rates implies that if a customer causes a cost to be incurred, the customer should pay that cost and that subsidies between customer classes and among customers within a class should be avoided. Ability to pay is not a criteria that has typically been utilized by commissions or by appellate courts in determining whether utility rates are fair, just and reasonable.

Q. DO THE RATES PROPOSED BY KIT CARSON IN THIS PROCEEDING ACCURATELY REFLECT COST CAUSATION?

A. Yes. The rates proposed by Kit Carson in this proceeding accurately reflect cost causation. Each customer must have a certain minimum amount of equipment in place in order to have access to the electric grid, and the customer charge that Kit

Carson is proposing more accurately reflects the cost of this minimum system that each customer needs than does the current rate design. The non-volumetric portion of fixed cost was determined through use of a zero-intercept methodology. The remaining portion of distribution costs, which are related to volume, are classified as demand-related and will be collected through a kWh energy charge for the residential class. This split of distribution costs between volumetric and non-volumetric assures that customers only have to pay for what they are actually using, namely the basic minimum system that all customers require plus as much size as customers require to meet their needs. In my opinion, the rates that Kit Carson is proposing based on this split meet the requirements for fair, just and reasonable rates based on the cost causation principle.

Q. DOES AN INCREASE IN THE CUSTOMER CHARGE OF OVER 50% FOR SOME CLASSES INDICATE THAT THE RATES THAT KIT CARSON IS PROPOSING ARE UNFAIR AND UNREASONABLE AS SOME PROTESTING CUSTOMERS HAVE CONTENDED?

A. No. It shows just how far Kit Carson's current customer charges deviate from ones that accurately reflect cost causation. Whenever the starting point for calculating a percentage difference is low, the denominator in the calculation will be low resulting in large percentage increases for even relatively small increases in the charge. The Customer Charge of $20.50 per customer per month that Kit Carson is proposing does not fully reflect a cost-based customer charge of $23.76 as indicated by the cost of service study for a 5.16% rate of return on rate base. Because the proposed Customer Charges more accurately reflect the actual cost of

providing service than the current rate design, I believe that the Customer Charges that Kit Carson is proposing are fair, just and reasonable.

Q. DO YOU AGREE THAT THE CONCEPT OF GRADUALISM IS IMPORTANT IN DESIGNING RATES FOR UTILITIES?

A. Yes. However, it is not nearly as important as the principle of cost causation. The principles of "gradualism" or "rate continuity", which were articulated in Principles of Public Utility Rates by James C. Bonbright, should not take priority over the principle of "cost of service", which was identified as an even more important principle in the Bonbright treatise. As the late professor Bonbright states, "Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service." (James C. Bonbright, Principles of Public Utility Rates, Columbia University Press: 1961; p. 294).

Q. DO THE RATES THAT KIT CARSON IS PROPOSING IMPOSE AN UNDUE HARDSHIP ON FIXED INCOME CUSTOMERS AS SOME PROTESTING CUSTOMERS HAVE CONTENDED?

A. No. In a regulatory context, "undue" and "unfair" refer to charges that do not accurately reflect the cost of providing electric service to customers. This criteria for fairness that has been developed through litigated regulatory processes is one of cost causation; namely do those who cause costs to be incurred pay those costs. The terms "undue " and "unfair" do not refer to achieving social policy goals through the utility ratemaking process. The customer charge and energy charge that Kit Carson is proposing are cost based as indicated by the cost of service study and reflect the costs of serving customers in the residential class.

Furthermore, because most fixed income customers have a stock of appliances similar to other customers and because they are frequently home all day, the impact on fixed income customers would not be unduly large or unfair compared to other residential customers, as the consumption of fixed income customers would be much closer to the average consumption of other residential customers than it would be to the typical low usage customers such as barns, vacation homes and hunting camps that receive significant subsidies under the current rate design.

Q. DO THE RATES THAT KIT CARSON IS PROPOSING IMPOSE AN UNDUE HARDSHIP ON LOCAL BUSINESSES AS SOME PROTESTING CUSTOMERS HAVE CONTENDED?

A. No. As noted above, in a regulatory context, "undue" and "unfair" refer to charges that do not accurately reflect the cost of providing electric service to customers. The rates for Commercial Service and Power Service customers more accurately reflect the cost of providing service to these customers than does the current rate design. Thus, I believe that the rates for these classes are more fair, just and reasonable than the current rate design. The rate increase for the Commercial Service class of 10% and for the Power Service class of 4.15% are below the average increase of 13.11% for the Cooperative as a whole, so these business customers are not being unduly burdened relative to other customer classes. Because a cooperative is a not for profit entity, any decreases in rates for these classes would result in increases for other customer classes, and this does not appear to be justified based on the cost of service study.

Q. DO YOU AGREE THAT THE PROPOSED RATE DESIGN WOULD DISCOURAGE CONSERVATION AS SOME PROTESTING CUSTOMERS HAVE CONTENDED?

A. No. Recovering non-volumetric fixed costs through a monthly customer charge rather than through an energy charge does not discourage conservation and energy efficiency. Kit Carson's distribution system costs are almost entirely fixed costs. Once these fixed costs have been incurred by the Cooperative, they must be recovered from customers in order to leave the Cooperative financially whole. Energy efficiency and conservation are aimed at reducing the variable costs that the cooperative incurs, namely generation, transmission and purchased power costs that can be affected by reduced customer usage. However, reducing customer usage will have no effect on the Cooperative's fixed distribution system costs which it has already incurred to meet the needs of its customers. If these fixed distribution costs are variablized by recovering them through a kWh charge, the Cooperative may over-recover the necessary fixed distribution system costs when sales are high and may under-recover fixed distribution system costs when sales are low, neither of which is appropriate or necessary if the right rate design is adopted. By recovering its non-volumetric fixed distribution system costs through a fixed monthly customer charge, the Cooperative is free to work with customers aggressively in pursuing energy efficiency and conservation goals without harming itself financially. This aligns the interest of the Cooperative and its customers in pursuing energy efficiency and conservation. By contrast, variablizing a Cooperative's non-volumetric fixed distribution costs makes it

necessary for the Cooperative to pursue increased sales in order to recover its fixed costs, which puts the Cooperative's interests and its customers' interests with regard to energy efficiency and conservation at odds with each other. The customer charge of $20.50 that Kit Carson is proposing creates a better environment for the Cooperative to aggressively pursue energy efficiency and conservation than does the current rate design, contrary to what the protesting customers have contended.

Q. ARE CUSTOMERS WITH ABOVE AVERAGE USAGE "ENERGY HOGS" AND DO THEY IMPOSE MORE COSTS ON THE SYSTEM THAN CUSTOMERS WITH BELOW AVERAGE USAGE?

A. Not necessarily. Customers that use large amounts of electricity are cost causers just as are customers who use low amounts of electricity. The issue that needs to be addressed in both cases in order to ensure fair treatment of both types of customers is to identify what costs they cause. The principle of cost causation that should be applied in order to ensure fair rates for all customers is that customers should pay the costs that they impose on the system. The classification of distribution costs into volumetric and non-volumetric components assures that customers only have to pay for what they are actually using, namely the basic minimum system that all customers require plus as much size as customers require to meet their needs. The protesting customers do not seem to make this distinction. Serving a house that uses 1,500 to 2,000 kWh per month compared to a house that uses 500 to 700 kWh per month could result in higher distribution costs for the cooperative. However, the cost of the minimum system that is not

related to volume would be the same for both customers and the difference in cost would be in the distribution demand-related component that is reflected as a part of the energy charge. Furthermore, the relationship between distribution-related costs and energy usage depends heavily on load factor. As noted above, distribution costs are classified either as demand-related or customer-related in accordance with standard cost of service methodologies. Distribution-related costs will vary with the demand that a customer places on the distribution system and not the amount of energy usage. Consequently, a low energy user with a high demand could impose more distribution cost on the cooperative than a high energy user with a relatively low demand. For example, a customer with annual energy usage of 6,000 kWh but with a maximum demand of 30 kW would be more costly to serve from a distribution cost perspective than a customer with annual energy usage of 87,000 kWh with a maximum demand of 10 kW. The rates that Kit Carson is proposing accurately reflect the difference between customer-related and demand-related distribution costs and only charge the customer for exactly what the customer is using, namely the cost of the minimum system plus whatever size the customer requires based on the customer's usage. The cost of purchased power would be a pass through in either case and could be reduced by customer conservation and energy efficiency efforts. There is no cost causative basis for customers using more kWh than the average to pay more non-volumetric fixed costs than customers using less than the average, as these non-volumetric fixed costs are related to the minimum system that all customers must have in place to provide access to the electric grid and are not related to the

customer's volume of usage. Based on my experience, there is no economic theory that supports assigning more non-volumetric fixed cost to large users and less to small users.

Q. SHOULD THE COMMISSION REQUIRE KIT CARSON TO REDUCE ITS COSTS AND OPERATIONAL EXPENSES BEFORE ALLOWING ANY RATE INCREASE?

A. Those protestors who raised this issue assume that Kit Carson has not already made efforts to reduce its costs and operational expenses, which is incorrect as more fully explained in the Direct Testimony of Mr. Luis Reyes. The members of the Cooperative's Board, which meets monthly, are also customers who pay the rates charged by the Cooperative. The Board has a personal interest in keeping the Cooperative's expenses as low as possible. Furthermore, protestors have provided no indication of which expenses might be excessive or imprudent. The law in the United States is well established, based on *Bluefield Waterworks and Improvement Co. v. West Virginia Public Service Commission* (262 U.S. 679, 1923) and *Federal Power Commission v. Hope Natural Gas Company* (320 U.S. 391, 1944), that a utility has the right to recover its prudently incurred expenses and earn a fair return on its investments of capital used to provide service to ratepayers. Additionally, the United States Supreme Court long ago determined that in order to disallow an expenditure, there must be a finding that the expenditure was imprudent or unreasonable. The foundational description of prudence was set forth in a footnote to the concurring opinion in *State of Missouri*

ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, et al., wherein Justice Brandeis stated that:

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown. *State of Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, et al.,* 262 U.S. 276 (1923)

Based on this long established legal principle and absent any indication that any expenditures by the Cooperative were imprudent or dishonest, the Commission has no basis for disapproving the Cooperative's rates based on a general desire by protestors that the Cooperative's expenses be less.

Q. IF THE COMMISSION WERE TO REDUCE THE CUSTOMER CHARGE THAT KIT CARSON IS PROPOSING, WOULD IT BE NECESSARY TO RAISE THE ENERGY CHARGE TO RECOVER THE RESULTING REVENE SHORTFALL?

A. Yes. The cooperative needs a certain amount of revenue to operate, recover the costs that it incurs and meet its debt covenants, and these costs are recovered from residential customers either through the customer charge or an energy charge per kWh. If the customer charge is reduced, the energy charge must be increased to cover the shortfall if the cooperative is to remain financially viable. One way or the other, the cooperative must get the money that it needs to operate. A customer charge that more fully reflects the cost of the minimum system necessary to

provide a customer with grid access has the benefits of reducing the variations in the cooperative's recovery of fixed costs, reducing the variability of customer energy bills and providing the right environment for energy conservation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF KIT CARSON ELECTRIC COOPERATIVE, INC.'S ADVICE NOTICE NO. 57,	)	
KIT CARSON ELECTRIC COOPERATIVE, INC.,	)	**Case No. 10-00379-UT**
Applicant.	)	

VERIFICATION

STATE OF KENTUCKY)
)
COUNTY OF JEFFERSON)

I, Martin J. Blake, being first duly sworn upon my oath, depose and state that I have read the foregoing Direct Testimony and it is true to the best of my knowledge.

Martin J Blake
MARTIN J. BLAKE

SUBSCRIBED AND SWORN TO before me this 28th day of December, 2010 by Martin J. Blake

NOTARY PUBLIC

My Commission Expires:

9/13/14

BRYAN S. POTTER, JR.
NOTARY PUBLIC
STATE AT LARGE
MY COMMISSION EXPIRES SEPTEMBER 13, 2011

Exhibit MJB-1

Prior Testimony of Dr. Martin J. Blake

Federal Energy Regulatory Commission

ER92-533	LG&E's open transmission access and authority to charge market-based rates for its generation.
ER94-1380	The first comparability tariff approved by the FERC.
ER97-4345	A market power analysis that was filed in support of OGE Energy Resources, Inc.'s request for the authority to charge market based rates.
ER98-511	A market power analysis that was filed in support of Oklahoma Gas and Electric Co.'s request for the authority to charge market based rates.
ER99-51	An affidavit in support of Commonwealth Edison Co.'s request for authority to charge cost based rates to its affiliates.
ER01-1938	Testimony in support of Southern Indiana Gas and Electric Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
ER02-708	Testimony in support of Central Illinois Power Company's request for a revision in transmission and ancillary service rates including cost of capital testimony
NJ03-2	Testimony in support of Southern Illinois Power Company's request for a revision in ancillary service rates
EL03-53	Testimony regarding the calculation of avoided cost for a qualifying facility interconnecting with a cooperative
EL02-111	Testimony regarding the process for developing a combined transmission service rate that would apply to the combined Midwest ISO and PJM footprint

Arkansas Public Service Commission

96-360-U	Direct and rebuttal testimony for Oklahoma Gas and Electric regarding recovery of stranded costs by Entergy Arkansas, Inc.

California Public Utility Commission

90-12-018 (phase 5)	Direct and rebuttal testimony for Southern California Edison Company concerning the reasonableness of contracting by Southern California Edison with Integrated Energy Group ("IEG") to provide marketing services to Southern California Edison and the reasonableness of the resulting marketing services performed by IEG.

Colorado

C08-0059	Provide an independent review, assessment and recommendation concerning Public Service Company of Colorado's Application and request for the Commission to approve the Company's 2007 Colorado Resource Plan ("2007 CRP") and to review supporting testimony in this proceeding as it relates to the retirement of Cameo Units 1 and 2 and Arapahoe Units 3 and 4.
02S-594E	Direct and surrebuttal testimony regarding pro forma adjustments to the revenue requirement in Aquila Networks-WPC rate case.
03S-539E	Testimony regarding the use of zero intercept methodology to allocate distribution costs and determine an appropriate customer charge in an Aquila Networks-WPC rate case.
07A-447E	Testimony regarding Public Service Company of Colorado's Integrated Resource Plan.

Illinois Commerce Commission

98-0013 and 98-0035	Testimony regarding non-discrimination with regard to affiliate transactions for electric utilities. I sponsored ComEd's proposed affiliate transactions rules and suggested some basic principles that the Illinois Commerce Commission should follow in developing rules and regulations for ensuring non-discrimination and non-cross subsidization in transactions with affiliated and unaffiliated alternative retail electric suppliers ("ARES").
98-0036	Testimony in a rulemaking to develop rules and regulations for assessing and assuring the reliability of the transmission and distribution systems as a part of electric utility restructuring in Illinois.
98-0147 and 98-0148	Testimony concerning standards of conduct and rules for functional separation. I sponsored ComEd's proposed standards of conduct and functional separation rules.

07-0572	Testimony in a reconciliation proceeding concerning the prudence and recovery of the costs of gas injections and withdrawals from the Hillsboro storage field.

Kentucky Public Service Commission

90-158	An LG&E rate case.
92-494	An LG&E biennial fuel adjustment clause review.
93-150	An application for approval of a DSM cost recovery mechanism and a set of initial programs.
94-332	An application for an environmental cost recovery mechanism.
92-494-B	Testimony regarding the confidentiality of coal bid data.
95-455	A biannual review of the environmental cost recovery mechanism.
91-423	Participation in the conference with Commission staff and intervenors to review LG&E's first integrated resource plan.
Other	Several fuel adjustment clause proceedings on behalf of LG&E.
98-489	Testimony on behalf of Blazer Energy Corp. in an application for an adjustment in their natural gas rates.
99-046	Direct and rebuttal testimony regarding Return on equity in support of Delta Natural Gas Company's request for an adjustment in rates
04-00067	Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates
07- 00089	Direct testimony regarding Return on Equity in support of Delta Natural Gas Company's request for an adjustment in rates

Nevada Public Utility Commission

01-10001	Direct testimony on behalf of Shareholders Association to support Nevada Power Company's request for return on equity

New Mexico Public Utility Commission

2797	Direct and rebuttal testimony in a general rate case for Plains Electric Generation and Transmission Cooperative, Inc.

Virginia State Corporation Commission

PUE-2008-00076 Direct and Rebuttal testimony regarding rate design for Northern Neck Electric Cooperative

U.S. District Court, District of New Mexico

CIV-08-00026 Reviewed the Expert Report filed by Gary L. Groninger and provided rebuttal testimony regarding whether a decision that was made by the Arkansas River Power Authority (ARPA) was prudent.

Oklahoma Corporation Commission

PUD 960000116 Testimony in an Oklahoma Gas and Electric Company rate case, including rebuttal of intervenor and staff proposals to disallow certain marketing, advertising, economic development and research and development expenses.

PUD 200300226 Testimony in an Oklahoma Gas and Electric Company case regarding the prudence of natural gas transportation and storage contracts

Indiana Utility Regulatory Commission

41884 Direct and rebuttal testimony to support a request by eleven gas local distribution companies for switching from a quarterly gas cost adjustment mechanism to a monthly gas cost adjustment mechanism

42027 Direct testimony in support of a transfer of functional control of transmission assets from electric utilities in Indiana to the Midwest System Operator, Inc.

Iowa District Court for Hamilton County

No. LACV025993 Testimony that net metering was not appropriate for making payments to a wind generator. When a utility sells electric energy to a customer, it is charging a retail rate that recovers the cost of distribution, transmission and generation service. When a customer sells electric energy to a utility, it is selling only generation service. The customer cannot sell distribution and transmission service to a utility, as the customer does not own these assets. Net metering is a subsidy to the wind generator that is paid by other customers of the utility and paying the customer for generation service on the basis of a retail rate that includes recovery of distribution and transmission costs is not appropriate.

Exhibit MJB-2

Cost of Service Study

for the

Test Year Ended December 31, 2009

Prepared for

KIT CARSON ELECTRIC COOPERATIVE

■ The Prime Group LLC ■

The Prime Group LLC
6001 Claymont Village Drive
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November 2010

Executive Summary

The Prime Group has prepared a fully allocated class cost of service study for Kit Carson Electric Cooperative ("Kit Carson") for the 12 months ended December 31, 2009. Based on pro-forma test-year results, Kit Carson had utility operating margins of $1,532,757 which represents an overall return on rate base of 1.87%. The pro-forma actual class rates of return ranged from a low of -9.45% for Irrigation Power Service (Rate No. 22) to a high of 18.96% for Power Service (Rate No. 4). The residential class on Rate No. 1 had a rate of return of -0.62%, which is below Kit Carson's overall rate of return. Overall, Residential, Commercial, and Irrigation had lower rates of return, and Power Service and Chevron had larger rates of return.

Why Are Cost of Service Studies Important?

Although there are a number of considerations in determining the level and structure of the rates that a utility should charge its customers, there are two basic principles of fairness used in designing utility rates that stand out above all of the others. The first principle of fairness is that customers should pay the costs that they impose on the system. It is generally recognized by both experts and non-experts alike that a utility's rates should reflect the cost of providing service. A cost of service study helps to determine what it costs to provide service to a class of customers so that this first principle can be applied. The second principle of fairness is that all customers should pay their fair share of the utility's margins. A cost of service study is prepared using standard methodologies for allocating costs that have been approved by regulatory commissions and the courts and that determine as accurately as possible what it costs to serve a class of customers. While it is sometimes necessary to consider the *value of service* and the *competitiveness of service,* the starting point in assessing the reasonableness of the rates to be charged by a utility is to evaluate the *cost of service.*

Designing rates that reflect the cost of providing service helps ensure that customers pay their fair share of the utility's costs and margins. In other words, implementing cost-based rates helps ensure that one class of customers does not subsidize another class of customers. From the perspective of inter-class subsidies, cost-based rates are more *equitable.*

Besides *equity* considerations, it is important for a utility's rates to send the right price signals to customers so that they can make informed decisions regarding their energy usage. Customers' usage patterns have a direct impact on the utility's costs, which in turn have a direct impact on the utility's rates. Therefore, with cost-based rates, customers are provided a proper *price signal* that reflects both the utility's costs and the results of their own purchase decisions. With cost-based rates, customers can make informed decisions based on the actual cost structure of the utility. When rates reflect the cost of providing service, the economics of a customer's decisions to purchase more or less of a utility service are aligned with the utility's economics, thus creating greater economic and engineering efficiencies for both the utility and its customers.

Another important reason for adopting a cost of service standard, when designing rates, is that cost-based rates are supportable and have more creditability before regulatory, legal or other authorities having direct or appellate jurisdiction over the utility's rates. With rates supported by a well-reasoned cost of service study, it is difficult for any party to advance arguments that the utility's rates are improperly subsidizing certain groups of customers. Regulatory agencies and courts tend to view rates not supported by a cost of service study as arbitrary and capricious.

On a more pragmatic level, a cost of service study is an important analytical tool for a utility. For example, a cost of service study can tell the management team whether the revenue collected from a particular rate class is at least covering the fully allocated cost of providing service. Utility managers, board members, and other bodies with legal or regulatory authority will generally want some assurance that all classes of customers are at least covering the cost of providing service. A cost of service study is an excellent analytical tool for tracking whether each customer class is making at least some contribution to the utility's margins or profitability.

Additionally, individual rate components that accurately reflect the cost of providing service can help to reduce a utility's margin volatility as well as the volatility of customer energy bills. For example, a rate design that shifts a significant portion of a utility's fixed costs and margins from the customer charge to the energy charge results in customers with high levels of kWh usage paying more than their fair share of the utility's costs and margins. It also results in high margins for the utility when weather is extreme and the utility is selling large amounts of kWh. High kWh sales also mean that customers are paying more fixed cost and margin than the utility actually needs and this is reflected in higher customer bills. Conversely, a rate design that shifts a significant portion of a utility's fixed costs and margins from the customer charge to the energy charge results in low margins when weather is mild and kWh sales are low. Low kWh sales also mean that customers are paying less fixed cost and margin than the utility actually needs and this is reflected in lower customer bills. The utility is actually making "weather wagers" which have negative impact both which show up as increased volatility in utility margins and customer bills. All of this can be avoided by adopting a rate design with rate components that more accurately reflect costs.

A cost of service study is also an important analytical tool for identifying specific cost components of providing service to customers. The ability to identify specific components of the a utility's costs for various functional services allows for the design of innovative cost-based rates – such as unbundled rates, seasonally-differentiated rates, time-of-use rates, real-time pricing rates, high-load factor rates, weather normalized rates, and other types of rates. In addition, a cost of service study is an important analytical tool for developing fixed carrying charges for new types of services, developing utility line extension policies and for benchmarking one utility's costs against another.

Principal Steps in Performing a Cost of Service Study

The three principal steps of an embedded cost of service study are ***functional assignment, classification,*** and ***class allocation.*** These three steps are necessary to ensure that the costs allocated to a class of customers reflect the costs that they impose on the utility as accurately as possible. In the first step – ***functional assignment*** – costs are assigned (or "functionalized") to the major functional groups related to providing service. Functional assignment serves the following purposes: (1) it groups associated costs together to facilitate allocation on the basis of cost responsibility; (2) it provides a rational mechanism for grouping costs that do not appear to be related to major service functions; and (3) it provides a device for separating assignable costs from joint costs, which must be allocated. Functional assignment involves assigning costs to the functional services provided by a utility, such as power production, purchasing electric power, the transmission of the power over high-voltage lines (typically at voltages of 69 KV or higher), and the distribution of power over distribution lines (typically at voltages of less than 69 KV). Functionally assigning all costs allows us to examine a utility's revenue requirement in finer detail and to more accurately assign cost responsibility in the next two steps of the study.

In this cost of service study, the following functional groups were identified in order to provide a high degree of detail for purposes of designing rates as well as analyzing and tracking costs:

- Purchased Power
- Transmission
- Station Equipment
- Primary & Secondary Distribution Plant
- Customer Services
- Distribution Meters
- Lighting Systems
- Meter Reading, Billing & Customer Service
- Load Management

In the second step – ***classification*** – the major cost drivers are identified for each group of functionally assigned costs. Identifying the major cost drivers allows the service characteristics that give rise to the costs to serve as a basis for allocation. In this study, once the costs are functionally assigned they are then classified by the following major cost drivers:

- Energy-related costs
- Demand-related costs
- Customer-related costs

Costs classified as *energy-related* vary with the amount of energy that the customer consumes measured in kilowatt-hours. Fuel and purchased power expenses billed on the basis of an energy charge are examples of costs typically classified as energy related. Costs classified as *demand-related* tend to vary with the capacity needs of customers, such as the amount of generation, transmission or distribution equipment necessary to meet customers' maximum demands at particular points in time. Production plant, purchased power expenses billed on the basis of a demand charge, and the cost of transmission lines are examples of costs typically classified as

demand costs. Those assets are sized to meet the maximum demands customers place on the system at a given time. To the extent that they are driven by the amount of equipment that a utility must install to meet customer needs, these demand related costs are also driven by customer usage patterns. Costs classified as *customer-related* are not related to customer usage and include costs incurred to serve customers regardless of the quantity of electric energy they purchase or the peak demands they place on the system. These costs include the cost of the minimum system necessary to provide a customer with access to the electric grid. As will be discussed later in this report, costs functionally assigned as Primary & Secondary Distribution Plant were classified as demand-related and customer-related using the zero-intercept methodology. Customer Services, Distribution Meters, Lighting System, Meter Reading, Billing & Customer Service were classified as customer-related.

In the third and final step – ***class allocation*** – functionally assigned and classified costs are directly assigned or allocated to the customer classes on the basis of an allocation factor that is representative of the service characteristic that drives the utility's costs. For example, energy-related costs are allocated on the basis of the amount of kilowatt hours used by the customer class and demand-related costs are allocated on the basis of the appropriate measurement of the maximum demand that the customer class places on the system.

The reason that allocation procedures must be used to determine the cost of providing service to each rate class is that most of a utility's costs are represented by what are referred to as joint costs. *Joint costs* are those costs incurred jointly for two or more types of operations where each operation does not have a separate incremental cost function. In the electric utility industry, production, transmission and most distribution facilities are jointly engaged in providing service to a multitude of customers with diverse load characteristics taking service at different rates of usage at various times of the day, month or year. Consequently, in the utility industry very few costs can be directly attributed to specific customers or specific customer groups. Therefore, most of the utility's costs must be allocated to the customer classes on the basis of an allocation process that reasonably attributes costs on the basis of cost causation.

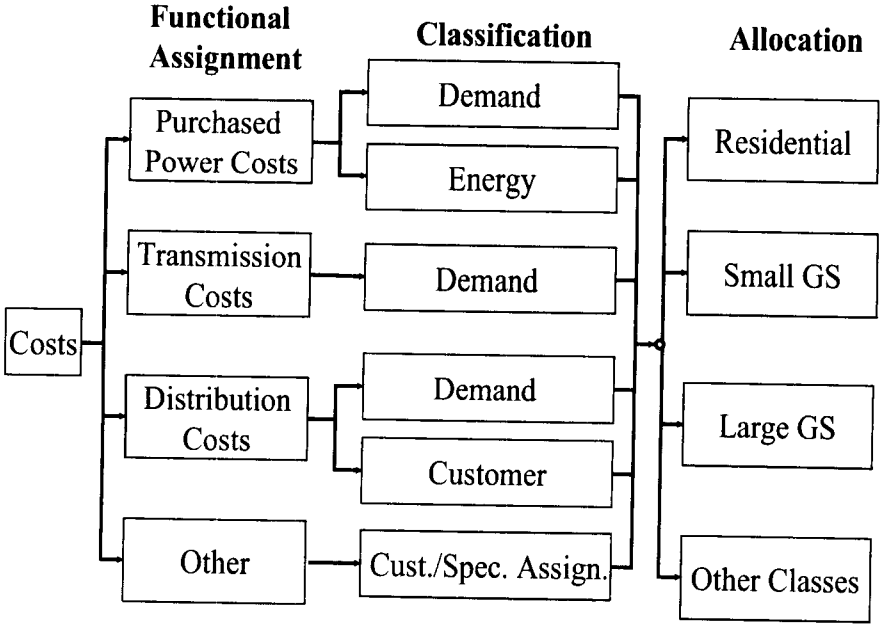
In this study, the following *allocation factors* are used to allocate costs to the various customer classes:

- **PPDA** – The demand cost components of purchased power costs are allocated on the basis of the average of each class's contribution to the 12 monthly coincident peak demands.
- **PPEA** – The energy cost component of purchased power costs is allocated on the basis of the kWh sales to each class of customers during the test year.
- **T01** –Transmission plant is allocated on the basis of the average of each class's contribution to the 12 monthly coincident peak demands.
- **SA1** – Substation demand costs are allocated on the basis of the maximum class demands for each customer class.

- **DA1** – Primary and secondary distribution demand-related costs are allocated on the basis of the sum of the individual customer demands for each customer class.
- **C01** – The customer cost component of primary and secondary distribution plant is allocated on the basis of the average number of customers for the test year.
- **SERV** – Customer services are allocated on the basis of the cost weighted average number of customers for the test year.
- **C03** – Meter costs are allocated on the basis of the cost weighted average number of customers for the test year.
- **C04** – Lighting costs were directly assigned to the lighting class.
- **C05** – Meter reading, billing, and customer service expenses are allocated to each class on the basis of the average number of customers in each class during the test year.
- **C06** – Load management expenses are allocated to each class that participates in load management on the basis of the average number of customers in those classes.

The three steps of the cost of service study are summarized in the graph shown in Figure 1. As explained above, costs are first assigned to the functional groups, then classified as demand-related, energy-related or customer-related, and then allocated to the customer classes, as follows:

Figure 1



Cost Determination

When we say that costs are functionally assigned, classified and then allocated, what is meant by the term "costs"? To what "costs" are we referring?

In reference to a cost of service study, "*costs*" refer to a utility's "revenue requirements" or, synonymously, the utility's "cost of service." A utility's rates must be sufficient to produce enough revenue to cover its revenue requirement on a going forward basis. Essentially, revenue requirements include all of the utility's accounting costs plus an appropriate level of margins. More specifically, a utility's revenue requirements include the following components of cost: (i) operation and maintenance expenses; (ii) depreciation expenses; (iii) utility operating margins (including interest expenses on borrowed funds); (iv) income taxes (as applicable); and (v) other taxes (e.g., property taxes) (as applicable). The following formula is useful in identifying the items generally included in revenue requirements:

Rev Req = O&M + Depreciation + UOM + IT + OT

Where:
- *Rev Req* = Revenue requirements
- *O&M* = Operation and maintenance expenses
- *Deprec* = Depreciation expenses
- *UOM* = Utility operating margins (including interest)
- *IT* = Income taxes (as applicable)
- *OT* = Other taxes, such as property taxes (as applicable)

One of the primary objectives of this study is to determine the extent to which revenues from each class of consumers contribute toward the return on total investment. For purposes of this study, Utility Operating Margins are defined as operating revenues less operation and maintenance expenses, depreciation expenses, income taxes (as applicable), and other taxes :

Utility Operating Margins = Operating Revenues – O&M – Deprec – IT – OT

The cost of service study also calculates a rate of return for each customer class. For purposes of this study, rate of return is calculated by dividing utility operating margins by the net cost rate base, as follows:

Rate of Return = Utility Operating Margins ÷ Net Cost Rate Base

In this formula, *net cost rate base* is a measure of the utility's net investment (gross investment less accumulated depreciation) required to provide service to customers. It must be *strongly* emphasized that since interest has not been identified as an operating expense in the cost of service, a portion of the Utility Operating Margins (as well as the Rate of Return) goes to cover interest expenses. It is important to recognize that net cost rate base represents the utility's investment in facilities needed to provide service to customers irrespective of how the

investment in these facilities was funded. As a general matter, a utility's net cost rate base will have been funded by both borrowed funds (i.e., short and long-term debt) and internally generated funds (members' equity). Therefore, the rate of return on rate base is comparable to the utility's weighted cost of capital (i.e., weighted by both debt and equity). The reason that the rate of return is calculated in this manner is to provide a clear representation of the contribution that each class is making toward providing a return on the utility's total capital (i.e., rate base) supplied to provide service.

The net cost rate base represents the value of the assets used to provide utility service. It includes the following components:

(1) Plant in service;
(2) Construction work in progress;
(3) Cash working capital;
(4) Materials and supplies;
(5) Prepayments; and
(6) Deferred Debits

less the following:

(1) Accumulated depreciation; and
(2) Customer Deposits.

Cash working capital represents an amount of cash funding required by the utility to carry out its business. For purposes of this study, cash working capital was calculated on the basis of 45 days of annual operation and maintenance expenses, excluding purchase power expenses (i.e., operation and maintenance expenses excluding purchase power expenses were multiplied by a factor determined by dividing 45 days by 365 days).

Pro-Forma Adjustments

A utility's rates should be designed to recover the cost of providing service to customers on a going forward basis. In preparing this cost of service study, costs were determined based on *historical* accounting costs for the 12 months ended December 31, 2009. Although it is standard practice to utilize a recent historical test year to determine revenue requirements, some of the components of cost may not be representative of the level of costs that the utility will likely experience on a going forward basis. For example, during the test year used in a cost of service study, the utility's wholesale power supplier may have increased rates. Therefore, to determine the appropriate revenue requirements representative on a going-forward basis, it is important to make a pro-forma adjustment to test-year purchased power expenses to incorporate the current rates being charged by the supplier. If a pro-forma adjustment was not made, then the purchased power expenses captured in the utility's annual revenue requirements will understate the level of expenses that the utility would expect to see once new rates go into effect.

The following pro-forma adjustments were made in this study:

- **Labor Adjustment.** A pro-forma adjustment was made to reflect the 3% increase in labor costs. The adjustment increased test-year expenses by $155,299.
- **Purchased Power Adjustment (Chevron).** A pro-forma adjustment was made to reflect the increase in Chevron's purchased power cost. The adjustment increased test-year expenses by $1,615,045.
- **Revenue Adjustment (Chevron).** A pro-forma adjustment was made to reflect the increase in revenue to offset Chevron's purchased power cost. The adjustment increased test-year revenues by $1,615,045.

Cost of Service Model

In the model used in this cost of service study, it is easy to determine the way in which a particular account is functionally assigned and classified. After the column containing the account number and account description in Schedule A of the report is a column titled "Name" and a column titled "Functional Vector". Each row has a unique "Name" so that it can be used to functionally assign and classify other accounts in Schedule A. The name that appears in the "Functional Vector" column for a particular account provides the "Name" of the row that was used to functionally assign and classify that account. The way in which a named row is used to functionally assign and classify an account is to turn it into a row of allocation factors by dividing each element in the row by the total system amount for the row. Calculated in this manner, the allocation factors sum to one. This row of allocation factors is then multiplied by the total system amount for the account that is being functionally assigned and classified.

As a simple example, say that we are trying to functionally assign and classify Account Y which contains $1,000,000 using the following row named X.

Name	Total System	Purchased Power		Distribution		Customer Service
		Energy	Demand	Customer	Demand	Customer
X	$240,000	$ -	$ -	$150,000	$70,000	$20,000

First, a row of allocation factors would be calculated using the values in row X as described above:

Name	Total System	Purchased Power		Distribution		Customer Service
		Energy	Demand	Customer	Demand	Customer
X	1.000	-	-	0.625	0.292	0.083

These allocation factors would then be multiplied by the $1,000,000 in Account Y to produce the following functional assignment and classification for this account:

Name	Total System	Purchased Power		Distribution		Customer Service
		Energy	Demand	Customer	Demand	Customer
Y	$1,000,000	$ -	$ -	$625,000	$291,667	$83,333

In the cost of service model, an account can be functionally assigned and classified on a different basis simply by inserting a new "Name" in the "Functional Vector" column. This provides tremendous flexibility in using the model.

As described above, each account in Schedule A is functionally assigned and classified using what are referred to in the model as "functional vectors." In Schedule A of the report, accounting costs are functionally assigned and classified using both explicitly determined and internally generated functional vectors. The explicitly determined functional vectors, which are primarily used to direct where costs are functionally assigned and classified, are shown on the last set of pages of Schedule A. Internally generated functional vectors are utilized throughout the study to functionally assign costs on the basis of similar costs or on the basis of internal cost drivers. An example of this process is the use of production, transmission and distribution labor to allocate Employee Benefits – Account 926. Because employee benefits largely follow labor costs, it is reasonable to allocate these costs to the functional groups on the basis of payroll costs. As described above, the functional vector used to allocate a specific cost is identified by the column in the model labeled "Functional Vector" and refers to a vector identified elsewhere in the analysis by the column labeled "Name."

Once costs for all of the major accounts are functionally assigned and classified, the resultant cost matrix for the major cost groupings (e.g., Plant in Service, Rate Base, Operation and Maintenance Expenses) is then transposed and allocated to the customer classes using "allocation vectors" or "allocation factors" which are calculated in the same manner as the functional vectors in Schedule A. The results of the class allocation step of the cost of service study are shown in Schedule B.

This linkage in the model between Schedule A, where each account is functionally assign and classified, and Schedule B, where these functionally assigned and classified costs are allocated to all of the utility's rate classes, provides significant flexibility in using the cost of service model to explore the impacts of scenarios that the utility may want to analyze. For example, the impact of building a new substation on a utility's costs and rates could be examined by increasing the dollar amount contained in the station equipment account (Account 362 in Schedule A) by the cost of the new substation. The cost of service model would do the rest and would functionally assign, classify and allocate this incremented cost to the appropriate rate classes.

Purchased Power Expenses

Purchased power expenses are the single largest component of Kit Carson's cost of service. Based on pro-forma results, purchased power expenses made up 64% of the total expenses during the test year. Because of the relationship between the maximum demand and energy consumption (load factor), this percentage will vary from one customer class to another.

In a cost of service study it is important to allocate purchased power expenses on the same basis as they are incurred by the utility. Kit Carson purchases all of its power requirements from Tri-State G&T. Tri-State's rate schedule consists of a production demand charge and an energy charge. The production demand charge is assessed on the basis of the coincident peak demands. Therefore, in the cost of service study the costs associated with the production demand charges are allocated on the basis of the class contribution to the twelve monthly coincident peak demands. In the cost of service study the energy charges are allocated to the customer classes on the basis of kWh sales. Purchased Power Costs are tabulated in Schedule C.

Distribution Costs

In the cost of service study, distribution costs are assigned to the following functional groups -- Station Equipment, Primary & Secondary Distribution Plant, Customer Services, Distribution Meters, Lighting Systems, and Load Management.

Station Equipment primarily consists of large distribution substations that are installed to meet the aggregate maximum demand of customers within a service region. In the cost of service study these costs are allocated to the customer classes on the basis of the maximum demand for each class of customer.

Primary & Secondary Distribution Plant consists of costs related to poles, towers and fixtures (Account No. 364), overhead conductors and devices (Account No. 365), underground conduit (Account No. 366), underground conductors and devices (Account No. 367) and lines transformers (Account No. 368). These distribution related costs are split into demand related costs and customer related costs in order to allocate these costs to customers with different usage patterns as fairly as possible. Every customer needs a certain minimum amount of equipment in order to have access to the electric grid, which is referred to as a minimum system. However, customers who use a lot of electric energy cannot get by with just a minimum system and must have larger equipment installed in order to reliably meet their needs. Since all customers need at least a minimum system to access the electric grid, the cost of the minimum system is classified as a customer related cost while the cost of the equipment that a customer needs above the minimum system is classified as demand related. By making this distinction, customers are only paying for the amount of equipment that is necessary to provide them with access to the electric grid and with safe, reliable service.

Two commonly used methodologies for determining demand/customer splits of distribution plant are the "minimum system" methodology and the "zero intercept" methodology. In fact, these are the only two methodologies referenced in the *Electric Utility Cost Allocation Manual* (January 1992) prepared by the National Association of Regulatory Utility Commissioners ("NARUC"). In the minimum system approach, a "minimum" standard equipment size is selected and the minimum system is obtained by pricing all the facilities at the unit cost of this minimum size. The minimum system determined in this manner is then classified as customer-related and allocated on the basis of the number of customers in each rate class. All costs in excess of the minimum system are classified as demand-related. As described above, the theory supporting this approach maintains that in order for a utility to serve even the smallest customer, it would have to install a minimum size system. Therefore, the costs associated with the minimum system are related to the number of customers that are served, instead of the demand imposed by the customers on the system.

In preparing this study, the "zero intercept" methodology was used to determine the customer component of transformers. Because the zero intercept methodology is less subjective than the minimum system approach, we prefer the zero intercept methodology over the minimum system methodology when the data necessary to perform the analysis is available. With the zero intercept methodology, we do not have to choose minimum size facilities to determine the customer component. In the zero intercept methodology, a zero-size transformer and conductor is the absolute minimum system determined from the application of a linear regression analysis using the utility's Continuing Property Records ("CPR").

The theory behind the zero intercept methodology is that there is a linear relationship between the unit cost of the equipment ($/transformer or $/ft of conductor) and the load carrying capability of the facilities. After establishing a linear relation, which is given by the equation:

$$\mathbf{y = a + bx}$$

where:

y is the unit cost of the facilities,
x is the size of the facilities, and
a, ***b*** are the coefficients representing the intercept and slope, respectively,

it can be determined that, theoretically, the unit cost of a transformer with a zero kVA rating or a conductor with zero cross-sectional area (MCM) is represented by the coefficient ***a***, the zero intercept. The zero intercept is essentially the cost component of transformers or conductors that is invariant to the size (and load carrying capability) of the equipment.

Like most systems, the number of transformers or feet of conductor on Kit Carson's distribution system is not uniformly distributed over all sizes of equipment. For this reason, it is necessary to use a weighted regression analysis, instead of a standard least-squares analysis, in the

determination of the zero intercept. Again, NARUC's *Electric Utility Cost Allocation Manual* recommends (at pages 93 and 94) that a weighted regression analysis be used when applying the zero-intercept methodology. Using a weighted regression analysis, the cost and size of each equipment type is, in effect, weighted by the number of installed units. In a weighted regression analysis, the weighted sum of squared differences

$$\sum_i n_i (y_i - \hat{y}_i)^2$$

is minimized, where n_i is the weighting factor for each size of equipment, and y is the observed value and $\hat{y}$ is the predicted value of the dependent variable (in this case the unit cost of the equipment).

The weighted regression analysis is performed by applying a transformation to the standard linear regression model ($y = a + bx$) and estimating the coefficients a and b using a standard multivariate least squares methodology. The transformation is applied by multiplying the equation (both sides of the linear model) by the square root of the number of feet of conductor or number of transformers ($\sqrt{n}$), as follows:

$$y\sqrt{n} = a\sqrt{n} + bx\sqrt{n}$$

The coefficients a and b are then determined by applying a multivariate least squares methodology using $y\sqrt{n}$ as the dependent variable and $\sqrt{n}$ and $x\sqrt{n}$ as the two independent variables. For more information concerning weighted least squares analysis, see Samprit Chatterjee and Bertram Price, *Regression Analysis by Example*, pages 101-105 and Douglas C. Montgomery and Elizabeth A. Peck, *Introduction to Linear Regression Analysis*, Second Edition, Wiley Series in Probability and Mathematical Statistics, page 108.

In this cost of service study, the zero intercept methodology was used for overhead conductor, underground conductor, and line transformers. To determine the customer-related portion of these costs, the applicable zero-intercept (coefficient a) is multiplied by the number of feet of conductor or number of transformers and divided by the total cost from the continuing property records ("CPR") data utilized in the study. The customer/demand percentages determined from the zero-intercept analyses are summarized below:

DISTRIBUTION PLANT	DEMAND-RELATED PERCENTAGE	CUSTOMER-RELATED PERCENTAGE
Overhead Conductor (Est.)	84.25%	15.75%
Underground Conductor	47.59%	52.41%
Line Transformers	28.43%	71.57%

A zero-intercept analysis for distribution poles is not performed because we have observed little correlation between the size of the pole and the load carrying capability of the equipment on the pole. Since the principal purpose of a pole or tower is to support overhead conductor, the customer/demand percentages for poles, towers and fixtures should not differ from the percentage used for overhead conductor. Consequently, the classification percentage determined for overhead conductors was also used to classify poles, towers and fixtures in the cost of service study.

In the study, customer services were allocated on the basis of the estimated cost of a typical service installation for each customer class, weighted by the number of customers within the class. The representative costs for typical services were provided by Kit Carson's engineering department. Similarly, distribution meters were also allocated on the basis of the estimated cost of a typical meter installation for each customer class, weighted by the number of customers within the class.

Distribution lighting equipment is primarily recorded in Street Lighting and Signal Systems (Account No. 373). These costs were directly assigned to private area and street lighting customers. These customer classes also receive an allocation of distribution substation and primary and secondary distribution costs and service costs. Traffic and athletic lighting customers own their own lighting equipment; therefore, these classes receive an allocation of distribution substation costs, primary and secondary distribution costs, service costs, and meter costs. Load management costs were directly assigned to the residential load management class.

Billing, Customer Service and Administrative Costs

Billing and customer service costs are allocated to the customer classes on the basis of the estimated cost of reading the meter, processing the bill, and providing miscellaneous customer service support to customers within each customer class.

Administrative and General ("A&G") expenses are assigned to each functional group and cost classification on the basis of an internally generated allocation factor that reflects the type of costs driving the A&G expense. For example, as explained earlier in this report, benefits are allocated to the functional groups and cost classifications on the basis of labor costs.

Class Rates of Return

The class rate of return provides information about whether each class of customers is making an appropriate contribution towards the utility's earnings requirements. If a utility is earning a low rate of return – or perhaps even a negative rate of return – from a particular class of customers, then this generally indicates that this class of customers is not paying its fair share and that the rates being charged to the customer class are too low. An important consideration is where the class rate of return falls relative to the overall rate of return earned by the utility from all customer classes. When a rate of return for a customer class is below the overall rate of return then this generally indicates that the customer class is being subsidized by other rate classes.

In terms of equity and efficiency, the rates of return should generally be the same for all classes of customers. However, in some situations the utility may consider other factors in determining the appropriate rate of return for a particular customer class. For example, the utility may want to consider the risk of serving particular customers. Some rate classes are riskier to serve than others. Residential customers tend to have revenue streams that are more volatile (because of the temperature sensitive nature of the load) and they often have a higher percentage of uncollectible revenues than other customer groups. On the other hand, some industrial customers can also create financial risks for the utility, especially large industrial customers that operate in volatile or risky industries and that create a potential for stranded utility investments. The utility may also want to consider competitive pressures from neighboring energy suppliers in establishing a targeted rate of return for a particular class of customers. Utilities will often establish a lower rate of return for a rate class in order to encourage a new energy technology as a part of a short-term marketing initiative.

Aside from these considerations, we generally recommend that the utility strive toward equalizing the rates of return for all customer classes. If a class rate of return falls significantly below the overall rate of return for the total system, and rate shock becomes in issue, then we urge the utility to consider employing the principle of gradualism by moving the rate of return for that class in the direction of (but not all the way to) the average rate of return for the total system. Likewise, if a class rate of return is significantly above the overall system rate of return, then we urge the utility to consider a strategy for reducing that class rate of return in the direction of the overall system average.

Table 1 shows the actual pro-forma rate of return for each customer class from the cost of service study.

Table 1. Summary of Returns

Rate	Revenue	Operating Expenses	Operating Margin	Rate Base	Rate of Return
Residential Service	$15,311,669	$15,604,712	$(293,043)	$47,227,703	-0.62%
Residential Seasonal Service	$1,959,765	$2,053,834	$(94,069)	$6,569,698	-1.43%
Commercial Service	$5,600,130	$5,487,110	$113,020	$14,254,166	0.79%
Power Service	$7,060,832	$5,567,254	$1,493,578	$7,876,983	18.96%
Security Lighting Service	$363,858	$298,847	$65,011	$971,991	6.69%
Interruptible Power Service	$112,683	$67,868	$44,815	$422,804	10.60%
Power Service Time-of-Use	$168,835	$149,487	$19,348	$236,880	8.17%
Residential Service Time-of-Use	$453,931	$473,676	$(19,745)	$1,225,233	-1.61%
Residential Seasonal Service Time-of-Use	$14,109	$15,812	$(1,704)	$48,960	-3.48%
Commercial Service Time-of-Use	$215,270	$210,721	$4,549	$513,849	0.89%
Irrigation Power Service Time-of-Use	$ -	$ -	$ -	$ -	0.00%
Irrigation Power Service	$5,777	$8,482	$(2,705)	$28,632	-9.45%
Chevron - Special Contract	$3,778,702	$3,575,001	$203,701	$2,685,151	7.59%
Total	$35,045,563	$33,512,806	$1,532,757	$82,062,050	1.87%

Unit Costs

Unit costs for each rate class that are calculated from the revenue requirement information contained in the cost of service model provide a good indication of what unbundled, cost-based rates would look like. In developing these unit costs, the utility's margins reflected in the distribution and customer charges. This ensures that the utility will continue to collect all of its margins, even in a retail choice environment. When margins recovered through the distribution and customer charges, purchased power or fuel costs become a straight pass through and is collected from customers on a dollar-for-dollar basis with no margin attached. These unbundled, cost-based rate components can be compared to the utility's existing rate structure to provide an indication of how much the utility's current rate structure deviates from one that is strictly cost based.

In the cost of service study, revenue requirements are calculated for the following cost categories:

- **Purchased Power Demand**
- **Purchased Power Energy**
- **Distribution Demand**
- **Distribution Customer**

Unit costs are developed by dividing (i) the revenue requirement by cost category for each customer class by (ii) the applicable billing units for each customer class. For the residential class (served under a two-part rate schedule consisting of a customer charge and an energy charge), the unit cost for all demand and energy cost categories are determined by dividing the revenue requirement by annual kWh. Unit customer costs are then calculated by dividing distribution customer costs by annual customer-months (i.e., the average number of customers during the test year multiplied by the number of months). For commercial and industrial customer classes with three-part rate schedules (consisting of a customer charge, demand charge, and energy charge), unit demand costs are determined by dividing production, transmission, and distribution demand costs by billing demand (kW-Months), unit energy costs are calculated by dividing energy costs by annual kWh sales, and unit customer costs are then calculated by dividing distribution customer costs by annual customer-months.

The unit costs by cost category are shown on the last set of pages in Schedule B. The billing determinants used to compute the unit costs are shown in Schedule D. The demand allocation factors used in the cost of service study are also derived in this schedule.

Using the Cost of Service Results to Design Rates

The cost of service study provides a great deal of useful information for designing rates and helps in addressing the key questions that a utility must consider when setting rates. Some of these key questions are:

- Does the utility want to take significant steps toward eliminating subsidies among classes indicated by the differences in individual class rates of return from the overall system rate of return?

- Is the overall system average rate of return sufficient to generate margins that provide a large enough pool of internal financial resources for dealing with emergencies after interest expenses on long term debt are paid?

- Do the individual rate components in the utility's existing rates accurately reflect the unit costs for those components from the cost of service study?

The unit costs calculated in Schedule B provide important information about how the utility might want to modify the various rate components included in its current rate schedules. For example, the unit cost analysis might indicate that the customer charge in a rate schedule is significantly below the customer cost determined from the cost of service study, or that the demand charge in one of the utility's three-part (customer/demand/energy) rate schedules is also significantly lower than the demand cost determined from the study. As noted above, rates that do not reflect unit costs will create subsidies within a given rate schedule, will likely result in increased margin volatility for the utility and will also likely increase customer bill volatility. For example, if a demand charge in a commercial/industrial rate schedule is below the unit demand cost then customers with low load factors will generally be subsidized by customers with high load factors. Just as a utility should strive to equalize the class rates of return, the utility should also strive to set its rates so that they reflect the unit cost of providing service and reduce subsidies among customers within customer classes.

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Plant in Service								
Intangible Plant								
301.00 ORGANIZATION	P301	PT&D	$ -	-	-	-	-	-
303.00 MISC. INTANGIBLE	P303	PT&D	-	-	-	-	-	-
Total Intangible Plant	PINT		$ -	$ -	$ -	$ -	$ -	$ -
Other Production Plant								
340.00 LAND AND LAND RIGHTS	P340	F017	$ -	-	-	-	-	-
341.00 STRUCTURES AND IMPROVEMENTS	P341	F017	3,963,364	3,963,364	-	-	-	-
342.00 FUEL HOLDERS, PRODUCERS & ACCESSORIES	P342	F017	-	-	-	-	-	-
343.00 PRIME MOVERS	P343	F017	-	-	-	-	-	-
344.00 GENERATORS	P344	F017	-	-	-	-	-	-
345.00 ACCESSORY ELECTRIC EQUIPMENT	P345	F017	-	-	-	-	-	-
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	P346	F017	-	-	-	-	-	-
Total Other Production Plant	POTHPRD		$ 3,963,364	$ 3,963,364	$ -	$ -	$ -	$ -
Transmission								
350.00 LAND AND LAND RIGHTS	P350	F011	$ 17,766	-	-	-	17,766	-
351.00 CLEARING LAND RIGHT-OF-WAY	P351	F011	210,304	-	-	-	210,304	-
352.00 STRUCTURES AND IMPROVEMENTS	P352	F011	-	-	-	-	-	-
353.00 STATION EQUIPMENT	P353	F011	-	-	-	-	-	-
354.00 TOWERS AND FIXTURES	P354	F011	-	-	-	-	-	-
355.00 POLES AND FIXTURES	P355	F011	3,846,017	-	-	-	3,846,017	-
356.00 CONDUCTORS AND DEVICES	P356	F011	2,496,641	-	-	-	2,496,641	-
359.00 ROADS AND TRAILS	P359	F011	14,595	-	-	-	14,595	-
Total Transmission Plant	PTRAN		$ 6,585,323	$ -	$ -	$ -	$ 6,585,323	$ -
Distribution								
360.00 LAND AND LAND RIGHTS	P360	F001	$ 122,258	-	-	-	-	122,258
361.00 STRUCTURES AND IMPROVEMENTS	P361	F001	5,871	-	-	-	-	5,871
362.00 STATION EQUIPMENT	P362	F001	8,385,910	-	-	-	-	8,385,910
364.00 POLES, TOWERS AND FIXTURES	P364	F002	6,294,553	-	-	-	-	-
365.00 OVERHEAD CONDUCTORS AND DEVICE	P365	F003	10,034,433	-	-	-	-	-
366.00 UNDERGROUND CONDUIT	P366	F004	-	-	-	-	-	-
367.00 UNDERGROUND CONDUCTORS AND DEV	P367	F004	21,143,096	-	-	-	-	-
368.00 LINE TRANSFORMERS	P368	F005	22,846,157	-	-	-	-	-
369.00 SERVICES	P369	F006	1,300,258	-	-	-	-	-
370.00 METERS	P370	F007	7,633,068	-	-	-	-	-
371.00 INSTALLATIONS ON CONSUMERS PRE	P371	F013	5,227	-	-	-	-	-
372.00 LEASED PROP. ON CONSUMERS PREMISES	P372	F013	-	-	-	-	-	-
373.00 STREET LIGHTING AND SIGNAL SYS	P373	F008	1,029,723	-	-	-	-	-
Total Distribution Plant	PDIST		$ 78,800,556	$ -	$ -	$ -	$ -	$ 8,514,040
Total Tranmission and Distribution Plant	PT&D		$ 85,385,879	$ -	$ -	$ -	$ 6,585,323	$ 8,514,040

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant		Customer Services		Meters	Lighting Systems	Meter Reading Billing and Cust Service
			Demand	Customer	Demand	Customer	Customer	Customer	Customer
Plant in Service									
Intangible Plant									
301.00 ORGANIZATION	P301	PT&D	-	-	-	-	-	-	-
303.00 MISC. INTANGIBLE	P303	PT&D	-	-	-	-	-	-	-
Total Intangible Plant	PINT		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Production Plant									
340.00 LAND AND LAND RIGHTS	P340	F017	-	-	-	-	-	-	-
341.00 STRUCTURES AND IMPROVEMENTS	P341	F017	-	-	-	-	-	-	-
342.00 FUEL HOLDERS, PRODUCERS & ACCESSORIES	P342	F017	-	-	-	-	-	-	-
343.00 PRIME MOVERS	P343	F017	-	-	-	-	-	-	-
344.00 GENERATORS	P344	F017	-	-	-	-	-	-	-
345.00 ACCESSORY ELECTRIC EQUIPMENT	P345	F017	-	-	-	-	-	-	-
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	P346	F017	-	-	-	-	-	-	-
Total Other Production Plant	POTHPRD		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission									
350.00 LAND AND LAND RIGHTS	P350	F011	-	-	-	-	-	-	-
351.00 CLEARING LAND RIGHT-OF-WAY	P351	F011	-	-	-	-	-	-	-
352.00 STRUCTURES AND IMPROVEMENTS	P352	F011	-	-	-	-	-	-	-
353.00 STATION EQUIPMENT	P353	F011	-	-	-	-	-	-	-
354.00 TOWERS AND FIXTURES	P354	F011	-	-	-	-	-	-	-
355.00 POLES AND FIXTURES	P355	F011	-	-	-	-	-	-	-
356.00 CONDUCTORS AND DEVICES	P356	F011	-	-	-	-	-	-	-
359.00 ROADS AND TRAILS	P359	F011	-	-	-	-	-	-	-
Total Transmission Plant	PTRAN		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution									
360.00 LAND AND LAND RIGHTS	P360	F001	-	-	-	-	-	-	-
361.00 STRUCTURES AND IMPROVEMENTS	P361	F001	-	-	-	-	-	-	-
362.00 STATION EQUIPMENT	P362	F001	-	-	-	-	-	-	-
364.00 POLES, TOWERS AND FIXTURES	P364	F002	5,303,161	991,392	-	-	-	-	-
365.00 OVERHEAD CONDUCTORS AND DEVICE	P365	F003	8,454,010	1,580,423	-	-	-	-	-
366.00 UNDERGROUND CONDUIT	P366	F004	-	-	-	-	-	-	-
367.00 UNDERGROUND CONDUCTORS AND DEV	P367	F004	10,061,999	11,081,097	-	-	-	-	-
368.00 LINE TRANSFORMERS	P368	F005	6,495,163	16,350,995	-	-	-	-	-
369.00 SERVICES	P369	F006	-	-	-	1,300,258	-	-	-
370.00 METERS	P370	F007	-	-	-	-	7,633,068	-	-
371.00 INSTALLATIONS ON CONSUMERS PRE	P371	F013	-	-	-	-	-	5,227	-
372.00 LEASED PROP. ON CONSUMERS PREMISES	P372	F013	-	-	-	-	-	-	-
373.00 STREET LIGHTING AND SIGNAL SYS	P373	F008	-	-	-	-	-	1,029,723	-
Total Distribution Plant	PDIST		$ 30,314,333	$ 30,003,907	$ -	$ 1,300,258	$ 7,633,068	$ 1,034,951	$ -
Total Tranmission and Distribution Plant	PT&D		$ 30,314,333	$ 30,003,907	$ -	$ 1,300,258	$ 7,633,068	$ 1,034,951	$ -

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Plant in Service					
Intangible Plant					
301.00 ORGANIZATION	P301	PT&D	-	-	ok
303.00 MISC. INTANGIBLE	P303	PT&D	-	-	ok
Total Intangible Plant	PINT		$ -	-	ok
Other Production Plant					
340.00 LAND AND LAND RIGHTS	P340	F017	-	-	ok
341.00 STRUCTURES AND IMPROVEMENTS	P341	F017	-	3,963,364	ok
342.00 FUEL HOLDERS, PRODUCERS & ACCESSORIES	P342	F017	-	-	ok
343.00 PRIME MOVERS	P343	F017	-	-	ok
344.00 GENERATORS	P344	F017	-	-	ok
345.00 ACCESSORY ELECTRIC EQUIPMENT	P345	F017	-	-	ok
346.00 MISCELLANEOUS POWER PLANT EQUIPMENT	P346	F017	-	-	ok
Total Other Production Plant	POTHPRD		$ -	3,963,364	ok
Transmission					
350.00 LAND AND LAND RIGHTS	P350	F011	-	17,766	ok
351.00 CLEARING LAND RIGHT-OF-WAY	P351	F011	-	210,304	ok
352.00 STRUCTURES AND IMPROVEMENTS	P352	F011	-	-	ok
353.00 STATION EQUIPMENT	P353	F011	-	-	ok
354.00 TOWERS AND FIXTURES	P354	F011	-	-	ok
355.00 POLES AND FIXTURES	P355	F011	-	3,846,017	ok
356.00 CONDUCTORS AND DEVICES	P356	F011	-	2,496,641	ok
359.00 ROADS AND TRAILS	P359	F011	-	14,595	ok
Total Transmission Plant	PTRAN		$ -	6,585,323	ok
Distribution					
360.00 LAND AND LAND RIGHTS	P360	F001	-	122,258	ok
361.00 STRUCTURES AND IMPROVEMENTS	P361	F001	-	5,871	ok
362.00 STATION EQUIPMENT	P362	F001	-	8,385,910	ok
364.00 POLES, TOWERS AND FIXTURES	P364	F002	-	6,294,553	ok
365.00 OVERHEAD CONDUCTORS AND DEVICE	P365	F003	-	10,034,433	ok
366.00 UNDERGROUND CONDUIT	P366	F004	-	-	ok
367.00 UNDERGROUND CONDUCTORS AND DEV	P367	F004	-	21,143,096	ok
368.00 LINE TRANSFORMERS	P368	F005	-	22,846,157	ok
369.00 SERVICES	P369	F006	-	1,300,258	ok
370.00 METERS	P370	F007	-	7,633,068	ok
371.00 INSTALLATIONS ON CONSUMERS PRE	P371	F013	-	5,227	ok
372.00 LEASED PROP. ON CONSUMERS PREMISES	P372	F013	-	-	ok
373.00 STREET LIGHTING AND SIGNAL SYS	P373	F008	-	1,029,723	ok
Total Distribution Plant	PDIST		$ -	78,800,556	ok
Total Tranmission and Distribution Plant	PT&D		$ -	85,385,879	ok

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Plant in Service (Contigued)								
General Plant								
389.00 LAND AND LAND RIGHTS	P389	PT&D	576,889	-	-	-	44,492	57,523
390.00 STRUCTURES AND IMPROVEMENTS	P390	PT&D	5,678,644	-	-	-	437,961	566,232
391.00 OFFICE FURNITURE AND EQUIPMENT	P391	PT&D	1,447,425	-	-	-	111,632	144,326
392.00 TRANSPORTATION EQUIPMENT	P392	PT&D	2,815,818	-	-	-	217,168	280,772
393.00 STORES EQUIPMENT	P393	PT&D	29,228	-	-	-	2,254	2,914
394.00 TOOLS, SHOP & GARAGE EQUIPMENT	P394	PT&D	361,751	-	-	-	27,900	36,071
395.00 LABORATORY EQUIPMENT	P395	PT&D	-	-	-	-	-	-
396.00 POWER OPERATED EQUIPMENT	P396	PT&D	225,929	-	-	-	17,425	22,528
397.00 COMMUNICATION EQUIPMENT	P397	PT&D	1,838,593	-	-	-	141,800	183,331
398.00 MISCELLANEOUS EQUIPMENT	P398	PT&D	7,375	-	-	-	569	735
399.00 OTHER TANGIBLE PROPERTY	P399	PT&D	-	-	-	-	-	-
Total General Plant	PGP		$ 12,981,653	$ -	$ -	$ -	$ 1,001,200	$ 1,294,433
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	$ -	-	-	-	-	-
102.00 ELECTRIC PLANT PURCHASED OR SOLD	P102	PDIST	$ -	-	-	-	-	-
OTHER		PDIST	$ -	-	-	-	-	-
Total Plant in Service	TPIS		$ 102,330,896	$ 3,963,364	$ -	$ -	$ 7,586,523	$ 9,808,473
Construction Work in Progress (CWIP)								
CWIP Transmission	CWIP1	F011	$ -	-	-	-	-	-
CWIP Distribution Plant	CWIP2	PGP	10,895,184	-	-	-	840,283	1,086,386
CWIP General Plant	CWIP3	F003	-	-	-	-	-	-
CWIP General Plant -- Generators	CWIP4	F016	-	-	-	-	-	-
RWIP	CWIP5	F004	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 10,895,184	$ -	$ -	$ -	$ 840,283	$ 1,086,386
Total Utility Plant			$ 113,226,080	$ 3,963,364	$ -	$ -	$ 8,426,806	$ 10,894,859

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant Demand	Pri & Sec. Distr Plant Customer	Customer Services Demand	Customer Services Customer	Meters Customer	Lighting Systems Customer	Meter Reading Billing and Cust Service Customer
Plant in Service (Continued)									
General Plant									
389.00 LAND AND LAND RIGHTS	P389	PT&D	204,811	202,714	-	8,785	51,571	6,992	-
390.00 STRUCTURES AND IMPROVEMENTS	P390	PT&D	2,016,075	1,995,429	-	86,475	507,642	68,830	-
391.00 OFFICE FURNITURE AND EQUIPMENT	P391	PT&D	513,876	508,613	-	22,041	129,393	17,544	-
392.00 TRANSPORTATION EQUIPMENT	P392	PT&D	999,693	989,456	-	42,879	251,720	34,130	-
393.00 STORES EQUIPMENT	P393	PT&D	10,377	10,271	-	445	2,613	354	-
394.00 TOOLS, SHOP & GARAGE EQUIPMENT	P394	PT&D	128,432	127,117	-	5,509	32,339	4,385	-
395.00 LABORATORY EQUIPMENT	P395	PT&D	-	-	-	-	-	-	-
396.00 POWER OPERATED EQUIPMENT	P396	PT&D	80,211	79,390	-	3,440	20,197	2,738	-
397.00 COMMUNICATION EQUIPMENT	P397	PT&D	652,751	646,067	-	27,998	164,361	22,285	-
398.00 MISCELLANEOUS EQUIPMENT	P398	PT&D	2,618	2,592	-	112	659	89	-
399.00 OTHER TANGIBLE PROPERTY	P399	PT&D	-	-	-	-	-	-	-
Total General Plant	PGP		$ 4,608,843	$ 4,561,648	$ -	$ 197,685	$ 1,160,495	$ 157,349	$ -
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	-	-	-	-	-
102.00 ELECTRIC PLANT PURCHASED OR SOLD	P102	PDIST	-	-	-	-	-	-	-
OTHER		PDIST	-	-	-	-	-	-	-
Total Plant in Service	TPIS		$ 34,923,176	$ 34,565,554	$ -	$ 1,497,943	$ 8,793,563	$ 1,192,299	$ -
Construction Work in Progress (CWIP)									
CWIP Transmission	CWIP1	F011	-	-	-	-	-	-	-
CWIP Distribution Plant	CWIP2	PGP	3,868,090	3,828,479	-	165,912	973,975	132,059	-
CWIP General Plant	CWIP3	F003	-	-	-	-	-	-	-
CWIP General Plant -- Generators	CWIP4	F016	-	-	-	-	-	-	-
RWIP	CWIP5	F004	-	-	-	-	-	-	-
Total Construction Work in Progress	TCWIP		$ 3,868,090	$ 3,828,479	$ -	$ 165,912	$ 973,975	$ 132,059	$ -
Total Utility Plant			$ 38,791,266	$ 38,394,034	$ -	$ 1,663,855	$ 9,767,537	$ 1,324,359	$ -

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Plant in Service (Continued)					
General Plant					
389.00 LAND AND LAND RIGHTS	P389	PT&D	-	576,889	ok
390.00 STRUCTURES AND IMPROVEMENTS	P390	PT&D	-	5,678,644	ok
391.00 OFFICE FURNITURE AND EQUIPMENT	P391	PT&D	-	1,447,425	ok
392.00 TRANSPORTATION EQUIPMENT	P392	PT&D	-	2,815,818	ok
393.00 STORES EQUIPMENT	P393	PT&D	-	29,228	ok
394.00 TOOLS, SHOP & GARAGE EQUIPMENT	P394	PT&D	-	361,751	ok
395.00 LABORATORY EQUIPMENT	P395	PT&D	-	-	ok
396.00 POWER OPERATED EQUIPMENT	P396	PT&D	-	225,929	ok
397.00 COMMUNICATION EQUIPMENT	P397	PT&D	-	1,838,593	ok
398.00 MISCELLANEOUS EQUIPMENT	P398	PT&D	-	7,375	ok
399.00 OTHER TANGIBLE PROPERTY	P399	PT&D	-	-	ok
Total General Plant	PGP		$ -	12,981,653	ok
106.00 COMPLETED CONSTR NOT CLASSIFIED	P106	PT&D	-	-	ok
102.00 ELECTRIC PLANT PURCHASED OR SOLD	P102	PDIST	-	-	ok
OTHER		PDIST	-	-	ok
Total Plant in Service	TPIS		$ -	102,330,896	ok
Construction Work in Progress (CWIP)					
CWIP Transmission	CWIP1	F011	-	-	ok
CWIP Distribution Plant	CWIP2	PGP	-	10,895,184	ok
CWIP General Plant	CWIP3	F003	-	-	ok
CWIP General Plant -- Generators	CWIP4	F016	-	-	ok
CWIP	CWIP5	F004	-	-	ok
Total Construction Work in Progress	TCWIP		$ -	10,895,184	ok
Total Utility Plant			$ -	113,226,080	ok

KIT CARSON ELECTRIC COOPERATIVE
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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Rate Base								
Utility Plant								
Plant in Service			$ 102,330,896	$ 3,963,364	$ -	$ -	$ 7,586,523	$ 9,808,473
Construction Work in Progress (CWIP)			10,895,184	-	-	-	840,282.97	1,086,386.04
Total Utility Plant	TUP		$ 113,226,080	$ 3,963,364	$ -	$ -	$ 8,426,806	$ 10,894,859
Less: Accumulated Provision for Depreciation								
Electric Plant Amortization	ADEPREPA	TUP	$ -	-	-	-	-	-
Retirement Work in Progress	RWIP	TUP	(99,557)	(3,485)	-	-	(7,410)	(9,580)
Transmission	ADEPRTP	PTRAN	2,952,058	-	-	-	2,952,058	-
Dist-Structures	ADEPRD1	P361	6,891	-	-	-	-	6,891
Dist-Station	ADEPRD2	P362	4,287,181	-	-	-	-	4,287,181
Dist-Poles and Fixtures	ADEPRD3	P364	2,750,866	-	-	-	-	-
Dist-OH Conductor	ADEPRD4	P365	3,221,312	-	-	-	-	-
Dist-UG Conduit	ADEPRD5	P366	-	-	-	-	-	-
Dist-UG Conductor	ADEPRD6	P367	6,616,251	-	-	-	-	-
Dist-Line Transformers	ADEPRD7	P368	5,920,231	-	-	-	-	-
Dist-Services	ADEPRD8	P369	838,554	-	-	-	-	-
Dist-Meters	ADEPRD9	P370	968,510	-	-	-	-	-
Dist-Installations on Customer Premises	ADEPRD10	F014	5,990	-	-	-	-	-
Dist-Lighting & Signal Systems	ADEPRD11	P373	392,543	-	-	-	-	-
Dist	ADEPRD12	PDIST	-	-	-	-	-	-
General Plant	ADEPRGP	PGP	6,321,064	-	-	-	487,507	630,289
Total Accumulated Depreciation	TADEPR		$ 34,181,893	$ (3,485)	$ -	$ -	$ 3,432,156	$ 4,914,782
Net Utility Plant	NTPLANT		$ 79,044,186	$ 3,966,849	$ -	$ -	$ 4,994,650	$ 5,980,077
Working Capital								
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	$ 1,065,682	-	-	-	11,360	66,063
Materials and Supplies	M&S	TPIS	2,041,120	79,054	-	-	151,323	195,642
Prepayments	PREPAY	TPIS	60,989	2,362	-	-	4,522	5,846
Total Working Capital	TWC		$ 3,167,791	$ 81,416	$ -	$ -	$ 167,204	$ 267,551
Deferred Debits								
Service Pension Cost	PENSCOST	TLB	$ -	-	-	-	-	-
Other Deferred Debits	DDEBPP	OMSUB2	-	-	-	-	-	-
Total Deferred Debits			$ -	$ -	$ -	$ -	$ -	$ -
Less: Customer Deposits	CSTDEP	TPIS	$ 149,927	5,807	-	-	11,115	14,371
Net Rate Base	RB		$ 82,062,050	$ 4,042,459	$ -	$ -	$ 5,150,739	$ 6,233,258

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Description	Name	Functional Vector	Pri & Sec. Distr Plant Demand	Pri & Sec. Distr Plant Customer	Customer Services Demand	Customer Services Customer	Meters Customer	Lighting Systems Customer	Meter Reading Billing and Cust Service Customer
Rate Base									
Utility Plant									
Plant in Service			$ 34,923,176	$ 34,565,554	$ -	$ 1,497,943	$ 8,793,563	$ 1,192,299	$ -
Construction Work in Progress (CWIP)			3,868,089.61	3,828,479.43	-	165,912.13	973,974.67	132,059.04	-
Total Utility Plant	TUP		$ 38,791,266	$ 38,394,034	$ -	$ 1,663,855	$ 9,767,537	$ 1,324,359	$ -
Less: Accumulated Provision for Depreciation									
Electric Plant Amortization	ADEPREPA	TUP	-	-	-	-	-	-	-
Retirement Work in Progress	RWIP	TUP	(34,108)	(33,759)	-	(1,463)	(8,588)	(1,164)	-
Transmission	ADEPRTP	PTRAN	-	-	-	-	-	-	-
Dist-Structures	ADEPRD1	P361	-	-	-	-	-	-	-
Dist-Station	ADEPRD2	P362	-	-	-	-	-	-	-
Dist-Poles and Fixtures	ADEPRD3	P364	2,317,605	433,261	-	-	-	-	-
Dist-OH Conductor	ADEPRD4	P365	2,713,955	507,357	-	-	-	-	-
Dist-UG Conduit	ADEPRD5	P366	-	-	-	-	-	-	-
Dist-UG Conductor	ADEPRD6	P367	3,148,674	3,467,577	-	-	-	-	-
Dist-Line Transformers	ADEPRD7	P368	1,683,122	4,237,109	-	-	-	-	-
Dist-Services	ADEPRD8	P369	-	-	-	-	-	-	-
Dist-Meters	ADEPRD9	P370	-	-	-	838,554	-	-	-
Dist-Installations on Customer Premises	ADEPRD10	F014	-	-	-	-	968,510	-	-
Dist-Lighting & Signal Systems	ADEPRD11	P373	-	-	-	-	-	5,990	-
Dist	ADEPRD12	PDIST	-	-	-	-	-	392,543	-
General Plant	ADEPRGP	PGP	2,244,151	2,221,171	-	96,257	565,071	76,617	-
Total Accumulated Depreciation	TADEPR		$ 12,073,398	$ 10,832,716	$ -	$ 933,348	$ 1,524,992	$ 473,986	$ -
Net Utility Plant	NTPLANT		$ 26,717,868	$ 27,561,318	$ -	$ 730,507	$ 8,242,545	$ 850,373	$ -
Working Capital									
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	325,873	208,383	-	2,975	101,259	10,719	339,050
Materials and Supplies	M&S	TPIS	696,587	689,454	-	29,878	175,399	23,782	-
Prepayments	PREPAY	TPIS	20,814	20,601	-	893	5,241	711	-
Total Working Capital	TWC		$ 1,043,275	$ 918,438	$ -	$ 33,746	$ 281,899	$ 35,211	$ 339,050
Deferred Debits									
Service Pension Cost	PENSCOST	TLB	-	-	-	-	-	-	-
Other Deferred Debits	DDEBPP	OMSUB2	-	-	-	-	-	-	-
Total Deferred Debits			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Less: Customer Deposits	CSTDEP	TPIS	51,167	50,643	-	2,195	12,884	1,747	-
Net Rate Base	RB		$ 27,709,976	$ 28,429,113	$ -	$ 762,059	$ 8,511,560	$ 883,837	$ 339,050

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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Rate Base					
Utility Plant					
Plant in Service			$ -	102,330,896	ok
Construction Work in Progress (CWIP)			-	10,895,184	ok
Total Utility Plant	TUP		$ -	113,226,080	ok
Less: Accumulated Provision for Depreciation					
Electric Plant Amortization	ADEPREPA	TUP	-	-	ok
Retirement Work in Progress	RWIP	TUP	-	(99,557)	ok
Transmission	ADEPRTP	PTRAN	-	2,952,058	ok
Dist-Structures	ADEPRD1	P361	-	6,891	ok
Dist-Station	ADEPRD2	P362	-	4,287,181	ok
Dist-Poles and Fixtures	ADEPRD3	P364	-	2,750,866	ok
Dist-OH Conductor	ADEPRD4	P365	-	3,221,312	ok
Dist-UG Conduit	ADEPRD5	P366	-	-	ok
Dist-UG Conductor	ADEPRD6	P367	-	6,616,251	ok
Dist-Line Transformers	ADEPRD7	P368	-	5,920,231	ok
Dist-Services	ADEPRD8	P369	-	838,554	ok
Dist-Meters	ADEPRD9	P370	-	968,510	ok
Dist-Installations on Customer Premises	ADEPRD10	F014	-	5,990	ok
Dist-Lighting & Signal Systems	ADEPRD11	P373	-	392,543	ok
Dist	ADEPRD12	PDIST	-	-	ok
General Plant	ADEPRGP	PGP	-	6,321,064	ok
Total Accumulated Depreciation	TADEPR		$ -	34,181,893	ok
Net Utility Plant	NTPLANT		$ -	79,044,186	ok
Working Capital					
Cash Working Capital - Operation and Maintenance Expenses	CWC	OMLPP	-	1,065,682	ok
Materials and Supplies	M&S	TPIS	-	2,041,120	ok
Prepayments	PREPAY	TPIS	-	60,989	ok
Total Working Capital	TWC		$ -	3,167,791	ok
Deferred Debits					
Service Pension Cost	PENSCOST	TLB	-	-	ok
Other Deferred Debits	DDEBPP	OMSUB2	-	-	ok
Total Deferred Debits			$ -	-	ok
Less: Customer Deposits	CSTDEP	TPIS	-	149,927	ok
Net Rate Base	RB		$ -	82,062,050	ok

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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Operation and Maintenance Expenses								
Purchased Power								
555 PURCHASED POWER	OM555	OMPP	$ 19,963,795	-	11,444,637	8,519,158	-	-
557 OTHER EXPENSES	OM557	OMPP	-	-	-	-	-	-
Total Purchased Power	TPP		$ 19,963,795	$ -	$ 11,444,637	$ 8,519,158	$ -	$ -
Transmission Expenses								
560 OPERATION SUPERVISION AND ENG	OM560	PTRAN	$ -	-	-	-	-	-
561 LOAD DISPATCHING	OM561	PTRAN	-	-	-	-	-	-
562 STATION EXPENSES	OM562	PTRAN	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	48,782	-	-	-	48,782	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	PTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	-	-	-	-	-	-
Total Transmission Expenses			$ 48,782	$ -	$ -	$ -	$ 48,782	$ -
Distribution Operation Expense								
580 OPERATION SUPERVISION AND ENGI	OM580	PDIST	$ 452,212	-	-	-	-	48,859
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	191,644	-	-	-	-	191,644
583 OVERHEAD LINE EXPENSES	OM583	P365	390,282	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	352,527	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P371	12,923	-	-	-	-	-
586 METER EXPENSES	OM586	P370	430,005	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P369	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	303,586	-	-	-	-	32,801
588 MISC DISTR EXP -- MAPPING	OM588x	F015	213,066	-	-	-	-	-
589 RENTS	OM589	PDIST	2,842	-	-	-	-	307
Total Distribution Operation Expense	OMDO		$ 2,349,089	$ -	$ -	$ -	$ -	$ 273,612

KIT CARSON ELECTRIC COOPERATIVE
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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant		Customer Services		Meters	Lighting Systems	Meter Reading Billing and Cust Service
			Demand	Customer	Demand	Customer	Customer	Customer	Customer
Operation and Maintenance Expenses									
Purchased Power									
555 PURCHASED POWER	OM555	OMPP	-	-	-	-	-	-	-
557 OTHER EXPENSES	OM557	OMPP	-	-	-	-	-	-	-
Total Purchased Power	TPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Expenses									
560 OPERATION SUPERVISION AND ENG	OM560	PTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	OM561	PTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	OM562	PTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	OM568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	-	-	-	-	-	-	-
Total Transmission Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Expense									
580 OPERATION SUPERVISION AND ENGI	OM580	PDIST	173,965	172,183	-	7,462	43,804	5,939	-
581 LOAD DISPATCHING	OM581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	OM582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	OM583	P365	328,813	61,469	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	OM584	P367	167,768	184,760	-	-	-	-	-
585 STREET LIGHTING EXPENSE	OM585	P371	-	-	-	-	-	-	-
586 METER EXPENSES	OM586	P370	-	-	-	-	-	12,923	-
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	-	-	430,005	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P369	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	116,789	115,593	-	5,009	29,407	3,987	-
588 MISC DISTR EXP – MAPPING	OM588x	F015	-	213,066	-	-	-	-	-
589 RENTS	OM589	PDIST	1,093	1,082	-	47	275	37	-
Total Distribution Operation Expense	OMDO		$ 788,428	$ 748,154	$ -	$ 12,518	$ 503,491	$ 22,887	$ -

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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Operation and Maintenance Expenses					
Purchased Power					
555 PURCHASED POWER	OM555	OMPP	-	19,963,795	ok
557 OTHER EXPENSES	OM557	OMPP	-	-	ok
Total Purchased Power	TPP		$ -	19,963,795	ok
Transmission Expenses					
560 OPERATION SUPERVISION AND ENG	OM560	PTRAN	-	-	ok
561 LOAD DISPATCHING	OM561	PTRAN	-	-	ok
562 STATION EXPENSES	OM562	PTRAN	-	-	ok
563 OVERHEAD LINE EXPENSES	OM563	PTRAN	-	48,782	ok
566 MISC. TRANSMISSION EXPENSES	OM566	PTRAN	-	-	ok
568 MAINTENACE SUPERVISION AND ENG	OM568	PTRAN	-	-	ok
570 MAINT OF STATION EQUIPMENT	OM570	PTRAN	-	-	ok
571 MAINT OF OVERHEAD LINES	OM571	PTRAN	-	-	ok
Total Transmission Expenses			$ -	48,782	ok
Distribution Operation Expense					
580 OPERATION SUPERVISION AND ENGI	OM580	PDIST	-	452,212	ok
581 LOAD DISPATCHING	OM581	P362	-	-	ok
582 STATION EXPENSES	OM582	P362	-	191,644	ok
583 OVERHEAD LINE EXPENSES	OM583	P365	-	390,282	ok
584 UNDERGROUND LINE EXPENSES	OM584	P367	-	352,527	ok
585 STREET LIGHTING EXPENSE	OM585	P371	-	12,923	ok
586 METER EXPENSES	OM586	P370	-	430,005	ok
586 METER EXPENSES - LOAD MANAGEMENT	OM586x	F012	-	-	ok
587 CUSTOMER INSTALLATIONS EXPENSE	OM587	P369	-	-	ok
588 MISCELLANEOUS DISTRIBUTION EXP	OM588	PDIST	-	303,586	ok
588 MISC DISTR EXP -- MAPPING	OM588x	F015	-	213,066	ok
589 RENTS	OM589	PDIST	-	2,842	ok
Total Distribution Operation Expense	OMDO		$ -	2,349,089	ok

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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Operation and Maintenance Expenses (Continued)								
Distribution Maintenance Expense								
590 MAINTENANCE SUPERVISION AND EN	OM590	PDIST	$ -	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	69,385	-	-	-	-	69,385
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	851,600	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	325,419	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	32,037	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	OM598	PDIST	-	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 1,278,441	$ -	$ -	$ -	$ -	$ 69,385
Total Distribution Operation and Maintenance Expenses			3,627,530	-	-	-	-	342,997
Transmission and Distribution Expenses			3,676,312	-	-	-	48,782	342,997
Purchased Power, Transmission and Distribution Expenses	OMSUB		$ 23,640,107	$ -	$ 11,444,637	$ 8,519,158	$ 48,782	$ 342,997
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	OM901	F009	$ -	-	-	-	-	-
902 METER READING EXPENSES	OM902	F009	487,182	-	-	-	-	-
903 RECORDS AND COLLECTION	OM903	F009	1,132,300	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	OM904	F009	46,000	-	-	-	-	-
905 MISC CUST ACCOUNTS	OM903	F009	17,007	-	-	-	-	-
Total Customer Accounts Expense	OMCA		$ 1,682,488	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	OM907	F010	$ -	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F010	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	OM908x	F012	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F010	118,245	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F012	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F010	-	-	-	-	-	-
911 SUPERVISION	OM911	F010	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F012	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F012	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F012	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F012	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ 118,245	$ -	$ -	$ -	$ -	$ -
Sub-Total Transmission, Distribution, Cust Acct and Cust Service	OMSUB2		5,477,046	-	-	-	48,782	342,997

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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant Demand	Pri & Sec. Distr Plant Customer	Customer Services Demand	Customer Services Customer	Meters Customer	Lighting Systems Customer	Meter Reading Billing and Cust Service Customer
Operation and Maintenance Expenses (Continued)									
Distribution Maintenance Expense									
590 MAINTENANCE SUPERVISION AND EN	OM590	PDIST	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	717,473	134,127	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	154,867	170,552	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	OM597	P370	-	-	-	-	-	32,037	-
598 MAINTENANCE OF MISC DISTR PLANT	OM598	PDIST	-	-	-	-	-	-	-
Total Distribution Maintenance Expense	OMDM		$ 872,340	$ 304,679	$ -	$ -	$ -	$ 32,037	$ -
Total Distribution Operation and Maintenance Expenses			1,660,767	1,052,832	-	12,518	503,491	54,925	-
Transmission and Distribution Expenses			1,660,767	1,052,832	-	12,518	503,491	54,925	-
Purchased Power, Transmission and Distribution Expenses	OMSUB		$ 1,660,767	$ 1,052,832	$ -	$ 12,518	$ 503,491	$ 54,925	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	OM901	F009	-	-	-	-	-	-	-
902 METER READING EXPENSES	OM902	F009	-	-	-	-	-	-	487,182
903 RECORDS AND COLLECTION	OM903	F009	-	-	-	-	-	-	1,132,300
904 UNCOLLECTIBLE ACCOUNTS	OM904	F009	-	-	-	-	-	-	46,000
905 MISC CUST ACCOUNTS	OM903	F009	-	-	-	-	-	-	17,007
Total Customer Accounts Expense	OMCA		$ -	$ -	$ -	$ -	$ -	$ -	$ 1,682,488
Customer Service Expense									
907 SUPERVISION	OM907	F010	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F010	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	OM908x	F012	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F010	-	-	-	-	-	-	118,245
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F012	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F010	-	-	-	-	-	-	-
911 SUPERVISION	OM911	F010	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	OM912	F012	-	-	-	-	-	-	-
913 ADVERTISING EXPENSES	OM913	F012	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	OM915	F012	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	OM916	F012	-	-	-	-	-	-	-
Total Customer Service Expense	OMCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 118,245
Sub-Total Transmission, Distribution, Cust Acct and Cust Service	OMSUB2		1,660,767	1,052,832	-	12,518	503,491	54,925	1,800,734

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Operation and Maintenance Expenses (Continued)					
Distribution Maintenance Expense					
590 MAINTENANCE SUPERVISION AND EN	OM590	PDIST	-	-	ok
592 MAINTENANCE OF STATION EQUIPME	OM592	P362	-	69,385	ok
593 MAINTENANCE OF OVERHEAD LINES	OM593	P365	-	851,600	ok
594 MAINTENANCE OF UNDERGROUND LIN	OM594	P367	-	325,419	ok
595 MAINTENANCE OF LINE TRANSFORME	OM595	P368	-	-	ok
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	OM596	P373	-	32,037	ok
597 MAINTENANCE OF METERS	OM597	P370	-	-	ok
598 MAINTENANCE OF MISC DISTR PLANT	OM598	PDIST	-	-	ok
Total Distribution Maintenance Expense	OMDM		$ -	1,278,441	ok
Total Distribution Operation and Maintenance Expenses			-	3,627,530	ok
Transmission and Distribution Expenses			-	3,676,312	ok
Purchased Power, Transmission and Distribution Expenses	OMSUB		$ -	23,640,107	ok
Customer Accounts Expense					
901 SUPERVISION-CUSTOMER ACCTS	OM901	F009	-	-	ok
902 METER READING EXPENSES	OM902	F009	-	487,182	ok
903 RECORDS AND COLLECTION	OM903	F009	-	1,132,300	ok
904 UNCOLLECTIBLE ACCOUNTS	OM904	F009	-	46,000	ok
905 MISC CUST ACCOUNTS	OM903	F009	-	17,007	ok
Total Customer Accounts Expense	OMCA		$ -	1,682,488	ok
Customer Service Expense					
907 SUPERVISION	OM907	F010	-	-	ok
908 CUSTOMER ASSISTANCE EXPENSES	OM908	F010	-	-	ok
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	OM908x	F012	-	-	ok
909 INFORMATIONAL AND INSTRUCTIONA	OM909	F010	-	118,245	ok
909 INFORM AND INSTRUC -LOAD MGMT	OM909x	F012	-	-	ok
910 MISCELLANEOUS CUSTOMER SERVICE	OM910	F010	-	-	ok
911 SUPERVISION	OM911	F010	-	-	ok
912 DEMONSTRATION AND SELLING EXP	OM912	F012	-	-	ok
913 ADVERTISING EXPENSES	OM913	F012	-	-	ok
915 MDSE-JOBBING-CONTRACT	OM915	F012	-	-	ok
916 MISC SALES EXPENSE	OM916	F012	-	-	ok
Total Customer Service Expense	OMCS		$ -	118,245	ok
Sub-Total Transmission, Distribution, Cust Acct and Cust Service	OMSUB2		-	5,477,046	ok

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Operation and Maintenance Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	OM920	OMSUB2	$ 1,177,609	-	-	-	10,489	73,747
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB2	594,672	-	-	-	-	21,071
923 OUTSIDE SERVICES EMPLOYED	OM923	OMSUB2	227,541	-	-	-	2,027	14,250
924 PROPERTY INSURANCE	OM924	NTPLANT	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB2	6,593	-	-	-	-	234
926 EMPLOYEE BENEFITS	OM926	LBSUB2	3,775	-	-	-	-	134
928 ASSOCIATED DUES	OM928	OMSUB2	176,283	-	-	-	1,570	11,040
929 DIRECTORS EXPENSE	OM929	OMSUB2	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	OMSUB2	563,864	-	-	-	5,022	35,312
931 RENTS AND LEASES	OM931	NTPLANT	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	298,074	-	-	-	22,989	29,722
Total Administrative and General Expense	OMAG		$ 3,048,411	$ -	$ -	$ -	$ 42,096	$ 185,508
Total Operation and Maintenance Expenses	TOM		$ 28,489,252	$ -	$ 11,444,637	$ 8,519,158	$ 90,878	$ 528,505
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 8,525,457	$ -	$ -	$ -	$ 90,878	$ 528,505

KIT CARSON ELECTRIC COOPERATIVE
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Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant		Customer Services		Meters	Lighting Systems	Meter Reading Billing and Cust Service
			Demand	Customer	Demand	Customer	Customer	Customer	Customer
Operation and Maintenance Expenses (Continued)									
Administrative and General Expense									
920 ADMIN. & GEN. SALARIES-	OM920	OMSUB2	357,078	226,367	-	2,691	108,255	11,809	387,172
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB2	186,638	95,441	-	1,811	81,305	5,602	202,805
923 OUTSIDE SERVICES EMPLOYED	OM923	OMSUB2	68,996	43,739	-	520	20,917	2,282	74,811
924 PROPERTY INSURANCE	OM924	NTPLANT	-	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB2	2,069	1,058	-	20	901	62	2,248
926 EMPLOYEE BENEFITS	OM926	LBSUB2	1,185	606	-	11	516	36	1,287
928 ASSOCIATED DUES	OM928	OMSUB2	53,453	33,886	-	403	16,205	1,768	57,958
929 DIRECTORS EXPENSE	OM929	OMSUB2	-	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	OM930	OMSUB2	170,977	108,390	-	1,289	51,835	5,655	185,386
931 RENTS AND LEASES	OM931	NTPLANT	-	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	105,824	104,741	-	4,539	26,646	3,613	-
Total Administrative and General Expense	OMAG		$ 946,220	$ 614,229	$ -	$ 11,285	$ 306,580	$ 30,825	$ 911,668
Total Operation and Maintenance Expenses	TOM		$ 2,606,987	$ 1,667,061	$ -	$ 23,803	$ 810,072	$ 85,750	$ 2,712,402
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ 2,606,987	$ 1,667,061	$ -	$ 23,803	$ 810,072	$ 85,750	$ 2,712,402

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Operation and Maintenance Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	OM920	OMSUB2	-	1,177,609	ok
921 OFFICE SUPPLIES AND EXPENSES	OM921	LBSUB2	-	594,672	ok
923 OUTSIDE SERVICES EMPLOYED	OM923	OMSUB2	-	227,541	ok
924 PROPERTY INSURANCE	OM924	NTPLANT	-	-	ok
925 INJURIES AND DAMAGES - INSURAN	OM925	LBSUB2	-	6,593	ok
926 EMPLOYEE BENEFITS	OM926	LBSUB2	-	3,775	ok
928 ASSOCIATED DUES	OM928	OMSUB2	-	176,283	ok
929 DIRECTORS EXPENSE	OM929	OMSUB2	-	-	ok
930 MISCELLANEOUS GENERAL EXPENSES	OM930	OMSUB2	-	563,864	ok
931 RENTS AND LEASES	OM931	NTPLANT	-	-	ok
935 MAINTENANCE OF GENERAL PLANT	OM935	PGP	-	298,074	ok
Total Administrative and General Expense	OMAG		$ -	3,048,411	ok
Total Operation and Maintenance Expenses	TOM		$ -	28,489,252	ok
Operation and Maintenance Expenses Less Purchase Power	OMLPP		$ -	8,525,457	ok

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Labor Expenses								
Purchased Power								
555 PURCHASED POWER	LB555	OMPP	$ -	-	-	-	-	-
557 OTHER EXPENSES	LB557	OMPP	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses								
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	$ -	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-
Total Transmission Labor Expenses			$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense								
580 OPERATION SUPERVISION AND ENGI	LB580	PDIST	$ 228,845	-	-	-	-	24,726
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	175	-	-	-	-	175
583 OVERHEAD LINE EXPENSES	LB583	P365	75,546	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	79,644	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	276,621	-	-	-	-	-
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P369	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	200,671	-	-	-	-	21,682
589 RENTS	LB589	PDIST	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 861,502	$ -	$ -	$ -	$ -	$ 46,582

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Cost of Service Study
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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant		Customer Services		Meters	Lighting Systems	Meter Reading Billing and Cust Service
			Demand	Customer	Demand	Customer	Customer	Customer	Customer
Labor Expenses									
Purchased Power									
555 PURCHASED POWER	LB555	OMPP	-	-	-	-	-	-	-
557 OTHER EXPENSES	LB557	OMPP	-	-	-	-	-	-	-
Total Purchased Power Labor	LBPP		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Labor Expenses									
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN	-	-	-	-	-	-	-
561 LOAD DISPATCHING	LB561	PTRAN	-	-	-	-	-	-	-
562 STATION EXPENSES	LB562	PTRAN	-	-	-	-	-	-	-
563 OVERHEAD LINE EXPENSES	LB563	PTRAN	-	-	-	-	-	-	-
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN	-	-	-	-	-	-	-
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN	-	-	-	-	-	-	-
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN	-	-	-	-	-	-	-
571 MAINT OF OVERHEAD LINES	LB571	PTRAN	-	-	-	-	-	-	-
Total Transmission Labor Expenses			$ -	$ -	$ -	$ -	$ -	$ -	$ -
Distribution Operation Labor Expense									
580 OPERATION SUPERVISION AND ENGI	LB580	PDIST	88,036	87,134	-	3,776	22,167	3,006	-
581 LOAD DISPATCHING	LB581	P362	-	-	-	-	-	-	-
582 STATION EXPENSES	LB582	P362	-	-	-	-	-	-	-
583 OVERHEAD LINE EXPENSES	LB583	P365	63,648	11,899	-	-	-	-	-
584 UNDERGROUND LINE EXPENSES	LB584	P367	37,902	41,741	-	-	-	-	-
585 STREET LIGHTING EXPENSE	LB585	P371	-	-	-	-	-	-	-
586 METER EXPENSES	LB586	P370	-	-	-	-	276,621	-	-
585 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012	-	-	-	-	-	-	-
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P369	-	-	-	-	-	-	-
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST	77,197	76,407	-	3,311	19,438	2,636	-
589 RENTS	LB589	PDIST	-	-	-	-	-	-	-
Total Distribution Operation Labor Expense	LBDO		$ 266,784	$ 217,181	$ -	$ 7,087	$ 318,227	$ 5,641	$ -

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer		Total Check	Status
Labor Expenses						
Purchased Power						
555 PURCHASED POWER	LB555	OMPP		-	-	ok
557 OTHER EXPENSES	LB557	OMPP		-	-	ok
Total Purchased Power Labor	LBPP		S	-	-	ok
Transmission Labor Expenses						
560 OPERATION SUPERVISION AND ENG	LB560	PTRAN		-	-	ok
561 LOAD DISPATCHING	LB561	PTRAN		-	-	ok
562 STATION EXPENSES	LB562	PTRAN		-	-	ok
563 OVERHEAD LINE EXPENSES	LB563	PTRAN		-	-	ok
566 MISC. TRANSMISSION EXPENSES	LB566	PTRAN		-	-	ok
568 MAINTENACE SUPERVISION AND ENG	LB568	PTRAN		-	-	ok
570 MAINT OF STATION EQUIPMENT	LB570	PTRAN		-	-	ok
571 MAINT OF OVERHEAD LINES	LB571	PTRAN		-	-	ok
Total Transmission Labor Expenses			S	-	-	ok
Distribution Operation Labor Expense						
580 OPERATION SUPERVISION AND ENGI	LB580	PDIST		-	228,845	ok
581 LOAD DISPATCHING	LB581	P362		-	-	ok
582 STATION EXPENSES	LB582	P362		-	175	ok
583 OVERHEAD LINE EXPENSES	LB583	P365		-	75,546	ok
584 UNDERGROUND LINE EXPENSES	LB584	P367		-	79,644	ok
585 STREET LIGHTING EXPENSE	LB585	P371		-	-	ok
586 METER EXPENSES	LB586	P370		-	276,621	ok
586 METER EXPENSES - LOAD MANAGEMENT	LB586x	F012		-	-	ok
587 CUSTOMER INSTALLATIONS EXPENSE	LB587	P369		-	-	ok
588 MISCELLANEOUS DISTRIBUTION EXP	LB588	PDIST		-	200,671	ok
589 RENTS	LB589	PDIST		-	-	ok
Total Distribution Operation Labor Expense	LBDO		S	-	861,502	ok

KIT CARSON ELECTRIC COOPERATIVE
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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Labor Expenses (Continued)								
Distribution Maintenance Labor Expense								
590 MAINTENANCE SUPERVISION AND EN	LB590	PDIST	$ -	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	35,890	-	-	-	-	35,890
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	459,941	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	160,154	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	16,283	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 672,269	$ -	$ -	$ -	$ -	$ 35,890
Total Distribution Operation and Maintenance Labor Expenses			1,533,771	-	-	-	-	82,473
Transmission and Distribution Labor Expenses			1,533,771	-	-	-	-	82,473
Purchased Power, Transmission and Distribution Labor Expenses	LBSUB		$ 1,533,771	$ -	$ -	$ -	$ -	$ 82,473
Customer Accounts Expense								
901 SUPERVISION/CUSTOMER ACCTS	LB901	F009	$ -	-	-	-	-	-
902 METER READING EXPENSES	LB902	F009	190,577	-	-	-	-	-
903 RECORDS AND COLLECTION	LB903	F009	527,051	-	-	-	-	-
904 UNCOLLECTIBLE ACCOUNTS	LB904	F009	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F009	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ 717,628	$ -	$ -	$ -	$ -	$ -
Customer Service Expense								
907 SUPERVISION	LB907	F010	$ -	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F010	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F012	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F010	76,152	-	-	-	-	-
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F012	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F010	-	-	-	-	-	-
911 SUPERVISION	LB911	F010	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F012	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F012	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F012	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F012	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ 76,152	$ -	$ -	$ -	$ -	$ -
Sub-Total Trans, Distr, Cust Acct and Cust Service Labor Exp	LBSUB2		2,327,551	-	-	-	-	82,473

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12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant Demand	Pri & Sec. Distr Plant Customer	Customer Services Demand	Customer Services Customer	Meters Customer	Lighting Systems Customer	Meter Reading Billing and Cust Service Customer
Labor Expenses (Continued)									
Distribution Maintenance Labor Expense									
590 MAINTENANCE SUPERVISION AND EN	LB590	PDIST	-	-	-	-	-	-	-
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	-	-	-	-	-	-
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	387,500	72,441	-	-	-	-	-
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	76,217	83,937	-	-	-	-	-
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	-	-	-	-	-
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	-	-	-	-	-	-
597 MAINTENANCE OF METERS	LB597	P370	-	-	-	-	-	16,283	-
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	-	-	-	-	-
Total Distribution Maintenance Labor Expense	LBDM		$ 463,718	$ 156,377	$ -	$ -	$ -	$ 16,283	$ -
Total Distribution Operation and Maintenance Labor Expenses			730,501	373,559	-	7,087	318,227	21,925	-
Transmission and Distribution Labor Expenses			730,501	373,559	-	7,087	318,227	21,925	-
Purchased Power, Transmission and Distribution Labor Expenses	LBSUB		$ 730,501	$ 373,559	$ -	$ 7,087	$ 318,227	$ 21,925	$ -
Customer Accounts Expense									
901 SUPERVISION/CUSTOMER ACCTS	LB901	F009	-	-	-	-	-	-	-
902 METER READING EXPENSES	LB902	F009	-	-	-	-	-	-	190,577
903 RECORDS AND COLLECTION	LB903	F009	-	-	-	-	-	-	527,051
904 UNCOLLECTIBLE ACCOUNTS	LB904	F009	-	-	-	-	-	-	-
905 MISC CUST ACCOUNTS	LB903	F009	-	-	-	-	-	-	-
Total Customer Accounts Labor Expense	LBCA		$ -	$ -	$ -	$ -	$ -	$ -	$ 717,628
Customer Service Expense									
907 SUPERVISION	LB907	F010	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F010	-	-	-	-	-	-	-
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F012	-	-	-	-	-	-	-
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F010	-	-	-	-	-	-	76,152
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F012	-	-	-	-	-	-	-
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F010	-	-	-	-	-	-	-
911 SUPERVISION	LB911	F010	-	-	-	-	-	-	-
912 DEMONSTRATION AND SELLING EXP	LB912	F012	-	-	-	-	-	-	-
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F012	-	-	-	-	-	-	-
915 MDSE-JOBBING-CONTRACT	LB915	F012	-	-	-	-	-	-	-
916 MISC SALES EXPENSE	LB916	F012	-	-	-	-	-	-	-
Total Customer Service Labor Expense	LBCS		$ -	$ -	$ -	$ -	$ -	$ -	$ 76,152
Sub-Total Trans, Distr, Cust Acct and Cust Service Labor Exp	LBSUB2		730,501	373,559	-	7,087	318,227	21,925	793,780

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Labor Expenses (Continued)					
Distribution Maintenance Labor Expense					
590 MAINTENANCE SUPERVISION AND EN	LB590	PDIST	-	-	ok
592 MAINTENANCE OF STATION EQUIPME	LB592	P362	-	35,890	ok
593 MAINTENANCE OF OVERHEAD LINES	LB593	P365	-	459,941	ok
594 MAINTENANCE OF UNDERGROUND LIN	LB594	P367	-	160,154	ok
595 MAINTENANCE OF LINE TRANSFORME	LB595	P368	-	-	ok
596 MAINTENANCE OF ST LIGHTS & SIG SYSTEMS	LB596	P373	-	16,283	ok
597 MAINTENANCE OF METERS	LB597	P370	-	-	ok
598 MAINTENANCE OF MISC DISTR PLANT	LB598	PDIST	-	-	ok
Total Distribution Maintenance Labor Expense	LBDM		$ -	672,269	ok
Total Distribution Operation and Maintenance Labor Expenses			-	1,533,771	ok
Transmission and Distribution Labor Expenses			-	1,533,771	ok
Purchased Power, Transmission and Distribution Labor Expenses	LBSUB		$ -	1,533,771	ok
Customer Accounts Expense					
901 SUPERVISION-CUSTOMER ACCTS	LB901	F009	-	-	ok
902 METER READING EXPENSES	LB902	F009	-	190,577	ok
903 RECORDS AND COLLECTION	LB903	F009	-	527,051	ok
904 UNCOLLECTIBLE ACCOUNTS	LB904	F009	-	-	ok
905 MISC CUST ACCOUNTS	LB903	F009	-	-	ok
Total Customer Accounts Labor Expense	LBCA		$ -	717,628	ok
Customer Service Expense					
907 SUPERVISION	LB907	F010	-	-	ok
908 CUSTOMER ASSISTANCE EXPENSES	LB908	F010	-	-	ok
908 CUSTOMER ASSISTANCE EXP-LOAD MGMT	LB908x	F012	-	-	ok
909 INFORMATIONAL AND INSTRUCTIONA	LB909	F010	-	76,152	ok
909 INFORM AND INSTRUC -LOAD MGMT	LB909x	F012	-	-	ok
910 MISCELLANEOUS CUSTOMER SERVICE	LB910	F010	-	-	ok
911 SUPERVISION	LB911	F010	-	-	ok
912 DEMONSTRATION AND SELLING EXP	LB912	F012	-	-	ok
913 WATER HEATER - HEAT PUMP PROGRAM	LB913	F012	-	-	ok
915 MDSE-JOBBING-CONTRACT	LB915	F012	-	-	ok
916 MISC SALES EXPENSE	LB916	F012	-	-	ok
Total Customer Service Labor Expense	LBCS		$ -	76,152	ok
Sub-Total Trans. Distr. Cust Acct and Cust Service Labor Exp	LBSUB2		-	2,327,551	ok

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Labor Expenses (Continued)								
Administrative and General Expense								
920 ADMIN. & GEN. SALARIES-	LB920	OMSUB2	$ 714,911	-	-	-	6,367	44,771
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB2	50	-	-	-	-	2
923 OUTSIDE SERVICES EMPLOYED	LB923	OMSUB2	-	-	-	-	-	-
924 PROPERTY NSURANCE	LB924	NTPLANT	-	-	-	-	-	-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB2	6,593	-	-	-	-	234
926 EMPLOYEE BENEFITS	LB926	LBSUB2	13	-	-	-	-	0
928 REGULATORY COMMISSION EXPENSES	LB928	OMSUB2	-	-	-	-	-	-
929 DUPLICATE CHARGES-CR	LB929	OMSUB2	-	-	-	-	-	-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	OMSUB2	25,548	-	-	-	228	1,600
931 RENTS AND LEASES	LB931	NTPLANT	-	-	-	-	-	-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	35,288	-	-	-	2,722	3,519
950 PAYROLL GENERAL LEDGER DEFAULT	LB950	PGP	-	-	-	-	-	-
Total Administrative and General Expense	LBAG		$ 782,402	$ -	$ -	$ -	$ 9,317	$ 50,125
Total Operation and Maintenance Expenses	TLB		$ 3,109,953	$ -	$ -	$ -	$ 9,317	$ 132,598
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 3,109,953	$ -	$ -	$ -	$ 9,317	$ 132,598

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant		Customer Services		Meters	Lighting Systems	Meter Reading Billing and Cust Service	
			Demand	Customer	Demand	Customer	Customer	Customer	Customer	
Labor Expenses (Continued)										
Administrative and General Expense										
920 ADMIN. & GEN. SALARIES-	LB920	OMSUB2	216,777	137,425	-	1,634	65,720	7,169		235,047
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB2	16	8	-	0	7	0		17
923 OUTSIDE SERVICES EMPLOYED	LB923	OMSUB2	-	-	-	-	-	-		-
924 PROPERTY INSURANCE	LB924	NTPLANT	-	-	-	-	-	-		-
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB2	2,069	1,058	-	20	901	62		2,248
926 EMPLOYEE BENEFITS	LB926	LBSUB2	4	2	-	0	2	0		4
928 REGULATORY COMMISSION EXPENSES	LB928	OMSUB2	-	-	-	-	-	-		-
929 DUPLICATE CHARGES-CR	LB929	OMSUB2	-	-	-	-	-	-		-
930 MISCELLANEOUS GENERAL EXPENSES	LB930	OMSUB2	7,747	4,911	-	58	2,349	256		8,399
931 RENTS AND LEASES	LB931	NTPLANT	-	-	-	-	-	-		-
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	12,528	12,400	-	537	3,155	428		-
950 PAYROLL GENERAL LEDGER DEFAULT	LB950	PGP	-	-	-	-	-	-		-
Total Administrative and General Expense	LBAG		$ 239,141	$ 155,804	$ -	$ 2,250	$ 72,133	$ 7,916	$	245,716
Total Operation and Maintenance Expenses	TLB		$ 969,642	$ 529,362	$ -	$ 9,337	$ 390,360	$ 29,840	$	1,039,496
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ 969,642	$ 529,362	$ -	$ 9,337	$ 390,360	$ 29,840	$	1,039,496

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Labor Expenses (Continued)					
Administrative and General Expense					
920 ADMIN. & GEN. SALARIES-	LB920	OMSUB2	-	714,911	ok
921 OFFICE SUPPLIES AND EXPENSES	LB921	LBSUB2	-	50	ok
923 OUTSIDE SERVICES EMPLOYED	LB923	OMSUB2	-	-	ok
924 PROPERTY INSURANCE	LB924	NTPLANT	-	-	ok
925 INJURIES AND DAMAGES - INSURAN	LB925	LBSUB2	-	6,593	ok
926 EMPLOYEE BENEFITS	LB926	LBSUB2	-	13	ok
928 REGULATORY COMMISSION EXPENSES	LB928	OMSUB2	-	-	ok
929 DUPLICATE CHARGES-CR	LB929	OMSUB2	-	-	ok
930 MISCELLANEOUS GENERAL EXPENSES	LB930	OMSUB2	-	25,548	ok
931 RENTS AND LEASES	LB931	NTPLANT	-	-	ok
935 MAINTENANCE OF GENERAL PLANT	LB935	PGP	-	35,288	ok
950 PAYROLL GENERAL LEDGER DEFAULT	LB950	PGP	-	-	ok
Total Administrative and General Expense	LBAG		$ -	782,402	ok
Total Operation and Maintenance Expenses	TLB		$ -	3,109,953	ok
Operation and Maintenance Expenses Less Purchase Power	LBLPP		$ -	3,109,953	ok

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector		Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Other Expenses									
Depreciation Expenses									
Transmission	DEPRTP	PTRAN	$	373,264	-	-	-	373,264	-
Dist-Structures	DEPRDP1	P361		-	-	-	-	-	-
Dist-Station	DEPRDP2	P362		-	-	-	-	-	-
Dist-Poles and Fixtures	DEPRDP3	P364		-	-	-	-	-	-
Dist-OH Conductor	DEPRDP4	P365		-	-	-	-	-	-
Dist-UG Conduit	DEPRDP5	P366		-	-	-	-	-	-
Dist-UG Conductor	DEPRDP6	P367		-	-	-	-	-	-
Dist-Line Transformers	DEPRDP7	P368		-	-	-	-	-	-
Dist-Services	DEPRDP8	P369		-	-	-	-	-	-
Dist-Meters	DEPRDP9	P370		-	-	-	-	-	-
Dist-Installations on Customer Premises	DEPRDP10	P371		-	-	-	-	-	-
Dist-Lighting & Signal Systems	DEPRDP11	P373		-	-	-	-	-	-
Distribution Plant	DEPRDP12	PDIST	$	2,415,111	-	-	-	-	260,942
General Plant	DEPRGP	PGP		334,100	-	-	-	25,767	33,314
DEPR EXP:GENERAL PLANT	DEPRGP	PGP		-	-	-	-	-	-
AMORT LIMITED-TERM ELECT PLANT	DEPRLTEP	PT&D		125,930	-	-	-	9,712	12,557
AMORT ELECT PLANT ACQUISIT ADJ	DEPRAADJ	PDIST		-	-	-	-	-	-
Total Depreciation Expense	TDEPR		$	3,248,405	-	-	-	408,743	306,812
Property Taxes	PTAX	NTPLANT	$	-	-	-	-	-	-
Other Taxes	OT	NTPLANT	$	4,805	241	-	-	304	364
Interest -- LTD	INTLTD	NTPLANT	$	2,679,440	134,468	-	-	169,309	202,713
Interest -- Other	INTOTH	NTPLANT	$	393	20	-	-	25	30
Other Deductions	DEDUCT	NTPLANT	$	2,689	135	-	-	170	203
Total Other Expenses	TOE		$	5,935,733	$ 134,864	$ -	$ -	$ 578,550	$ 510,122
Total Cost of Service (O&M + Other Expenses)			$	34,424,985	$ 134,864	$ 11,444,637	$ 8,519,158	$ 669,428	$ 1,038,627

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant		Customer Services		Meters	Lighting Systems	Meter Reading Billing and Cust Service
			Demand	Customer	Demand	Customer	Customer	Customer	Customer
Other Expenses									
Depreciation Expenses									
Transmission	DEPRTP	PTRAN	-	-	-	-	-	-	-
Dist-Structures	DEPRDP1	P361	-	-	-	-	-	-	-
Dist-Station	DEPRDP2	P362	-	-	-	-	-	-	-
Dist-Poles and Fixtures	DEPRDP3	P364	-	-	-	-	-	-	-
Dist-OH Conductor	DEPRDP4	P365	-	-	-	-	-	-	-
Dist-UG Conduit	DEPRDP5	P366	-	-	-	-	-	-	-
Dist-UG Conductor	DEPRDP6	P367	-	-	-	-	-	-	-
Dist-Line Transformers	DEPRDP7	P368	-	-	-	-	-	-	-
Dist-Services	DEPRDP8	P369	-	-	-	-	-	-	-
Dist-Meters	DEPRDP9	P370	-	-	-	-	-	-	-
Dist-Installations on Customer Premises	DEPRDP10	P371	-	-	-	-	-	-	-
Dist-Lighting & Signal Systems	DEPRDP11	P373	-	-	-	-	-	-	-
Distribution Plant	DEPRDP12	PDIST	929,086	919,572	-	39,851	233,941	31,720	-
General Plant	DEPRGP	PGP	118,615	117,400	-	5,088	29,867	4,050	-
DEPR EXP-GENERAL PLANT	DEPRGP	PGP	-	-	-	-	-	-	-
AMORT LIMITED-TERM ELECT PLANT	DEPRLTEP	PT&D	44,709	44,251	-	1,918	11,258	1,526	-
AMORT ELECT PLANT ACQUISIT ADJ	DEPRAADJ	PDIST	-	-	-	-	-	-	-
Total Depreciation Expense	TDEPR		1,092,409	1,081,223	-	46,856	275,066	37,296	-
Property Taxes	PTAX	NTPLANT	-	-	-	-	-	-	-
Other Taxes	OT	NTPLANT	1,624	1,675	-	44	501	52	-
Interest -- LTD	INTLTD	NTPLANT	905,682	934,274	-	24,763	279,406	28,826	-
Interest -- Other	INTOTH	NTPLANT	133	137	-	4	41	4	-
Other Deductions	DEDUCT	NTPLANT	909	938	-	25	280	29	-
Total Other Expenses	TOE		$ 2,000,758	$ 2,018,246	$ -	$ 71,692	$ 555,294	$ 66,206	$ -
Total Cost of Service (O&M + Other Expenses)			$ 4,607,745	$ 3,685,308	$ -	$ 95,494	$ 1,365,366	$ 151,956	$ 2,712,402

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector		Load Management Customer	Total Check	Status
Other Expenses						
Depreciation Expenses						
Transmission	DEPRTP	PTRAN		-	373,264	ok
Dist-Structures	DEPRDP1	P361		-	-	ok
Dist-Station	DEPRDP2	P362		-	-	ok
Dist-Poles and Fixtures	DEPRDP3	P364		-	-	ok
Dist-OH Conductor	DEPRDP4	P365		-	-	ok
Dist-UG Conduit	DEPRDP5	P366		-	-	ok
Dist-UG Conductor	DEPRDP6	P367		-	-	ok
Dist-Line Transformers	DEPRDP7	P368		-	-	ok
Dist-Services	DEPRDP8	P369		-	-	ok
Dist-Meters	DEPRDP9	P370		-	-	ok
Dist-Installations on Customer Premises	DEPRDP10	P371		-	-	ok
Dist-Lighting & Signal Systems	DEPRDP11	P373		-	-	ok
Distribution Plant	DEPRDP12	PDIST		-	2,415,111	ok
General Plant	DEPRGP	PGP		-	334,100	ok
DEPR EXP GENERAL PLANT	DEPRGP	PGP		-	-	ok
AMORT LIMITED-TERM ELECT PLANT	DEPRLTEP	PT&D		-	125,930	ok
AMORT ELECT PLANT ACQUISIT ADJ	DEPRAADJ	PDIST		-	-	ok
Total Depreciation Expense	TDEPR			-	3,248,405	ok
Property Taxes	PTAX	NTPLANT		-	-	ok
Other Taxes	OT	NTPLANT		-	4,805	ok
Interest – LTD	INTLTD	NTPLANT		-	2,679,440	ok
Interest – Other	INTOTH	NTPLANT		-	393	ok
Other Deductions	DEDUCT	NTPLANT		-	2,689	ok
Total Other Expenses	TOE		$	-	5,935,733	ok
Total Cost of Service (O&M + Other Expenses)			$	-	34,424,985	ok

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Total System	Production Plant Demand	Purchased Power Demand	Purchased Power Energy	Transmission Plant Demand	Station Equipment Demand
Functional Vectors								
Station Equipment	F001		1.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Poles, Towers and Fixtures	F002		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meters	F007		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Street Lighting	F008		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Meter Reading	F009		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Billing	F010		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Transmission	F011		1.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Load Management	F012		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Purchased Power Expenses	OMPP		19,963,795	-	11,444,637	8,519,158	-	-
Installations on Customer Premises - Plant in Service	F013		1.00000	-	-	-	-	-
Installations on Customer Premises - Accum Depr	F014		1.00000	-	-	-	-	-
Mapping	F015		1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators - Demand	F016		1.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Production	F017		1.000000	1.000000	0.000000	0.000000	0.000000	0.000000

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Pri & Sec. Distr Plant		Customer Services		Meters	Lighting Systems	Meter Reading Billing and Cust Service
			Demand	Customer	Demand	Customer	Customer	Customer	Customer
Functional Vectors									
Station Equipment	F001		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Poles, Towers and Fixtures	F002		0.842500	0.157500	0.000000	0.000000	0.000000	0.000000	0.000000
Overhead Conductors and Devices	F003		0.842500	0.157500	0.000000	0.000000	0.000000	0.000000	0.000000
Underground Conductors and Devices	F004		0.475900	0.524100	0.000000	0.000000	0.000000	0.000000	0.000000
Line Transformers	F005		0.284300	0.715700	0.000000	0.000000	0.000000	0.000000	0.000000
Services	F006		0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
Meters	F007		0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000
Street Lighting	F008		0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000
Meter Reading	F009		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Billing	F010		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000
Transmission	F011		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Load Management	F012		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Purchased Power Expenses	OMPP		-	-	-	-	-	-	-
Installations on Customer Premises - Plant in Service	F013		-	-	-	-	-	1.00000	-
Installations on Customer Premises - Accum Depr	F014		-	-	-	-	-	1.00000	-
Mapping	F015		0.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Generators - Demand	F016		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Production	F017		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Functional Assignment and Classification

12 Months Ended December 31, 2009

Description	Name	Functional Vector	Load Management Customer	Total Check	Status
Functional Vectors					
Station Equipment	F001		0.000000	1.000000	ok
Poles, Towers and Fixtures	F002		0.000000	1.000000	ok
Overhead Conductors and Devices	F003		0.000000	1.000000	ok
Underground Conductors and Devices	F004		0.000000	1.000000	ok
Line Transformers	F005		0.000000	1.000000	ok
Services	F006		0.000000	1.000000	ok
Meters	F007		0.000000	1.000000	ok
Street Lighting	F008		0.000000	1.000000	ok
Meter Reading	F009		0.000000	1.000000	ok
Billing	F010		0.000000	1.000000	ok
Transmission	F011		0.000000	1.000000	ok
Load Management	F012		1.000000	1.000000	ok
Purchased Power Expenses	OMPP		-	19,963,795	ok
Installations on Customer Premises - Plant in Service	F013		-	1.000000	ok
Installations on Customer Premises - Accum Depr	F014		-	1.000000	ok
Mapping	F015		0.000000	1.000000	ok
Generators - Demand	F016		0.000000	1.000000	ok
Production	F017		0.000000	1.000000	ok

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Plant in Service							
Production Plant							
Demand	PLOPD	T01	$ 3,963,364	$ 1,152,993	$ 133,061	$ 724,830	$ 1,145,326
Purchase Power							
Demand	PLPPD	PPDA	$ -	$ -	$ -	$ -	$ -
Energy	PLPPE	PPEA	-	$ -	$ -	$ -	$ -
Total Purchase Power	PLPPT		$ -	$ -	$ -	$ -	$ -
Transmission Plant							
Demand	PLSED	T01	$ 7,586,523	$ 2,207,015	$ 254,700	$ 1,387,443	$ 2,192,339
Station Equipment							
Demand	PLSED	SA1	$ 9,808,473	$ 2,879,072	$ 332,258	$ 1,809,932	$ 2,859,927
Primary & Secondary Distribution Plant							
Demand	PLDPD	DA1	$ 34,923,176	$ 19,916,721	$ 2,812,656	$ 6,915,261	$ 3,524,610
Customer	PLDPC	C01	34,565,554	$ 26,067,688	$ 3,697,220	$ 3,852,316	$ 271,567
Total Primary Distribution Plant	PLD		$ 69,488,731	$ 45,984,408	$ 6,509,876	$ 10,767,577	$ 3,796,177
Customer Services							
Demand	PLCSD	CSA	$ -	$ -	$ -	$ -	$ -
Customer	PLCSC	SERV	1,497,943	$ 943,770	$ 133,856	$ 348,679	$ 39,328
Total Customer Services			$ 1,497,943	$ 943,770	$ 133,856	$ 348,679	$ 39,328
Meters							
Customer	PLMC	C03	$ 8,793,563	$ 4,902,131	$ 695,277	$ 2,636,708	$ 372,161
Lighting Systems							
Customer	PLLSC	C04	$ 1,192,299	$ -	$ -	$ -	$ -
Meter Reading, Billing and Customer Service							
Customer	PLMRBC	C05	$ -	$ -	$ -	$ -	$ -
Load Management							
Customer	PLCSC	C06	$ -	$ -	$ -	$ -	$ -
Total	PLT		$ 102,330,896	$ 58,069,389	$ 8,059,028	$ 17,675,168	$ 10,405,259

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Plant in Service												
Production Plant												
Demand	PLOPD	T01	$	-	$	4,174	$	35,329	$	42,209	$	843
Purchase Power												
Demand	PLPPD	PPDA	$	-	$	-	$	-	$	-	$	-
Energy	PLPPE	PPEA	$	-	$	-	$	-	$	-	$	-
Total Purchase Power	PLPPT		$	-	$	-	$	-	$	-	$	-
Transmission Plant												
Demand	PLSED	T01	$	-	$	7,990	$	67,625	$	80,796	$	1,614
Station Equipment												
Demand	PLSED	SA1	$	-	$	10,423	$	-	$	105,399	$	2,106
Primary & Secondary Distribution Plant												
Demand	PLDPD	DA1	$	57,602	$	509,795	$	170,896	$	714,056	$	29,297
Customer	PLDPC	C01	$	51,004	$	896	$	8,661	$	478,130	$	20,606
Total Primary Distribution Plant	PLD		$	108,606	$	510,691	$	179,556	$	1,192,186	$	49,904
Customer Services												
Demand	PLCSD	CSA	$	-	$	-	$	-	$	-	$	-
Customer	PLCSC	SERV	$	-	$	130	$	1,254	$	17,310	$	2,984
Total Customer Services			$	-	$	130	$	1,254	$	17,310	$	2,984
Meters												
Customer	PLMC	C03	$	-	$	1,228	$	11,869	$	89,914	$	3,875
Lighting Systems												
Customer	PLLSC	C04	$	1,192,299	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	PLMRBC	C05	$	-	$	-	$	-	$	-	$	-
Load Management												
Customer	PLCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	PLT		$	1,300,905	$	534,634	$	295,634	$	1,527,814	$	61,327

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Plant in Service										
Production Plant										
Demand	PLOPD	T01	$	32,395	$	-	$	4,836	$	687,368
Purchase Power										
Demand	PLPPD	PPDA	$	-	$	-	$	-	$	-
Energy	PLPPE	PPEA	$	-	$	-	$	-	$	-
Total Purchase Power	PLPPT		$	-	$	-	$	-	$	-
Transmission Plant										
Demand	PLSED	T01	$	62,010	$	-	$	9,257	$	1,315,734
Station Equipment										
Demand	PLSED	SA1	$	80,893	$	-	$	12,075	$	1,716,387
Primary & Secondary Distribution Plant										
Demand	PLDPD	DA1	$	262,326	$	-	$	9,957	$	-
Customer	PLDPC	C01	$	116,272	$	-	$	1,195	$	-
Total Primary Distribution Plant	PLD		$	378,598	$	-	$	11,152	$	-
Customer Services										
Demand	PLCSD	CSA	$	-	$	-	$	-	$	-
Customer	PLCSC	SERV	$	10,524	$	-	$	108	$	-
Total Customer Services			$	10,524	$	-	$	108	$	-
Meters										
Customer	PLMC	C03	$	79,582	$	-	$	818	$	-
Lighting Systems										
Customer	PLLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	PLMRBC	C05	$	-	$	-	$	-	$	-
Load Management										
Customer	PLCSC	C06	$	-	$	-	$	-	$	-
Total	PLT		$	644,003	$	-	$	38,246	$	3,719,489

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Net Utility Plant							
Production Plant							
Demand	NPOPD	T01	$ 3,966,849	$ 1,154,006	$ 133,178	$ 725,467	$ 1,146,333
Purchase Power							
Demand	NPPPD	PPDA	$ -	$ -	$ -	$ -	$ -
Energy	NPPPE	PPEA	-	$ -	$ -	$ -	$ -
Total Purchase Power	NPPPT		-	$ -	$ -	$ -	$ -
Transmission Plant							
Demand	PLSED	T01	$ 4,994,650	$ 1,453,007	$ 167,684	$ 913,434	$ 1,443,345
Station Equipment							
Demand	NPSED	SA1	$ 5,980,077	$ 1,755,327	$ 202,573	$ 1,103,488	$ 1,743,654
Primary Distribution Plant							
Demand	NPDPD	DA1	$ 26,717,868	$ 15,237,225	$ 2,151,814	$ 5,290,499	$ 2,696,492
Customer	NPDPC	C01	27,561,318	$ 20,785,428	$ 2,948,029	$ 3,071,697	$ 216,538
Total Primary Distribution Plant			$ 54,279,186	$ 36,022,653	$ 5,099,842	$ 8,362,196	$ 2,913,030
Customer Services							
Demand	NPCSD	CSA	$ -	$ -	$ -	$ -	$ -
Customer	NPCSC	SERV	730,507	$ 460,251	$ 65,278	$ 170,041	$ 19,179
Total Customer Services			$ 730,507	$ 460,251	$ 65,278	$ 170,041	$ 19,179
Meters							
Customer	NPMC	C03	$ 8,242,545	$ 4,594,956	$ 651,710	$ 2,471,488	$ 348,841
Lighting Systems							
Customer	NPLSC	C04	$ 850,373	$ -	$ -	$ -	$ -
Meter Reading, Billing and Customer Service							
Customer	NPMRBC	C05	$ -	$ -	$ -	$ -	$ -
Load Management							
Customer	NPCSC	C06	$ -	$ -	$ -	$ -	$ -
Total	NPT		$ 79,044,186	$ 45,440,200	$ 6,320,265	$ 13,746,114	$ 7,614,382

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Net Utility Plant												
Production Plant												
Demand	NPOPD	T01	$	-	$	4,178	$	35,360	$	42,247	$	844
Purchase Power												
Demand	NPPPD	PPDA	$	-	$	-	$	-	$	-	$	-
Energy	NPPPE	PPEA	$	-	$	-	$	-	$	-	$	-
Total Purchase Power	NPPPT		$	-	$	-	$	-	$	-	$	-
Transmission Plant												
Demand	PLSED	T01	$	-	$	5,260	$	44,522	$	53,193	$	1,063
Station Equipment												
Demand	NPSED	SA1	$	-	$	6,354	$	-	$	64,260	$	1,284
Primary Distribution Plant												
Demand	NPDPD	DA1	$	44,068	$	390,017	$	130,743	$	546,286	$	22,414
Customer	NPDPC	C01	$	40,669	$	714	$	6,906	$	381,243	$	16,431
Total Primary Distribution Plant			$	84,737	$	390,731	$	137,649	$	927,530	$	38,845
Customer Services												
Demand	NPCSD	CSA	$	-	$	-	$	-	$	-	$	-
Customer	NPCSC	SERV	$	-	$	63	$	612	$	8,442	$	1,455
Total Customer Services			$	-	$	63	$	612	$	8,442	$	1,455
Meters												
Customer	NPMC	C03	$	-	$	1,151	$	11,125	$	84,280	$	3,632
Lighting Systems												
Customer	NPLSC	C04	$	850,373	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	NPMRBC	C05	$	-	$	-	$	-	$	-	$	-
Load Management												
Customer	NPCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	NPT		$	935,110	$	407,737	$	229,267	$	1,179,951	$	47,123

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Net Utility Plant										
Production Plant										
Demand	NPOPD	T01	$	32,424	$	-	$	4,840	$	687,972
Purchase Power										
Demand	NPPPD	PPDA	$	-	$	-	$	-	$	-
Energy	NPPPE	PPEA	$	-	$	-	$	-	$	-
Total Purchase Power	NPPPT		$	-	$	-	$	-	$	-
Transmission Plant										
Demand	PLSED	T01	$	40,825	$	-	$	6,094	$	866,224
Station Equipment										
Demand	NPSED	SA1	$	49,319	$	-	$	7,362	$	1,046,455
Primary Distribution Plant										
Demand	NPDPD	DA1	$	200,692	$	-	$	7,618	$	-
Customer	NPDPC	C01	$	92,711	$	-	$	953	$	-
Total Primary Distribution Plant			$	293,403	$	-	$	8,570	$	-
Customer Services										
Demand	NPCSD	CSA	$	-	$	-	$	-	$	-
Customer	NPCSC	SERV	$	5,132	$	-	$	53	$	-
Total Customer Services			$	5,132	$	-	$	53	$	-
Meters										
Customer	NPMC	C03	$	74,596	$	-	$	766	$	-
Lighting Systems										
Customer	NPLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	NPMRBC	C05	$	-	$	-	$	-	$	-
Load Management										
Customer	NPCSC	C06	$	-	$	-	$	-	$	-
Total	NPT		$	495,699	$	-	$	27,686	$	2,600,652

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Net Cost Rate Base							
Production Plant							
Demand	RBOPD	T01	$ 4,042,459	$ 1,176,002	$ 135,716	$ 739,295	$ 1,168,182
Purchase Power							
Demand	RBPPD	PPDA	$ -	$ -	$ -	$ -	$ -
Energy	RBPPE	PPEA	-	$ -	$ -	$ -	$ -
Total Purchase Power	RBPPT		-	$ -	$ -	$ -	$ -
Transmission Plant							
Demand	PLSED	T01	$ 5,150,739	$ 1,498,415	$ 172,924	$ 941,980	$ 1,488,451
Station Equipment							
Demand	RBSED	SA1	$ 6,233,258	$ 1,829,643	$ 211,149	$ 1,150,207	$ 1,817,476
Primary Distribution Plant							
Demand	RBDPD	DA1	$ 27,709,976	$ 15,803,026	$ 2,231,717	$ 5,486,950	$ 2,796,620
Customer	RBDPC	C01	28,429,113	$ 21,439,877	$ 3,040,850	$ 3,168,412	$ 223,356
Total Primary Distribution Plant			$ 56,139,089	$ 37,242,903	$ 5,272,567	$ 8,655,362	$ 3,019,976
Customer Services							
Demand	RBCSD	CSA	$ -	$ -	$ -	$ -	$ -
Customer	RBCSC	SERV	762,059	$ 480,130	$ 68,098	$ 177,386	$ 20,008
Total Customer Services			$ 762,059	$ 480,130	$ 68,098	$ 177,386	$ 20,008
Meters							
Customer	RBMC	C03	$ 8,511,560	$ 4,744,924	$ 672,980	$ 2,552,151	$ 360,227
Lighting Systems							
Customer	RBLSC	C04	$ 883,837	$ -	$ -	$ -	$ -
Meter Reading, Billing and Customer Service							
Customer	RBMRBC	C05	$ 339,050	$ 255,687	$ 36,264	$ 37,786	$ 2,664
Load Management							
Customer	RBCSC	C06	$ -	$ -	$ -	$ -	$ -
Total	RBT		$ 82,062,050	$ 47,227,703	$ 6,569,698	$ 14,254,166	$ 7,876,983

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Net Cost Rate Base												
Production Plant												
Demand	RBOPD	T01	$	-	$	4,257	$	36,034	$	43,052	$	860
Purchase Power												
Demand	RBPPD	PPDA	$	-	$	-	$	-	$	-	$	-
Energy	RBPPE	PPEA	$	-	$	-	$	-	$	-	$	-
Total Purchase Power	RBPPT		$	-	$	-	$	-	$	-	$	-
Transmission Plant												
Demand	PLSED	T01	$	-	$	5,424	$	45,913	$	54,855	$	1,096
Station Equipment												
Demand	RBSED	SA1	$	-	$	6,623	$	-	$	66,981	$	1,338
Primary Distribution Plant												
Demand	RBDPD	DA1	$	45,704	$	404,499	$	135,598	$	566,571	$	23,246
Customer	RBDPC	C01	$	41,949	$	737	$	7,123	$	393,247	$	16,948
Total Primary Distribution Plant			$	87,654	$	405,236	$	142,721	$	959,819	$	40,194
Customer Services												
Demand	RBCSD	CSA	$	-	$	-	$	-	$	-	$	-
Customer	RBCSC	SERV	$	-	$	66	$	638	$	8,806	$	1,518
Total Customer Services			$	-	$	66	$	638	$	8,806	$	1,518
Meters												
Customer	RBMC	C03	$	-	$	1,188	$	11,488	$	87,031	$	3,751
Lighting Systems												
Customer	RBLSC	C04	$	883,837	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	RBMRBC	C05	$	500	$	9	$	85	$	4,690	$	202
Load Management												
Customer	RBCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	RBT		$	971,991	$	422,804	$	236,880	$	1,225,233	$	48,960

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Net Cost Rate Base										
Production Plant										
Demand	RBOPD	T01	$	33,042	$	-	$	4,932	$	701,085
Purchase Power										
Demand	RBPPD	PPDA	$	-	$	-	$	-	$	-
Energy	RBPPE	PPEA	$	-	$	-	$	-	$	-
Total Purchase Power	RBPPT		$	-	$	-	$	-	$	-
Transmission Plant										
Demand	PLSED	T01	$	42,101	$	-	$	6,285	$	893,295
Station Equipment										
Demand	RBSED	SA1	$	51,407	$	-	$	7,674	$	1,090,759
Primary Distribution Plant										
Demand	RBDPD	DA1	$	208,144	$	-	$	7,901	$	-
Customer	RBDPC	C01	$	95,630	$	-	$	983	$	-
Total Primary Distribution Plant			$	303,774	$	-	$	8,883	$	-
Customer Services										
Demand	RBCSD	CSA	$	-	$	-	$	-	$	-
Customer	RBCSC	SERV	$	5,354	$	-	$	55	$	-
Total Customer Services			$	5,354	$	-	$	55	$	-
Meters										
Customer	RBMC	C03	$	77,030	$	-	$	791	$	-
Lighting Systems										
Customer	RBLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	RBMRBC	C05	$	1,140	$	-	$	12	$	12
Load Management										
Customer	RBCSC	C06	$	-	$	-	$	-	$	-
Total	RBT		$	513,849	$	-	$	28,632	$	2,685,151

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Operation and Maintenance Expenses							
Production Plant							
Demand	OMOPD	T01	$ -	$ -	$ -	$ -	$ -
Purchase Power							
Demand	OMPPD	PPDA	$ 11,444,637	$ 4,648,787	$ 575,618	$ 2,041,783	$ 2,802,978
Energy	OMPPE	PPEA	8,519,158	$ 3,585,358	$ 444,526	$ 1,490,470	$ 1,903,427
Total Purchase Power	OMPPT		19,963,795	$ 8,234,145	$ 1,020,144	$ 3,532,253	$ 4,706,405
Transmission Plant							
Demand	PLSED	T01	$ 90,878	$ 26,438	$ 3,051	$ 16,620	$ 26,262
Station Equipment							
Demand	OMSED	SOMA	$ 528,505	$ 155,132	$ 17,903	$ 97,524	$ 154,100
Primary Distribution Plant							
Demand	OMDPD	DOM	$ 2,606,987	$ 1,486,767	$ 209,963	$ 516,219	$ 263,109
Customer	OMDPC	C01	1,667,061	$ 1,257,218	$ 178,313	$ 185,793	$ 13,097
Total Primary Distribution Plant			$ 4,274,048	$ 2,743,985	$ 388,276	$ 702,012	$ 276,207
Customer Services							
Demand	OMCSD	SERV	$ -	$ -	$ -	$ -	$ -
Customer	OMCSC	SERV	23,803	$ 14,997	$ 2,127	$ 5,541	$ 625
Total Customer Services			$ 23,803	$ 14,997	$ 2,127	$ 5,541	$ 625
Meters							
Customer	OMMC	C03	$ 810,072	$ 451,589	$ 64,050	$ 242,896	$ 34,284
Lighting Systems							
Customer	OMLSC	C04	$ 85,750	$ -	$ -	$ -	$ -
Meter Reading, Billing and Customer Service							
Customer	OMMRBC	C05	$ 2,712,402	$ 2,045,493	$ 290,115	$ 302,285	$ 21,309
Load Management							
Customer	OMCSC	C06	$ -	$ -	$ -	$ -	$ -
Total	OMT		$ 28,489,252	$ 13,671,778	$ 1,785,666	$ 4,899,131	$ 5,219,192

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Operation and Maintenance Expenses												
Production Plant												
Demand	OMOPD	T01	$	-	$	-	$	-	$	-	$	-
Purchase Power												
Demand	OMPPD	PPDA	$	82,140	$	-	$	97,403	$	163,425	$	4,698
Energy	OMPPE	PPEA	$	77,760	$	11,409	$	26,334	$	130,442	$	3,749
Total Purchase Power	OMPPT		$	159,900	$	11,409	$	123,737	$	293,867	$	8,448
Transmission Plant												
Demand	PLSED	T01	$	-	$	96	$	810	$	968	$	19
Station Equipment												
Demand	OMSED	SOMA	$	-	$	562	$	-	$	5,679	$	113
Primary Distribution Plant												
Demand	OMDPD	DOM	$	4,300	$	38,056	$	12,757	$	53,304	$	2,187
Customer	OMDPC	C01	$	2,460	$	43	$	418	$	23,060	$	994
Total Primary Distribution Plant			$	6,760	$	38,099	$	13,175	$	76,363	$	3,181
Customer Services												
Demand	OMCSD	SERV	$	-	$	-	$	-	$	-	$	-
Customer	OMCSC	SERV	$	-	$	2	$	20	$	275	$	47
Total Customer Services			$	-	$	2	$	20	$	275	$	47
Meters												
Customer	OMMC	C03	$	-	$	113	$	1,093	$	8,283	$	357
Lighting Systems												
Customer	OMLSC	C04	$	85,750	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	OMMRBC	C05	$	4,002	$	70	$	680	$	37,518	$	1,617
Load Management												
Customer	OMCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	OMT		$	256,412	$	50,351	$	139,515	$	422,954	$	13,783

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Operation and Maintenance Expenses										
Production Plant										
Demand	OMOPD	T01	$	-	$	-	$	-	$	-
Purchase Power										
Demand	OMPPD	PPDA	$	79,974	$	-	$	3,937	$	943,893
Energy	OMPPE	PPEA	$	62,405	$	-	$	1,528	$	781,748
Total Purchase Power	OMPPT		$	142,379	$	-	$	5,466	$	1,725,641
Transmission Plant										
Demand	PLSED	T01	$	743	$	-	$	111	$	15,761
Station Equipment										
Demand	OMSED	SOMA	$	4,359	$	-	$	651	$	92,483
Primary Distribution Plant										
Demand	OMDPD	DOM	$	19,582	$	-	$	743	$	-
Customer	OMDPC	C01	$	5,608	$	-	$	58	$	-
Total Primary Distribution Plant			$	25,190	$	-	$	801	$	-
Customer Services										
Demand	OMCSD	SERV	$	-	$	-	$	-	$	-
Customer	OMCSC	SERV	$	167	$	-	$	2	$	-
Total Customer Services			$	167	$	-	$	2	$	-
Meters										
Customer	OMMC	C03	$	7,331	$	-	$	75	$	-
Lighting Systems										
Customer	OMLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	OMMRBC	C05	$	9,124	$	-	$	94	$	94
Load Management										
Customer	OMCSC	C06	$	-	$	-	$	-	$	-
Total	OMT		$	189,293	$	-	$	7,199	$	1,833,979

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Labor Expenses							
Production Plant							
Demand	LBOPD	T01	$ -	$ -	$ -	$ -	$ -
Purchase Power							
Demand	LBPPD	PPDA	$ -	$ -	$ -	$ -	$ -
Energy	LBPPE	PPEA	-	$ -	$ -	$ -	$ -
Total Purchase Power	LBPPT		-	$ -	$ -	$ -	$ -
Transmission Plant							
Demand	PLSED	T01	$ 9,317	$ 2,710	$ 313	$ 1,704	$ 2,692
Station Equipment							
Demand	LBSED	SOMA	$ 132,598	$ 38,921	$ 4,492	$ 24,468	$ 38,663
Primary Distribution Plant							
Demand	LBDPD	DOM	$ 969,642	$ 552,988	$ 78,093	$ 192,002	$ 97,861
Customer	LBDPC	C01	529,362	$ 399,220	$ 56,622	$ 58,997	$ 4,159
Total Primary Distribution Plant			$ 1,499,004	$ 952,208	$ 134,715	$ 250,999	$ 102,020
Customer Services							
Demand	LBCSD	SERV	$ -	$ -	$ -	$ -	$ -
Customer	LBCSC	SERV	9,337	$ 5,883	$ 834	$ 2,173	$ 245
Total Customer Services			$ 9,337	$ 5,883	$ 834	$ 2,173	$ 245
Meters							
Customer	LBMC	C03	$ 390,360	$ 217,613	$ 30,864	$ 117,048	$ 16,521
Lighting Systems							
Customer	LBLSC	C04	$ 29,840	$ -	$ -	$ -	$ -
Meter Reading, Billing and Customer Service							
Customer	LBMRBC	C05	$ 1,039,496	$ 783,911	$ 111,183	$ 115,847	$ 8,167
Load Management							
Customer	LBCSC	C06	$ -	$ -	$ -	$ -	$ -
Total	LBT		$ 3,109,953	$ 2,001,246	$ 282,402	$ 512,240	$ 168,307

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Labor Expenses												
Production Plant												
Demand	LBOPD	T01	$	-	$	-	$	-	$	-	$	-
Purchase Power												
Demand	LBPPD	PPDA	$	-	$	-	$	-	$	-	$	-
Energy	LBPPE	PPEA	$	-	$	-	$	-	$	-	$	-
Total Purchase Power	LBPPT		$	-	$	-	$	-	$	-	$	-
Transmission Plant												
Demand	PLSED	T01	$	-	$	10	$	83	$	99	$	2
Station Equipment												
Demand	LBSED	SOMA	$	-	$	141	$	-	$	1,425	$	28
Primary Distribution Plant												
Demand	LBDPD	DOM	$	1,599	$	14,154	$	4,745	$	19,826	$	813
Customer	LBDPC	C01	$	781	$	14	$	133	$	7,322	$	316
Total Primary Distribution Plant			$	2,380	$	14,168	$	4,878	$	27,148	$	1,129
Customer Services												
Demand	LBCSD	SERV	$	-	$	-	$	-	$	-	$	-
Customer	LBCSC	SERV	$	-	$	1	$	8	$	108	$	19
Total Customer Services			$	-	$	1	$	8	$	108	$	19
Meters												
Customer	LBMC	C03	$	-	$	55	$	527	$	3,991	$	172
Lighting Systems												
Customer	LBLSC	C04	$	29,840	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	LBMRBC	C05	$	1,534	$	27	$	260	$	14,378	$	620
Load Management												
Customer	LBCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	LBT		$	33,755	$	14,401	$	5,756	$	47,150	$	1,970

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Labor Expenses										
Production Plant										
Demand	LBOPD	T01	$	-	$	-	$	-	$	-
Purchase Power										
Demand	LBPPD	PPDA	$	-	$	-	$	-	$	-
Energy	LBPPE	PPEA	$	-	$	-	$	-	$	-
Total Purchase Power	LBPPT		$	-	$	-	$	-	$	-
Transmission Plant										
Demand	PLSED	T01	$	76	$	-	$	11	$	1,616
Station Equipment										
Demand	LBSED	SOMA	$	1,094	$	-	$	163	$	23,203
Primary Distribution Plant										
Demand	LBDPD	DOM	$	7,283	$	-	$	276	$	-
Customer	LBDPC	C01	$	1,781	$	-	$	18	$	-
Total Primary Distribution Plant			$	9,064	$	-	$	295	$	-
Customer Services										
Demand	LBCSD	SERV	$	-	$	-	$	-	$	-
Customer	LBCSC	SERV	$	66	$	-	$	1	$	-
Total Customer Services			$	66	$	-	$	1	$	-
Meters										
Customer	LBMC	C03	$	3,533	$	-	$	36	$	-
Lighting Systems										
Customer	LBLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	LBMRBC	C05	$	3,497	$	-	$	36	$	36
Load Management										
Customer	LBCSC	C06	$	-	$	-	$	-	$	-
Total	LBT		$	17,329	$	-	$	542	$	24,855

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Depreciation Expenses							
Production Plant							
Demand	DPOPD	T01	$ -	$ -	$ -	$ -	$ -
Purchase Power							
Demand	DPPPD	PPDA	$ -	$ -	$ -	$ -	$ -
Energy	DPPPE	PPEA	-	$ -	$ -	$ -	$ -
Total Purchase Power	DPPPT		-	$ -	$ -	$ -	$ -
Transmission Plant							
Demand	PLSED	T01	$ 408,743	$ 118,909	$ 13,723	$ 74,752	$ 118,118
Station Equipment							
Demand	DPSED	SA1	$ 306,812	$ 90,058	$ 10,393	$ 56,615	$ 89,460
Primary Distribution Plant							
Demand	DPDPD	DA1	$ 1,092,409	$ 623,002	$ 87,981	$ 216,312	$ 110,251
Customer	DPDPC	C01	1,081,223	$ 815,406	$ 115,650	$ 120,502	$ 8,495
Total Primary Distribution Plant			$ 2,173,632	$ 1,438,408	$ 203,631	$ 336,814	$ 118,746
Customer Services							
Demand	DPCSD	SERV	$ -	$ -	$ -	$ -	$ -
Customer	DPCSC	SERV	46,856	$ 29,521	$ 4,187	$ 10,907	$ 1,230
Total Customer Services			$ 46,856	$ 29,521	$ 4,187	$ 10,907	$ 1,230
Meters							
Customer	DPMC	C03	$ 275,066	$ 153,340	$ 21,748	$ 82,477	$ 11,641
Lighting Systems							
Customer	DPLSC	C04	$ 37,296	$ -	$ -	$ -	$ -
Meter Reading, Billing and Customer Service							
Customer	DPMRBC	C05	$ -	$ -	$ -	$ -	$ -
Load Management							
Customer	DPCSC	C06	$ -	$ -	$ -	$ -	$ -
Total	DPT		$ 3,248,405	$ 1,830,237	$ 253,683	$ 561,565	$ 339,195

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Depreciation Expenses												
Production Plant												
Demand	DPOPD	T01	$	-	$	-	$	-	$	-	$	-
Purchase Power												
Demand	DPPPD	PPDA	$	-	$	-	$	-	$	-	$	-
Energy	DPPPE	PPEA	$	-	$	-	$	-	$	-	$	-
Total Purchase Power	DPPPT		$	-	$	-	$	-	$	-	$	-
Transmission Plant												
Demand	PLSED	T01	$	-	$	430	$	3,643	$	4,353	$	87
Station Equipment												
Demand	DPSED	SA1	$	-	$	326	$	-	$	3,297	$	66
Primary Distribution Plant												
Demand	DPDPD	DA1	$	1,802	$	15,947	$	5,346	$	22,336	$	916
Customer	DPDPC	C01	$	1,595	$	28	$	271	$	14,956	$	645
Total Primary Distribution Plant			$	3,397	$	15,975	$	5,617	$	37,292	$	1,561
Customer Services												
Demand	DPCSD	SERV	$	-	$	-	$	-	$	-	$	-
Customer	DPCSC	SERV	$	-	$	4	$	39	$	541	$	93
Total Customer Services			$	-	$	4	$	39	$	541	$	93
Meters												
Customer	DPMC	C03	$	-	$	38	$	371	$	2,813	$	121
Lighting Systems												
Customer	DPLSC	C04	$	37,296	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	DPMRBC	C05	$	-	$	-	$	-	$	-	$	-
Load Management												
Customer	DPCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	DPT		$	40,693	$	16,774	$	9,671	$	48,296	$	1,928

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Depreciation Expenses										
Production Plant										
Demand	DPOPD	T01	$	-	$	-	$	-	$	-
Purchase Power										
Demand	DPPPD	PPDA	$	-	$	-	$	-	$	-
Energy	DPPPE	PPEA	$	-	$	-	$	-	$	-
Total Purchase Power	DPPPT		$	-	$	-	$	-	$	-
Transmission Plant										
Demand	PLSED	T01	$	3,341	$	-	$	499	$	70,889
Station Equipment										
Demand	DPSED	SA1	$	2,530	$	-	$	378	$	53,689
Primary Distribution Plant										
Demand	DPDPD	DA1	$	8,206	$	-	$	311	$	-
Customer	DPDPC	C01	$	3,637	$	-	$	37	$	-
Total Primary Distribution Plant			$	11,843	$	-	$	349	$	-
Customer Services										
Demand	DPCSD	SERV	$	-	$	-	$	-	$	-
Customer	DPCSC	SERV	$	329	$	-	$	3	$	-
Total Customer Services			$	329	$	-	$	3	$	-
Meters										
Customer	DPMC	C03	$	2,489	$	-	$	26	$	-
Lighting Systems										
Customer	DPLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	DPMRBC	C05	$	-	$	-	$	-	$	-
Load Management										
Customer	DPCSC	C06	$	-	$	-	$	-	$	-
Total	DPT		$	20,533	$	-	$	1,254	$	124,578

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Property Taxes								
Production Plant								
Demand	PTOPD	T01	$	- $	- $	- $	- $	-
Purchase Power								
Demand	PTPPD	PPDA	$	- $	- $	- $	- $	-
Energy	PTPPE	PPEA		- $	- $	- $	- $	-
Total Purchase Power	PTPPT			- $	- $	- $	- $	-
Transmission Plant								
Demand	PLSED	T01	$	- $	- $	- $	- $	-
Station Equipment								
Demand	PTSED	SOMA	$	- $	- $	- $	- $	-
Primary Distribution Plant								
Demand	PTDPD	DOM	$	- $	- $	- $	- $	-
Customer	PTDPC	C01		- $	- $	- $	- $	-
Total Primary Distribution Plant			$	- $	- $	- $	- $	-
Customer Services								
Demand	PTCSD	SERV	$	- $	- $	- $	- $	-
Customer	PTCSC	SERV		- $	- $	- $	- $	-
Total Customer Services			$	- $	- $	- $	- $	-
Meters								
Customer	PTMC	C03	$	- $	- $	- $	- $	-
Lighting Systems								
Customer	PTLSC	C04	$	- $	- $	- $	- $	-
Meter Reading, Billing and Customer Service								
Customer	PTMRBC	C05	$	- $	- $	- $	- $	-
Load Management								
Customer	PTCSC	C06	$	- $	- $	- $	- $	-
Total	PTT		$	- $	- $	- $	- $	-

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6	Interruptible Power Service Rate 15	Power Service Time-of-Use Rate 16	Residential Service Time-of-Use Rate 17	Residential Seasonal Service Time-of-Use Rate 18
Property Taxes								
Production Plant								
Demand	PTOPD	T01	$	- $	- $	- $	- $	-
Purchase Power								
Demand	PTPPD	PPDA	$	- $	- $	- $	- $	-
Energy	PTPPE	PPEA	$	- $	- $	- $	- $	-
Total Purchase Power	PTPPT		$	- $	- $	- $	- $	-
Transmission Plant								
Demand	PLSED	T01	$	- $	- $	- $	- $	-
Station Equipment								
Demand	PTSED	SOMA	$	- $	- $	- $	- $	-
Primary Distribution Plant								
Demand	PTDPD	DOM	$	- $	- $	- $	- $	-
Customer	PTDPC	C01	$	- $	- $	- $	- $	-
Total Primary Distribution Plant			$	- $	- $	- $	- $	-
Customer Services								
Demand	PTCSD	SERV	$	- $	- $	- $	- $	-
Customer	PTCSC	SERV	$	- $	- $	- $	- $	-
Total Customer Services			$	- $	- $	- $	- $	-
Meters								
Customer	PTMC	C03	$	- $	- $	- $	- $	-
Lighting Systems								
Customer	PTLSC	C04	$	- $	- $	- $	- $	-
Meter Reading, Billing and Customer Service								
Customer	PTMRBC	C05	$	- $	- $	- $	- $	-
Load Management								
Customer	PTCSC	C06	$	- $	- $	- $	- $	-
Total	PTT		$	- $	- $	- $	- $	-

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Property Taxes										
Production Plant										
Demand	PTOPD	T01	$	-	$	-	$	-	$	-
Purchase Power										
Demand	PTPPD	PPDA	$	-	$	-	$	-	$	-
Energy	PTPPE	PPEA	$	-	$	-	$	-	$	-
Total Purchase Power	PTPPT		$	-	$	-	$	-	$	-
Transmission Plant										
Demand	PLSED	T01	$	-	$	-	$	-	$	-
Station Equipment										
Demand	PTSED	SOMA	$	-	$	-	$	-	$	-
Primary Distribution Plant										
Demand	PTDPD	DOM	$	-	$	-	$	-	$	-
Customer	PTDPC	C01	$	-	$	-	$	-	$	-
Total Primary Distribution Plant			$	-	$	-	$	-	$	-
Customer Services										
Demand	PTCSD	SERV	$	-	$	-	$	-	$	-
Customer	PTCSC	SERV	$	-	$	-	$	-	$	-
Total Customer Services			$	-	$	-	$	-	$	-
Meters										
Customer	PTMC	C03	$	-	$	-	$	-	$	-
Lighting Systems										
Customer	PTLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	PTMRBC	C05	$	-	$	-	$	-	$	-
Load Management										
Customer	PTCSC	C06	$	-	$	-	$	-	$	-
Total	PTT		$	-	$	-	$	-	$	-

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Total System		Residential Service Rate 1		Residential Seasonal Service Rate 2		Commercial Service Rate 3		Power Service Rate 4
Other Taxes												
Production Plant												
Demand	OTOPD	T01	$	241	$	70	$	8	$	44	$	70
Purchase Power												
Demand	OTPPD	PPDA	$	-	$	-	$	-	$	-	$	-
Energy	OTPPE	PPEA		-	$	-	$	-	$	-	$	-
Total Purchase Power	OTPPT			-	$	-	$	-	$	-	$	-
Transmission Plant												
Demand	PLSED	T01	$	304	$	88	$	10	$	56	$	88
Station Equipment												
Demand	OTSED	SOMA	$	364	$	107	$	12	$	67	$	106
Primary Distribution Plant												
Demand	OTDPD	DOM	$	1,624	$	926	$	131	$	322	$	164
Customer	OTDPC	C01		1,675	$	1,264	$	179	$	187	$	13
Total Primary Distribution Plant			$	3,300	$	2,190	$	310	$	508	$	177
Customer Services												
Demand	OTCSD	SERV	$	-	$	-	$	-	$	-	$	-
Customer	OTCSC	SERV		44	$	28	$	4	$	10	$	1
Total Customer Services			$	44	$	28	$	4	$	10	$	1
Meters												
Customer	OTMC	C03	$	501	$	279	$	40	$	150	$	21
Lighting Systems												
Customer	OTLSC	C04	$	52	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	OTMRBC	C05	$	-	$	-	$	-	$	-	$	-
Load Management												
Customer	OTCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	OTT		$	4,805	$	2,762	$	384	$	836	$	463

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Other Taxes												
Production Plant												
Demand	OTOPD	T01	$	-	$	0	$	2	$	3	$	0
Purchase Power												
Demand	OTPPD	PPDA	$	-	$	-	$	-	$	-	$	-
Energy	OTPPE	PPEA	$	-	$	-	$	-	$	-	$	-
Total Purchase Power	OTPPT		$	-	$	-	$	-	$	-	$	-
Transmission Plant												
Demand	PLSED	T01	$	-	$	0	$	3	$	3	$	0
Station Equipment												
Demand	OTSED	SOMA	$	-	$	0	$	-	$	4	$	0
Primary Distribution Plant												
Demand	OTDPD	DOM	$	3	$	24	$	8	$	33	$	1
Customer	OTDPC	C01	$	2	$	0	$	0	$	23	$	1
Total Primary Distribution Plant			$	5	$	24	$	8	$	56	$	2
Customer Services												
Demand	OTCSD	SERV	$	-	$	-	$	-	$	-	$	-
Customer	OTCSC	SERV	$	-	$	0	$	0	$	1	$	0
Total Customer Services			$	-	$	0	$	0	$	1	$	0
Meters												
Customer	OTMC	C03	$	-	$	0	$	1	$	5	$	0
Lighting Systems												
Customer	OTLSC	C04	$	52	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service												
Customer	OTMRBC	C05	$	-	$	-	$	-	$	-	$	-
Load Management												
Customer	OTCSC	C06	$	-	$	-	$	-	$	-	$	-
Total	OTT		$	57	$	25	$	14	$	72	$	3

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Other Taxes										
Production Plant										
Demand	OTOPD	T01	$	2	$	-	$	0	$	42
Purchase Power										
Demand	OTPPD	PPDA	$	-	$	-	$	-	$	-
Energy	OTPPE	PPEA	$	-	$	-	$	-	$	-
Total Purchase Power	OTPPT		$	-	$	-	$	-	$	-
Transmission Plant										
Demand	PLSED	T01	$	2	$	-	$	0	$	53
Station Equipment										
Demand	OTSED	SOMA	$	3	$	-	$	0	$	64
Primary Distribution Plant										
Demand	OTDPD	DOM	$	12	$	-	$	0	$	-
Customer	OTDPC	C01	$	6	$	-	$	0	$	-
Total Primary Distribution Plant			$	18	$	-	$	1	$	-
Customer Services										
Demand	OTCSD	SERV	$	-	$	-	$	-	$	-
Customer	OTCSC	SERV	$	0	$	-	$	0	$	-
Total Customer Services			$	0	$	-	$	0	$	-
Meters										
Customer	OTMC	C03	$	5	$	-	$	0	$	-
Lighting Systems										
Customer	OTLSC	C04	$	-	$	-	$	-	$	-
Meter Reading, Billing and Customer Service										
Customer	OTMRBC	C05	$	-	$	-	$	-	$	-
Load Management										
Customer	OTCSC	C06	$	-	$	-	$	-	$	-
Total	OTT		$	30	$	-	$	2	$	158

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Cost of Service Summary -- Unadjusted Results							
Operating Revenues							
Sales to Members	REVUC	R01	$ 33,063,162	$ 15,143,415	$ 1,938,230	$ 5,538,593	$ 6,983,243
Forfeited Discounts	FORDIS	REVUC	134,080	$ 61,411	$ 7,860	$ 22,460	$ 28,319
Rent From Electric Property	RENTEP	REVUC	120,129	$ 55,021	$ 7,042	$ 20,123	$ 25,372
Other Electric Revenues	OTHREV	REVUC	113,147	$ 51,823	$ 6,633	$ 18,954	$ 23,898
Total Operating Revenues	TOR		$ 33,430,518	$ 15,311,669	$ 1,959,765	$ 5,600,130	$ 7,060,832
Operating Expenses							
Operation and Maintenance Expenses			$ 28,489,252	$ 13,671,778	$ 1,785,666	$ 4,899,131	$ 5,219,192
Depreciation and Amortization Expenses			3,248,405	1,830,237	253,683	561,565	339,195
Property Taxes		NPT	-	-	-	-	-
Other Taxes			4,805	2,762	384	836	463
Total Operating Expenses	TOE		$ 31,742,462	$ 15,504,778	$ 2,039,732	$ 5,461,531	$ 5,558,849
Utility Operating Margin	TOM		$ 1,688,056	$ (193,108)	$ (79,967)	$ 138,599	$ 1,501,983
Net Cost Rate Base			$ 82,062,050	$ 47,227,703	$ 6,569,698	$ 14,254,166	$ 7,876,983
Rate of Return			**2.06%**	**-0.41%**	**-1.22%**	**0.97%**	**19.07%**
Average Rate per kWh (Revenue/kWh)			0.1092	0.1259	0.1300	0.1108	0.1093
Average Annual kWh (Annual kWh/Customer)			9,830	459	402	1,292	23,411
Coincident Load Factor				0.82	0.82	0.78	0.72
Non-Coincident Load Factor				1.21	1.30	0.80	0.65
Average Purchased Power Cost Per Kwh				0.0684	0.0684	0.0706	0.0737

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Cost of Service Summary -- Unadjusted Results												
Operating Revenues												
Sales to Members	REVUC	R01	$	359,860	$	111,445	$	166,980	$	448,943	$	13,954
Forfeited Discounts	FORDIS	REVUC	$	1,459	$	452	$	677	$	1,821	$	57
Rent From Electric Property	RENTEP	REVUC	$	1,307	$	405	$	607	$	1,631	$	51
Other Electric Revenues	OTHREV	REVUC	$	1,231	$	381	$	571	$	1,536	$	48
Total Operating Revenues	TOR		$	363,858	$	112,683	$	168,835	$	453,931	$	14,109
Operating Expenses												
Operation and Maintenance Expenses			$	256,412	$	50,351	$	139,515	$	422,954	$	13,783
Depreciation and Amortization Expenses				40,693		16,774		9,671		48,296		1,928
Property Taxes		NPT		-		-		-		-		-
Other Taxes				57		25		14		72		3
Total Operating Expenses	TOE		$	297,162	$	67,149	$	149,199	$	471,322	$	15,714
Utility Operating Margin	TOM		$	66,696	$	45,534	$	19,636	$	(17,391)	$	(1,605)
Net Cost Rate Base			$	971,991	$	422,804	$	236,880	$	1,225,233	$	48,960
Rate of Return				**6.86%**		**10.77%**		**8.29%**		**-1.42%**		**-3.28%**
Average Rate per kWh (Revenue/kWh)				0.1379		0.2911		0.1890		0.1026		0.1109
Average Annual kWh (Annual kWh/Customer)				113		42,533		10,156		911		608
Coincident Load Factor				1.01		#DIV/0!		0.29		0.85		0.85
Non-Coincident Load Factor				0.49		1.06		0.29		1.20		1.73
Average Purchased Power Cost Per Kwh				0.0613		0.0298		0.1400		0.0671		0.0671

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Cost of Service Summary -- Unadjusted Results										
Operating Revenues										
Sales to Members	REVUC	R01	$	212,905	$	-	$	5,714	$	2,139,882
Forfeited Discounts	FORDIS	REVUC	$	863	$	-	$	23	$	8,678
Rent From Electric Property	RENTEP	REVUC	$	774	$	-	$	21	$	7,775
Other Electric Revenues	OTHREV	REVUC	$	729	$	-	$	20	$	7,323
Total Operating Revenues	TOR		$	215,270	$	-	$	5,777	$	2,163,657
Operating Expenses										
Operation and Maintenance Expenses			$	189,293	$	-	$	7,199	$	1,833,979
Depreciation and Amortization Expenses				20,533		-		1,254		124,578
Property Taxes		NPT		-		-		-		-
Other Taxes				30		-		2		158
Total Operating Expenses	TOE		$	209,856	$	-	$	8,455	$	1,958,715
Utility Operating Margin	TOM		$	5,415	$	-	$	(2,678)	$	204,942
Net Cost Rate Base			$	513,849	$	-	$	28,632	$	2,685,151
Rate of Return				**1.05%**		**#DIV/0!**		**-9.35%**		**7.63%**
Average Rate per kWh (Revenue/kWh)				0.1017		#DIV/0!		0.1114		0.0494
Average Annual kWh (Annual kWh/Customer)				1,793		#DIV/0!		4,273		3,608,079
Coincident Load Factor				0.83		#DIV/0!		0.41		0.59
Non-Coincident Load Factor				0.75		#DIV/0!		0.12		0.73
Average Purchased Power Cost Per Kwh				0.0680		#DIV/0!		0.1066		0.0399

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Cost of Service Summary -- Pro-Forma ()							
Operating Revenues							
Total Operating Revenue -- Actual			$ 33,430,518	$ 15,311,669	$ 1,959,765	$ 5,600,130	$ 7,060,832
Pro-Forma Adjustments:							
MolyCorp Revenue			1,615,045	$ -	$ -	$ -	$ -
Total Pro-Forma Operating Revenue			$ 35,045,563	$ 15,311,669	$ 1,959,765	$ 5,600,130	$ 7,060,832
Operating Expenses							
Total Operating Expenses -- Actual	OPEXP		$ 31,742,462	$ 15,504,778	$ 2,039,732	$ 5,461,531	$ 5,558,849
Pro-Forma Adjustments:							
Adjustment to Labor (3% Increase)		LBT	155,299	$ 99,935	$ 14,102	$ 25,579	$ 8,405
Adjustment to Purchased Power Demand (MolyCorp)			1,212,621	$ -	$ -	$ -	$ -
Adjustment to Purchased Power Energy (MolyCorp)			402,423	$ -	$ -	$ -	$ -
Total Pro-forma Operating Expenses			$ 33,512,806	$ 15,604,712	$ 2,053,834	$ 5,487,110	$ 5,567,254
Utility Operating Margin -- Pro-Forma			$ 1,532,757	$ (293,043)	$ (94,069)	$ 113,020	$ 1,493,578
Net Cost Rate Base			$ 82,062,050	$ 47,227,703	$ 6,569,698	$ 14,254,166	$ 7,876,983
Rate of Return			**1.87%**	**-0.62%**	**-1.43%**	**0.79%**	**18.96%**
Average Rate per kWh (Revenue/kWh)			$ 0.1092	$ 0.1259	$ 0.1300	$ 0.1108	$ 0.1093
Average Purchased Power Cost Per Kwh				$ 0.0684	$ 0.0684	$ 0.0706	$ 0.0737
Average Annual kWh (Annual kWh/Customer)			9,830	459	402	1,292	23,411

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Cost of Service Summary -- Pro-Forma ()												
Operating Revenues												
Total Operating Revenue -- Actual			$	363,858	$	112,683	$	168,835	$	453,931	$	14,109
Pro-Forma Adjustments:												
MolyCorp Revenue			$	-	$	-	$	-	$	-	$	-
Total Pro-Forma Operating Revenue			$	363,858	$	112,683	$	168,835	$	453,931	$	14,109
Operating Expenses												
Total Operating Expenses -- Actual	OPEXP		$	297,162	$	67,149	$	149,199	$	471,322	$	15,714
Pro-Forma Adjustments:												
Adjustment to Labor (3% Increase)		LBT	$	1,686	$	719	$	287	$	2,354	$	98
Adjustment to Purchased Power Demand (MolyCorp)			$	-	$	-	$	-	$	-	$	-
Adjustment to Purchased Power Energy (MolyCorp)			$	-	$	-	$	-	$	-	$	-
Total Pro-forma Operating Expenses			$	298,847	$	67,868	$	149,487	$	473,676	$	15,812
Utility Operating Margin -- Pro-Forma			$	65,011	$	44,815	$	19,348	$	(19,745)	$	(1,704)
Net Cost Rate Base			$	971,991	$	422,804	$	236,880	$	1,225,233	$	48,960
Rate of Return				**6.69%**		**10.60%**		**8.17%**		**-1.61%**		**-3.48%**
Average Rate per kWh (Revenue/kWh)			$	0.1379	$	0.2911	$	0.1890	$	0.1026	$	0.1109
Average Purchased Power Cost Per Kwh			$	0.0613	$	0.0298	$	0.1400	$	0.0671	$	0.0671
Average Annual kWh (Annual kWh/Customer)				113		42,533		10,156		911		608

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Commercial Service Time-of-Use Rate 19	Irrigation Power Service Time-of-Use Rate 20	Irrigation Power Service Rate 22	MolyCorp - Special Contract
Cost of Service Summary -- Pro-Forma ()						
Operating Revenues						
Total Operating Revenue -- Actual			$ 215,270	$ -	$ 5,777	$ 2,163,657
Pro-Forma Adjustments:						
MolyCorp Revenue			$ -	$ -	$ -	$ 1,615,045
Total Pro-Forma Operating Revenue			$ 215,270	$ -	$ 5,777	$ 3,778,702
Operating Expenses						
Total Operating Expenses -- Actual	OPEXP		$ 209,856	$ -	$ 8,455	$ 1,958,715
Pro-Forma Adjustments:						
Adjustment to Labor (3% Increase)		LBT	$ 865	$ -	$ 27	$ 1,241
Adjustment to Purchased Power Demand (MolyCorp)			$ -	$ -	$ -	$ 1,212,621
Adjustment to Purchased Power Energy (MolyCorp)			$ -	$ -	$ -	$ 402,423
Total Pro-forma Operating Expenses			$ 210,721	$ -	$ 8,482	$ 3,575,001
Utility Operating Margin -- Pro-Forma			$ 4,549	$ -	$ (2,705)	$ 203,701
Net Cost Rate Base			$ 513,849	$ -	$ 28,632	$ 2,685,151
Rate of Return			**0.89%**	**#DIV/0!**	**-9.45%**	**7.59%**
Average Rate per kWh (Revenue/kWh)			$ 0.1017	#DIV/0!	$ 0.1114	$ 0.0494
Average Purchased Power Cost Per Kwh			$ 0.0680	#DIV/0!	$ 0.1066	$ 0.0399
Average Annual kWh (Annual kWh/Customer)			1,793	#DIV/0!	4,273	3,608,079

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class	E01	Energy	1.000000	0.397146	0.049240	0.165098	0.210840
Demand Allocation Factors							
Purchase Power -- Average 12 CP	D01	CPDemands	1.000000	0.371424	0.046279	0.153510	0.210554
Station Equipment -- Maximum Class Demand	D02	NCP	1.000000	0.362574	0.044894	0.159245	0.218613
Primary Distribution Plant -- Maximum Class Demand	D03	NCP	1.000000	0.362574	0.044894	0.159245	0.218613
Services	SERV		1.000000	0.630044	0.089360	0.232772	0.026255
Customer Allocation Factors							
Primary Distribution Plant -- Average Number of Customers	C01	Cust05	1.000000	0.75415	0.10696	0.11145	0.00786
Customer Services -- Average Number of Customers	C02	Cust05	1.000000	0.75415	0.10696	0.11145	0.00786
Meter Costs -- Weighted Cost of Meters	C03		1.000000	0.55747	0.07907	0.29985	0.04232
Lighting Systems -- Lighting Customers	C04	Cust04	1.000000	-	-	-	-
Meter Reading and Billing -- Weighted Cost	C05	Cust03	1.000000	0.75413	0.10696	0.11145	0.00786
Load Management	C06	Cust06	1.000000	0.70815	0.10044	0.10465	0.00738
Rev	R01		33,063,162	15,143,415	1,938,230	5,538,593	6,983,243
Energy	Energy		302,909,954	120,299,391	14,915,162	50,009,679	63,865,598
Customers (Monthly Bills)			369,780	261,860	37,140	38,698	2,728
Average Customers (Bills/12)	Cust01		30,815	21,822	3,095	3,225	227
Average Customers (Lighting = Lights)	Cust02		30,815	21,822	3,095	3,225	227
Average Customers (Ligthing =45 Lights per Cust)	Cust03		28,936	21,822	3,095	3,225	227
Street Lighting	Cust04		23,056	-	-	-	-
Average Customers	Cust05		28,935	21,822	3,095	3,225	227
Load Management	Cust06		30,815	21,822	3,095	3,225	227
Winter CP Demands	CPDemands		444,372	165,050	20,565	68,216	93,564
Summer CP Demands	CPDemands		109,716	35,847	4,310	20,020	27,567
12 Month Coincident Peak Demands	NCP		554,088	200,898	24,875	88,236	121,131
Class Maximum Demands			39,571	11,336	1,308	7,126	11,261
Sum of the Individual Customer Max Demand			209,406	109,074	15,403	37,871	19,302

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Security Lighting Service Rate 6	Interruptible Power Service Rate 15	Power Service Time-of-Use Rate 16	Residential Service Time-of-Use Rate 17	Residential Seasonal Service Time-of-Use Rate 18
Allocation Factors							
Energy Allocation Factors							
Energy Usage by Class	E01	Energy	0.008613	0.001264	0.002917	0.014449	0.000415
Demand Allocation Factors							
Purchase Power -- Average 12 CP	D01	CPDemands	0.007988	-	0.007661	0.013211	0.000404
Station Equipment -- Maximum Class Demand	D02	NCP	0.006406	-	0.007597	0.012746	0.000366
Primary Distribution Plant -- Maximum Class Demand	D03	NCP	0.006406	-	0.007597	0.012746	0.000366
Services	SERV		-	0.000087	0.000837	0.011556	0.001992
Customer Allocation Factors							
Primary Distribution Plant -- Average Number of Customers	C01	Cust05	0.00148	0.00003	0.00025	0.01383	0.00060
Customer Services -- Average Number of Customers	C02	Cust05	0.00148	0.00003	0.00025	0.01383	0.00060
Meter Costs -- Weighted Cost of Meters	C03		-	0.00014	0.00135	0.01023	0.00044
Lighting Systems -- Lighting Customers	C04	Cust04	1.00000	-	-	-	-
Meter Reading and Billing -- Weighted Cost	C05	Cust03	0.00148	0.00003	0.00025	0.01383	0.00060
Load Management	C06	Cust06	0.06235	0.00002	0.00024	0.01299	0.00056
Rev	R01		359,860	111,445	166,980	448,943	13,954
Energy	Energy		2,609,075	382,800	883,600	4,376,730	125,806
Customers (Monthly Bills)			23,056	9	87	4,803	207
Average Customers (Bills/12)	Cust01		1,921	1	7	400	17
Average Customers (Lighting = Lights)	Cust02		1,921	1	7	400	17
Average Customers (Ligthing =45 Lights per Cust)	Cust03		43	1	7	400	17
Street Lighting	Cust04		23,056	-	-	-	-
Average Customers	Cust05		43	1	7	400	17
Load Management	Cust06		1,921	1	7	400	17
Winter CP Demands	CPDemands		3,550	-	3,404	5,870	179
Summer CP Demands	CPDemands		-	-	805	1,192	24
12 Month Coincident Peak Demands	NCP		3,550	-	4,209	7,062	203
Class Maximum Demands			604	41	347	415	8
Sum of the Individual Customer Max Demand			642	2,792	936	3,911	160

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Commercial Service Time-of-Use Rate 19	Irrigation Power Service Time-of-Use Rate 20	Irrigation Power Service Rate 22	MolyCorp - Special Contract
Allocation Factors						
Energy Allocation Factors						
Energy Usage by Class	E01	Energy	0.006913	-	0.000169	0.142937
Demand Allocation Factors						
Purchase Power -- Average 12 CP	D01	CPDemands	0.006197	-	0.000117	0.182656
Station Equipment -- Maximum Class Demand	D02	NCP	0.006237	-	0.000307	0.181013
Primary Distribution Plant -- Maximum Class Demand	D03	NCP	0.006237	-	0.000307	0.181013
Services	SERV		0.007026	-	0.000072	-
Customer Allocation Factors						
Primary Distribution Plant -- Average Number of Customers	C01	Cust05	0.00336	-	0.00003	-
Customer Services -- Average Number of Customers	C02	Cust05	0.00336	-	0.00003	-
Meter Costs -- Weighted Cost of Meters	C03		0.00905	-	0.00009	-
Lighting Systems -- Lighting Customers	C04	Cust04	-	-	-	-
Meter Reading and Billing -- Weighted Cost	C05	Cust03	0.00336	-	0.00003	0.00003
Load Management	C06	Cust06	0.00316	-	0.00003	0.00003
Rev	R01		212,905	-	5,714	2,139,882
Energy	Energy		2,093,887	-	51,278	43,296,948
Customers (Monthly Bills)			1,168	-	12	12
Average Customers (Bills/12)	Cust01		97	-	1	1
Average Customers (Lighting = Lights)	Cust02		97	-	1	1
Average Customers (Ligthing =45 Lights per Cust)	Cust03		97	-	1	1
Street Lighting	Cust04		-	-	-	-
Average Customers	Cust05		97	-	1	-
Load Management	Cust06		97	-	1	1
Winter CP Demands	CPDemands		2,754	-	52	81,167
Summer CP Demands	CPDemands		702	-	118	19,130
12 Month Coincident Peak Demands	NCP		3,456	-	170	100,297
Class Maximum Demands			319	-	48	6,758
Sum of the Individual Customer Max Demand			1,437	-	55	17,823

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Transmission Residual Demand Allocator	TRDA		38,967	11,336	1,308	7,126	11,261
Transmission Plant In Service			$ 6,585,323				
Customer Specific Assignment			$ -				
Transmission Residual		TRDA	$ 6,585,323	$ 1,915,753	$ 221,087	$ 1,204,340	$ 1,903,014
Transmission Total	TA1		$ 6,585,323	$ 1,915,753	$ 221,087	$ 1,204,340	$ 1,903,014
Transmission Plant Allocator	T01	TA1	1.000000	0.29091	0.03357	0.18288	0.28898
Transmission Residual Demand Allocator	TOMDA		38,967	11,336	1,308	7,126	11,261
Transmission Plant In Service			$ 6,585,323				
Customer Specific Assignment			$ -				
Transmission Residual		TOMDA	$ 6,585,323	$ 1,915,753	$ 221,087	$ 1,204,340	$ 1,903,014
Transmission Total	TOMA		$ 6,585,323	$ 1,915,753	$ 221,087	$ 1,204,340	$ 1,903,014
Transmission O&M Allocator	T02	TOMA	1.000000	0.29091	0.03357	0.18288	0.28898
Distribution Residual Demand Allocator	DDA		190,941	109,074	15,403	37,871	19,302
Distribution Plant In Service			$ 30,314,333				
Customer Specific Assignment			$ 50,000				
Distribution Residual		DOMDA	$ 30,264,333	$ 17,288,292.7	$ 2,441,467	$ 6,002,648	$ 3,059,464
Distribution Total	DTI		$ 30,314,333	$ 17,288,292.7	$ 2,441,467	$ 6,002,648	$ 3,059,464
Distribution Plant Allocator	DA1	DTI	1.000000	0.57030	0.08054	0.19801	0.10092
Distribution Residual Demand Allocator	DOMDA		190,941	109,073.76	15,403	37,871	19,302
Distribution Plant In Service			$ 30,314,333				
Customer Specific Assignment			$ 50,000				
Distribution Residual		DOMDA	$ 30,264,333	$ 17,288,292.7	$ 2,441,467	$ 6,002,648	$ 3,059,464
Distribution Total	DOMA		$ 30,314,333	$ 17,288,292.7	$ 2,441,467	$ 6,002,648	$ 3,059,464
Distribution O&M Allocator	DOM	DOMA	1.000000	0.57030	0.08054	0.19801	0.10092
Substation Residual Demand Allocator	SDA		38,619	11,336	1,308	7,126	11,261
Substation Plant In Service			$ 8,514,040				
Customer Specific Assignment			$ -				
Substation Residual		SDA	$ 8,514,040	$ 2,499,118	$ 288,410	$ 1,571,074	$ 2,482,500
Substation Total	ST1		$ 8,514,040	$ 2,499,118	$ 288,410	$ 1,571,074	$ 2,482,500
Substation Plant Allocator	SA1	ST1	1.000000	0.29353	0.03387	0.18453	0.29158
Substation Residual Demand Allocator	SOMDA		$ 38,619	11,336	1,308	7,126	11,261
Substation Plant In Service			$ 8,514,040				
Customer Specific Assignment			$ -				
Substation Residual		SOMDA	$ 8,514,040	$ 2,499,118	$ 288,410	$ 1,571,074	$ 2,482,500
Substation Total	STOM		$ 8,514,040	$ 2,499,118	$ 288,410	$ 1,571,074	$ 2,482,500
Substation O&M Allocator	SOMA	STOM	1.000000	0.29353	0.03387	0.18453	0.29158

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Transmission Residual Demand Allocator	TRDA			-		41		347		415		8
Transmission Plant In Service												
Customer Specific Assignment												
Transmission Residual		TRDA	$	-	$	6,935	$	58,701	$	70,133	$	1,401
Transmission Total	TA1		$	-	$	6,935	$	58,701	$	70,133	$	1,401
Transmission Plant Allocator	T01	TA1		-		0.00105		0.00891		0.01065		0.00021
Transmission Residual Demand Allocator	TOMDA			-		41		347		415		8
Transmission Plant In Service												
Customer Specific Assignment												
Transmission Residual		TOMDA	$	-	$	6,935	$	58,701	$	70,133	$	1,401
Transmission Total	TOMA		$	-	$	6,935	$	58,701	$	70,133	$	1,401
Transmission O&M Allocator	T02	TOMA		-		0.00105		0.00891		0.01065		0.00021
Distribution Residual Demand Allocator	DDA			-		2,792		936		3,911		160
Distribution Plant In Service												
Customer Specific Assignment				50000								
Distribution Residual		DOMDA	$	-	$	442,517	$	148,342	$	619,821	$	25,431
Distribution Total	DTI		$	50,000	$	442,517	$	148,342	$	619,821	$	25,431
Distribution Plant Allocator	DA1	DTI		0.00165		0.01460		0.00489		0.02045		0.00084
Distribution Residual Demand Allocator	DOMDA			-		2,792		936		3,911		160
Distribution Plant In Service												
Customer Specific Assignment				50000								
Distribution Residual		DOMDA	$	-	$	442,517	$	148,342	$	619,821	$	25,431
Distribution Total	DOMA		$	50,000	$	442,517	$	148,342	$	619,821	$	25,431
Distribution O&M Allocator	DOM	DOMA		0.00165		0.01460		0.00489		0.02045		0.00084
Substation Residual Demand Allocator	SDA			-		41		-		415		8
Substation Plant In Service												
Customer Specific Assignment												
Substation Residual		SDA	$	-	$	9,047	$	-	$	91,489	$	1,828
Substation Total	ST1		$	-	$	9,047	$	-	$	91,489	$	1,828
Substation Plant Allocator	SA1	ST1		-		0.00106		-		0.01075		0.00021
Substation Residual Demand Allocator	SOMDA			-		41		-		415		8
Substation Plant In Service												
Customer Specific Assignment												
Substation Residual		SOMDA	$	-	$	9,047	$	-	$	91,489	$	1,828
Substation Total	STOM		$	-	$	9,047	$	-	$	91,489	$	1,828
Substation O&M Allocator	SOMA	STOM		-		0.00106		-		0.01075		0.00021

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Transmission Residual Demand Allocator	TRDA			319		-		48		6,758
Transmission Plant In Service										
Customer Specific Assignment										
Transmission Residual		TRDA	$	53,827	$	-	$	8,035	$	1,142,095
Transmission Total	TA1		$	53,827	$	-	$	8,035	$	1,142,095
Transmission Plant Allocator	T01	TA1		0.00817		-		0.00122		0.17343
Transmission Residual Demand Allocator	TOMDA			319		-		48		6,758
Transmission Plant In Service										
Customer Specific Assignment										
Transmission Residual		TOMDA	$	53,827	$	-	$	8,035	$	1,142,095
Transmission Total	TOMA		$	53,827	$	-	$	8,035	$	1,142,095
Transmission O&M Allocator	T02	TOMA		0.00817		-		0.00122		0.17343
Distribution Residual Demand Allocator	DDA			1,437		-		55		-
Distribution Plant In Service										
Customer Specific Assignment										
Distribution Residual		DOMDA	$	227,707	$	-	$	8,643	$	-
Distribution Total	DTI		$	227,707	$	-	$	8,643	$	-
Distribution Plant Allocator	DA1	DTI		0.00751		-		0.00029		-
Distribution Residual Demand Allocator	DOMDA			1,437		-		55		-
Distribution Plant In Service										
Customer Specific Assignment								0		0
Distribution Residual		DOMDA	$	227,707	$	-	$	8,643	$	-
Distribution Total	DOMA		$	227,707	$	-	$	8,643	$	-
Distribution O&M Allocator	DOM	DOMA		0.00751		-		0.00029		-
Substation Residual Demand Allocator	SDA			319		-		48		6,758
Substation Plant In Service										
Customer Specific Assignment										
Substation Residual		SDA	$	70,217	$	0 -	$	0 10,482	$	0 1,489,874
Substation Total	ST1		$	70,217	$	-	$	10,482	$	1,489,874
Substation Plant Allocator	SA1	ST1		0.00825		-		0.00123		0.17499
Substation Residual Demand Allocator	SOMDA			319		-		48		6,758
Substation Plant In Service										
Customer Specific Assignment										
Substation Residual		SOMDA	$	70,217	$	0 -	$	0 10,482	$	0 1,489,874
Substation Total	STOM		$	70,217	$	-	$	10,482	$	1,489,874
Substation O&M Allocator	SOMA	STOM		0.00825		-		0.00123		0.17499

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Customer Services Demand	CSD		190,941	109,074	15,403	37,871	19,302
Customer Services Allocator	CSA	CSD	1.000000	0.57124	0.08067	0.19834	0.10109
Purchased Power Residual Demand Allocator	PPDRA		453,791	200,898	24,875	88,236	121,131
Purchased Power Demand Costs			$ 11,444,637				
Customer Specific Assignment			$ 943,893		0	-	-
Purchased Power Demand Residual		PPDRA	$ 10,500,744	$ 4,648,787	$ 575,618	$ 2,041,783	$ 2,802,978
Purchased Power Demand Total	PPDT		$ 11,444,637	$ 4,648,787	$ 575,618	$ 2,041,783	$ 2,802,978
Purchased Power Demand Allocator	PPDA	PPDT	1.000000	0.40620	0.05030	0.17841	0.24492
Purchased Power Residual Energy Allocator	PPERA		259,613,006	120,299,391	14,915,162	50,009,679	63,865,598
Purchased Power Energy Costs			$ 8,519,158				
Customer Specific Assignment			$ 781,748		0		
Purchased Power Energy Residual		PPERA	$ 7,737,410	$ 3,585,358	$ 444,526	$ 1,490,470	$ 1,903,427
Purchased Power Energy Total	PPET		$ 8,519,158	$ 3,585,358	$ 444,526	$ 1,490,470	$ 1,903,427
Purchased Power Energy Allocator	PPEA	PPET	1.000000	0.42086	0.05218	0.17496	0.22343

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Customer Services Demand	CSD			-		2,792		936		3,911		160
Customer Services Allocator	CSA	CSD		-		0.01462		0.00490		0.02048		0.00084
Purchased Power Residual Demand Allocator	PPDRA			3,550		-		4,209		7,062		203
Purchased Power Demand Costs												
Customer Specific Assignment				-		-		-		-		-
Purchased Power Demand Residual		PPDRA	$	82,140	$	-	$	97,403	$	163,425	$	4,698
Purchased Power Demand Total	PPDT		$	82,140	$	-	$	97,403	$	163,425	$	4,698
Purchased Power Demand Allocator	PPDA	PPDT		0.00718		-		0.00851		0.01428		0.00041
Purchased Power Residual Energy Allocator	PPERA			2,609,075		382,800		883,600		4,376,730		125,806
Purchased Power Energy Costs												
Customer Specific Assignment				-		-		-		-		-
Purchased Power Energy Residual		PPERA	$	77,760	$	11,409	$	26,334	$	130,442	$	3,749
Purchased Power Energy Total	PPET		$	77,760	$	11,409	$	26,334	$	130,442	$	3,749
Purchased Power Energy Allocator	PPEA	PPET		0.00913		0.00134		0.00309		0.01531		0.00044

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Customer Services Demand	CSD			1,437		-		55		-
Customer Services Allocator	CSA	CSD		0.00752		-		0.00029		-
Purchased Power Residual Demand Allocator	PPDRA			3,456		-		170		-
Purchased Power Demand Costs										
Customer Specific Assignment				-		-		-		943,893
Purchased Power Demand Residual		PPDRA	$	79,974	$	-	$	3,937	$	-
Purchased Power Demand Total	PPDT		$	79,974	$	-	$	3,937	$	943,893
Purchased Power Demand Allocator	PPDA	PPDT		0.00699		-		0.00034		0.08247
Purchased Power Residual Energy Allocator	PPERA			2,093,887		-		51,278		-
Purchased Power Energy Costs										
Customer Specific Assignment				-		-		-		781,748
Purchased Power Energy Residual		PPERA	$	62,405	$	-	$	1,528	$	-
Purchased Power Energy Total	PPET		$	62,405	$	-	$	1,528	$	781,748
Purchased Power Energy Allocator	PPEA	PPET		0.00733		-		0.00018		0.09176

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Operating Expenses							
Purchased Power Demand			$ 12,657,258	$ 4,648,787	$ 575,618	$ 2,041,783	$ 2,802,978
Purchased Power Energy			$ 8,921,581	$ 3,585,358	$ 444,526	$ 1,490,470	$ 1,903,427
Distribut on Demand	DEMEXP		$ 4,725,018	$ 2,368,961	$ 326,680	$ 926,134	$ 687,142
Distribut on Customer	CUSEXP		$ 6,841,592	$ 4,833,352	$ 685,475	$ 967,185	$ 96,118
Total			$ 33,145,450	$ 15,436,458	$ 2,032,299	$ 5,425,572	$ 5,489,665
Rate Base							
Distribution Demand			$ 43,136,431	$ 20,307,086	$ 2,751,506	$ 8,318,432	$ 7,270,729
Distribution Customer			$ 38,925,619	$ 26,920,617	$ 3,818,192	$ 5,935,734	$ 606,254
Total			$ 82,062,050	$ 47,227,703	$ 6,569,698	$ 14,254,166	$ 7,876,983
Operating Expenses-Unit Costs							
Purchased Power Demand				0.03864	0.03859	0.04083	14.95
Purchased Power Energy				0.02980	0.02980	0.02980	0.02980
Distribution Demand				0.01969	0.02190	0.01852	3.66
Distribution Customer				$ 18.46	$ 18.46	$ 24.99	$ 35.23
Rate Base-Unit Costs							
Distribution Demand				0.16880	0.18448	0.16634	38.77
Distribution Customer				102.81	102.81	153.39	222.23

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Security Lighting Service Rate 6		Interruptible Power Service Rate 15		Power Service Time-of-Use Rate 16		Residential Service Time-of-Use Rate 17		Residential Seasonal Service Time-of-Use Rate 18
Operating Expenses												
Purchased Power Demand			$	82,140	$	-	$	97,403	$	163,425	$	4,698
Purchased Power Energy			$	77,760	$	11,409	$	26,334	$	130,442	$	3,749
Distribution Demand	DEMEXP		$	2,709	$	54,460	$	20,817	$	85,833	$	3,271
Distribution Customer	CUSEXP		$	132,240	$	761	$	3,078	$	88,988	$	3,939
Total			$	294,849	$	66,630	$	147,632	$	468,688	$	15,657
Rate Base												
Distribution Demand			$	45,704	$	420,804	$	217,545	$	731,459	$	26,541
Distribution Customer			$	926,287	$	2,000	$	19,334	$	493,774	$	22,419
Total			$	971,991	$	422,804	$	236,880	$	1,225,233	$	48,960
Operating Expenses-Unit Costs												
Purchased Power Demand				3.56		-		23.14		0.03734		0.03735
Purchased Power Energy				3.37		0.02980		0.02980		0.02980		0.02980
Distribution Demand				0.12		9.43		2.64		0.01961		0.02600
Distribution Customer			$	5.74	$	84.60	$	35.38	$	18.53	$	19.03
Rate Base-Unit Costs												
Distribution Demand				1.98		72.84		27.57		0.16712		0.21097
Distribution Customer				40.18		222.23		222.23		102.81		108.31

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector		Commercial Service Time-of-Use Rate 19		Irrigation Power Service Time-of-Use Rate 20		Irrigation Power Service Rate 22		MolyCorp - Special Contract
Operating Expenses										
Purchased Power Demand			$	79,974	$	-	$	3,937	$	2,156,515
Purchased Power Energy			$	62,405	$	-	$	1,528	$	1,184,172
Distribution Demand	DEMEXP		$	36,724	$	-	$	2,641	$	209,648
Distribution Customer	CUSEXP		$	29,252	$	-	$	312	$	891
Total			$	208,355	$	-	$	8,418	$	3,551,225
Rate Base										
Distribution Demand			$	334,694	$	-	$	26,792	$	2,685,139
Distribution Customer			$	179,155	$	-	$	1,841	$	12
Total			$	513,849	$	-	$	28,632	$	2,685,151
Operating Expenses-Unit Costs										
Purchased Power Demand				0.03819		#DIV/0!		0.07679		21.50
Purchased Power Energy				0.02980		#DIV/0!		0.02980		0.02735
Distribution Demand				0.01754		#DIV/0!		0.05149		1.91
Distribution Customer			$	25.04		#DIV/0!	$	26.02		74.27
Rate Base-Unit Costs										
Distribution Demand				0.15984		#DIV/0!		0.52248		24.44
Distribution Customer				153.39		#DIV/0!		153.39		0.98

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Unit Revenue Requirement @ Current Class Revenues							
Purchased Power							
Purchased Power Demand (Per Kwh or Kw)				0.03864	0.03859	0.04083	14.95
Purchased Power Energy (Per Kwh)				0.02980	0.02980	0.02980	0.02980
Distribution Demand							
Distribution Demand (Per Kwh or Kw)				0.01969	0.02190	0.01852	3.66
Distribution Demand Margin (Per Kwh or Kw)				(0.00105)	(0.00264)	0.00132	7.35
Total Distribution Demand (Per Kwh or Kw)				0.01864	0.01926	0.01984	11.01
Distribution Customer							
Distribution Customer (Per Customer Per Month)				18.46	18.46	24.99	35.23
Distribution Customer Margin (Per Customer Per Month)				(0.64)	(1.47)	1.22	42.14
Total Distribution Customer (Per Customer Per Month)				17.82	16.98	26.21	77.37
Unit Revenue Requirement @ Total System Rate of Return							
Purchased Power							
Purchased Power Demand (Per Kwh or Kw)				0.03864	0.03859	0.04083	14.95
Purchased Power Energy (Per Kwh)				0.02980	0.02980	0.02980	0.02980
Distribution Demand							
Distribution Demand (Per Kwh or Kw)				0.01969	0.02190	0.01852	3.66
Distribution Demand Margin (Per Kwh or Kw)				0.00315	0.00345	0.00311	0.72
Total Distribution Demand (Per Kwh or Kw)				0.02285	0.02535	0.02163	4.39
Distribution Customer							
Distribution Customer (Per Customer Per Month)				18.46	18.46	24.99	35.23
Distribution Customer Margin (Per Customer Per Month)				1.92	1.92	2.86	4.15
Total Distribution Customer (Per Customer Per Month)				20.38	20.38	27.86	39.38

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Security Lighting Service Rate 6	Interruptible Power Service Rate 15	Power Service Time-of-Use Rate 16	Residential Service Time-of-Use Rate 17	Residential Seasonal Service Time-of-Use Rate 18
Unit Revenue Requirement @ Current Class Revenues							
Purchased Power							
Purchased Power Demand (Per Kwh or Kw)			3.56	-	23.14	0.03734	0.03735
Purchased Power Energy (Per Kwh)			3.37	0.02980	0.02980	0.02980	0.02980
Distribution Demand							
Distribution Demand (Per Kwh or Kw)			0.12	9.43	2.64	0.01961	0.02600
Distribution Demand Margin (Per Kwh or Kw)			0.13	7.72	2.25	(0.00269)	(0.00734)
Total Distribution Demand (Per Kwh or Kw)			0.25	17.15	4.89	0.01692	0.01866
Distribution Customer							
Distribution Customer (Per Customer Per Month)			5.74	84.60	35.38	18.53	19.03
Distribution Customer Margin (Per Customer Per Month)			2.69	23.56	18.15	(1.66)	(3.77)
Total Distribution Customer (Per Customer Per Month)			8.42	108.15	53.53	16.87	15.26
Unit Revenue Requirement @ Total System Rate of Return							
Purchased Power							
Purchased Power Demand (Per Kwh or Kw)			3.56	-	23.14	0.03734	0.03735
Purchased Power Energy (Per Kwh)			3.37	0.02980	0.02980	0.02980	0.02980
Distribution Demand							
Distribution Demand (Per Kwh or Kw)			0.12	9.43	2.64	0.01961	0.02600
Distribution Demand Margin (Per Kwh or Kw)			0.04	1.36	0.51	0.00312	0.00394
Total Distribution Demand (Per Kwh or Kw)			0.15	10.79	3.15	0.02273	0.02994
Distribution Customer							
Distribution Customer (Per Customer Per Month)			5.74	84.60	35.38	18.53	19.03
Distribution Customer Margin (Per Customer Per Month)			0.75	4.15	4.15	1.92	2.02
Total Distribution Customer (Per Customer Per Month)			6.49	88.75	39.53	20.45	21.05

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Commercial Service Time-of-Use Rate 19	Irrigation Power Service Time-of-Use Rate 20	Irrigation Power Service Rate 22	MolyCorp - Special Contract
Unit Revenue Requirement @ Current Class Revenues						
Purchased Power						
Purchased Power Demand (Per Kwh or Kw)			0.03819	#DIV/0!	0.07679	21.50
Purchased Power Energy (Per Kwh)			0.02980	#DIV/0!	0.02980	0.02735
Distribution Demand						
Distribution Demand (Per Kwh or Kw)			0.01754	#DIV/0!	0.05149	1.91
Distribution Demand Margin (Per Kwh or Kw)			0.00142	#DIV/0!	(0.04936)	1.85
Total Distribution Demand (Per Kwh or Kw)			0.01895	#DIV/0!	0.00214	3.76
Distribution Customer						
Distribution Customer (Per Customer Per Month)			25.04	#DIV/0!	26.02	74.27
Distribution Customer Margin (Per Customer Per Month)			1.36	#DIV/0!	(14.49)	0.07
Total Distribution Customer (Per Customer Per Month)			26.40	#DIV/0!	11.53	74.35
Unit Revenue Requirement @ Total System Rate of Return						
Purchased Power						
Purchased Power Demand (Per Kwh or Kw)			0.03819	#DIV/0!	0.07679	21.50
Purchased Power Energy (Per Kwh)			0.02980	#DIV/0!	0.02980	0.02735
Distribution Demand						
Distribution Demand (Per Kwh or Kw)			0.01754	#DIV/0!	0.05149	1.91
Distribution Demand Margin (Per Kwh or Kw)			0.00299	#DIV/0!	0.00976	0.46
Total Distribution Demand (Per Kwh or Kw)			0.02052	#DIV/0!	0.06125	2.36
Distribution Customer						
Distribution Customer (Per Customer Per Month)			25.04	#DIV/0!	26.02	74.27
Distribution Customer Margin (Per Customer Per Month)			2.86	#DIV/0!	2.86	0.02
Total Distribution Customer (Per Customer Per Month)			27.91	#DIV/0!	28.88	74.29

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Total System	Residential Service Rate 1	Residential Seasonal Service Rate 2	Commercial Service Rate 3	Power Service Rate 4
Unit Revenue Requirement @ Specified Rate of Return			5.16%	5.16%	5.16%	5.16%	5.16%
Purchased Power							
Purchased Power Production Demand				0.03864	0.03859	0.04083	14.95
Purchased Power Energy (Per Kwh)				0.02980	0.02980	0.02980	0.02980
Distribution Demand							
Distribution Demand (Per Kwh or Kw)				0.01969	0.02190	0.01852	3.66
Distribution Demand Margin (Per Kwh or Kw)				0.00871	0.00952	0.00858	2.00
Total Distribution Demand (Per Kwh or Kw)				0.02840	0.03142	0.02710	5.66
Distribution Customer							
Distribution Customer (Per Customer Per Month)				18.46	18.46	24.99	35.23
Distribution Customer Margin (Per Customer Per Month)				5.30	5.30	7.91	11.47
Total Distribution Customer (Per Customer Per Month)				23.76	23.76	32.91	46.70

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Security Lighting Service Rate 6	Interruptible Power Service Rate 15	Power Service Time-of-Use Rate 16	Residential Service Time-of-Use Rate 17	Residential Seasonal Service Time-of-Use Rate 18
Unit Revenue Requirement @ Specified Rate of Return			5.16%	5.16%	5.16%	5.16%	5.16%
Purchased Power							
Purchased Power Production Demand			3.56		23.14	0.03734	0.03735
Purchased Power Energy (Per Kwh)			3.37	0.02980	0.02980	0.02980	0.02980
Distribution Demand							
Distribut on Demand (Per Kwh or Kw)			0.12	9.43	2.64	0.01961	0.02600
Distribut on Demand Margin (Per Kwh or Kw)			0.10	3.76	1.42	0.00862	0.01089
Total Distribution Demand (Per Kwh or Kw)			0.22	13.19	4.06	0.02823	0.03688
Distribution Customer							
Distribution Customer (Per Customer Per Month)			5.74	84.60	35.38	18.53	19.03
Distribution Customer Margin (Per Customer Per Month)			2.07	11.47	11.47	5.30	5.59
Total Distribution Customer (Per Customer Per Month)			7.81	96.07	46.84	23.83	24.62

KIT CARSON ELECTRIC COOPERATIVE
Cost of Service Study
Class Allocation

12 Months Ended December 31, 2009

Description	Name	Allocation Vector	Commercial Service Time-of-Use Rate 19	Irrigation Power Service Time-of-Use Rate 20	Irrigation Power Service Rate 22	MolyCorp - Special Contract
Unit Revenue Requirement @ Specified Rate of Return			5.16%	5.16%	5.16%	5.16%
Purchased Power						
Purchased Power Production Demand			0.03819	#DIV/0!	0.07679	21.50
Purchased Power Energy (Per Kwh)			0.02980	#DIV/0!	0.02980	0.02735
Distribution Demand						
Distribution Demand (Per Kwh or Kw)			0.01754	#DIV/0!	0.05149	1.91
Distribution Demand Margin (Per Kwh or Kw)			0.00825	#DIV/0!	0.02696	1.26
Total Distribution Demand (Per Kwh or Kw)			0.02579	#DIV/0!	0.07845	3.17
Distribution Customer						
Distribution Customer (Per Customer Per Month)			25.04	#DIV/0!	26.02	74.27
Distribution Customer Margin (Per Customer Per Month)			7.91	#DIV/0!	7.91	0.05
Total Distribution Customer (Per Customer Per Month)			32.96	#DIV/0!	33.93	74.32

The Prime Group
Zero Intercept Statistics
Overhead Conductors

Utility	State	Test Period	Classification Percentages		R-Square	Number of Services	Miles of Line	Services per Mile
			Customer	Demand				
Cooperative 1	IN	2000	7.64%	92.36%	0.9787684	13,129	1,015.00	12.93
Cooperative 2	IN	2006	31.83%	68.17%	0.8915221	12,146	1,520.20	7.99
Cooperative 3	IN	2006	13.65%	86.35%	0.9477100	17,369	1,342.00	12.94
Cooperative 4	MS	2004	28.25%	71.75%	0.8848200	41,822	5,054.00	8.28
Cooperative 5	FL	2005	3.64%	96.36%	0.8746500	164,515	6,511.00	25.27
Cooperative 6	IN	2006	20.95%	79.05%	0.9719100	7,563	1,015.00	7.45
Cooperative 7	IN	2005	25.68%	74.32%	0.8927728	31,812	3,261.00	9.76
Cooperative 8	IN	2005	10.35%	89.65%	0.9408800	11,897	1,742.00	6.83
Cooperative 9	IN	2005	6.84%	93.16%	0.9384100	23,200	1,630.00	14.23
Cooperative 10	FL	2006	8.72%	91.28%	0.9378809	17,991	2,517.00	7.15
			15.76%	84.25%	100.00%			

KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 367 -- Underground Conductor

December 31, 2009

Description	Size		Cost	Quantity	Unit Cost ($ per Unit)
#4 Triplex	125.220	$	73,111.63	52,834	1.38380
4/0 Triplex	634.800	$	109,267.95	46,089	2.37080
2/0 25KV	133.100	$	87,718.75	73,090	1.20015
1/0 25KV FN	105.600	$	1,065,027.38	427,935	2.48876
1/0 25KV RN	105.600	$	412,651.84	184,956	2.23108
#2 25KV	66.360	$	145,289.05	60,070	2.41866
2/0 Triplex	399.300	$	531,147.89	30,440	17.44901
#2 15KV FN	66.360	$	501,370.33	351,265	1.42733
#2 25KV RN	66.360	$	52,283.34	33,945	1.54024
4/0 25KV	211.600	$	643,357.10	253,901	2.53389
1/0 15KV FN	105.600	$	804,000.86	274,029	2.93400
1/0 15KV RN	105.600	$	259,920.19	186,020	1.39727
1/0 25KV JAC	105.600	$	4,543,944.08	2,254,806	2.01523
350 MCM Triplex	1,050.000	$	777.83	180	4.32128
4/0 15KV	211.600	$	662,160.52	321,439	2.05999
500 MCM	500.000	$	89,398.63	6,229	14.35200
500 MCM 15KV	500.000	$	435,653.98	132,890	3.27831
500 MCM 25KV	500.000	$	1,203,669.10	152,342	7.90110
#2 Triplex	199.080	$	112,344.13	79,409	1.41475
1/0 Triplex	316.800	$	845,341.92	422,290	2.00180
4/0 25KV	211.600	$	856,197.80	148,034	5.78379
1/0 25KV	105.600	$	1,213,578.32	488,336	2.48513
4/0 25KV JAC	211.600	$	202,220.60	72,855	2.77566
500 MCM 25KV	500.000	$	309,354.06	61,465	5.03301
		$	15,159,787	6,114,849	

KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 367 -- Underground Conductor

December 31, 2009

n	y	x	est y	y*n^.5	n^.5	xn^.5
52,834	1.38380	125.22	2.217	318.0751353	229.856477	28782.62804
46,089	2.37080	634.80	5.949	508.9723064	214.683488	136281.0782
73,090	1.20015	133.10	2.274	324.4617105	270.3516229	35983.80101
427,935	2.48876	105.60	2.073	1628.065483	654.1674098	69080.07847
184,956	2.23108	105.60	2.073	959.5101512	430.0651113	45414.87576
60,070	2.41866	66.36	1.785	592.7943669	245.0918195	16264.29314
30,440	17.44901	399.30	4.224	3044.339878	174.4706279	69666.12172
351,265	1.42733	66.36	1.785	845.9431739	592.6761342	39329.98826
33,945	1.54024	66.36	1.785	283.7758395	184.2416891	12226.27849
253,901	2.53389	211.60	2.849	1276.791234	503.8858998	106622.2564
274,029	2.93400	105.60	2.073	1535.883414	523.4777932	55279.25496
186,020	1.39727	105.60	2.073	602.6431102	431.3003594	45545.31795
2,254,806	2.01523	105.60	2.073	3026.065939	1501.601145	158569.081
180	4.32128	1,050.00	8.990	57.97602516	13.41640786	14087.22826
321,439	2.05999	211.60	2.849	1167.92243	566.9559066	119967.8698
6,229	14.35200	500.00	4.961	1132.717729	78.92401409	39462.00704
132,890	3.27831	500.00	4.961	1195.076029	364.540807	182270.4035
152,342	7.90110	500.00	4.961	3083.878685	390.3101331	195155.0665
79,409	1.41475	199.08	2.757	398.6718045	281.7960255	56099.95276
422,290	2.00180	316.80	3.620	1300.849359	649.8384415	205868.8183
148,034	5.78379	211.60	2.849	2225.324608	384.7518681	81413.49529
488,336	2.48513	105.60	2.073	1736.634557	698.8104178	73794.38012
72,855	2.77566	211.60	2.849	749.1964544	269.9166538	57114.36394
61,465	5.03301	500.00	4.961	1247.791081	247.9213585	123960.6792

KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 367 -- Underground Conductor

December 31, 2009

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per MCM)	0.0073239	0.002547
Zero Intercept ($ per Unit)	1.2994014	0.504213
R-Square	0.7838928	

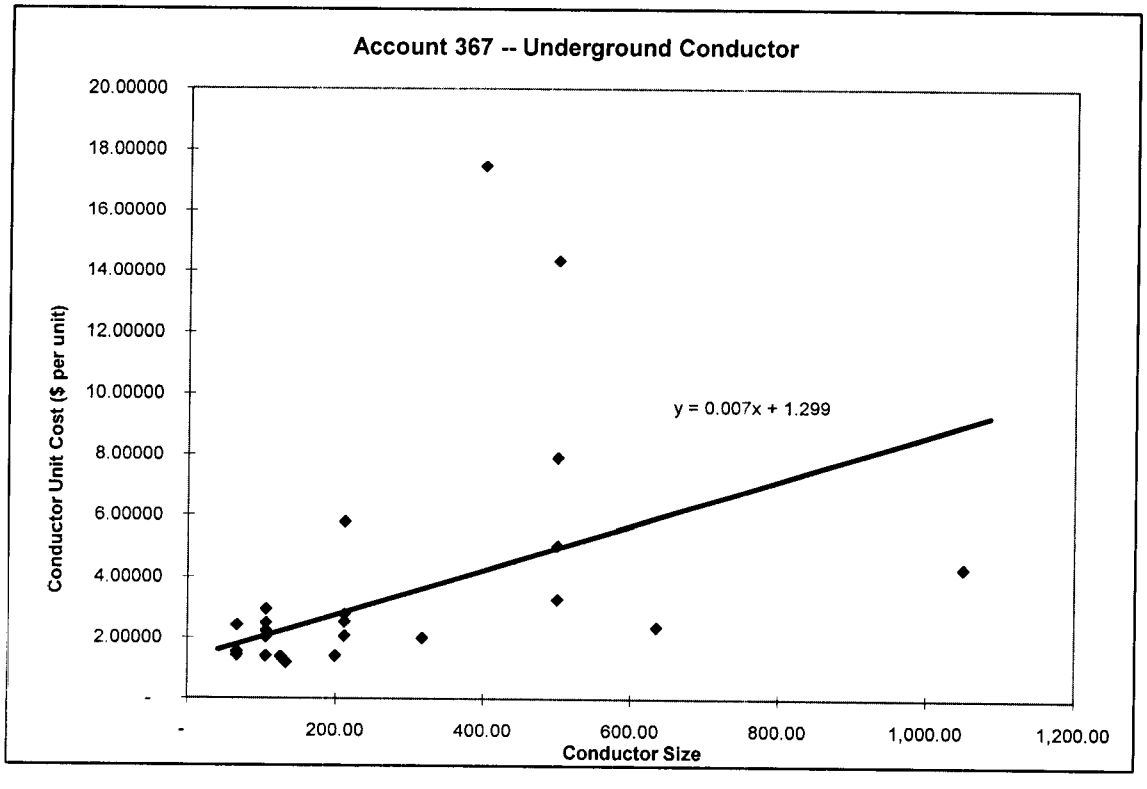
Plant Classification

Total Number of Feet		6,114,849
Zero Intercept		1.2994014
Zero Intercept Cost	$	7,945,643
Total Cost of Sample	$	15,159,787
Percentage of Total		0.524126315
Percentage Classified as Customer-Related		52.41%
Percentage Classified as Demand-Related		47.59%

KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 367 -- Underground Conductor

December 31, 2009



KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 368 -- Line Transformers

December 31, 2009

Description	Size KVA	Cost	Quantity	Unit Cost	Estimated Unit Cost
50 KVA URD	50.0	$ 9,945.81	7	$ 1,420.83	$ 1,510.71
1.5KVA	1.5	$ 19,725.13	93	$ 212.10	$ 875.90
1000KVA URD	1,000.0	$ 184,612.78	13	$ 14,200.98	$ 13,945.13
1000KVA Auto	1,000.0	$ 223,610.24	36	$ 6,211.40	$ 13,945.13
100KVA	100.0	$ 26,452.59	7	$ 3,778.94	$ 2,165.15
100KVA URD	100.0	$ 155,723.02	52	$ 2,994.67	$ 2,165.15
10KVA CONV	10.0	$ 158,957.32	250	$ 635.83	$ 987.15
10KVA CON7200	10.0	$ 40,758.09	38	$ 1,072.58	$ 987.15
10KVA CSP7200	10.0	$ 606,100.53	1,612	$ 375.99	$ 987.15
10KVA CSP7.2	10.0	$ 3,451,871.00	3,820	$ 903.63	$ 987.15
10KVA URD-7200	10.0	$ 313,263.17	311	$ 1,007.28	$ 987.15
10KVA URD-7200 DW	10.0	$ 2,817,155.60	2,251	$ 1,251.51	$ 987.15
110KVA	110.0	$ 13,298.28	8	$ 1,662.29	$ 2,296.04
112.5KVA	112.5	$ 32,484.42	5	$ 6,496.88	$ 2,328.76
150KVA	150.0	$ 327,594.67	57	$ 5,747.27	$ 2,819.59
150KVA URD	150.0	$ 215,386.12	41	$ 5,253.32	$ 2,819.59
150KVA URD 3PH	150.0	$ 26,828.58	5	$ 5,365.72	$ 2,819.59
15KVA 14.4	15.0	$ 13,368.21	26	$ 514.16	$ 1,052.60
15KVA 14.4 CSP	15.0	$ 2,203.89	3	$ 734.63	$ 1,052.60
15KVA CONV	15.0	$ 131,913.65	196	$ 673.03	$ 1,052.60
15KVA URD	15.0	$ 1,260,500.17	805	$ 1,565.84	$ 1,052.60
15KVA CSP	15.0	$ 545,464.51	447	$ 1,220.28	$ 1,052.60
15KVA CONV	15.0	$ 33,146.15	31	$ 1,069.23	$ 1,052.60
15KVA CONV7200	15.0	$ 2,558.51	9	$ 284.28	$ 1,052.60
15KVA CSP	15.0	$ 668,461.87	940	$ 711.13	$ 1,052.60
15KVA URD-7200	15.0	$ 196,050.95	263	$ 745.44	$ 1,052.60
167KVA	167.0	$ 168,555.76	32	$ 5,267.37	$ 3,042.10
167KVA URD	167.0	$ 83,268.55	18	$ 4,626.03	$ 3,042.10
167KVA URD	167.0	$ 57,079.30	16	$ 3,567.46	$ 3,042.10
225KVA	225.0	$ 34,158.48	7	$ 4,879.78	$ 3,801.26
250KVA URD	250.0	$ 16,845.99	4	$ 4,211.50	$ 4,128.48
250KVA, CONV-7200	250.0	$ 3,410.46	1	$ 3,410.46	$ 4,128.48
25KVA	25.0	$ 3,504,999.79	2,683	$ 1,306.37	$ 1,183.48
300KVA	300.0	$ 700,361.07	91	$ 7,696.28	$ 4,782.92
37.5KVA	37.5	$ 318,983.07	178	$ 1,792.04	$ 1,347.10
3KVA	3.0	$ 57,075.91	499	$ 114.38	$ 895.53
45KVA	45.0	$ 325,417.44	74	$ 4,397.53	$ 1,445.26
500KVA	500.0	$ 590,757.61	62	$ 9,528.35	$ 7,400.70
50KVA	50.0	$ 352,182.01	250	$ 1,408.73	$ 1,510.71
5KVA	5.0	$ 92,825.56	548	$ 169.39	$ 921.71
7.5KVA	7.5	$ 11,876.66	70	$ 169.67	$ 954.43
750KVA	750.0	$ 206,160.42	16	$ 12,885.03	$ 10,672.92
75KVA	75.0	$ 782,108.45	254	$ 3,079.17	$ 1,837.93
250KVA Auto	250.0	$ 12,322.45	2	$ 6,161.23	$ 4,128.48
300KVA	300.0	$ 9,069.36	1	$ 9,069.36	$ 4,782.92
1500KVA	1,500.0	$ 87,817.24	5	$ 17,563.45	$ 20,489.57
112.5KVA	112.5	$ 27,127.36	5	$ 5,425.47	$ 2,328.76
225KVA	225.0	$ 54,176.05	6	$ 9,029.34	$ 3,801.26
300KVA	300.0	$ 92,237.31	8	$ 11,529.66	$ 4,782.92
150KVA	150.0	$ 31,794.65	5	$ 6,358.93	$ 2,819.59
750KVA	750.0	$ 39,341.53	3	$ 13,113.84	$ 10,672.92
1500KVA	1,500.0	$ 106,735.79	6	$ 17,789.30	$ 20,489.57
225KVA 3PH URD	225.0	$ 6,527.36	1	$ 6,527.36	$ 3,801.26
112.5KVA	112.5	$ 41,247.81	7	$ 5,892.54	$ 2,328.76
45KVA	45.0	$ 18,998.72	3	$ 6,332.91	$ 1,445.26
300KVA	300.0	$ 55,079.11	5	$ 11,015.82	$ 4,782.92
		$ 19,365,976.53	16,186		

KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 368 -- Line Transformers

December 31, 2009

n	y	x	yn^.5	n^.5	xn^.5
7	1,420.83	50.0	3759.1628	2.6458	132.2876
93	212.10	1.5	2045.4007	9.6437	14.4655
13	14,200.98	1,000.0	51202.3726	3.6056	3605.5513
36	6,211.40	1,000.0	37268.3733	6.0000	6000.0000
7	3,778.94	100.0	9998.1392	2.6458	264.5751
52	2,994.67	100.0	21594.8974	7.2111	721.1103
250	635.83	10.0	10053.3436	15.8114	158.1139
38	1,072.58	10.0	6611.8353	6.1644	61.6441
1612	375.99	10.0	15096.0090	40.1497	401.4972
3820	903.63	10.0	55849.9612	61.8061	618.0615
311	1,007.28	10.0	17763.5247	17.6352	176.3519
2251	1,251.51	10.0	59377.6612	47.4447	474.4470
8	1,662.29	110.0	4701.6520	2.8284	311.1270
5	6,496.88	112.5	14527.4743	2.2361	251.5576
57	5,747.27	150.0	43390.9740	7.5498	1132.4752
41	5,253.32	150.0	33637.6606	6.4031	960.4686
5	5,365.72	150.0	11998.1057	2.2361	335.4102
26	514.16	15.0	2621.7217	5.0990	76.4853
3	734.63	15.0	1272.4165	1.7321	25.9808
196	673.03	15.0	9422.4036	14.0000	210.0000
805	1,565.84	15.0	44426.7934	28.3725	425.5878
447	1,220.28	15.0	25799.5860	21.1424	317.1356
31	1,069.23	15.0	5953.2243	5.5678	83.5165
9	284.28	15.0	852.8367	3.0000	45.0000
940	711.13	15.0	21802.8222	30.6594	459.8913
263	745.44	15.0	12089.0195	16.2173	243.2591
32	5,267.37	167.0	29796.7302	5.6569	944.6947
18	4,626.03	167.0	19626.5855	4.2426	708.5210
16	3,567.46	167.0	14269.8250	4.0000	668.0000
7	4,879.78	225.0	12910.6919	2.6458	595.2940
4	4,211.50	250.0	8422.9950	2.0000	500.0000
1	3,410.46	250.0	3410.4600	1.0000	250.0000
2683	1,306.37	25.0	67667.1149	51.7977	1294.9421
91	7,696.28	300.0	73417.7890	9.5394	2861.8176
178	1,792.04	37.5	23908.7919	13.3417	500.3124
499	114.38	3.0	2555.0686	22.3383	67.0149
74	4,397.53	45.0	37829.0090	8.6023	387.1046
62	9,528.35	500.0	75026.2915	7.8740	3937.0039
250	1,408.73	50.0	22273.9461	15.8114	790.5694
548	169.39	5.0	3965.3114	23.4094	117.0470
70	169.67	7.5	1419.5324	8.3666	62.7495
16	12,885.03	750.0	51540.1050	4.0000	3000.0000
254	3,079.17	75.0	49073.8487	15.9374	1195.3033
2	6,161.23	250.0	8713.2880	1.4142	353.5534
1	9,069.36	300.0	9069.3600	1.0000	300.0000
5	17,563.45	1,500.0	39273.0636	2.2361	3354.1020
5	5,425.47	112.5	12131.7242	2.2361	251.5576
6	9,029.34	225.0	22117.2798	2.4495	551.1352
8	11,529.66	300.0	32610.8137	2.8284	848.5281
5	6,358.93	150.0	14218.9997	2.2361	335.4102
3	13,113.84	750.0	22713.8429	1.7321	1299.0381
6	17,789.30	1,500.0	43574.7038	2.4495	3674.2346
1	6,527.36	225.0	6527.3600	1.0000	225.0000
7	5,892.54	112.5	15590.2068	2.6458	297.6470
3	6,332.91	45.0	10968.9161	1.7321	77.9423
5	11,015.82	300.0	24632.1268	2.2361	670.8204

KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 368 -- Line Transformers

December 31, 2009

Weighted Linear Regression Statistics

	Estimate	Standard Error
Size Coefficient ($ per KVA)	13.08886912	1.199262749
Zero Intercept ($ per Transformer)	856.263203	103.8285163
R-Square	0.830753676	

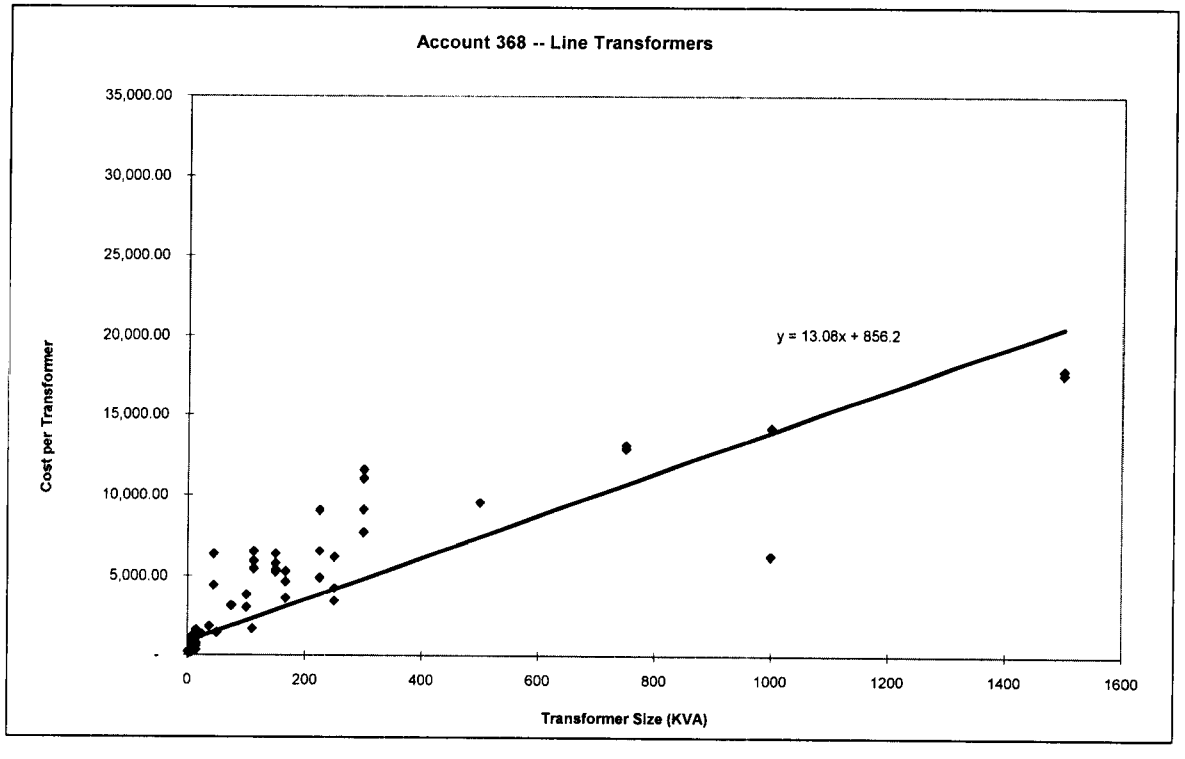
Plant Classification

Total Number of Transformers		16,186
Zero Intercept		856.263203
Zero Intercept Cost	$	13,859,476.20
Total Cost of Sample		19,365,976.53
Percentage of Total		71.57%
Percentage Classified as Customer-Related		71.57%
Percentage Classified as Demand-Related		28.43%

KIT CARSON ELECTRIC COOPERATIVE

Zero Intercept Analysis
Account 368 -- Line Transformers

December 31, 2009



Kit Carson Electric Cooperative
Summary
For Year Ended December 2009

Customer Class	kWh	Revenue Per Books	Test Year Rate Calculated Billings	Difference	Percent Difference	Cost Based Rates (5.16% ROR) Equalized	Difference	Percent Difference	Proposed Rates - 5.16% Overall ROR	Difference	Percent Difference
Residential Service	120,299,391	$ 15,143,415	$ 14,992,683	$ (150,732)	-1.00%	$ 17,872,790	$ 2,880,107	19.21%	$ 16,290,112	$ 1,297,429	8.65%
Residential Seasonal Service	14,915,162	$ 1,938,230	$ 1,944,133	$ 5,903	0.30%	$ 2,371,278	$ 427,145	21.97%	$ 2,189,798	$ 245,665	12.64%
Commercial Service	50,009,679	$ 5,538,593	5,510,308	$ (28,285)	-0.51%	6,160,997	$ 650,690	11.81%	$ 6,061,079	$ 550,771	10.00%
Power Service	63,865,598	$ 6,983,243	7,142,975	$ 159,732	2.29%	5,895,911	$ (1,247,064)	-17.46%	$ 7,439,500	$ 296,525	4.15%
Security Lighting Service	2,609,075	$ 359,860	359,496	$ (363)	-0.10%	344,998	$ (14,498)	-4.03%	$ 407,222	$ 47,726	13.28%
Interruptible Power Service	382,800	$ 111,445	111,741	$ 297	0.27%	88,431	$ (23,310)	-20.86%	$ 111,746	$ 5	0.00%
Power Service Time-of-Use	883,600	$ 166,980	167,213	$ 233	0.14%	159,880	$ (7,333)	-4.39%	$ 167,219	$ 6	0.00%
Residential Service Time-of-Use	4,376,730	$ 448,943	447,301	$ (1,642)	-0.37%	531,621	$ 84,320	18.85%	$ 486,461	$ 39,159	8.75%
Residential Seasonal Service Time-of-Use	125,806	$ 13,954	13,842	$ (112)	-0.80%	18,185	$ 4,343	31.38%	$ 15,994	$ 2,152	15.55%
Commercial Service Time-of-Use	2,093,887	$ 212,905	212,634	$ (271)	-0.13%	234,864	$ 22,231	10.46%	$ 233,889	$ 21,255	10.00%
Irrigation Power Service Time-of-Use	-	$ -	-	$ -	0.00%	-	$ -	#DIV/0!	$ -	$ -	#DIV/0!
Irrigation Power Service	51,278	$ 5,714	5,714	$ 0	0.00%	9,896	$ 4,182	73.19%	$ 8,418	$ 2,705	47.33%
Chevron - Special Contract	43,296,948	$ 2,139,882	2,139,421	$ (461)	-0.02%	3,689,749	$ 1,550,329	72.46%	$ 3,967,172	$ 1,827,751	85.43%
	302,909,954	$ 33,063,162	$ 33,047,459	$ (15,703)	-0.05%	$ 37,378,601	$ 4,331,141	13.11%	$ 37,378,608	$ 4,331,149	13.11%

Kit Carson Electric Cooperative
Residential Service
Rate No. 1

	Test Year Rate			Proposed Rate		
	Billing Units	Rate	Calculated Billings	Billing Units	Rate	Calculated Billings
Facility Charge						
	Customer Months	*Per Customer*		*Customer Months*	*Per Customer*	
All Cust. Months	261,860	$ 10.00	$ 2,618,600			
Customer Charge						
Customer Months				261,860	$ 20.50	$ 5,368,130
Energy Charge						
	kWh	*Per kWh*		*kWh*	*Per kWh*	
All kWh	120,299,391	$0.10519	$ 12,654,293			
Purchased Power Energy				120,299,391	$ 0.02980	$ 3,584,922
Purchased Power Demand				120,299,391	$ 0.03864	$ 4,648,368
Distribution Demand				120,299,391	$ 0.02235	$ 2,688,691
					$ 0.09079	$ 10,921,982
Fuel Adjustment						
Total Fuel Adjustment			$ 177,765			$ -
Total Rate 1			$ 14,992,683			$ 16,290,112

Kit Carson Electric Cooperative
Residential Seasonal Service
Rate No. 2

	Test Year Rate				Proposed Rate			
	Billing Units		Rate	Calculated Billings	Billing Units		Rate	Calculated Billings
Facility Charge								
	Customer Months		*Per Customer*					
All Cust. Months	37,140	$	10.00	$ 371,400				
Customer Charge								
					Customer Months		*Per Customer*	
Customer Months					37,140	$	22.50	$ 835,650
Energy Charge								
	kWh		*Per kWh*		*kWh*		*Per kWh*	
All kWh	14,915,162		$0.10845	$ 1,617,549				
Purchased Power Energy					14,915,162	$	0.02980	$ 444,472
Purchased Power Demand					14,915,162	$	0.03859	$ 575,576
Distribution Demand					14,915,162	$	0.02240	$ 334,100
						$	0.09079	$ 1,354,148
Fuel Adjustment								
Total Fuel Adjustment				$ 15,859				$ -
Total Rate 2				$ 1,944,133				$ 2,189,798

Kit Carson Electric Cooperative
Commercial Service
Rate No. 3

	Test Year Rate			Proposed Rate		
	Billing Units	Rate	Calculated Billings	Billing Units	Rate	Calculated Billings
Facility Charge						
	Customer Months	*Per Customer*				
All Cust. Months	38,698	$ 15.00	$ 580,470			
Customer Charge						
				Customer Months	*Per Customer*	
Customer Months				38,698	$ 31.00	$ 1,199,638
Energy Charge						
	kWh	*Per kWh*		*kWh*	*Per kWh*	
All kWh	50,009,679	$0.10045	$ 5,023,472			
Purchased Power Energy				50,009,679	$ 0.02980	$ 1,490,288
Purchased Power Demand				50,009,679	$ 0.04083	$ 2,041,895
Distribution Demand				50,009,679	$ 0.02658	$ 1,329,257
					$ 0.09721	$ 4,861,441
Fuel Adjustment						
Total Fuel Adjustment			$ 65,779			$ -
Total Rate 3			$ 5,510,308			$ 6,061,079

Kit Carson Electric Cooperative
Power Service
Rate No. 4

	Test Year Rate				Proposed Rate			
	Billing Units		Rate	Calculated Billings	Billing Units		Rate	Calculated Billings
Facility Charge					**Customer Charge**			
	Customer Months		*Per Customer*		*Customer Months*		*Per Customer*	
Customer Months	2,729	$	30.00	$ 81,870	2,729	$	50.00	$ 136,450
Energy Charge					**Energy Charge**			
	kWh		*Per kWh*		*kWh*		*Per kWh*	
All Kwh's	63,865,598	$	0.06764	$ 4,319,869	Purchased Power Energy	63,865,598	$ 0.04681	$ 2,989,549
Demand Charge					**Demand Charge**			
	kW		*Per kW*		*kW*		*Per kW*	
Primary	53,526	$	15.00	$ 802,891	Purchased Power Demand	187,544	$ 14.95	$ 2,803,776
Secondary	134,017	$	15.50	$ 2,077,270	Distribution Demand	187,544	$ 8.05	$ 1,509,725
	187,544			$ 2,880,162			$ 23.00	$ 4,313,501
Fuel Adjustment					**Fuel Adjustment**			
Total Fuel Adjustment				$ 119,191	Total Fuel Adjustment			$ -
Total Rate 4				$ 7,142,975	**Total Rate 4**			$ 7,439,500

Kit Carson Electric Cooperative
Security Lighting Service
Rate No. 6

Description	Test Year Rate Billing Units	Test Year Rate	Calculated Billings
Security Lights (Jan-Jun)			
	Kwh *Lights*	*Per Light*	
175W M.WV Metered Steel Fiber	8	$6.35	$ 51
400W M.V Fixture Metered Steel Fiber	28	$8.10	$ 227
175W M.WV Metered Wood	56	$4.45	$ 249
400W M.W Fixture Metered Wood	35	$6.20	$ 217
175W M.W Unmetered Steel Fiber	7	$13.15	$ 92
400W M.W Unmetered Steel Fiber	1,172	$21.80	$ 25,550
150W HPS Security Light Red River	147	$3.40	$ 500
175W M.V Fixture Unmetered Wood	8,462	$11.30	$ 95,621
250W M.V Fixture Unmetered Wood	1,158	$15.55	$ 18,007
400W M.V Fixture Unmetered Wood	2,363	$19.90	$ 47,024
45kwh	7	$6.30	$ 44
Shield	7	$2.00	$ 14
Security Lights (Jul-Dec)			
	Kwh *Lights*	*Per Light*	
175W M.WV Metered Steel Fiber	5	$6.35	$ 32
400W M.V Fixture Metered Steel Fiber	20	$8.10	$ 162
175W M.WV Metered Wood	40	$7.37	$ 295
400W M.W Fixture Metered Wood	25	$6.20	$ 155
175W M.W Unmetered Steel Fiber	5	$13.15	$ 66
400W M.W Unmetered Steel Fiber	837	$27.65	$ 23,143
150W HPS Security Light Red River	105	$5.35	$ 562
175W M.V Fixture Unmetered Wood	6,041	$14.22	$ 85,903
250W M.V Fixture Unmetered Wood	836	$19.12	$ 15,984
400W M.V Fixture Unmetered Wood	1,682	$25.75	$ 43,312
45kwh	5	$6.30	$ 32
Shield	5	$2.00	$ 10
Additional Charges			
	Units	*Per Unit*	
Fuel Adjustment	-	$0.00	$ 1,719
DSA	-	$0.00	$ 528
Number of Lights	13,450		
Total Rate 6			$ 359,496

Description	Proposed Rate Billing Units	Proposed Rate	Calculated Billings
Security Lights (Jan-Dec)			
	Kwh *Lights*	*Per Light*	
175W M.WV Metered Steel Fiber	13	$6.35	$ 83
400W M.V Fixture Metered Steel Fiber	48	$8.10	$ 389
175W M.WV Metered Wood	96	$7.37	$ 708
400W M.W Fixture Metered Wood	60	$6.20	$ 372
175W M.W Unmetered Steel Fiber	12	$13.15	$ 158
400W M.W Unmetered Steel Fiber	2,009	$27.65	$ 55,549
150W HPS Security Light Red River	252	$5.35	$ 1,348
175W M.V Fixture Unmetered Wood	14,503	$14.22	$ 206,233
250W M.V Fixture Unmetered Wood	1,994	$19.12	$ 38,125
400W M.V Fixture Unmetered Wood	4,045	$25.75	$ 104,159
45kwh	12	$6.30	$ 76
Shield	12	$2.00	$ 24
Additional Charges			
	Units	*Per Unit*	
Fuel Adjustment	-	$0.00	$ -
DSA	-	$0.00	$ -
Number of Lights	23,056		
Total Rate 6			$ 407,222

Kit Carson Electric Cooperative
Interruptible Power Service
Rate No. 15

	Test Year Rate				Proposed Rate			
	Billing Units		Rate	Calculated Billings	Billing Units		Rate	Calculated Billings
Facility Charge					**Customer Charge**			
	Customer Months		*Per Customer*		*Customer Months*		*Per Customer*	
Customer Months	8	$	400.00	$ 3,200	Customer Months	8	$ 400.00	$ 3,200
Energy Charge					**Energy Charge**			
	kWh		*Per kWh*		*kWh*		*Per kWh*	
All Kwh's	382,800	$	0.06504	$ 24,897	Purchased Power Energy	382,800	$ 0.04210	$ 16,116
Demand Charge					**Demand Charge**			
	kW		*Per kW*		*kW*		*Per kW*	
All Kw's	5,777	$	11.00	$ 63,546	Purchased Power Demand	5,777	$ -	$ -
					Distribution Demand	5,777	$ 16.00	$ 92,430
							$ 16.00	$ 92,430
Fuel Adjustment					**Fuel Adjustment**			
Total Fuel Adjustment				$ 1,832	Total Fuel Adjustment			$ -
Minimum Bills				$ 9,114				
Revenue Adjustment				$ 9,152				
Total Rate 15				$ 111,741	**Total Rate 15**			$ 111,746

Kit Carson Electric Cooperative
Power Service Time-of-Use
Rate No. 16

	Test Year Rate			Proposed Rate		
	Billing Units	**Rate**	**Calculated Billings**	**Billing Units**	**Rate**	**Calculated Billings**
Facility Charge						
	Customer Months	*Per Customer*		*Customer Months*	*Per Customer*	
Customer Months	87	$ 46.67	$ 4,060			
Customer Charge						
Customer Months				87	$ 50.00	$ 4,350
Demand Charge						
	kW	*Per kW*				
Off-Peak (9 PM - 6 AM)	3,680.9	$ 6.35	$ 23,374			
On-Peak (6 AM - 9 PM)	4,209.3	$ 19.42	$ 81,744			
All kW	7,890.2		$ 105,118			
On-Peak Demand Charge						
				kW	*Per kW*	
Purchased Power Demand				4,209	$ 23.14	$ 97,402
Distribution Demand				4,209	$ 4.96	$ 20,878
					$ 28.10	$ 118,280
Off-Peak Demand Charge						
				kW	*Per kW*	
Distribution Demand				3,681	$ 4.96	$ 18,257
Energy Charge						
	kWh	*Per kWh*		*kWh*	*Per kWh*	
All Kwh	883,600	$ 0.06784	$ 59,943	883,600	$ 0.02980	$ 26,331
Fuel Adjustment						
Total Fuel Adjustment			$ 1,303			$ -
Total Rate 16			$ 167,213			$ 167,219

Kit Carson Electric Cooperative
Residential Service Time-of-Use
Rate No. 17

	Test Year Rate			Proposed Rate		
	Billing Units	Rate	Calculated Billings	Billing Units	Rate	Calculated Billings
Facility Charge						
	Customer Months	*Per Customer*		*Customer Months*	*Per Customer*	
Customer Months	4,803	$ 12.00	$ 57,636			
Customer Charge						
Customer Months				4,803	$ 20.50	$ 98,462
Energy Charge						
	kWh	*Per kWh*		*kWh*	*Per kWh*	
On-Peak (6 AM - 1 PM)	1,621,836	$0.11789	$ 191,198			
Off-Peak (1 PM - 4 PM)	2,754,894	$0.07659	$ 210,997			
On-Peak (4 PM - 9 PM)	-	$0.11789	$ -			
Off-Peak (9 PM - 6 AM)	-	$0.07659	$ -			
All kWh	4,376,730		$ 402,196			
On-Peak Energy Charge						
Purchased Power Energy				1,621,836	$ 0.02980	$ 48,331
Purchased Power Demand				1,621,836	$ 0.10066	$ 163,254
Distribution Demand				1,621,836	$ 0.02155	$ 34,951
					$ 0.15201	$ 246,535
Off-Peak Energy Charge						
				kW	*Per kW*	
Purchased Power Energy				2,754,894	$ 0.02980	$ 82,096
Distribution Demand				2,754,894	$ 0.02155	$ 59,368
					$ 0.05135	$ 141,464
Fuel Adjustment						
Total Fuel Adjustment			$ 4,485			$ -
Total Rate 17			$ 447,301			$ 486,461

Kit Carson Electric Cooperative
Residential Seasonal Service Time-of-Use
Rate No. 18

	Test Year Rate			Proposed Rate		
	Billing Units	Rate	Calculated Billings	Billing Units	Rate	Calculated Billings
Facility Charge						
	Customer Months	*Per Customer*		*Customer Months*	*Per Customer*	
Customer Months	207	$ 12.00	$ 2,484			
Customer Charge						
Customer Months				207	$ 22.50	$ 4,658
Energy Charge						
	kWh	*Per kWh*		*kWh*	*Per kWh*	
On-Peak (6 AM - 1 PM)	48,440	$0.12385	$ 5,999			
Off-Peak (1 PM - 4 PM)	77,366	$0.07485	$ 5,791			
On-Peak (4 PM - 9 PM)	-	$0.12385	$ -			
Off-Peak (9 PM - 6 AM)	-	$0.07485	$ -			
All kWh	125,806		$ 11,790			
On-Peak Energy Charge						
Purchased Power Energy				48,440	$ 0.02980	$ 1,444
Purchased Power Demand				48,440	$ 0.10066	$ 4,876
Distribution Demand				48,440	$ 0.02155	$ 1,044
					$ 0.15201	$ 7,363
Off-Peak Energy Charge						
				kW	*Per kW*	
Purchased Power Energy				77,366	$ 0.02980	$ 2,306
Distribution Demand				77,366	$ 0.02155	$ 1,667
					$ 0.05135	$ 3,973
Fuel Adjustment						
Total Fuel Adjustment			$ 178			$ -
Total Rate 18			$ 13,842			$ 15,994

Kit Carson Electric Cooperative
Commercial Service Time-of-Use
Rate No. 19

	Test Year Rate			Proposed Rate		
	Billing Units	Rate	Calculated Billings	Billing Units	Rate	Calculated Billings
Facility Charge						
	Customer Months	*Per Customer*		*Customer Months*	*Per Customer*	
Customer Months	1,168	$ 17.50	$ 20,440			
Customer Charge						
				Customer Months	*Per Customer*	
Customer Months				1,168	$ 32.25	$ 37,668
Energy Charge						
	kWh	*Per kWh*				
On-Peak (6 AM - 9 PM)	1,141,585	$0.10965	$ 125,175			
Off-Peak (9 PM - 6 AM)	952,302	$0.07345	$ 69,947			
All kWh	2,093,887		$ 195,121			
	-					
On-Peak Energy Charge						
				kWh	*Per kWh*	
Purchased Power Energy				1,141,585	$ 0.02980	$ 34,019
Purchased Power Demand				1,141,585	$ 0.07005	$ 79,968
Distribution Demand				1,141,585	$ 0.02572	$ 29,362
					$ 0.12557	$ 143,349
Off-Peak Energy Charge						
				kW	*Per kW*	
Purchased Power Energy				952,302	$ 0.02980	$ 28,379
Distribution Demand				952,302	$ 0.02572	$ 24,493
					$ 0.05552	$ 52,872
Fuel Adjustment						
Total Fuel Adjustment			$ 4,313			$ -
Total Rate 19			$ 212,634			$ 233,889

Kit Carson Electric Cooperative
Irrigation Power Service
Rate No. 22

	Test Year Rate			Proposed Rate		
	Billing Units	Rate	Calculated Billings	Billing Units	Rate	Calculated Billings
Facility Charge						
	Customer Months	*Per Customer*		*Customer Months*	*Per Customer*	
All Cust. Months	12	$ 30.00	$ 360			
Customer Charge						
Customer Months				12	$ 26.02	$ 312
Energy Charge						
	kWh	*Per kWh*		*kWh*	*Per kWh*	
All kWh	51,278	$0.10104	$ 5,181			
Purchased Power Energy				51,278	$ 0.02980	$ 1,528
Purchased Power Demand				51,278	$ 0.07679	$ 3,938
Distribution Demand				51,278	$ 0.05149	$ 2,640
					$ 0.15808	$ 8,106
Fuel Adjustment						
Total Fuel Adjustment			$ 173			$ -
Total Rate 22			$ 5,714			$ 8,418

Kit Carson Electric Cooperative
Chevron

	Test Year Rate				Proposed Rate			
	Billing Units		Rate	Calculated Billings	Billing Units		Rate	Calculated Billings
Customer Charge								
	Cust.		*Per Cust.*		*Customer Months*		*Per Customer*	
(Jan-Nov)	11	$	579.84	$ 6,378				
(Dec)	1	$	594.34	$ 594				
All Customers	12			$ 6,973	Customer Months	12	$ 600.00	$ 7,200
Demand Charge								
	kW		*Per kW*		*kW*		*Per kW*	
All TSGT CP Kw's (Jan-Nov)	56,977	$	9.27	$ 528,177				
All TSGT CP Kw's (Dec)	4,421	$	9.50	$ 42,000				
All KCEC CP Kw's (Jan-Nov)	93,751	$	3.72	$ 348,754				
All KCEC CP Kw's (Dec)	6,552	$	3.81	$ 24,963				
All Kw's	161,701			$ 943,893	Purchased Power Demand (CP)	100,297	$ 21.50	$ 2,156,386
					Distribution Demand (NCP)	109,874	$ -	$ -
								$ 2,156,386
Factor Penalty								
	kW		*Per kW*		*kW*		*Per kW*	
All TSGT CP kW (Jan-Nov)	3,013	$	9.27	$ 27,928				
All TSGT CP kW (Dec)	-	$	9.50	$ -				
All KCEC CP kW (Jan-Nov)	4,799	$	3.72	$ 17,852				
All KCEC CP kW (Dec)	-	$	3.81	$ -				
All Kw's	7,811			$ 45,779	Purchased Power Demand (CP)	4,799	$ 21.50	$ 103,174
Energy Charge								
	kWh		*Per kWh*		*kWh*		*Per kWh*	
(Jan-Nov)	39,831,279	$	0.01802	$ 717,760				
(Dec)	3,465,669	$	0.01847	$ 64,011				
All kWh	43,296,948			$ 781,771	All kWh	43,296,948	$ 0.02735	$ 1,184,172
System Charge								
	kWh		*Per kWh*		*kWh*		*Per kWh*	
All kWh	43,296,948	$	0.00200	$ 86,594	All kWh	43,296,948	$ 0.00200	$ 86,594
Loss Adjustment				$ 170,540				$ 314,692
Utility Margin								
	kWh		*Per kWh*		*kWh*		*Per kWh*	
(Jan-Nov)	39,831,279	$	0.00215	$ 85,637				
(Dec)	3,465,669	$	0.00220	$ 7,624				
All kWh	43,296,948			$ 93,262	All kWh	43,296,948	$ 0.00220	$ 95,253
Supervision &Inspection Fee								
	Charges		*Rate*		*Charges*		*Rate*	
All Kw's	$ 2,121,838.85		0.005	$ 10,609	$ 3,940,270.23		0.005	$ 19,701
Total				$ 2,139,421				$ 3,967,172