STATE OF KANSAS

BEFORE THE KANSAS CORPORATION COMMISSION

Application for Revised Rates, Tariffs, and Rate Design Changes

of

Mid-Kansas Electric Company, LLC

Docket No. 09-MKEE-_________-RTS

June 5, 2009

PREFILED DIRECT TESTIMONY
RICHARD J. MACKE
LEADER, RATES AND FINANCIAL PLANNING
POWER SYSTEM ENGINEERING, INC.

ON BEHALF OF
MID-KANSAS ELECTRIC COMPANY, LLC

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PART I - QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Richard J. Macke. My business address is 12301 Central Avenue, N.E., Suite 250, Blaine, Minnesota 55434.

Q. What is your profession?

A. I lead the Rate and Financial Planning Department at Power System Engineering, Inc. ("PSE"), which is headquartered at 1532 W. Broadway, Suite 100, Madison, Wisconsin 53713.

Q. Please describe the business activities of PSE.

A. Power System Engineering, Inc. is a consulting firm serving electric utilities across the country, but primarily in the Midwest. Our headquarters is in Madison, Wisconsin with regional offices in Indianapolis, Indiana; Minneapolis, Minnesota; and Marietta, OH. PSE is involved in: power supply, transmission and distribution system planning; distribution, substation and transmission design; construction contracting and supervision; retail and wholesale rate and cost of service ("COS") studies; demand-side management and other economic feasibility studies; merger and acquisition feasibility analysis; load forecasting; financial and operating consultation; telecommunication and network design, mapping/GIS; and system automation including Supervisory Control and Data Acquisition ("SCADA"), Demand Side Management ("DSM"), metering, and outage management systems.

Q. Please describe your responsibilities with PSE.

A. The Rates and Financial Planning Department, which I lead, includes staff in both Minnesota and Indiana who provide consulting services predominantly to electric cooperative and municipal utilities. These services include:

- Cost of Service Studies;
- Retail Rate Design and Analysis;
- Load Management Analysis;
- Individual Customer Profitability;
- Financial Forecasting;
- Capital Credit Allocations;
- Special Fees and Charges;
- Line Extension Policies/Charges;
- Large Power Contract Rates/Proposals;
- Merger Analysis;
- Rate Consolidation;
- Pole Attachment Charges;
- Distributed Generation Rates; and
- Power Cost Adjustments.

Q. What is your educational background?

A. I graduated from Bethel University in St. Paul, Minnesota in 1996 with a Bachelor of Arts degree in Business, which included an emphasis in Finance and Marketing. In 2007, I received my Master of Business Administration degree, with an emphasis in Finance and Strategic Management, from the University of Minnesota in Minneapolis, Minnesota.

Q. What is your professional background?

A. From 1996 to 1998, I was employed by PSE in its Blaine, Minnesota office as a Financial Analyst in the Utility Planning and Rates Department. My work responsibilities primarily were focused on retail rate studies, including revenue requirements and bundled/unbundled cost of service studies. I also provided analysis used to support testimony, mergers and acquisitions analysis and financial forecasting.

From 1998 to 1999, I was employed as a Senior Analyst by Energy & Resource Consulting Group, LLC in Denver, Colorado, a financial, engineering and management consulting firm. I performed consulting services related to electric, gas and water rate studies. As part of the Legend Consulting Advisor Team contracted to the City Council of the City of New Orleans, Louisiana, I assisted in various electric and gas utility matters. I also provided general financial, management and public policy support to clients.

I rejoined PSE in 1999; and from 1999 to 2002, I held the position of Rate and Financial Analyst in the Rates and Financial Planning Department. From 2002 to March 2008, I held the position of Senior Rate and Financial Analyst in the Utility Planning and Rate Division. My responsibilities have included performing complex financial analyses, such as rate studies consisting of determination of revenue requirements, bundled and unbundled cost of service analysis and rate design. Other responsibilities included performing analysis of special rates and programs, key account analyses, financial forecasting, merger and acquisition analysis, activity-based costing, policy development and evaluation and other financial analyses for various PSE clients. Additional responsibilities included strategic planning, litigation support, regulatory compliance, capital expenditure and operational assessments and advisement. From April 2008 to Present, I have held the position of Leader, Rates and Financial Planning. In this capacity, I continue to provide rate and financial consulting services to clients in addition to managing the Rates and Financial Planning Department.

Q. Have you previously presented testimony before the Kansas Corporation Commission ("KCC" or "Commission") relative to rate change applications?

A. Yes. I submitted testimony on behalf of Pioneer Electric Cooperative in Docket No. 09-PNRE-563-RTS and on behalf of Wheatland Electric Cooperative, Inc. in Docket No. 09-WHLE-681-RTS.

Q. Do you have any other rate related experience?

A. Yes. I have directed well over 100 rate study efforts. While in many cases these rate studies were conducted for self-regulated electric cooperatives, I have also performed such analyses that were ultimately filed in regulated rate cases on behalf of cooperatives in Iowa, Kansas, Michigan, Minnesota and New Hampshire.

PART II - INTRODUCTION

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present my analysis of Mid-Kansas Electric Company, LLC's ("MKEC") retail revenue requirements, class cost of service study and proposed rates for each Member-System division.

Q. What do you mean by the term "Member-System division"?

A. The term "Member-System division" refers to the areas of the acquired Aquila, Inc. ("Aquila") system as assigned to MKEC's six distribution Member-System owners. My testimony and analysis is structured around evaluating retail rates and costs separately for each division given the unique characteristics of each Member-System's portion of the acquired area. The six Member-Systems who own MKEC are:

- Lane-Scott Electric Cooperative, Inc. ("Lane-Scott");
- Prairie Land Electric Cooperative, Inc. ("Prairie Land");
- Southern Pioneer Electric Company, Inc. ("Southern Pioneer");
- Victory Electric Cooperative Association, Inc. ("Victory");
- Western Cooperative Electric Association, Inc. ("Western"); and
- Wheatland Electric Cooperative, Inc. ("Wheatland").

Q. What are MKEC's objectives in filing this rate application?

A. MKEC has three primary objectives in filing this rate application. The first objective is to continue the process toward the ultimate goal of spinning the acquired Aquila area down to each of the Member-Systems. The distribution facilities, including most of the 34.5 kV facilities, were spun down to the Member-Systems on December 31, 2007. On December 31, 2008, additional 34.5 kV facilities, primarily the 115-34.5 kV step down substations, were spun down. In order for the spin down of the retail consumers and certified territory to take place, it is necessary to establish retail rates that reflect the cost of each Member-System to serve its assigned service area.

The second objective is financial. The cost of serving the subject areas has risen since Aquila's previous rate change which became effective on March 30, 2005 (Docket No. 04-AQLE-1065-RTS). This cost increase makes an increase in rates necessary and unavoidable; and this rate application will allow the Member-Systems to increase operating revenues in order to achieve acceptable financial operating results.

The third objective of this rate application is to modify rate design to ensure fair and equitable recovery of costs by rate class and rate components. The 2005 rate application by Aquila did not include a class cost of service study, a fact which concerned Commission Staff and which the Commission stated was problematic (Commission Order, Docket No. 04-AQLE-1065-RTS, page 43, paragraph 131). A new class cost of service study has been completed and is being submitted for each of the Member-System divisions. Using the cost of service study results in determining the proposed rate design will ensure that cost recovery is achieved in a way that is fair and equitable between and within the various rate classes.

Q. Are you including analysis and new retail rates for each of the six MKEC Member System divisions?

A. I am including analysis and rate proposals for five of the six. I am not including analysis or new rates for the Wheatland division. Wheatland proposes to simply adopt MKEC's existing retail rates for its division at this time.

Q. Are you sponsoring any exhibits?

A. Yes. I have included the following exhibits detailing the analysis completed for each division:

Exhibit __(RJM-1)	-	Curriculum Vitae - Richard J. Macke.
Exhibit __(RJM-XX-2)	-	Statement of Operations - Present Rates.
Exhibit __(RJM-XX-3)	-	Revenue Requirements.
Exhibit __(RJM-XX-4)	-	Cost of Service Analysis.
Exhibit __(RJM-XX-5)	-	Statement of Operations - Proposed Rates.
Exhibit __(RJM-XX-6)	-	Comparison of Present and Proposed Rate Schedules.
Exhibit __(RJM-7)		Present Rate Schedules.
Exhibit __(RJM-XX-8)	-	Present Rate Schedules with Redline Proposed Changes.
Exhibit __(RJM-XX-9)	-	Proposed Rate Schedules.
Exhibit __(RJM-XX-10)	-	Calculation of ECA Base.

With two exceptions, each exhibit contains a two-letter abbreviation (referred to above as "XX") designating the division to which the exhibit/analysis applies. The exceptions are Exhibit___(RJM-1) and Exhibit___(RJM-7) which are common for all. The following is how I have designated the two-letter abbreviations:

Member-System		Abbreviation
Lane-Scott	-	("LS").
Prairie Land	-	("PL").
Southern Pioneer	-	("SP").
Victory	-	("VI").
Western	-	("WE").

Q. Have the exhibits been prepared by you or by others under your supervision?

A. Yes.

PART III - DIRECT TESTIMONY

A. GENERAL OVERVIEW OF METHODOLOGY AND APPROACH

1. Revenue Requirements

Q. Please provide a brief overview of the revenue requirements analysis.

A. In order to ensure financial viability, a utility's retail rates must be designed to generate sufficient revenue to meet operating expenses and margin requirements. The margin requirements must be adequate to cover interest expense and accomplish other capital management objectives such as rotating patronage capital and maintaining (or achieving) a desired equity position. In this testimony I will refer to the total operating expense and margin requirements as the "revenue requirements." This is expressed by the following equation:

REVENUE REQUIREMENTS = OPERATING EXPENSE + MARGIN REQUIREMENTS

To evaluate a utility's revenue requirements and the adequacy of its present rate structure to meet these requirements, it is common practice to analyze revenue and costs for a 12-month period of time, commonly referred to as the "Pro Forma Test Year" or simply "Test Year."

Q. What Test Year did you use to establish revenue requirements?

A. The Test Year revenue requirements for the divisional studies were based on actual historical results for 12 months ending May 2008, adjusted for known and measurable changes.

Q. Please describe what types of adjustments to the actual test year results to actual results for June 1, 2007 to May 31, 2008 you are proposing.

A. I am proposing several types of adjustments to the actual results for the historical test year period. First, adjustments have been made to normalize revenues or expenses that were experienced during the historical period, but were not reflective of a full 12 months, or were in some other way abnormal. This relates mainly to accounting effects of the various asset spin downs or spin ups that have occurred. Second, adjustments have been made to reflect known and measurable changes related to changes that occurred after the end of the historical test year. As a general rule, I have limited known or measurable changes to such changes that occurred between June 1 and December 31, 2008.

The specific adjustments are discussed more completely in the Revenue Requirements section of my testimony for each Member-System division.

Q. In determining the adjustment to revenue under present rates, how were the pro forma billing determinants determined?

A. The pro forma average number of consumers is based on the number of consumers as of May 2008. The pro forma energy by rate class is the actual test year average usage by consumer multiplied by the number of pro forma consumers. Pro forma year demand was calculated by scaling the actual test year demand by the ratio of actual test year to pro forma year energy.

Q. How was the retail Energy Cost Adjustment (“ECA”) determined in the calculation of the adjustment to revenue under present rates?

A. The ECA used to determine the adjustment to revenue under present rates was determined based on the wholesale ECA charges indicated in the purchased power expense schedule. That is, the amount of revenue collected through the retail ECA has been synchronized with the amount of ECA purchased power expense. This is the current practice.

Q. Please describe the pro forma adjustments to the purchased power expense.

A. The pro forma Test Year purchased power expense is based on the testimony and exhibits of Thomas Hestermann, Manager of Regulatory Affairs, Sunflower Electric Power Corporation. Mr. Hestermann's Schedule 17 summarizes the purchased power expense for each Member-System. This amount is compared to the actual amount booked by the Member-System in the historical test year to determine the proposed adjustment amount.

Q. How have you determined the margin requirements for each MKEC division?

A. The margin requirements were determined using an Operating Times Interest Earned Ratio ("TIER"). Operating TIER measures the ability of the Member-Systems to meet long-term debt obligations with operating margins. This is a common means of determining the margin requirements for electric cooperatives around the country, including in Kansas.

The basic formula for Operating TIER is as follows:

$$\text{Operating TIER} = \frac{\text{Operating Margins plus Long-Term Interest Expense}}{\text{Long-Term Interest Expense}}$$

Q. Why are you basing the margin requirements on an Operating TIER as opposed to some other TIER measurement?

A. There are three different forms of TIER measurements that are used by cooperatives and their lenders: Operating TIER, Modified TIER and Total TIER. Operating TIER, as defined in the above formula, is based on Operating Margins, whereas Total TIER is based on Total Margins. Modified TIER is somewhere in between Operating TIER and Total TIER, in that it includes non-operating income and expenses except for patronage capital allocations from associated organizations. I have used an Operating TIER to establish margin requirements for a couple of reasons. First, the use of an Operating TIER ensures that rates are not affected by non-operating income and/or expenses. Non-operating income and/or expenses are normally considered "below the line" and are not normally considered in setting rates.

Second, an Operating TIER metric was what was specified in the Stipulation and Agreement ("S&A") in Docket No. MKEE-524-ACQ concerning the Aquila acquisition. Footnote No. 7 on page 8 reads:

> "For purposes of a potential refund, the TIER calculation shall be determined from the <u>operating revenues and expenses</u> solely from the operation of the WPK division and not the Distribution Cooperatives' system-wide operations." (emphasis added)

Q. What is the appropriate Operating TIER for purposes of determining the margin requirements in this application?

A. After considering a number of factors, I recommend that the targeted Operating TIER be set at 2.20. The MKEC Board of Trustees along with each Member-System's Board of Trustees has confirmed the appropriateness of a 2.20 Operating TIER for this application.

It is important that the retail rates produce adequate margins to allow the Member-Systems to: 1) achieve and maintain an adequate capital structure, 2) provide stability in terms of handling contingencies and extending the time in between rate adjustments, 3) retire member equity (often referred to as capital credits) and 4) provide members an ownership stake in the cooperative.

Q. How does the requested Operating TIER compare to lender requirements or other industry results?

A. The minimum Operating TIER as determined by the Rural Development Utilities Programs ("RD"), formerly RUS, is 1.10. For most cooperatives, this minimum requirement applies to the 2 best out of the 3 most recent calendar years. In MKEC's case, the TIER requirement is more stringently measured on a rolling 4 quarters basis. To account for contingencies and to reduce the frequency of rate increase needs, an Operating TIER of greater than 1.10 is appropriate.

According to the most recent information available from the National Rural Utilities Cooperative Finance Corporation ("CFC") for its electric cooperative borrowers, the Operating TIER for cooperatives on a national and state level is as follows:

Table 1
Summary of Operating TIER
(2003-2007 Median Values)
Source: CFC Key Ratio Trend Analysis

Year	National	Kansas	National (2 best of 3 yrs)	Kansas (2 best of 3 yrs)
2003	N/A	N/A	2.42	2.76
2004	1.86	1.98	2.53	2.63
2005	1.80	2.21	2.47	2.67
2006	1.79	2.03	2.49	2.86
2007	1.73	1.87	2.40	2.81
Ave.	*1.80*	*2.02*	*2.46*	*2.76*

As can be seen in the above table, the median Operating TIER in Kansas has recently ranged from 1.87 to 2.21, with an average of 2.02. When considering the 2 best of the 3 most recent calendar years, the range in Kansas is 2.63 to 2.81, with an average of 2.76.

It is important to keep in mind that, compared to these national and state medians, the MKEC Members-Systems are somewhat unique. For example, since the acquisition was financed with debt, there is currently very little if any equity. In order to migrate towards a more balanced capital structure required to maintain access to lower cost debt, build reserves against contingencies, provide members with an ownership stake, and fund a portion of plant renewals, replacements and growth, the Member-Systems need to be allowed to achieve an adequate equity ratio. This is challenging but important, especially when considering the amount of plant investments needed in the service area in the near future to repair storm damage and to meet other replacement and growth requirements. Without adequate funding of these investments from rates, the capital structures of the Member-Systems will continue to be dominated by debt which potentially limits access to needed financing and increases debt costs and business risk for member-consumers.

Q. What is the equity ratio for the Member-Systems?

A. Using 2008 year-end financial statements, I have summarized each Member-System's equity in Table 2 in terms of: 1) percent of total capitalization and 2) percent of assets.

Table 2
MKEC Member Equity Position
As of 12/31/08

1. Equity Percent of Total Capitalization

MKEC Member	Equity	Total Capitalization	Equity Ratio
	($)	($)	(%)
LS	(482,448)	979,370[1]	-49.26
PL	750,299	31,266,299	2.40
SP	(1,486,912)	56,941,855[2]	-2.61
VI	1,923,683	44,856,180	4.29
WE	(863,439)	15,014,152[3]	-5.75
National Median (CFC borrowers for 2007)			41.14
State Median (CFC borrowers for 2007)			41.27

2. Equity Percent of Assets

MKEC Member	Equity	Assets	Equity Ratio
	($)	($)	(%)
LS	(482,448)	1,510,044	-32
PL	750,299	30,769,112	2
SP	(1,486,912)	66,202,298	-2
VI	1,923,683	46,566,949	4
WE	(863,439)	16,377,483	-5
National Median (CFC borrowers for 2007)			47.26
State Median (CFC borrowers for 2007)			47.27

[1] Total Capitalization includes $1,461,818 of Notes Payable as Long-Term Debt.
[2] Total Capitalization includes $50,748,663 of Notes Payable as Long-Term Debt.
[3] Total Capitalization includes $1,560,037 of Notes Payable as Long-Term Debt.

As can be seen, the Member-Systems currently have very little equity. I would also note that, at the historic O-TIER levels referenced in Table 1, the equity ratios for cooperatives in Kansas have actual dropped around five percentage points. Given the specifics of the Member-Systems, and in order to build or increase equity, I believe it is reasonable to target an O-TIER of 2.20 which is approximately 10 percent above the recent average for cooperatives in Kansas.

Q. Did you consider any guidance contained in the S&A in Docket No. 06-MKEE-524-ACQ on the appropriate Operating TIER?

A. Yes. Paragraph 17b of the S&A in Docket No. 06-MKEE-524-ACQ does in fact discuss Operating TIER. The S&A allows the distribution members to achieve an Operating TIER of up to 2.20 before a revenue refund plan must be implemented.

Q. What happens to the margins achieved by rates for the Member-Systems?

A. With the exception of Southern Pioneer, MKEC's Member-Systems are structured as non-profit cooperatives. As such, at the end of the year, any operating margins generated during the year are allocated to the member-consumers, who are also the owners of the cooperatives, in proportion to each member-consumer's patronage. These margins are retained by the Cooperatives for a period of time. Eventually these retained margins, sometimes referred to as patronage capital, will be retired or paid back to the members as capital credits. In the meantime, the margins are invested back into the system and provide the largest component of each Cooperative's equity. This helps to 1) lower the cost and amount of borrowing and 2) contributes to financial stability, thereby reducing risk.

Cooperatives have no "outside" investors and have no incentive to increase margins to the detriment of the consumer since every consumer participates in ownership of the cooperative. Rather, the objective is to provide safe, reliable electricity at the most economical price to the membership.

Q. Has the TIER approach to setting margin requirements for rural electric cooperatives been endorsed by the KCC in prior cases?

A. Yes. In my discussions with KCC Staff and my own experience reviewing and preparing rate applications for rate regulated rural electric cooperatives in Kansas, the KCC does typically consider TIER in evaluating rate applications filed by electric cooperatives.

2. Cost of Service Analysis

Q. Have you prepared a retail Cost of Service ("COS") study for each MKEC Member-System division?

A. Yes. A class COS analysis has been prepared to provide information that will be used in evaluating and designing proposed retail rates for each division, except Wheatland. The basic objective of a COS is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology employed is often referred to as the "fully allocated average embedded" COS approach, meaning that 1) costs are allocated on an average system-wide basis and 2) embedded or accounting costs as recorded on the Cooperative's books are used in the analysis. I believe that this is generally the most appropriate technique to use in allocating cost responsibility to the various classes and developing rate design data for rural electric cooperatives.

Q. Were there any consumers or consumer classes that were addressed separately apart from the fully allocated, average embedded COS analysis?

A. Yes. MKEC serves some very large individual loads and provides some unique rates such as real-time pricing programs for which service is priced directly from wholesale rates, or even day ahead hourly market prices.

In these instances, these service offerings were addressed separately given the specific cost of service and rate setting factors of each. The proposed rate revenues generated from these rates were then credited against the overall revenue requirements in developing the general COS analysis for the remaining classes. The revenues generated by the Local Access Charge ("LAC"), addressed by Dennis Eicher, President, D.R. Eicher Consulting, Inc., were handled in similar fashion.

Q. Please describe the general class COS you prepared for each Member-System division.

A. Exhibit __(RJM-XX-4) includes the COS analysis for each division. The detailed calculations and assumptions that go into the analysis are as follows:

Page	Description
1-3	Cost of Service Summary
4-5	Classification of Plant in Service
6-11	Classification of Revenue Requirements
12-13	Adjusted Statement of Operations
14-17	Summary of Classification Factors
18	Summary of Allocation of Revenue Requirements to Rate Classes
19	Allocation of Plant in Service to Rate Classes
20-22	Allocation of Revenue Requirements to Rate Classes
23	Rate Class Weighting Factors
24	Summary of Class Demands
25-26	Calculation of Class Demand Characteristics
27	Calculation of Outdoor Lighting Demand Characteristics
28-29	Development of Allocation Factors.

Q. Please explain the general procedure for conducting a COS study.

A. The basic procedure used to determine the cost responsibility of each consumer classification is as follows:

Step 1 - Classify the plant account records into basic cost causative categories.

Step 2 - Classify the Test Year expenses and margin requirement into the same cost causative categories.

Step 3 - Develop allocation factors for each rate class.

Step 4 - Allocate costs to the various rate classes using the class allocation factors developed for each cost causative category.

Q. Please explain what you mean by cost causative categories.

A. Plant investments, Test Year expenses and margin requirement are classified into the following cost causative categories:

1. Direct - Costs which are directly attributable to one specific customer classification. Expense associated with security and street lighting is an example of a Direct Expense.
2. Consumer - Costs that are directly related to the number of customers and which do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses best illustrate this type of expense.
3. Capacity - Costs which result from providing and maintaining in readiness for operation facilities required to meet the peak demand whether it be the system peak, circuit peak or individual customer service peak. The expense of owning, operating and maintaining a three-phase backbone feeder would fall within this category as would the demand charge from the purchased power expense.
4. Energy - Costs which are related to the amount of energy used. The major item in this category is the ECA in the purchased power rate.

Each of these general cost causative categories is further subdivided as follows:

Direct	Consumer	Capacity	Energy
As Assigned		Power Supply Distribution Substation Primary Line Line Transformer	Power Supply
	Secondary & Service Meter Customer Accounting		

Q. Please explain the methodology used in assigning plant accounts to cost causative categories.

A. The cost causative classification of the various electric plant accounts is presented on pages 4 and 5 of Exhibit __(RJM-XX-4). The methodology used in assigning the plant accounts to the cost causative categories is discussed as follows:

1. Intangible Plant (Acct. 301 to 303) - The Intangible Plant accounts were prorated to the cost categories in the same relationship as the distribution plant allocations.
2. Land, Structures, Station and Battery (Accts. 360 to 363) - The Land and Land Rights, Structures and Improvements, Station Equipment, and Battery accounts were classified as capacity related since the facilities represented by the investment are generally dictated by capacity considerations.
3. Primary Line and Devices (Accts. 364, 365, 366, 367) - The Primary Line and Device accounts were assigned to the capacity component.
4. Line Transformers (Acct. 368) - Classification of the Line Transformer account was assigned to the capacity component.

5. Services and Meters (Accts. 369 and 370) - Because the investment in Services and Meters is basically independent of usage level, it was assigned entirely to the customer component.

6. Consumer Premise (Acct. 371) - The investment in installations on Consumer's Premises was assigned to Primary Line.

7. Street Lighting (Acct. 373) - Investment in street or security lighting facilities was assigned directly to the Lighting Class.

8. General Plant Accounts (Accts. 389 to 399) - The General Plant accounts were assigned to the cost causative categories in the same relationship as the total distribution plant allocations. Because the assignment of the investment in general plant has minimal impact on the classification of Test Year expenses, which ultimately is used to determine class COS responsibility, a more detailed analysis of general plant investment was not warranted.

Q. Please explain how revenue requirements were classified.

A. The Adjusted Operating Statement shown in Exhibit __(RJM-XX-4), pages 12-13, forms the basis for the COS analysis. Actual expenses by account for the historical 12-month period were used to establish the pattern of the Test Year cost breakdown to the various accounts.

The various components of the revenue requirements were classified to the four basic cost causative categories as presented on pages 6 through 11 of Exhibit __(RJM-XX-4). The factors used in the expense classification are summarized on pages 14 through 17 of

Exhibit __(RJM-XX-4). The methodology and rationale for that methodology is discussed below:

1. <u>Purchased Power (Acct. 555)</u> - The demand and energy charge portions of the cost of Purchased Power were assigned to the capacity and energy components, respectively.
2. <u>Distribution Operation and Maintenance (Accts. 580 - 598)</u> - Distribution expense accounts that are related to specific plant accounts (Accts. 582, 583, 584, 585, 586, 587, 591, 592, 593, 594, 595, 596 and 597) were classified in proportion to the corresponding plant accounts. These expenses result from operating and maintaining the distribution plant and thus may be considered plant related. The remaining distribution expense accounts (Accts. 580, 581, 588, 589, 590 and 598) were prorated on the basis of the sum of the previously assigned distribution expense accounts. These accounts basically represent overhead or general distribution expenses.
3. <u>Consumer Accounting (Accts. 901 - 905)</u> - Consumer Accounting expenses were assigned in total to the consumer component since this expense is basically independent of energy usage or capacity requirements. Instead, these accounts are related to the number of consumers.
4. <u>Consumer Service and Information and Sales (Accts. 907 - 916)</u> - Consumer Service and Information and Sales expenses are also considered consumer related expenses.
5. <u>Administrative and General (Accts. 920 - 932)</u> - Administrative and General (A&G) expenses are common costs for which there exists no obvious relationship

to the functional categories. Thus, we have assigned them in proportion to the total of all other expenses without power supply.

6. Depreciation and Amortization (Accts. 403 - 407) - Depreciation and Amortization expense was allocated in proportion to the total plant account assignments.
7. Property Taxes (Acct. 408) - Property Taxes were assigned in proportion to the total plant account assignments.
8. Other Taxes, Other Interest, and Other Deductions - Other Taxes, Other Interest, and Other Deductions were assigned in a manner similar to the A&G Accounts.
9. Net Operating Income (Margin Requirement) - Since margin is comprised of interest expense, which is a function of plant investment, it is reasonable to classify this cost in proportion to the total plant assignments. This approach most nearly parallels the method used to determine target margin requirements (i.e., TIER method).

Q. Please discuss the allocation of costs to rate classes.

A. The allocation of the revenue requirement to each consumer classification is presented on page 18 of Exhibit __(RJM-XX-4). The allocations are based on various allocation factors that reflect certain cost causative drivers as discussed below:

1. Direct Cost Allocation - Costs specifically associated with street or security lighting facilities (investment and O&M) directly assigned to the Lighting Class are an example of a possible direct cost allocation.
2. Consumer Costs Allocations - Generally speaking, consumer related costs were allocated to the various classes on the basis of the total number of consumers in each class. However, several adjustments were made in the general allocation

procedure to reflect differences in the cost of providing basic service. Weighting factors were developed on page 23 of Exhibit __(RJM-XX-4) to recognize the higher cost of three-phase service versus standard single-phase service for each subcategory of consumer related cost. A "weighting factor" of 0.02 was used to allocate the consumer expense related to providing basic service to an individual security or street light. Because these lights make use of facilities and services which have been primarily provided for under other rate schedules, it may be argued that it costs no more to prepare a bill for a consumer with a security light than for one without. However, it seems only fair that the lighting classes should be required to pay at least a token portion of the consumer related expense; hence, the 0.02 weighting factor.

3. Capacity Cost Allocations - Three different allocation factors were developed for the capacity component. (See pages 24 to 27 of Exhibit __(RJM-XX-4) for the development of class demands):

    a. Line transformer capacity related costs were allocated in accordance with the estimated, undiversified non-coincidental peak demand of each consumer in each class as this definition of demand most closely approximates transformer capacity requirements.

    b. Primary line and substation capacity allocated costs were allocated using the Average and Excess Demand Method based on the average monthly coincidental demand for each class (not necessarily coincidental with the system). Distribution system capacity related costs are a function not only of the system peak, but also the individual circuit and even consumer peak demand. The Average and Excess Demand Method gives recognition to the average demand imposed on the system by each class as well as the average monthly peak demand of the class (non-coincidental) and prevents any class from getting a "free ride" from a capacity standpoint.

c. Purchased power demand charges were allocated in accordance with the average monthly coincidental class demands (12CP).

4. Energy Cost Allocations - Energy related costs were allocated on the basis of total energy sales in each rate class.

Allocation factors for each category are developed on pages 28 and 29 of Exhibit __(RJM-XX-4).

3. Rate Design

Q. How should the results of a COS be applied?

A. It is vital to recognize some of the inherent limitations of a COS study. First, it must be emphasized that a COS analysis, while basically an engineering and economic evaluation, is an art; not an exact science. There are many different methodologies, techniques and assumptions that have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can significantly affect the results of the analysis, the results should be treated as providing an indication of the general range of class cost responsibility; not as precise values.

Second, a COS analysis is of necessity directed at determining the cost imposed by a rate class on the system rather than at determining the cost imposed by individual customers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to his/her assigned consumer classification. Furthermore, the study does not address the problem of maintaining relatively smooth transitions between the various rate classes or subclasses of customers which may be eligible to receive service under more than one rate schedule.

Third, accurate demand characteristics and load factor data for individual customer classes are often unavailable. Capacity allocations must therefore be made on the basis of estimates or “typical” data. These assumptions or estimates can have an effect on the end results.

Fourth, a COS analysis does not address itself to many of the other legitimate objectives of rate design such as customer acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the desire to keep each rate schedule competitive, in as much as possible, with the corresponding rate schedule of neighboring utilities or the need to keep the rate structure simple so that it is easily administered and understood by customers.

With the above limitations in mind, a COS study may be used as a general guide for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a manner which avoids unjustifiable price discrimination. The study also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail customers.

Q. What objectives have you considered in developing the proposed rates?

A. There are many legitimate objectives that influence the design of rates. Some of the more important ones are as follows:

1. The proposed rates must develop the requisite total revenue.
2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.
3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
4. Abrupt departures from historical rate practices and levels should be avoided.
5. The rate structure should be acceptable to the membership.
6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.
7. The rates should promote the efficient use of energy and system capacity.
8. Whenever possible, the rate schedule should be competitive with those of neighboring utilities and alternative energy sources.

It is generally not possible to fully accomplish all of the above objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the utility must be made.

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as the need to avoid abrupt changes. In general, it is my belief that the principle of rate moderation (i.e., the need to avoid abrupt changes) should be used to temper the results of the COS analysis. Thus, the dollar and percentage increase or decrease for each class as shown in the Cost of Service Summary table for each Member-System was tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. The final part of your testimony concerns the proposed rates developed for each division. How will you be presenting that information?

A. I will present the proposed rates separately for each division in the following sections. Each section will summarize the results of the revenue requirements and cost of service study and will describe the specific proposed rate changes that have been developed for and approved by the individual Member-System Boards and the MKEC Board.

B. LANE-SCOTT DIVISION

1. Lane-Scott Division - Revenue Requirements

Q. Please briefly describe the revenue requirements analysis you completed for the Lane-Scott division.

A. Exhibit __(RJM-LS-2) provides a Statement of Operations for the Test Year based on the revenue generated by Lane-Scott's present rates.

Page 1 of Exhibit __(RJM-LS-2) provides a summary of the Statement of Operations for the Historical Test Year of June 2007-May 2008. The results shown in Column (c) reflect an unadjusted Test Year as actually recorded on Lane-Scott's books. Column (d) summarizes the various adjustments for known and measurable changes to the revenue and expense accounts with the resulting adjusted Pro Forma Test Year shown in Column (e).

Page 2 of Exhibit __(RJM-LS-2) provides a summary of each of the proposed adjustments. Pages 3 through 19 of Exhibit __(RJM-LS-2) provide the detailed calculations for the adjustments, including:

- Revenue;
- Purchased Power Expense;
- Payroll Expense;
- Payroll Related Expenses;
- Depreciation Expense;
- Interest on Long Term Debt Expense;
- Rate Case Expense;
- Distribution Lease Related Expenses;
- Transmission O&M Expense;
- Other Interest Expense; and
- Property Tax Expense.

Pages 3 and 4 of Exhibit __(RJM-LS-2) present the average number of consumers, energy sales, billing demand and revenue for Lane-Scott's rate classes as recorded for Historical and Pro Forma Test Years.

Pages 5 through 7 of Exhibit __(RJM-LS-2) present the calculation of revenue under present rates for the Pro Forma Test Year. Pro Forma Test Year number of consumers, energy sales and billing demand (page 4) are multiplied by appropriate tariff rates to determine the class and system revenue for the Pro Forma Test Year.

Q. In determining the adjustment to revenue under present rates, how were the pro forma billing determinants determined?

A. The pro forma average number of consumers is based on the number of consumers as of May 2008. The pro forma energy by rate class is the actual test year average usage by consumer multiplied by the number of pro forma consumers. Pro forma year demand was calculated by scaling the actual test year demand by the ratio of actual test year to pro forma year energy.

Q. How was the retail ECA determined in the calculation of revenue under present rates?

A. The ECA used to determine revenue under present rates was determined based on the wholesale ECA charges indicated in the purchased power expense schedule. That is the amount of revenue collected through the retail ECA has been synchronized with the amount of ECA purchased power expense.

Q. Please describe the pro forma adjustments to the purchased power expense.

A. The pro forma Test Year purchased power expense is based on the testimony and exhibits of Mr. Hestermann. In particular, Mr. Hestermann's Schedule l7 summarizes the purchased power expense for each Member-System. This amount is compared to the actual amount booked by Lane-Scott in the historical test year to determine the adjustment amount.

Q. Please explain the pro forma adjustments to the actual operating expenses.

A. The following briefly describes these adjustments.

Payroll Expense was adjusted to reflect the effect on wages for employees added during the test year, employees leaving during the test year, and wage increases in October 2007 and October 2008.

Payroll Related Expense was adjusted to reflect the changes in payroll expense and the known rate changes.

Depreciation Expense was adjusted to reflect the annualization of May 2008 depreciation expense plus the depreciation expense for plant added between June 2008 and December 2008.

Interest on Long Term Debt was adjusted to reflect the annualization of the long term debt outstanding as of December 31, 2008 at the current interest rate(s).

Rate Case Expense is an adjustment to Administrative and General ("A&G") based on an estimated rate case expense amortized over three years.

Distribution Lease Related Expense is an adjustment to A&G to remove lease payments made by Lane-Scott to MKEC during June 2008 to December 2008, which was prior to the spin down of distribution assets.

Transmission O&M Expense was adjusted to include a normalized amount of operation and maintenance expense related to the 34.5 kV facilities that are being operated and maintained by Lane-Scott.

Q. What are Lane-Scott's Test Year revenue requirements?

A. Exhibit __(RJM-LS-3) summarizes the operating results for Lane-Scott on both an unadjusted and an adjusted basis for the Test Year ended on May 31, 2008. A summary of the Operating Statement is provided as follows:

Table 3
Lane-Scott Electric Cooperative, Inc.
Statement of Operations - Present Rates

Description	**12-Months Ending May 31, 2008**	**Pro Forma Test Year**
	($)	($)
Operating Revenue	3,431,166	3,487,861
Operating Expenses[1]	4,204,166	3,787,891
Net Operating Income	(773,000)	(300,030)

It should be emphasized that the Net Operating Income is stated before long-term ("LT") interest expense on long term debt is deducted, since LT interest plus margin requirements are treated together as the margin requirement.

Column D of Exhibit __(RJM-LS-3) shows that, in order to achieve the required Operating TIER of 2.20, the present rates would need to support a total revenue requirement of $3,837,891.

[1] Before interest expense is deducted.

Q. Please identify the Operating Income required in the Test Year to achieve a 2.20 TIER.

A. To achieve an Operating TIER of 2.20, Lane-Scott needs to generate a Net Operating Income (before LT interest) of $110,000.

Q. Please summarize the increase Lane-Scott is requesting.

A. With Pro Forma Test Year Operating Expenses of $3,737,891 and LT Interest and Margin Requirements of $110,000, the total Pro Forma Test Year Revenue Requirements are calculated to be $3,847,891. Revenue for the present rates on a Pro Forma Test Year basis is calculated at $3,487,861. To achieve the targeted Operating TIER of 2.20, revenue must be increased by approximately $360,030 or 10.4 percent. The following table presents a summary of the revenue requirements analysis for the Test Year.

Table 4 Lane-Scott Electric Cooperative, Inc. Revenue Requirements Summary TIER = 2.20 Objective			
			($)
1.	Operating Expenses (Excluding Interest)		3,737,891
2.	Margin Requirements		
	a. Interest Expense		50,000
	b. Target TIER		2.20
	c. Total Margin Requirements (Before Interest)		110,000
	d. Net Operating Income Required		110,000
3.	Total Revenue Requirements		3,847,891
4.	Revenue From Present Rates		
	a. Tariff Revenue		3,471,580
	b. Other Operating Revenue		16,281
	c. Total Revenue		3,487,861
5.	Required Increase (Decrease)		360,030
		or	10.4%

2. Lane-Scott Division - Cost of Service Study

Q. Please summarize the results of the COS study you performed for Lane-Scott.

A. Results obtained from the COS analysis are summarized in Tables 5, 6 and 7 on the following pages. Table 5 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 5
Lane-Scott Electric Cooperative, Inc.
Cost of Service Summary

Rate Class	Revenue Present Rates[2]	Revenue Requirement	Increase/(Decrease) Amount	Increase/(Decrease) Percent[3]
	($)	($)	($)	(%)
Residential (04-RS)	1,415,071	1,467,409	52,338	3.7
Residential W/Space Heat (04-RS)	32,697	38,511	5,813	17.9
GS Small (04-GSS)	502,465	633,562	131,097	26.2
GS Large (04-GSL)	1,414,781	1,570,000	155,218	11.0
Municipal Power (04-M-I)	1,188	1,359	171	14.5
Water Pumping (04-WP)	34,973	39,508	4,535	13.0
Irrigation (04-IP-I)	6,790	4,879	(1,910)	(28.3)
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	79,896	92,663	12,767	16.1
Total[4]	3,487,862	3,847,891	360,030	10.3

Table 6 shows a breakdown of the COS by cost category for each class.

Table 6
Lane-Scott Electric Cooperative, Inc.
Cost Allocation Summary

Rate Class	Power Supply Capacity	Power Supply Energy	Trans-mission	Distribution Consumer	Distribution Capacity	Total COS
	($)	($)	($)	($)	($)	($)
Residential (04-RS)	238,240	729,362	13,374	169,156	317,278	1,467,409
Residential W/Space Heat (04-RS)	7,152	18,117	365	4,212	8,665	38,511
GS Small (04-GSS)	98,390	295,673	5,470	104,672	129,357	633,562
GS Small W/Space Heat (04-Rider 1)	-	-	-	-	-	-
GS Large (04-GSL)	295,488	806,640	15,649	85,094	367,130	1,570,000
GS Large W/Space Heat (04-Rider 1)	-	-	-	-	-	-
Industrial (04-IS)	-	-	-	-	-	-
Municipal Power (04-M-I)	183	206	7	797	167	1,359
Water Pumping (04-WP)	7,944	19,267	398	2,504	9,395	39,508
Irrigation (04-IP-I)	952	1,214	37	1,767	909	4,879
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	14,013	31,490	677	30,485	15,999	92,663
Total	662,360	1,901,968	35,978	398,686	848,900	3,847,891

[2] Includes an allocated share of Other Operating Revenue.

[3] Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

[4] The class cost of service excludes rate classes or consumers which are served under non-standard rates.

Table 7 provides total costs by class expressed in terms of $/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 7
Lane-Scott Electric Cooperative, Inc.
Unit Cost Summary

Rate Class	Power Supply		Trans-mission	Distribution		Total Cost
	Capacity	Energy		Consumer	Capacity	
	(¢/kWh)	(¢/kWh)	(¢/kWh)	($/mo.)	(¢/kWh)	(¢/kWh)
Residential (04-RS)	1.81	5.55	0.10	9.49	2.41	11.16
Residential W/Space Heat (04-RS)	2.19	5.55	0.11	9.49	2.65	11.79
GS Small (04-GSS)	1.85	5.55	0.10	13.04	2.43	11.89
GS Large (04-GSL)	2.03	5.55	0.11	34.42	2.52	10.80
Municipal Power (04-M-I)	4.92	5.55	0.18	9.49	4.49	36.60
Water Pumping (04-WP)	2.29	5.55	0.11	9.49	2.70	11.37
Irrigation (04-IP-I)	4.35	5.55	0.17	29.45	4.15	22.29
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	2.47	5.55	0.12	0.19	2.82	16.32
Total – Average	1.93	5.55	0.10	9.21	2.48	11.22

3. Lane-Scott Division - Rate Design

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as the need to avoid abrupt changes were considered. In general, it is my belief that the principle of rate moderation (i.e., the need to avoid abrupt changes) should be used to temper the results of the COS analysis. Thus, the dollar and percentage increase or decrease for each class as shown in Table 5 was tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Have you established general guidelines for distributing the requisite rate increase to the various classes?

A. Yes. Recognizing the principle of "rate moderation," I have adopted the following general guidelines in distributing the requisite rate increase to the various classes:

1. No class should receive an increase greater than 20 percent, or about twice the average.
2. No class should receive a rate decrease.

Q. Summarize the revenue impact of your proposed rates.

A. The rate design recommendations contained and discussed herein result in an approximate $358,000 revenue increase or 10.3 percent. Table 8 presents a comparison of the Present and Proposed Rates by class of service.

Table 8
Lane-Scott Electric Cooperative, Inc.
Comparison of Revenue
Present and Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease)**	
				Amount	**Percent**
		($)	($)	($)	(%)
1	Residential Service (04-RS)	1,441,011	1,537,129	96,119	6.7
2	General Service Small (04-GSS)	500,120	600,055	99,935	20.0
3	General Service Large (04-GSL)	1,408,177	1,554,609	146,432	10.4
4	Industrial Service (04-IS)	-	-	-	0.0
5	Industrial Service-Primary Discount	-	-	-	0.0
6	Interruptible Industrial Service (04-INT)	-	-	-	0.0
7	Sub-Transmission & Transmission Level Service (04-STR)	-	-	-	0.0
8	Municipal Power Service (04-M-I)	1,182	1,378	196	16.6
9	Water Pumping Service (04-WP)	34,810	40,143	5,333	15.3
10	Irrigation Service (04-IP-I))	6,758	7,364	606	9.0
11	Large Industrial Interruptible (LG-IND)	-	-	-	0.0
12	Private Area / Street Lighting (04-PAL-SL-I)	78,439	87,858	9,419	12.0
13	Security (Decorative) Lighting Service (04-DOL-I)	1,084	1,214	130	12.0
14	Total	3,471,580	3,829,750	358,170	10.3

Q. What type of ECA is Lane-Scott proposing?

A. Lane-Scott proposes a monthly ECA that compares the actual monthly average purchased power expense per kWh sold to the base purchased power expense per kWh sold as contained in this application. In Kansas, this form of ECA is commonly referred to as ECA2.

Q. Have you determined the base to be used in calculating the future ECA?

A. Yes. In Exhibit__(RJM-LS-10) I calculated the ECA base at $0.076734 per kWh sold.

Q. Have you prepared a comparison of the Present and Proposed Rates?

A. Yes, I have. Exhibit __(RJM-LS-6) provides a comparison of the present versus proposed rates as follows:

Exhibit __(RJM-LS-6) - Comparison of Present and Proposed Rate Schedules.

Q. Is Lane-Scott proposing changes to other charges in addition to the rate schedules identified above?

A. No.

Q. Have you prepared rate schedules reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit __(RJM-7) includes the present rate schedules. This exhibit is followed by Exhibit __(RJM-LS-8) that includes redline versions of present rate schedules showing all proposed changes, additions and deletions. Finally, Exhibit __(RJM-LS-9) presents a “clean” version of proposed rate schedules.

Q. Does this conclude your prefiled Direct Testimony for the Lane-Scott division?

A. Yes, it does.

C. PRAIRIE LAND DIVISION

1. Prairie Land Division - Revenue Requirements

Q. Please briefly describe the revenue requirements analysis you completed for the Prairie Land division.

A. Exhibit __(RJM-PL-2) provides a Statement of Operations for the Test Year based on the revenue generated by Prairie Land's present rates.

Page 1 of Exhibit __(RJM-PL-2) provides a summary of the Statement of Operations for the Historical Test Year of June 2007-May 2008. The results shown in Column (c) reflect an unadjusted Test Year as actually recorded on Prairie Land's books. Column (d) summarizes the various adjustments for known and measurable changes to the revenue and expense accounts with the resulting adjusted Pro Forma Test Year shown in Column (e).

Pages 2 and 3 of Exhibit __(RJM-PL-2) provide a summary of each of the proposed adjustments. Pages 4 through 22 of Exhibit __(RJM-PL-2) provide the detailed calculations for the adjustments, including:

- Revenue;
- Purchased Power Expense;
- Payroll Expense;
- Payroll Related Expense;
- Depreciation Expense;
- Interest on Long Term Debt Expense
- Rate Case Expense;
- Rent Expense;
- Transmission O&M Expense;
- Other Interest Expense; and
- Property Tax Expense.

Pages 4 and 5 of Exhibit __(RJM-PL-2) present the average number of consumers, energy sales, billing demand and revenue for Prairie Land's rate classes as recorded for Historical and Pro Forma Test Years.

Pages 6 through 12 of Exhibit __(RJM-PL-2) present the calculation of revenue under present rates for the Pro Forma Test Year. Pro Forma Test Year number of consumers, energy sales and billing demand (page 5) are multiplied by appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Prairie Land's present tariff rates for the various rate schedules.

Q. In determining the adjustment to revenue under present rates, how were the pro forma billing determinants determined?

A. The pro forma average number of consumers is based on the number of consumers as of May 2008. The pro forma energy by rate class is the actual test year average usage by consumer multiplied by the number of pro forma consumers. Pro forma year demand was calculated by scaling the actual test year demand by the ratio of actual test year to pro forma year energy.

Q. How was the retail ECA determined in the calculation of revenue under present rates?

A. The ECA used to determine revenue under present rates was determined based on the wholesale ECA charges indicated in the purchased power expense schedule. That is the amount of revenue collected through the retail ECA has been synchronized with the amount of ECA purchased power expense.

Q. Please describe the pro forma adjustments to the purchased power expense.

A. The pro forma Test Year purchased power expense is based on the testimony and exhibits of Mr. Hestermann. Mr. Hestermann's Schedule l7 summarizes the purchased power expense for each Member-System. This amount is compared to the actual amount booked by Prairie Land in the historical test year to determine the adjustment amount.

Q. Please explain the remaining pro forma adjustments to the actual operating expenses.

A. The following briefly describes these adjustments.

Payroll Expense was adjusted to reflect the effect on wages for employees added during the test year, employees leaving during the test year, and wage increases in October 2007 and October 2008.

Payroll Related Expense was adjusted to reflect the changes in payroll expense and the known rate changes.

Depreciation Expense was adjusted to reflect the annualization of May 2008 depreciation expense plus the depreciation expense for plant added between June 2008 and December 2008.

Interest on Long Term Debt was adjusted to reflect the annualization of the long term debt outstanding as of December 31, 2008 at the current interest rate(s).

Rate Case Expense is an adjustment to A&G based on an estimated rate case expense amortized over three years.

Rent Expense is an adjustment to Distribution Operations to remove lease payments made by Prairie Land to MKEC during June 2008 to December 2008, which was prior to the spin down of the distribution assets.

Transmission O&M Expense was adjusted to include a normalized amount of operation and maintenance expense related to the 34.5 kV facilities that are being operated and maintained by Prairie Land.

Other Interest Expense was adjusted to reflect the refinancing of short term debt to long term debt.

Property Tax Expense was adjusted for property taxes to be paid from June 2008 to December 2008.

Q. What are Prairie Land's Test Year revenue requirements?

A. Exhibit __(RJM-PL-3) summarizes the operating results for Prairie Land on both an unadjusted and an adjusted basis for the Test Year ended on May 31, 2008. A summary of the Operating Statement is provided as follows:

Table 9
Prairie Land Electric Cooperative, Inc.
Statement of Operations - Present Rates

Description	**12-Months Ending May 31, 2008**	**Pro Forma Test Year**
	($)	($)
Operating Revenue	27,851,435	26,817,419
Operating Expenses[5]	29,525,054	27,986,717
Net Operating Income	(1,673,619)	(1,169,298)

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[5] Before interest expense is deducted.

It should be emphasized that the Net Operating Income is stated before LT interest expense on long term debt is deducted, since LT interest plus margin requirements are treated together as the margin requirement.

Column D of Exhibit __(RJM-PL-3) shows that, in order to achieve the required Operating TIER of 2.20, the present rates would need to support a total revenue requirement of $29,507,016.

Q. Please identify the Operating Income required in the Test Year to achieve a 2.20 TIER.

A. To achieve an Operating TIER of 2.20, Prairie Land needs to generate a Net Operating Income (before LT interest) of $2,787,215.

Q. Please summarize the increase Prairie Land is requesting.

A. With Pro Forma Test Year Operating Expenses of $26,719,801 and LT Interest and Margin Requirements of $2,787,215, the total Pro Forma Test Year Revenue Requirements are calculated to be $29,507,016. Revenue for the present rates on a Pro Forma Test Year basis is estimated to be approximately $26,817,419. To achieve the targeted Operating TIER of 2.20, revenue must be increased by approximately $2,689,597 or 10.15 percent. The following table presents a summary of revenue requirements analysis for the Test Year.

Table 10
Prairie Land Electric Cooperative, Inc.
Revenue Requirements Summary
TIER = Modified 2.20 Objective

			($)
1.	Operating Expenses (Excluding Interest)		26,719,801
2.	Margin Requirements		
	a. Interest Expense		1,266,916
	b. Target TIER		2.20
	c. Net Operating Income Required		2,787,215
3.	Total Revenue Requirements		29,507,016
4.	Revenue From Present Rates		
	a. Tariff Revenue		26,501,965
	b. Other Operating Revenue		315,454
	c. Total Revenue		26,817,419
5.	Required Increase (Decrease)		2,689,597
		or	10.15%

2. Prairie Land Division - Cost of Service Study

Q. Please summarize the results of the COS study you performed for Prairie Land.

A. Results obtained from the COS analysis are summarized in Tables 11, 12 and 13 on the following pages. Table 11 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 11
Prairie Land Electric Cooperative, Inc.
Cost of Service Summary

Rate Class	Revenue Present Rates[6]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[7]
	($)	($)	($)	(%)
Residential (04-RS)	9,638,965	9,961,600	322,635	3.4
Residential W/Space Heat (04-RS)	580,794	676,246	95,452	16.6
GS Small (04-GSS)	1,475,429	1,961,853	486,424	33.4
GS Small W/Space Heat (04-Rider 1)	217,055	304,149	87,094	40.6
GS Large (04-GSL)	7,871,996	8,790,013	918,017	11.8
GS Large W/Space Heat (04-Rider 1)	15,680	19,405	3,725	24.0
Industrial (04-IS)	5,237,201	5,433,924	196,722	3.8
Municipal Power (04-M-I)	21,649	28,016	6,367	29.8
Water Pumping (04-WP)	326,032	325,931	(100)	(0.0)
Irrigation (04-IP-I)	88,795	88,842	48	0.1
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	682,090	670,552	(11,538)	(1.7)
Total[8]	26,155,685	28,260,532	2,104,846	8.0

Table 12 shows a breakdown of the COS by cost category for each class.

6 Includes an allocated share of Other Operating Revenue.

7 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

8 The class cost of service excludes rate classes or consumers which are served under non-standard rates.

Table 12
Prairie Land Electric Cooperative, Inc.
Cost Allocation Summary

Rate Class	Power Supply		Trans-	Distribution		Total
	Capacity	Energy	mission	Consumer	Capacity	COS
	($)	($)	($)	($)	($)	($)
Residential (04-RS)	1,672,556	4,774,682	82,266	1,450,152	1,981,943	9,961,600
Residential W/Space Heat (04-RS)	114,467	322,347	5,593	99,358	134,479	676,246
GS Small (04-GSS)	287,433	759,971	13,635	584,931	315,883	1,961,853
GS Small W/Space Heat (04-Rider 1)	56,933	170,055	2,863	6,789	67,509	304,149
GS Large (04-GSL)	1,883,195	4,422,937	84,712	592,531	1,806,638	8,790,013
GS Large W/Space Heat (04-Rider 1)	3,991	10,645	190	614	3,965	19,405
Industrial (04-IS)	733,346	3,634,538	48,868	10,915	1,006,256	5,433,924
Municipal Power (04-M-I)	4,166	9,102	182	10,096	4,470	28,016
Water Pumping (04-WP)	59,092	180,128	3,001	15,865	67,845	325,931
Irrigation (04-IP-I)	11,379	28,057	523	19,771	29,112	88,842
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	88,568	223,875	4,116	258,702	95,292	670,552
Total	4,915,126	14,536,338	245,950	3,049,725	5,513,393	28,260,532

Table 13 provides total costs by class expressed in terms of $/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 13
Prairie Land Electric Cooperative, Inc.
Unit Cost Summary

Rate Class	Power Supply		Trans-	Distribution		Total
	Capacity	Energy	mission	Consumer	Capacity	Cost
	(¢/kWh)	(¢/kWh)	(¢/kWh)	($/mo.)	(¢/kWh)	(¢/kWh)
Residential (04-RS)	1.84	5.26	0.09	13.35	2.18	10.98
Residential W/Space Heat (04-RS)	1.87	5.26	0.09	13.35	2.20	11.04
GS Small (04-GSS)	1.99	5.26	0.09	17.68	2.19	13.58
GS Small W/Space Heat (04-Rider 1)	1.76	5.26	0.09	17.68	2.09	9.41
GS Large (04-GSL)	2.24	5.26	0.10	51.17	2.15	10.46
GS Large W/Space Heat (04-Rider 1)	1.97	5.26	0.09	51.17	1.96	9.59
Industrial (04-IS)	1.06	5.26	0.07	60.64	1.46	7.87
Municipal Power (04-M-I)	2.41	5.26	0.11	13.35	2.58	16.20
Water Pumping (04-WP)	1.73	5.26	0.09	13.35	1.98	9.52
Irrigation (04-IP-I)	2.13	5.26	0.10	40.18	5.46	16.66
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	2.08	5.26	0.10	0.27	2.24	15.76
Total - Average	1.78	5.26	0.09	12.22	2.00	10.23

3. Prairie Land Division - Rate Design

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as the need to avoid abrupt changes were considered. In general, it is my belief that the principle of rate moderation (i.e., the need to avoid abrupt changes) should be used to temper the results of the COS analysis. Thus, the dollar and percentage increase or decrease for each class as shown in Table 11 was tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Have you established general guidelines for distributing the requisite rate increase to the various classes?

A. Yes. Recognizing the principle of "rate moderation," I have adopted the following general guidelines in distributing the requisite rate increase to the various classes:

1. No class should receive an increase greater than twice the average.
2. No class should receive a rate decrease.

Q. Summarize the revenue impact of your proposed rates.

A. The retail rate design recommendations contained and discussed herein result in an approximate $2,106,840 revenue increase or 7.9 percent. In addition, revenue from the LAC as determined in Mr. Eicher's testimony totals $584,751. That total revenue increase is therefore $2,691,591 or 10.2 percent. Table 14 presents a comparison of the Present and Proposed Rates by class of service.

Table 14
Prairie Land Electric Cooperative, Inc.
Comparison of Revenue
Present and Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Increase (Decrease) Percent**
		($)	($)	($)	(%)
1	Residential Service (04-RS)	10,096,502	10,706,087	609,585	6.0
2	General Service Small (04-GSS)	1,672,071	1,938,184	266,112	15.9
3	General Service Large (04-GSL)	7,792,546	8,789,075	996,530	12.8
4	Industrial Service (04-IS)	5,174,037	5,386,206	212,168	4.1
5	Interruptible Industrial Service (04-INT)	449,969	460,089	10,120	2.2
6	Municipal Power Service (04-M-I)	21,388	23,946	2,558	12.0
7	Water Pumping Service (04-WP)	322,100	322,103	4	0.0
8	Irrigation Service (04-IP-I)	87,724	87,908	185	0.2
9	Temporary Service (04-CS)	17,153	18,515	1,362	7.9
10	Real-Time Price (RTP) Program (04-RTP)	194,612	194,612	-	0.0
11	Private Area / Street Lighting (04-PAL-SL-I)	127,132	128,666	1,534	1.2
12	Security (Decorative) Lighting Service (04-DOL-I)	2,361	2,390	29	1.2
13	Controlled Private Area Lighting (04-PAL-I)	149,188	150,982	1,794	1.2
14	Street Lighting Service (04-SL-I)	205,940	208,512	2,572	1.2
15	Vapor Street Lighting Service (04-OSL-V-I)	189,243	191,530	2,287	1.2
16	**Total Retail Rates**	26,501,965	28,608,805	2,106,840	7.9
17					
18	Local Access Charge Revenue - Third Party	-	584,751	584,751	
19					
20	**Total All Rates**	26,501,965	29,193,556	2,691,591	10.2

Q. What type of ECA is being proposed for the Prairie Land division?

A. Prairie Land is proposing a monthly ECA that compares the actual monthly average purchased power expense per kWh sold to the base purchased power expense per kWh sold as contained in this application.

Q. Have you determined the base to be used in calculating the future ECA?

A. Yes. In Exhibit__(RJM-PL-10) I have calculated the ECA base at $0.070372 per kWh sold.

Q. Have you prepared a comparison of the Present and Proposed Rates?

A. Yes, I have. Exhibit __(RJM-PL-6) provides a comparison of the present versus proposed rates as follows:

Exhibit __(RJM-PL-6) - Comparison of Present and Proposed Rate Schedules.

Q. Is Prairie Land proposing changes to other charges in addition to the rate schedules identified above?

A. No.

Q. Have you prepared rate schedules reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit __(RJM-7) includes Prairie Land's present rate schedules. This exhibit is followed by Exhibit __(RJM-PL-8) that includes redline versions of present rate schedules showing all proposed changes, additions and deletions. Finally, Exhibit __(RJM-PL) presents a "clean" version of proposed rate schedules.

Q. Does this conclude your prefiled Direct Testimony for the Prairie Land division?

A. Yes, it does.

D. SOUTHERN PIONEER DIVISION

1. Southern Pioneer Division - Revenue Requirements

Q. Please briefly describe the revenue requirements analysis you completed for the Southern Pioneer division.

A. Exhibit __(RJM-SP-2) provides a Statement of Operations for the Test Year based on the revenue generated by Southern Pioneer's present rates.

Page 1 of Exhibit __(RJM-SP-2) provides a summary of the Statement of Operations for the Historical Test Year of June 2007-May 2008. The results shown in Column (c) reflect an unadjusted Test Year as actually recorded on Southern Pioneer's books. Column (d) summarizes the various adjustments for known and measurable changes to the revenue and expense accounts with the resulting adjusted Pro Forma Test Year shown in Column (e).

Pages 2 and 3 of Exhibit __(RJM-SP-2) provide a summary of each of the proposed adjustments. Pages 4 through 22 of Exhibit __(RJM-SP-2) provide the detailed calculations for the adjustments, including:

- Revenue;
- Purchased Power Expense;
- Payroll Expense;
- Payroll Related Expense;
- Depreciation Expense;
- Interest on Long Term Debt Expense
- Rate Case Expense;
- Rent Expense;
- Transmission O&M Expense;
- Other Interest Expense; and
- Property Tax Expense.

Pages 4 and 5 of Exhibit __(RJM-SP-2) present the average number of consumers, energy sales, billing demand and revenue for Southern Pioneer's rate classes as recorded for Historical and Pro Forma Test Years.

Pages 6 through 11 of Exhibit __(RJM-SP-2) present the calculation of revenue under present rates for the Pro Forma Test Year. Pro Forma Test Year number of consumers, energy sales and billing demand (page 5) are multiplied by appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Southern Pioneer's present tariff rates for the various rate schedules.

Q. Please explain the pro forma adjustments to revenue.

A. The pro forma average number of consumers is based on the number of consumers as of May 2008. The pro forma energy by rate class is the actual test year average usage by consumer multiplied by the number of pro forma consumers. Pro forma year demand was calculated by scaling the actual test year demand by the ratio of actual test year to pro forma year energy.

Q. How was the retail ECA determined in the calculation of revenue under present rates?

A. The ECA used to determine revenue under present rates was determined based on the wholesale ECA charges indicated in the purchased power expense schedule. That is the amount of revenue collected through the retail ECA has been synchronized with the amount of ECA purchased power expense.

Q. Please describe the pro forma adjustments to the purchased power expense.

A. The pro forma Test Year purchased power expense is based on the testimony and exhibits of Mr. Hestermann. Mr. Hestermann's Schedule 17 summarizes the purchased power expense for each Member-System. This amount is compared to the actual amount booked by Southern Pioneer in the historical test year to determine the adjustment amount.

Q. Please explain the remaining pro forma adjustments to the actual operating expenses.

A. The following briefly describes these adjustments.

Payroll Expense was adjusted to reflect the effect on wages for employees added during the test year, employees leaving during the test year, and wage increases in May 2008 and December 2008.

Payroll Related Expense was adjusted to reflect the changes in payroll expense and the known rate changes.

Depreciation Expense was adjusted to reflect the annualization of May 2008 depreciation expense plus the depreciation expense for plant added between June 2008 and December 2008.

Interest on Long Term Debt was adjusted to reflect the annualization of the long term debt outstanding as of December 31, 2008 at the current interest rate(s).

Rate Case Expense is an adjustment to A&G based on an estimated rate case expense amortized over three years.

Rent Expense is an adjustment to Distribution Operations to remove lease payments made by Southern Pioneer to MKEC during June 2008 to December 2008, which was prior to the spin down of the distribution assets.

Transmission O&M Expense was adjusted to include a normalized amount of operation and maintenance expense related to the 34.5 kV facilities that are being operated and maintained by Southern Pioneer.

Other Interest Expense was adjusted to reflect the refinancing of short term debt to long term debt.

Property Tax Expense was adjusted for property taxes to be paid from June 2008 to December 2008.

Q. What are Southern Pioneer's Test Year revenue requirements?

A. Exhibit __(RJM-SP-3) summarizes the operating results for Southern Pioneer on both an unadjusted and an adjusted basis for the Test Year ended on May 31, 2008. A summary of the Operating Statement is provided as follows:

Table 15
Southern Pioneer Electric Company, Inc.
Statement of Operations - Present Rates

Description	**12-Months Ending May 31, 2008**	**Pro Forma Test Year**
	($)	($)
Operating Revenue	46,306,928	54,101,259
Operating Expenses[9]	48,671,948	58,218,034
Net Operating Income	(2,365,020)	(4,116,775)

It should be emphasized that the Net Operating Income is stated before LT interest expense on long term debt is deducted, since LT interest plus margin requirements are treated together as the margin requirement.

[9] Before interest expense is deducted.

Column D of Exhibit __(RJM-SP-3) shows that, in order to achieve the required Operating TIER of 2.20, the present rates would need to support a total revenue requirement of $63,578,770.

Q. Please identify the Operating Income required in the Test Year to achieve a 2.20 TIER.

A. To achieve an Operating TIER of 2.20, Southern Pioneer needs to generate a Net Operating Income (before LT interest) of $8,090,959.

Q. Please summarize the increase Southern Pioneer is requesting.

A. With Pro Forma Test Year Operating Expenses of $55,487,811 and LT Interest and Margin Requirements of $8,090,959, the total Pro Forma Test Year Revenue Requirements are calculated to be $59,978,911. Revenue for the present rates on a Pro Forma Test Year basis is approximately $63,578,770. To achieve the targeted Operating TIER of 2.20, revenue must be increased by approximately $9,477,511 or 17.6 percent. The following table presents a summary of revenue requirements analysis for the Test Year.

Table 16
Southern Pioneer Electric Company, Inc.
Revenue Requirements Summary
TIER = 2.20 Objective

		($)
1.	Operating Expenses (Excluding Interest)	55,487,811
2.	Margin Requirements	
	a. Interest Expense	2,730,223
	b. Target TIER	2.20
	c. Total Margin Requirements (Before Interest)	6,006,490
	d. Plus: Federal and State Tax Expense	2,084,469
	e. Net Pre-Tax Operating Income Required	8,090,959
3.	Total Revenue Requirements	63,578,770
4.	Revenue From Present Rates	
	a. Tariff Revenue	53,843,022
	b. Other Operating Revenue	258,238
	c. Total Revenue	54,101,259
5.	Required Increase (Decrease)	9,477,511
	or	17.60%

2. Southern Pioneer Division - Cost of Service Study

Q. Please summarize the results of the COS study you performed for Southern Pioneer.

A. Results obtained from the COS analysis are summarized in Tables 17, 18 and 19 on the following pages. Table 17 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 17 Southern Pioneer Electric Company, Inc. Cost of Service Summary				
			Increase (Decrease)	
Rate Class	Revenue Present Rates[10]	Revenue Requirement	Amount	Percent[11]
	($)	($)	($)	(%)
Residential (04-RS)	12,165,910	13,899,329	1,733,420	14.4
Residential W/Space Heat (04-RS)	653,837	822,646	168,809	26.0
GS Small (04-GSS)	1,642,541	2,285,792	643,251	39.5
GS Large (04-GSL)	11,556,750	13,609,249	2,052,498	17.9
GS Large W/Space Heat (04-Rider 1)	241,833	268,736	26,903	11.2
Industrial (04-IS)	2,515,992	2,717,687	201,695	8.1
Municipal Power (04-M-I)	119,057	177,505	58,448	49.5
Water Pumping (04-WP)	43,113	66,660	23,547	55.1
Irrigation (04-IP-I)	146,239	147,023	784	0.5
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	749,604	882,371	132,767	17.9
Total[12]	29,834,876	34,876,998	5,042,122	16.9

Table 18 shows a breakdown of the COS by cost category for each class.

Table 18 Southern Pioneer Electric Company, Inc Cost Allocation Summary						
	Power Supply		Trans-	Distribution		Total
Rate Class	Capacity	Energy	mission	Consumer	Capacity	COS
	($)	($)	($)	($)	($)	($)
Residential (04-RS)	2,277,877	6,178,725	72,909	1,721,042	3,648,776	13,899,329
Residential W/Space Heat (04-RS)	137,103	375,021	4,401	87,571	218,549	822,646
GS Small (04-GSS)	346,731	899,733	10,929	499,387	529,012	2,285,792
GS Large (04-GSL)	2,708,531	6,531,414	83,319	565,168	3,720,816	13,609,249
GS Large W/Space Heat (04-Rider 1)	53,148	122,055	1,610	20,167	71,757	268,736
Industrial (04-IS)	389,941	1,661,186	14,977	5,193	646,388	2,717,687
Municipal Power (04-M-I)	30,589	79,692	966	19,752	46,506	177,505
Water Pumping (04-WP)	18,572	25,686	492	276	21,634	66,660
Irrigation (04-IP-I)	26,588	65,367	823	8,626	45,619	147,023
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	62,953	229,549	2,885	462,859	124,125	882,371
Total	6,052,034	16,168,430	193,311	3,390,041	9,073,183	34,876,998

10 Includes an allocated share of Other Operating Revenue.

11 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

12 The class cost of service excludes rate classes or consumers which are served under non-standard rates.

Table 19 provides total costs by class expressed in terms of $/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 19
Southern Pioneer Electric Company, Inc.
Unit Cost Summary

Rate Class	Power Supply Capacity	Power Supply Energy	Trans-mission	Distribution Consumer	Distribution Capacity	Total Cost
	(¢/kWh)	(¢/kWh)	(¢/kWh)	($/mo.)	(¢/kWh)	(¢/kWh)
Residential (04-RS)	1.96	5.31	0.06	11.51	3.13	11.94
Residential W/Space Heat (04-RS)	1.94	5.31	0.06	11.51	3.09	11.64
GS Small (04-GSS)	2.05	5.31	0.06	15.93	3.12	13.48
GS Large (04-GSL)	2.20	5.31	0.07	40.99	3.02	11.06
GS Large W/Space Heat (04-Rider 1)	2.31	5.31	0.07	40.99	3.12	11.69
Industrial (04-IS)	1.25	5.31	0.05	48.09	2.07	8.68
Municipal Power (04-M-I)	2.04	5.31	0.06	11.51	3.10	11.82
Water Pumping (04-WP)	3.84	5.31	0.10	11.51	4.47	13.77
Irrigation (04-IP-I)	2.16	5.31	0.07	32.67	3.70	11.94
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	1.46	5.31	0.07	0.23	2.87	20.40
Total - Average	1.99	5.31	0.06	10.76	2.98	11.45

3. Southern Pioneer Division - Rate Design

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as the need to avoid abrupt changes were considered. In general, it is my belief that the principle of rate moderation (i.e., the need to avoid abrupt changes) should be used to temper the results of the COS analysis. Thus, the dollar and percentage increase or decrease for each class as shown in Table 17 was tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Have you established general guidelines for distributing the requisite rate increase to the various classes?

A. Yes. Recognizing the principle of "rate moderation" and the principle of "member acceptance," I have adopted the following general guidelines in distributing the requisite rate increase to the various classes:

1. No class should receive an increase greater than one and one-half the average percent.
2. No class should receive a rate decrease.

Q. Summarize the revenue impact of your proposed rates.

A. The retail rate design recommendations contained and discussed herein result in an approximate $8,667,423 revenue increase or 16.1 percent. In addition, revenue from the LAC as determined in Mr. Eicher's testimony totals $814,958. That total revenue increase is therefore $9,482,381 or 10.1 percent. Table 20 presents a comparison of the Present and Proposed Rates by class of service.

Table 20
Southern Pioneer Electric Company, Inc.
Comparison of Revenue
Present and Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Increase (Decrease) Percent**
		($)	($)	($)	(%)
1	Residential Service (04-RS)				
2	General Use	12,060,607	14,068,738	2,008,131	16.7
3	Space Heating	648,178	768,680	120,502	18.6
4	General Service Small (04-GSS)	1,628,324	2,019,988	391,664	24.1
5	General Service Large (04-GSL)	11,456,720	13,373,044	1,916,324	16.7
6	General Service Space Heating	239,740	263,316	23,577	9.8
7	Industrial Service (04-IS)	2,494,214	2,912,107	417,893	16.8
8	Interruptible Industrial Service (04-INT)	-	-	-	0.0
9	Real -Time Pricing (RTP)	160,598	160,598	-	0.0
10	Transmission Level Service (04-STR)	24,105,785	27,726,216	3,620,431	15.0
11	Municipal Power Service (04-M-I)	118,026	146,507	28,481	24.1
12	Water Pumping Service (04-WP)	42,740	53,022	10,282	24.1
13	Irrigation Service (04-IP-I))	144,974	155,661	10,687	7.4
14	Temporary Service (04-CS)	-	-	-	0.0
15	Lighting	743,116	862,566	119,451	16.1
16	**Total Retail Rates**	53,843,022	62,510,445	8,667,423	16.1
17					
18	Local Access Charge Revenue - Third Party	-	814,958	814,958	
19					
20	**Total All Rates**	53,843,022	63,325,402	9,482,381	17.6

Q. What type of ECA is being proposed for the Southern Pioneer division?

A. Southern Pioneer is proposing a monthly ECA that compares the actual monthly average purchased power expense per kWh sold to the base purchased power expense per kWh sold as contained in this application.

Q. Have you determined the base to be used in calculating the future ECA?

A. Yes. In Exhibit__(RJM-SP-10) I have calculated the ECA base at $0.073290 per kWh sold.

Q. Have you prepared a comparison of the Present and Proposed Rates?

A. Yes, I have. Exhibit __(RJM-SP-6) provides a comparison of the present versus proposed rates as follows:

Exhibit __(RJM-SP-6) - Comparison of Present and Proposed Rate Schedules.

Q. Is Southern Pioneer proposing changes to other charges in addition to the rate schedules identified above?

A. No.

Q. Have you prepared rate schedules reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit __(RJM-7) includes Southern Pioneer's present rate schedules. This exhibit is followed by Exhibit __(RJM-SP-8) that includes redline versions of present rate schedules showing all proposed changes, additions and deletions. Finally, Exhibit __(RJM-SP-9) presents a "clean" version of proposed rate schedules.

Q. Does this conclude your prefiled Direct Testimony for the Southern Pioneer division?

A. Yes, it does.

E. VICTORY DIVISION

1. Victory Division - Revenue Requirements

Q. Please briefly describe the revenue requirements analysis you completed for the Victory division.

A. Exhibit __(RJM-VI-2) provides a Statement of Operations for the Test Year based on the revenue generated by Victory's present rates.

Page 1 of Exhibit __(RJM-VI-2) provides a summary of the Statement of Operations for the Historical Test Year of June 2007-May 2008. The results shown in Column (c) reflect an unadjusted Test Year as actually recorded on Victory's books. Column (d) summarizes the various adjustments for known and measurable changes to the revenue and expense accounts with the resulting adjusted Pro Forma Test Year shown in Column (e).

Pages 2 and 3 of Exhibit __(RJM-VI-2) provide a summary of each of the proposed adjustments. Pages 4 through 24 of Exhibit __(RJM-VI-2) provide the detailed calculations for the adjustments, including:

- Revenue;
- Purchased Power Expense;
- Payroll Expense;
- Payroll Related Expenses;
- Depreciation Expense;
- Interest on Long Term Debt Expense;
- Rate Case Expense;
- Distribution Lease Related Expenses;
- Transmission O&M Expense;
- Other Interest Expense; and
- Property Tax Expense.

Pages 4 and 5 of Exhibit __(RJM-VI-2) present the average number of consumers, energy sales, billing demand and revenue for Victory's rate classes as recorded for Historical and Pro Forma Test Years.

Pages 6 through 14 of Exhibit __(RJM-VI-2) present the calculation of revenue under present rates for the Pro Forma Test Year. Pro Forma Test Year number of consumers, energy sales and billing demand (page 5) are multiplied by appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Victory's present tariff rates for the various rate schedules.

Q. Please explain the pro forma adjustments to revenue.

A. The pro forma average number of consumers is based on the number of consumers as of May 2008. The pro forma energy by rate class is the actual test year average usage by consumer multiplied by the number of pro forma consumers. Pro forma year demand was calculated by scaling the actual test year demand by the ratio of actual test year to pro forma year energy.

Q. How was the retail ECA determined in the calculation of revenue under present rates?

A. The ECA used to determine revenue under present rates was determined based on the wholesale ECA charges indicated in the purchased power expense schedule. That is the amount of revenue collected through the retail ECA has been synchronized with the amount of ECA purchased power expense.

Q. Please describe the pro forma adjustments to the purchased power expense.

A. The pro forma Test Year purchased power expense is based on the testimony and exhibits of Mr. Hestermann. Mr. Hestermann's Schedule l7 summarizes the purchased power expense for each Member-System. This amount is compared to the actual amount booked by Victory in the historical test year to determine the adjustment amount.

Q. Please explain the pro forma adjustments to the actual operating expenses.

A. The following briefly describes these adjustments.

<u>Payroll Expense</u> was adjusted to reflect the effect on wages for employees added during the test year, employees leaving during the test year, and wage increases in October 2007 and October 2008.

<u>Payroll Related Expense</u> was adjusted to reflect the changes in payroll expense and the known rate changes.

<u>Depreciation Expense</u> was adjusted to reflect the annualization of May 2008 depreciation expense plus the depreciation expense for plant added between June 2008 and December 2008.

<u>Interest on Long Term Debt</u> to reflect the annualization of the long term debt outstanding as of December 31, 2008 at the current interest rate(s).

<u>Rate Case Expense</u> is an adjustment to Administrative and General ("A&G") based on an estimated rate case expense amortized over three years.

<u>Distribution Lease Related Expense</u> is an adjustment to A&G to remove lease payments made by Victory to MKEC during June 2008 to December 2008, which was prior to the spin down of distribution assets.

Transmission O&M Expense was adjusted to include a normalized amount of operation and maintenance expense related to the 34.5 kV facilities that are being operated and maintained by Victory.

Q. What are Victory's Test Year revenue requirements?

A. Exhibit __(RJM-VI-3) summarizes the operating results for Victory on both an unadjusted and an adjusted basis for the Test Year ended on May 31, 2008. A summary of the Operating Statement is provided as follows:

Table 21
Victory Electric Cooperative Association, Inc.
Statement of Operations - Present Rates

Description	12-Months Ending May 31, 2008	Pro Forma Test Year
	($)	($)
Operating Revenue	40,112,282	39,902,562
Operating Expenses[13]	41,892,246	42,395,388
Net Operating Income	(1,779,964)	(2,492,826)

It should be emphasized that the Net Operating Income is stated before LT interest expense on long term debt is deducted, since LT interest plus margin requirements are treated together as a return requirement.

Column D of Exhibit __(RJM-VI-3) shows that, in order to achieve the required Operating TIER of 2.20, the present rates would need to support a total revenue requirement of $44,990,031.

13 Before interest expense is deducted.

Q. Please identify the Operating Income required in the Test Year to achieve a 2.20 TIER.

A. To achieve an Operating TIER of 2.20, Victory needs to generate a Net Operating Income (before LT interest) of $4,756,845.

Q. Please summarize the increase Victory is requesting.

A. With Pro Forma Test Year Operating Expenses of $40,233,186 and LT Interest and Margin Requirements of $4,756,845, the total Pro Forma Test Year Revenue Requirements are calculated to be $44,990,031. Revenue for the present rates on a Pro Forma Test Year basis is $39,902,562. To achieve the targeted Operating TIER of 2.20, revenue must be increased by approximately $5,087,469 or 12.8 percent. The following table presents a summary of revenue requirements analysis for the Test Year.

Table 22
Victory Electric Cooperative Association, Inc.
Revenue Requirements Summary
O-TIER = 2.20 Objective

			($)
1.	Operating Expenses (Excluding Interest)		40,233,186
2.	Margin Requirements		
	a. Interest Expense		2,162,202
	b. Target O-TIER		2.20
	c. Net Operating Income Required		4,756,845
3.	Total Revenue Requirements		44,990,031
4.	Revenue From Present Rates		
	a. Tariff Revenue		39,762,269
	b. Other Operating Revenue		140,293
	c. Total Revenue		39,902,562
5.	Required Increase (Decrease)		5,087,469
		or	12.8%

2. Victory Division - Cost of Service Study

Q. Please summarize the results of the COS study you performed for Victory.

A. Results obtained from the COS analysis are summarized in Tables 23, 24 and 25 on the following pages. Table 23 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 23
Victory Electric Cooperative Association, Inc.
Cost of Service Summary

Rate Class	Revenue Present Rates[14]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[15]
	($)	($)	($)	(%)
Residential (04-RS)	10,577,425	11,349,294	771,869	7.3
Residential W/Space Heat (04-RS)	228,855	272,509	43,655	19.2
GS Small (04-GSS)	1,250,792	1,664,755	413,963	33.3
GS Large (04-GSL)	11,001,177	12,142,250	1,141,074	10.4
GS Large W/Space Heat (04-Rider 1)	244,483	334,100	89,617	36.9
Industrial (04-IS)	381,643	402,665	21,022	5.5
Municipal Power (04-M-I)	90,528	114,008	23,481	26.1
Water Pumping (04-WP)	494,684	507,749	13,065	2.7
Irrigation (04-IP-I)	219,098	216,481	(2,617)	(1.2)
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	581,701	754,671	172,970	29.9
Total[16]	25,070,385	27,758,483	2,688,098	10.7

[14] Includes an allocated share of Other Operating Revenue.

[15] Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

[16] The class cost of service excludes rate classes or consumers which are served under non-standard rates.

Table 24 shows a breakdown of the COS by cost category for each class.

Table 24
Victory Electric Cooperative Association, Inc.
Cost Allocation Summary

Rate Class	Power Supply Capacity	Power Supply Energy	Trans-mission	Distribution Consumer	Distribution Capacity	Total COS
	($)	($)	($)	($)	($)	($)
Residential (04-RS)	1,827,677	5,361,154	218,572	1,579,096	2,362,795	11,349,294
Residential W/Space Heat (04-RS)	46,093	133,224	5,478	31,516	56,198	272,509
GS Small (04-GSS)	250,895	706,633	29,502	377,905	299,819	1,664,755
GS Large (04-GSL)	2,414,700	6,369,861	276,556	546,960	2,534,173	12,142,250
GS Large W/Space Heat (04-Rider 1)	68,512	171,695	7,692	15,416	70,785	334,100
Industrial (04-IS)	86,394	214,187	9,660	5,114	87,310	402,665
Municipal Power (04-M-I)	19,750	53,757	2,290	14,117	24,095	114,008
Water Pumping (04-WP)	89,140	291,700	11,178	5,909	109,821	507,749
Irrigation (04-IP-I)	32,354	93,897	3,852	41,880	44,498	216,481
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	78,198	215,864	9,120	357,798	93,691	754,671
Total	4,913,714	13,611,973	573,901	2,975,711	5,683,185	27,758,483

Table 25 provides total costs by class expressed in terms of $/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 25
Victory Electric Cooperative Association, Inc.
Unit Cost Summary

Rate Class	Power Supply Capacity	Power Supply Energy	Trans-mission	Distribution Consumer	Distribution Capacity	Total Cost
	(¢/kWh)	(¢/kWh)	(¢/kWh)	($/mo.)	(¢/kWh)	(¢/kWh)
Residential (04-RS)	1.81	5.31	0.22	13.68	2.34	11.23
Residential W/Space Heat (04-RS)	1.84	5.31	0.22	13.68	2.24	10.85
GS Small (04-GSS)	1.88	5.31	0.22	18.02	2.25	12.50
GS Large (04-GSL)	2.01	5.31	0.23	51.39	2.11	10.11
GS Large W/Space Heat (04-Rider 1)	2.12	5.31	0.24	51.39	2.19	10.32
Industrial (04-IS)	2.14	5.31	0.24	60.88	2.16	9.97
Municipal Power (04-M-I)	1.95	5.31	0.23	13.68	2.38	11.25
Water Pumping (04-WP)	1.62	5.31	0.20	13.68	2.00	9.24
Irrigation (04-IP-I)	1.83	5.31	0.22	40.58	2.51	12.23
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	1.92	5.31	0.22	0.27	2.30	18.55
Total - Average	1.92	5.31	0.22	13.29	2.22	10.82

3. Victory Division - Rate Design

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as the need to avoid abrupt changes were considered. In general, it is my belief that the principle of rate moderation (i.e., the need to avoid abrupt changes) should be used to temper the results of the COS analysis. Thus, the dollar and percentage increase or decrease for each class as shown in Table 23 was tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Have you established general guidelines for distributing the requisite rate increase to the various classes?

A. Yes. Recognizing the principle of "rate moderation," I have adopted the following general guidelines in distributing the requisite rate increase to the various classes:

1. No class should receive an increase greater than approximately twice the average percent.
2. No class should receive a rate decrease.

Q. Summarize the revenue impact of your proposed rates.

A. The retail rate design recommendations contained and discussed herein result in an approximate $4,448,756 revenue increase or 11.2 percent. In addition, revenue from the LAC as determined in Mr. Eicher's testimony totals $639,118. That total revenue increase is therefore $5,087,874 or 12.8 percent. Table 26 presents a comparison of the Present and Proposed Rates by class of service.

Table 26
Victory Electric Cooperative Association, Inc.
Comparison of Revenue
Present and Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Percent**
		($)	($)	($)	(%)
1	Residential Service (04-RS)	10,745,808	11,680,191	934,383	8.7
2	General Service Small (04-GSS)	1,243,793	1,452,821	209,029	16.8
3	General Service Large (04-GSL)	10,939,614	12,251,883	1,312,268	12.0
4	General Service Space Heating (04-Rider 1)	243,115	274,291	31,176	12.8
5	Industrial Service (04-IS)	379,508	403,812	24,304	6.4
6	Interruptible Industrial Service (04-INT)	335,296	357,890	22,594	6.7
7	Economic Development Rider (04-EDR)	977,590	1,009,283	31,693	3.2
8	Real-Time Pricing Program (04-RTP)	176,952	176,952	-	0.0
9	Sub-Transmission & Transmission Level Service (04-STR)	13,341,524	15,101,777	1,760,253	13.2
10	Municipal Power Service (04-M-I)	90,021	105,366	15,344	17.0
11	Water Pumping Service (04-WP)	491,915	506,585	14,670	3.0
12	Irrigation Service (04-IP-I)	217,872	218,290	419	0.2
13	Temporary Service (04-CS)	815	907	91	11.2
14	Private Area / Street Lighting (04-PAL-SL-I)	232,575	269,786	37,212	16.0
15	Security (Decorative) Lighting Service (04-DOL-I)	16,968	19,682	2,714	16.0
16	Controlled Private Area Lighting (04-PAL-I)	87,581	101,596	14,015	16.0
17	Street Lighting Dusk to Dawn (04-SL-I)	16,549	19,202	2,653	16.0
18	Vapor Street Lighting/Ornamental (04-OSL-V-I)	224,775	260,712	35,937	16.0
19	**Total Retail Rates**	39,762,269	44,211,026	4,448,756	11.2
20					
21	Local Access Charge Revenue - Third Party	-	639,118	639,118	
22					
23	**Total All Rates**	39,762,269	44,850,143	5,087,874	12.8

Q. What type of ECA is being proposed for the Victory division?

A. Victory is proposing a monthly ECA that compares the actual monthly average purchased power expense per kWh sold to the base purchased power expense per kWh sold as contained in this application.

Q. Have you determined the base to be used in calculating the future ECA?

A. Yes. In Exhibit__(RJM-VI-10) I have calculated the ECA base at $0.072010 per kWh sold.

Q. Have you prepared a comparison of the Present and Proposed Rates?

A. Yes, I have. Exhibit __(RJM-VI-6) provides a comparison of the present versus proposed rates as follows:

Exhibit __(RJM-VI-6) - Comparison of Present and Proposed Rate Schedules.

Q. Is Victory proposing changes to other charges in addition to the rate schedules identified above?

A. No.

Q. Have you prepared rate schedules reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit __(RJM-7) includes Victory's present rate schedules. This exhibit is followed by Exhibit __(RJM-VI-8) that includes redline versions of present rate schedules showing all proposed changes, additions and deletions. Finally, Exhibit __(RJM-VI-9) presents a "clean" version of proposed rate schedules.

Q. Does this conclude your prefiled Direct Testimony for the Victory division?

A. Yes, it does.

F. WESTERN DIVISION

1. Western Division - Revenue Requirements

Q. Please briefly describe the revenue requirements analysis you completed for the Western division.

A. Exhibit __(RJM-WE-2) provides a Statement of Operations for the Test Year based on the revenue generated by Western's present rates.

Page 1 of Exhibit __(RJM-WE-2) provides a summary of the Statement of Operations for the Historical Test Year of June 2007-May 2008. The results shown in Column (c) reflect an unadjusted Test Year as actually recorded on Western's books. Column (d) summarizes the various adjustments for known and measurable changes to the revenue and expense accounts with the resulting adjusted Pro Forma Test Year shown in Column (e).

Pages 2 and 3 of Exhibit __(RJM-WE-2) provide a summary of each of the proposed adjustments. Pages 4 through 25 of Exhibit __(RJM-WE-2) provide the detailed calculations for the adjustments, including:

- Revenue;
- Purchased Power Expense;
- Payroll Expense;
- Payroll Related Expenses;
- Depreciation Expense;
- Interest on Long Term Debt Expense;
- Rate Case Expense;
- Distribution Lease Related Expenses;
- Transmission O&M Expense; and
- Other Interest Expense

Pages 4 and 5 of Exhibit __(RJM-WE-2) present the average number of consumers, energy sales, billing demand and revenue for Western's rate classes as recorded for Historical and Pro Forma Test Years.

Pages 6 through 11 of Exhibit __(RJM-WE-2) present the calculation of revenue under present rates for the Pro Forma Test Year. Pro Forma Test Year number of consumers, energy sales and billing demand (page 5) are multiplied by appropriate service schedule rates to determine the class and system revenue for the Pro Forma Test Year. These revenue calculations are based on Western's present tariff rates for the various rate schedules.

Q. Please explain the pro forma adjustments to revenue.

A. The pro forma average number of consumers is based on the number of consumers as of May 2008. The pro forma energy by rate class is the actual test year average usage by consumer multiplied by the number of pro forma consumers. Pro forma year demand was calculated by scaling the actual test year demand by the ratio of actual test year to pro forma year energy.

Q. How was the retail ECA determined in the calculation of revenue under present rates?

A. The ECA used to determine revenue under present rates was determined based on the wholesale ECA charges indicated in the purchased power expense schedule. That is the amount of revenue collected through the retail ECA has been synchronized with the amount of ECA purchased power expense.

Q. Please describe the pro forma adjustments to the purchased power expense.

A. The pro forma Test Year purchased power expense is based on the testimony and exhibits of Mr. Hestermann. Mr. Hestermann's Schedule 17 summarizes the purchased power expense for each Member-System. This amount is compared to the actual amount booked by Western in the historical test year to determine the adjustment amount.

Q. Please explain the remaining pro forma adjustments to the actual operating expenses.

A. The following briefly describes these adjustments.

Payroll Expense was adjusted to reflect the effect on wages for employees added during the test year, employees leaving during the test year, and wage increases in November 2007 and November 2008.

Payroll Related Expense was adjusted to reflect the changes in payroll expense and the known rate changes.

Depreciation Expense was adjusted to reflect the annualization of May 2008 depreciation expense plus the depreciation expense for plant added between June 2008 and December 2008.

Interest on Long Term Debt was adjusted to reflect the annualization of the long term debt outstanding as of December 31, 2008 at the current interest rate(s).

Rate case Expense is an adjustment to A&G based on an estimated rate case expense amortized over three years.

Distribution Lease Related Expense is an adjustment to A&G to remove lease payments made by Western to MKEC during June 2008 to December 2008, which was prior to the spin down of the distribution assets.

Transmission O&M Expense was adjusted to include a normalized amount of operation and maintenance expense related to the 34.5 kV facilities that are being operated and maintained by Western.

Other Interest Expense was adjusted to reflect the refinancing of short term debt to long term debt.

Q. What are Western's Test Year revenue requirements?

A. Exhibit___(RJM-WE-3) summarizes the operating results for Western on both an unadjusted and an adjusted basis for the Test Year ended on May 31, 2008. A summary of the Operating Statement is provided as follows:

Table 27
Western Cooperative Electric Association, Inc.
Statement of Operations - Present Rates

Description	12-Months Ending May 31, 2008	Pro Forma Test Year
	($)	($)
Operating Revenue	15,042,942	16,072,335
Operating Expenses[17]	17,082,019	16,761,201
Net Operating Income	(2,039,077)	(688,865)

It should be emphasized that the Net Operating Income is stated before LT interest expense on long term debt is deducted, since LT interest plus margin requirements are treated together as a return requirement.

[17] Before interest expense is deducted.

Column D of Exhibit __(RJM-WE-3) shows that, in order to achieve the required Operating TIER of 2.20, the present rates would need to support a total revenue requirement of $17,361,094.

Q. Please identify the Operating Income required in the Test Year to achieve a 2.20 TIER.

A. To achieve an Operating TIER of 2.20, Western needs to generate a Net Operating Income (before LT interest) of $1,099,804.

Q. Please summarize the increase Western is requesting.

A. With Pro Forma Test Year Operating Expenses of $16,261,290 and LT Interest and Margin Requirements of $1,099,804, the total Pro Forma Test Year Revenue Requirements are calculated to be $17,361,094. Revenue for the present rates on a Pro Forma Test Year basis is $16,072,335. To achieve the targeted Operating TIER of 2.20, revenue must be increased by approximately $1,288,759 or 8.04 percent. The following table presents a summary of revenue requirements analysis for the Test Year.

Table 28
Western Cooperative Electric Association, Inc.
Revenue Requirements Summary
Method B - TIER = 2.20 Objective

			($)
1.	Operating Expenses (Excluding Interest)		16,261,290
2.	Margin Requirements		
	a. Interest expense		499,911
	b. Target TIER		2.20
	c. Net Operating Income Required		1,099,804
3.	Total Revenue Requirements		17,361,094
4.	Revenue From Present Rates		
	a. Tariff Revenue		16,034,498
	b. Other Operating Revenue		37,838
	c. Total Revenue		16,072,335
5.	Required Increase (Decrease)		1,288,759
		or	8.04%

2. Western Division - Cost of Service Study

Q. Please summarize the results of the COS study you performed for Western.

A. Results obtained from the COS analysis are summarized in Tables 29, 30 and 31 on the following pages. Table 29 provides a comparison of the calculated cost of providing service to each rate class with the revenue generated under the present rates by that class.

Table 29
Western Cooperative Electric Association, Inc.
Cost of Service Summary

Rate Class	Revenue Present Rates[18]	Revenue Requirement	Increase (Decrease) Amount	Increase (Decrease) Percent[19]
	($)	($)	($)	(%)
Residential (04-RS)	3,806,033	3,733,722	(72,311)	(1.9)
Residential W/Space Heat (04-RS)	174,547	190,916	16,368	9.4
GS Small (04-GSS)	844,109	1,026,098	181,988	21.6
GS Large (04-GSL)	4,755,554	5,006,866	251,312	5.3
Industrial (04-IS)	2,695,609	2,846,817	151,208	5.6
Municipal Power (04-M-I)	2,700	3,035	335	12.4
Water Pumping (04-WP)	63,279	67,636	4,357	6.9
Irrigation (04-IP-I)	5,943	6,997	1,054	17.8
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	248,682	178,697	(69,985)	(28.2)
Total[20]	12,596,456	13,060,782	464,326	3.7

Table 30 shows a breakdown of the COS by cost category for each class.

Table 30
Western Cooperative Electric Association, Inc.
Cost Allocation Summary

Rate Class	Power Supply Capacity	Power Supply Energy	Trans-mission	Distribution Consumer	Distribution Capacity	Total COS
	($)	($)	($)	($)	($)	($)
Residential (04-RS)	690,049	1,890,065	117,950	283,889	751,768	3,733,722
Residential W/Space Heat (04-RS)	36,308	96,962	6,121	12,628	38,897	190,916
GS Small (04-GSS)	173,864	459,230	29,138	180,345	183,520	1,026,098
GS Large (04-GSL)	932,643	2,744,984	165,923	140,685	1,022,631	5,006,866
Industrial (04-IS)	455,597	1,715,645	93,855	4,707	577,013	2,846,817
Municipal Power (04-M-I)	720	949	88	705	572	3,035
Water Pumping (04-WP)	14,548	34,525	2,305	1,834	14,424	67,636
Irrigation (04-IP-I)	2,007	2,363	236	834	1,558	6,997
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	20,997	70,878	4,640	53,286	28,897	178,697
Total	2,326,733	7,015,601	420,256	678,914	2,619,279	13,060,782

18 Includes an allocated share of Other Operating Revenue.

19 Percentage is calculated using only rate schedule revenue (excludes Other Operating Revenue).

20 The class cost of service excludes rate classes or consumers which are served under non-standard rates.

Table 31 provides total costs by class expressed in terms of $/customer/month (consumer component) and ¢/kWh (capacity and energy components).

Table 31
Western Cooperative Electric Association, Inc.
Unit Cost Summary

Rate Class	Power Supply		Trans-	Distribution		Total
	Capacity	Energy	mission	Consumer	Capacity	Cost
	(¢/kWh)	(¢/kWh)	(¢/kWh)	($/mo.)	(¢/kWh)	(¢/kWh)
Residential (04-RS)	1.91	5.23	0.33	5.88	2.08	10.33
Residential W/Space Heat (04-RS)	1.96	5.23	0.33	5.88	2.10	10.30
GS Small (04-GSS)	1.98	5.23	0.33	11.62	2.09	11.68
GS Large (04-GSL)	1.78	5.23	0.32	21.95	1.95	9.54
Industrial (04-IS)	1.39	5.23	0.29	26.01	1.76	8.68
Municipal Power (04-M-I)	3.97	5.23	0.49	5.88	3.15	16.72
Water Pumping (04-WP)	2.20	5.23	0.35	5.88	2.18	10.24
Irrigation (04-IP-I)	4.44	5.23	0.52	17.37	3.45	15.48
Lighting (PAL-SL-I, DOL-I) (PAL-I, SL-I)	1.55	5.23	0.34	0.29	2.13	13.18
Total - Average	1.73	5.23	0.31	6.46	1.95	9.73

3. Western Division - Rate Design

Q. Please describe how the proposed rates were developed.

A. The first step in designing the proposed rates was to establish the proposed or targeted increase for each class. While the COS analysis played an important role in establishing the targeted increase for each class, other rate design objectives such as the need to avoid abrupt changes were considered. In general, it is my belief that the principle of rate moderation (i.e., the need to avoid abrupt changes) should be used to temper the results of the COS analysis. Thus, the dollar and percentage increase or decrease for each class as shown in Table 29 was tempered by experienced judgment in order to accomplish the overall rate design objectives.

Q. Have you established general guidelines for distributing the requisite rate increase to the various classes?

A. Yes. Recognizing the principle of "rate moderation," I have adopted the following general guidelines in distributing the requisite rate increase to the various classes:

1. No class should receive an increase greater than twice the average percent.
2. No class should receive a rate decrease.

Q. Summarize the revenue impact of your proposed rates.

A. The retail rate design recommendations contained and discussed herein result in an approximate $784,519 revenue increase or 4.9 percent. In addition, revenue from the LAC as determined in Mr. Eicher's testimony totals $501,892. That total revenue increase is therefore $1,286,410 or 8.0 percent. Table 32 presents a comparison of the Present and Proposed Rates by class of service.

Table 32
Western Cooperative Electric Association, Inc.
Comparison of Revenue
Present and Proposed Rates

(1)	(2)	(3)	(4)	(5)	(6)
Line No.	**Rate Class**	**Revenue Present Rates**	**Revenue Proposed Rates**	**Increase (Decrease) Amount**	**Increase (Decrease) Percent**
		($)	($)	($)	(%)
1	Residential Service (04-RS)	3,968,623	4,048,983	80,360	2.0
2	General Service Small (04-GSS)	841,574	926,069	84,496	10.0
3	General Service Large (04-GSL)	4,741,269	4,949,590	208,321	4.4
4	Industrial Service (04-IS)	822,758	858,533	35,775	4.3
5	Industrial Service-Primary Discount	1,864,754	1,894,510	29,756	1.6
6	Interruptible Industrial Service (04-INT)	177,994	195,295	17,302	9.7
7	Sub-Transmission & Transmission Level Service (04-STR)	3,290,477	3,613,018	322,540	9.8
8	Municipal Power Service (04-M-I)	2,692	2,961	269	10.0
9	Water Pumping Service (04-WP)	63,089	67,541	4,452	7.1
10	Irrigation Service (04-IP-I))	5,925	6,518	592	10.0
11	Large Industrial Interruptible (LG-IND)[21]	7,408	8,004	596	8.0
12	Private Area / Street Lighting (04-PAL-SL-I)	247,935	247,993	58	0.0
13	**Total Retail**	16,034,498	16,819,016	784,519	4.9
14					
15	Local Access Charge Revenue	-	501,892	501,892	
16					
17	**Total Rate Revenue**	16,034,498	17,320,908	1,286,410	8.0

Q. What type of ECA is being proposed for the Western division?

A. Western is proposing a monthly ECA that compares the actual monthly average purchased power expense per kWh sold to the base purchased power expense per kWh sold as contained in this application.

Q. Have you determined the base to be used in calculating the future ECA?

A. Yes. In Exhibit__(RJM-WE-10) I have calculated the ECA base at $0.071806 per kWh sold.

[21] Present Rates include ECA.

Q. Have you prepared a comparison of the Present and Proposed Rates?

A. Yes, I have. Exhibit __(RJM-WE-6) provides a comparison of the present versus proposed rates as follows:

Exhibit __(RJM-WE-6) - Comparison of Present and Proposed Rate Schedules.

Q. Is Western proposing changes to other charges in addition to the rate schedules identified above?

A. No.

Q. Have you prepared rate schedules reflecting the proposed changes discussed in your testimony?

A. Yes. Exhibit __(RJM-7) includes Western's present rate schedules. This exhibit is followed by Exhibit __(RJM-WE-8) that includes redline versions of present rate schedules showing all proposed changes, additions and deletions. Finally, Exhibit __(RJM-WE-9) presents a "clean" version of proposed rate schedules.

Q. Does this conclude your prefiled Direct Testimony for the Western division?

A. Yes, it does.

Mid-Kansas Electric Company, LLC
Exhibit Index

Exhibit	Title
Exhibit___(RJM-1)	Curriculum Vitae - Richard J. Macke
Exhibit___(RJM-7)	Present Rate Schedules

Exhibit___(RJM-1)

RICHARD J. MACKE

Leader, Rates and Financial Planning

SUMMARY OF EXPERIENCE & EXPERTISE

- Over 12 years of experience in electric utility consulting.
- Specialized expertise in financial analyses with particular emphasis on utility finance, rate and cost of service matters, financial planning and financial modeling.

PROFESSIONAL EXPERIENCE

Power System Engineering – Blaine, Minnesota (1999 – Present)

Leader, Rates and Financial Planning (April 2008 – Present)

Senior Rate and Financial Analyst (2002 – March 2008)
Senior Rate and Financial Analyst in Utility Planning and Rate Division. Responsibilities include providing senior level consulting services to clients in the areas of cost of service, rate design, financial planning and forecasting, merger and acquisition analysis and support. Additional responsibilities include strategic planning, litigation support, regulatory compliance, capital expenditure and operational assessments and advisement.

Rate and Financial Analyst (1999 – 2002)
Rate and Financial Analyst in Rates and Financial Planning Division. Emphasis on performing complex financial analyses, such as rate studies consisting of determination of revenue requirements, bundled and unbundled cost of service analysis and rate design. Other responsibilities include performing analysis of special rates and programs, key account analyses, financial forecasting, activity-based costing, policy development and evaluation and other financial analyses for various PSE clients.

Energy & Resource Consulting Group, LLC – Denver, Colorado (1998 – 1999)

Senior Analyst
Senior Analyst for financial, engineering and management consulting firm. Performed consulting services related to electric, gas and water rate studies. Part of the Financial and Engineering Advisor Team contracted to the City Council of the City of New Orleans, Louisiana to assist in various electric and gas utility matters. Provided expert testimony and participated in various regulatory proceedings involving the City Council, the Public Utilities Commission of Texas and the Public Utilities Commission of Nevada. Provided general financial, management and public policy support to clients.

Power System Engineering – Blaine, Minnesota (1996 – 1998)

Financial Analyst
Financial Analyst in Utility Planning and Rates Division. Emphasis on retail rate studies, including revenue requirements, and bundled/unbundled cost of service studies. Provide analysis used to support testimony, mergers and acquisitions cases and financial forecasting.

Cenerprise, Inc. – Minneapolis, Minnesota (February – May 1996)

Energy Sales Analyst Intern for NSP Subsidiary
Performed cost savings analyses for businesses, schools and hospitals. Created training packages for use in other Cenerprise offices consisting of rate tariffs, preliminary consumption analysis, savings analysis, cost projections and financial analysis.

EDUCATION

University of Minnesota – Minneapolis, Minnesota, 2007
Master of Business Administration
Emphasis: Finance and Strategic Management
Bethel University – St. Paul, Minnesota, 1996
Bachelor of Arts Degree in Business
Emphasis: Finance and Marketing
Minor: Economics

ADDENDUM REFERENCES

Expert Testimony

Exhibit___(RJM-7)

THE STATE CORPORATION COMMISSION OF KANSAS Index No. ______

AQUILA INC d/b/a AQUILA NETWORKS-WPK Schedule:
(Name of Issuing Utility)

Replacing Schedule _ Sheet
Which was filed

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding
shall modify the tariff as shown hereon.

Sheet of Sheets

Copies of the official tariff sheets are available at offices providing service under the tariffs, and at the governing state or national commission offices. The information available here attempts to be materially the same, but should there be any discrepancies, in all cases the official tariffs on file with the governing commission will hold over these documents.

Issued ______________________
Month Day Year

Effective ______________________
Month Day Year

By ______________________
Signature Title

MID-KANSAS ELECTRIC COMPANY, LLC
(Name of Issuing Utility)

Schedule: General Rate Index

Replacing Schedule General Rate Index Sheet 1
Which was filed February 4, 2002

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding
shall modify the tariff as shown hereon.

GENERAL RATE INDEX

Issued April 1, 2007
Month Day Year

Effective Upon Commission Approval
Month Day Year

By L. Earl Watkins, Jr. President and CEO
Signature Title

AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: General Rate Index

Replacing Schedule General Rate Index Sheet 2
Which was filed January 7, 2002

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding
shall modify the tariff as shown hereon.

GENERAL RATE INDEX
CANCELLED SCHEDULES

DESCRIPTION	SCHEDULE	CANCELLED
Street Lighting Service – Ornamental System	92-OSL-25	August 1, 2001
Sports Field Lighting	01-SFL-I	January 7, 2002
Green Power	01-GP	January 2002

Issued March 18, 2005
Month Day Year

Effective Upon Commission Approval
Month Day Year

By W. Scott Keith Director, Regulatory
Signature Title

04-AQLE-1065-RTS
Approved
Kansas Corporation Commission
March 30, 2005
/S/ Susan K. Duffy

RESIDENTIAL SERVICE

AVAILABLE

Entire Service Area.

APPLICABLE

To all electric service supplied through one (1) meter for residential purposes.

Where a business, professional or other gainful enterprise is conducted in or on a residential premise, this schedule shall be applicable only to the separately metered service for residential purpose.

CHARACTER OF SERVICE

Alternating current, 60 cycle, single phase, 115 or 115/230 volts.

NET MONTHLY BILL

	RESIDENTIAL GENERAL USE	RESIDENTIAL SPACE HEATING
Customer Charge	\$8.39 per meter per month.	\$8.39 per meter per month.
Delivery Charge		
Summer		
All kWh	\$0.06011 per kWh.	\$0.06011 per kWh.
Winter		
0 – 800 kWh	\$0.04576 per kWh.	\$0.04576 per kWh.
801 – 5800 kWh	\$0.04576 per kWh.	\$0.01901 per kWh.
5801 kWh and above	\$0.04576 per kWh.	\$0.04576 per kWh.

Minimum

The minimum bill shall be the customer charge.

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

Issued March 18, 2005
Month Day Year

Effective Upon Commission Approval
Month Day Year

By W. Scott Keith Director, Regulatory
Signature Title

04-AQLE-1065-RTS
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/S/ Susan K. Duffy

DEFINITION OF SUMMER AND WINTER BILLING PERIODS

The summer billing period includes all bills dated July 1 to October 31, inclusive. The winter billing period includes all bills dated November 1 to June 30, inclusive.

SPACE HEATING

If the customer permanently installs and uses in his residence equipment for electric space heating of not less than three (3) kilowatt capacity, and has so informed the Company in writing, all kWh used on winter bills shall be at the rates shown in the Net Monthly Bill section, above.

DELAYED PAYMENT

As per schedule DPC.

RECONNECTION CHARGE

In the event a customer orders a disconnection and reconnection of service at the same premises within a period of twelve (12) months, The Company may collect as a reconnection charge the sum of such minimum bills as would have accrued during the period of disconnection.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

Issued March 18, 2005
Month Day Year

Effective Upon Commission Approval
Month Day Year

By W. Scott Keith Director, Regulatory
Signature Title

04-AQLE-1065-RTS
Approved
Kansas Corporation Commission
March 30, 2005
/S/ Susan K. Duffy

THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 3

AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: N/A

Replacing Schedule N/A Sheet 1
Which were filed January 7, 2002

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 1 Sheets

HELD FOR FUTURE USE

Issued March 18, 2005
Month Day Year

Effective Upon Commission Approval
Month Day Year

By W. Scott Keith Director, Regulatory
Signature Title

04-AQLE-1065-RTS
Approved
Kansas Corporation Commission
March 30, 2005
/S/ Susan K. Duffy

GENERAL SERVICE SMALL

AVAILABLE

Entire Service Area.

APPLICABLE

To all electric service of a single character supplied at one (1) point of delivery and used for general business or commercial purposes, institutions, public or private, and purpose for which no specific rate schedule is provided. This rate is applicable to service of less than ten (10) kW of Demand. If a demand of ten (10) kW or over is reached during a twelve (12) month period, service will be changed to the GSL Rate. This schedule is not applicable to temporary, breakdown, standby, supplementary, resale or shared service.

CHARACTER OF SERVICE

Alternating current, approximately 60 cycles; single phase, 115 or 115/230 volt; three phase, 3 wire, 230 volt; three phase, 4 wire, 115/230 volt.

NET MONTHLY BILL

Customer Charge

$ 9.78 per meter per month.

Delivery Charge

	Winter Bills November 1 to June 30 inclusive	Summer Bills July 1 to October 31 inclusive
All kWh per month	$0.03285 per kWh	$0.04504 per kWh

Minimum

The minimum bill shall be the customer charge.

Issued March 18, 2005 (Month Day Year)	04-AQLE-1065-RTS Approved Kansas Corporation Commission March 30, 2005 /S/ Susan K. Duffy
Effective Upon Commission Approval (Month Day Year)	
By W. Scott Keith (Signature) Director, Regulatory (Title)	

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

DEMAND

Customer's average kilowatt load during the fifteen (15) minute period of maximum use during the month.

DELAYED PAYMENT

As per Schedule DPC.

CONTRACT PERIOD

Not less than one (1) year for single phase service in excess of ten (10) kW demand and for all three phase service, in accordance with Agreement for Electric Service by the Company.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

Issued March 18, 2005
Month Day Year

Effective Upon Commission Approval
Month Day Year

By W. Scott Keith Director, Regulatory
Signature Title

04-AQLE-1065-RTS
Approved
Kansas Corporation Commission
March 30, 2005
/S/ Susan K. Duffy

GENERAL SERVICE LARGE

AVAILABLE

Entire Service Area.

APPLICABLE

To all electric service of a single character supplied at one (1) point of delivery and used for general business or commercial purposes, institutions, public or private, and purpose for which no specific rate schedule is provided. This schedule is not applicable to temporary, breakdown, standby, supplementary, resale or shared service. This rate is applicable to service of ten (10) kW of Demand and over.

CHARACTER OF SERVICE

Alternating current, approximately 60 cycles; single phase, 115 or 115/230 volt; three phase, 3 wire, 230 volt; three phase, 4 wire, 115/230 volt.

NET MONTHLY BILL

Customer Charge

$11.18 per meter per month.

	Winter Bills November 1 to June 30 inclusive	Summer Bills July 1 to October 31 inclusive
Demand Charge		
Per kW over 9	$4.47 per month	$6.99 per month
Delivery Charge		
All kWh per month	$0.02933 per kWh	$0.03978 per kWh

Minimum

The minimum bill shall be the customer charge plus $ 5.85 for each kW over nine (9) kW of the highest demand during the twelve (12) months ending currently.

Issued March 18, 2005
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Effective Upon Commission Approval
Month Day Year

By W. Scott Keith — Director, Regulatory
Signature — Title

04-AQLE-1065-RTS
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March 30, 2005
/S/ Susan K. Duffy

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

DEMAND

Customer's average kilowatt load during the fifteen (15) minute period of maximum use during the month.

POWER FACTOR

If the average power factor for the month (determined at the option of the Company by permanent measurement or by test under normal operating conditions) is less than eighty-five percent (85%), the demand will be adjusted by multiplying by eighty-five percent (85%) and dividing by the average power factor expressed in percent.

PRIMARY SERVICE DISCOUNT

The rate provision of the net monthly bill excluding the Energy Cost Adjustment Clause will be discounted two percent (2%) if all service is delivered and metered at a primary distribution voltage of 4160 volts or higher and customer owns and maintains all necessary transformation equipment and substation.

DELAYED PAYMENT

As per Schedule DPC.

CONTRACT PERIOD

Not less than one (1) year for single phase service in excess of nine (9) kW demand and for all three phase service, in accordance with Agreement for Electric Service by the Company.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

Issued March 18, 2005
Month Day Year

Effective Upon Commission Approval
Month Day Year

By W. Scott Keith Director, Regulatory
Signature Title

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/S/ Susan K. Duffy

RIDER NO. 1 - SPACE HEATING SERVICE

APPLICABILITY

Applicable to Schedules GSS and GSL, for customers who use electric space heating equipment as the sole source of comfort heating for the space heated and when such equipment is of size and design approved by the Company.

Space heating equipment shall be permanently installed of not less than three (3) kilowatts total input rating, operating at 220 volts or higher.

All provisions of the applicable schedule remain effective subject only to the modifications and additional provisions prescribed by this rider.

RATE

The customer, at his option, can be billed under either of the following:

a) During the eight (8) consecutive billing months of November 1 through June 30 where customer arranges the wiring so the electric energy used for space heating can be metered separately, all kWh at $0.01861 plus energy cost adjustment. For electricity used during other periods, the demand and kWh on the separate circuit shall be arithmetically combined for billing purposes with other electric service supplied and billed at the applicable rate.

b) Where customer has installed and in regular use electric space heating that is not less than thirty percent (30%) of the total connected load, the demand used for billing purposes in the billing months of November 1 through June 30 shall not exceed the highest similarly established in the next preceding billing months of July, August, September, or October.

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c) Use during months not included in the Heating Season: Demand established and kWh used by equipment connected to space heating circuits will be added to demands and kWh measured for billing the service supplied under the schedule with which this rider is applied and the total service will be billed under such schedule.

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

HEATING SEASON

Eight (8) consecutive months, November 1 to June 30, inclusive.

AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: 04-IS

Replacing Schedule 01-IS Sheet 1

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

Which was filed December 17, 2001

No supplement or separate understanding shall modify the tariff as shown hereon.

INDUSTRIAL SERVICE

AVAILABLE

Entire Service Area.

APPLICABLE

To all electric service of a single character supplied at one (1) point of delivery and used for industrial or manufacturing purposes in which a product is produced or processed and from which point the end product does not normally reach the ultimate consumer. This schedule is not applicable to temporary, breakdown, standby, supplementary, resale or shared service.

CHARACTER OF SERVICE

Alternating current, approximately 60 cycles; at any one standard voltage required by customer as described in Company's Standards for Electric Service.

NET MONTHLY BILL

Customer charge

$100.62 per meter per month

	Winter Bills November 1 to June 30 inclusive	Summer Bills July 1 to October 31 inclusive
Demand Charge		
Per kW over 10	$7.43 per month	$10.62 per month
Delivery Charge		
All kWh per month	$0.01643 per kWh	$0.02717 per kWh

Minimum

1. The Demand Charge

2. Where it is necessary to make unusual extension or to reinforce distribution lines to provide service such that in the judgment of the Company, revenue to be derived from or the duration of the prospective business is not sufficient under the above stated minimum to warrant the investment, The Company may require an adequate minimum bill calculated upon reasonable considerations before undertaking to supply the service.

Issued March 18, 2005
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Effective Upon Commission Approval
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The Kansas Corporation Commission must approve minimum bills thus determined. In such cases, the consumer shall enter into a written contract with the Company as to the character, amount and duration of the business offered.

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

DEMAND

Customer's average kilowatt load during the fifteen (15) minute period of maximum use during the month, but not less than seventy-five percent (75%) of highest demand in previous eleven (11) months nor less than fifty (50) kilowatts.

POWER FACTOR

If the average power factor for the month (determined at the option of the Company by permanent measurement or by test under normal operating conditions) is less than eighty-five percent (85%), the demand will be adjusted by multiplying by eighty-five percent (85%) and dividing by the average power factor expressed in percent.

PRIMARY SERVICE DISCOUNT

The rate provision of the net monthly bill excluding the energy cost adjustment clause will be discounted two percent (2%) if all service is delivered and metered at a primary distribution voltage of 4160 volts or higher and customer owns and maintains all necessary transformation equipment and substation.

DELAYED PAYMENT

As per Schedule DPC.

CONTRACT PERIOD

Not less than one (1) year, or such term as may be specified for a line extension, in accordance with the Agreement for Electric Service.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

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INTERRUPTIBLE INDUSTRIAL SERVICE

AVAILABLE

In all rate areas of Aquila Inc d/b/a Aquila Networks - WPK, with the Company reserving the right to remove this rate schedule or modify it in any manner, subject to Kansas Corporation Commission approval. The Company reserves the right to limit the number and amount of the contracts of kW demand to a total load for interruption of five thousand (5,000) kW demand under this rate.

APPLICABLE

The customer must be presently eligible for the IS rate and complete a written application to the Company. Customer must dedicate by contract agreement at least two hundred (200) kW to interruption at any time and designate when applicable a desired kW portion to be billed on the non-interruptible basis. Customer must furnish the Company with the names of a primary and secondary designated representative, one of which can be contacted twenty-four (24) hours a day.

CHARACTER OF SERVICE

Alternating current, approximately 60 cycles; at any one standard voltage required by customer as described in Company's Standards for Electric Service.

NET MONTHLY BILL

Customer Charge

$100.62 per meter per month

	Winter Bills November 1 to June 30 inclusive	Summer Bills July 1 to October 31 inclusive
Demand Charge		
Non-Interruptible		
All kW of billing demand	$7.43 per month	$10.62 per month
Interruptible		
All kW of billing demand	$4.47 per month	$4.47 per month
Penalty		
All kW of billing demand	$31.24 per month	$31.24 per month
Delivery Charge		
All kWh per month	$0.01643 per kWh	$0.02717 per kWh

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Minimum

1. The Demand Charge

2. Where it is necessary to make an unusual extension or to reinforce distribution lines to provide service such that in the judgment of the Company the revenue to be derived from or the duration of the prospective business is not sufficient under the above stated minimum to warrant the investment, the Company may require an adequate minimum bill calculated upon reasonable considerations before undertaking to supply the service. The Kansas Corporation Commission must approve minimum bills thus determined. In such cases, the consumer shall enter into a written contract with the Company as to the character, amount and duration of the business offered.

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

DEMAND

A. Non-Interruptible: The amount of kW required and designated by contractual agreement not to be interrupted.

B. Penalty: The customer's average kilowatt load during the fifteen (15) minute period of maximum use during any interruptible period during the month less the kW billed under Part A of this section.

C. Interruptible: The customer's average kilowatt load during the fifteen (15) minute period of maximum use during any non-interruptible period during the month less the kW billed under Parts A & B of this section; but not less than seventy-five percent (75%) of the highest demand (add Parts A, B. & C) in the previous eleven (11) months nor less than two hundred (200) kilowatts (add parts B & C).

POWER FACTOR

If the average power factor for the month (determined at the option of the Company by permanent measurement or by test under normal operating conditions) is less than eighty-five percent (85%), the demand will be adjusted by multiplying by eighty-five percent (85%) and dividing by the average power factor expressed in percent.

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Effective Upon Commission Approval (Month Day Year)	
By W. Scott Keith (Signature) Director, Regulatory (Title)	

PRIMARY SERVICE DISCOUNT

The rate provision of the net monthly bill excluding the energy cost adjustment clause will be discounted two percent (2%) if all service is delivered and metered at a primary distribution voltage of 4160 volts or higher and customer owns and maintains all necessary transformation equipment and substation.

CONTRACT PERIOD

Not less than one (1) year, or such term as may be specified for a line extension, in accordance with the Agreement for Electric Service. Six (6) months written notice, except upon the following occurrence, must be given by customer to the Company before customer may change from this rate schedule to another applicable rate schedule. The customer will automatically default by placing twenty-five percent (25%) or more of its contracted interruptible demand on Company system during a declared interruptible period in each of any two (2) calendar months out of a rolling twelve (12) calendar month period. The customer shall pay all applicable charges under this tariff and then transfer to another rate schedules for the following billing month. Customer may reapply for interruptible service on June 1st of the calendar year following the occurrence of default.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

1. Application/Placement on Rate: Rate applicant will be placed on a list in the order in which they make requests. Applicants will be placed on the rate as soon as the necessary facilities are in place and approved by the Company.

Note: For the purpose of this rate, the loads used in the cumulative total will be determined by Company on an expected value basis using actual meter data indicative of loads which can be interrupted during the hours of 11 a.m. and 11 p.m., from June 15th to September 15th.

2. Interruptions: Notice: The Company may interrupt the interruptible portion of service under this schedule at any time with at least two (2) hours advance notice. While additional advance notice is not required, the Company will endeavor to give customer twenty-four (24) hours prior notice when possible.

Period of Interruption: A period of interruption is a time interval, of either a four (4) or eight (8) hour increment, as communicated to the customer's designated representative by Company designated representative. Time intervals may extend over consecutive periods with each having a two (2) hours minimum notice.

Duration of Interruption: It is further understood and agreed that service to the customer shall be interrupted when, in the opinion of Company System Operator, continued service would contribute to the establishment of a predetermined Company system peak load and during any system emergency such as a sudden loss of generation or transmission or other situations when reduction in load on Company system is required. The interruption of service shall continue until conditions causing interruptions have been cleared.

3. Responsibility: The customer will be responsible for monitoring his load in order to comply with the terms of the contract and provisions of this service schedule.

The Company shall purchase and install an electronic meter relay which shall provide the customer with an instantaneous, visual monitor of its demand.

4. Liability: The Company shall have no liability to the customer or any other person, firm, or corporation for any loss, damage, or injury by reason of any interruption or curtailment as provided herein.

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ECONOMIC DEVELOPMENT RIDER

PURPOSE

The purpose of this Rider is to stimulate economic development in the Company's service area which will be characterized by customer's capital investment and expansion and new employment.

AVAILABILITY

Available in all territory served by the Company, to qualifying customers who contract for service under schedules GSL or IS. This Rider is available for four (4) years from the date of initial service under this Rider.

Electric service under this Rider is not available in conjunction with service provided pursuant to any other special contract agreements.

APPLICABILITY

Upon the request of the customer and acceptance by the Company, the provisions of this rider will be applicable to:

1. New industrial and commercial customers who create employment and contract for more than fifty (50) kW of billing demand, or

2. Existing customers and new owners of existing facilities who invest in new facilities which increase employment and result in an increase in billing demand of fifty (50) kW, or

3. Current or new owners who reopen a facility that has been closed for twelve (12) or more months which results in increased employment and who contracts for at least fifty (50) kW of billing demand.

4. The Economic Development Rider is not applicable to any customer who is directly engaged in the retail trade of rendering goods and services to the general public.

5. The Economic Development Rider is not applicable for new or expanded facilities under construction or otherwise committed to operation prior to the first effective date of this rider.

RATE DISCOUNT

Prior to adjustments for energy costs (ECA) and taxes, the customer's net monthly bills less the applicable customer charge calculated in accordance with rate schedule Commercial General Service-Large (GSL), and Industrial Service (IS) will be discounted by:

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By W. Scott Keith Director, Regulatory Signature Title	

40% during the first contract year
30% during the second contract year
20% during the third contract year
10% during the fourth contract year

After the fourth (4th) contract year, the rate discount shall cease.

CONDITIONS:

1. For purposes of this Rider, the reductions indicated above in RATE DISCOUNT shall apply as follows:

a) For new commercial and industrial customers: the total demand and delivery for service.

b) For existing customers: each month determine the demand in excess of the highest actual peak demand established during the twelve (12) billing months previous to the implementation of the Rider. The ratio of the newly established excess demand to the current month total demand applied against the customer's current demand and delivery charges will be the portion of the bill subject to the discount.

2. All provisions set forth in the customer's rate schedule are applicable to the extent they are not superseded by provisions contained in this Rider.

3. It is solely within the discretion of the Company to determine if a customer meets the criteria for receiving service under this Rider. The Company may withdraw this Rider only if the Company determines the requirements of the Rider are not being met.

4. The Company will not require a contribution in aid of construction for standard facilities installed to serve the customer if the Company analysis of expected revenues from the new load on an ongoing basis is determined to be sufficient to justify the required investment in the facilities. Bills for separately metered service to existing customers pursuant to the provisions of this Rider, will be calculated independently of any other service rendered the customer at the same or other locations.

5. Any customer taking service under this Rider which initiates a subsequent qualified expansion may,

a) include the load resulting from the subsequent expansion with the amount currently covered by this Rider and discount the resultant total for the remaining life of the existing contract, or

b) terminate the existing agreement for the currently qualified load and initiate a new service rider for the subsequent qualified expansion of an existing location.

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REAL-TIME PRICE (RTP) PROGRAM

PURPOSE

Real-time pricing (RTP) offers customers electricity at marginal-cost based prices. This offers customers the ability to more accurately respond to the true costs of providing power. Customers benefit from the opportunity to consume more power during relatively frequent low-cost hours, while reducing usage during the relatively few high-cost hours.

Hourly prices under the RTP program will be provided on a day-ahead basis to customers. Prices for weekends and holidays will be provided on the preceding business day. Prices become binding at 4:00 p.m. of the preceding day. Power under the RTP program is firm.

AVAILABILITY

This service is available to all customers who agree to abide by the terms and conditions of the service agreement.

This program is not available for resale, standby, back-up, or supplemental service.

CHARACTER OF SERVICE

Single-phase, 60 Hertz, nominally 120/240 volts firm electric service, provided from the Company's secondary distribution system. Three-phase secondary service shall be available where three-phase facilities are available without additional construction or may be made available at additional charge at voltages not exceeding 480 volts. Three-phase primary distribution service shall be available where primary distribution facilities are available without additional construction.

MONTHLY RATE

RTP Bill = Base Bill + Incremental Delivery Charge + RTP Service Charge + Reactive Demand Adjustment.

The components of the RTP Bill are defined below.

Base Bill = Standard Tariff Bill + β*(Standard Tariff Bill - Σ_h (P_h^{RTP} * CBL_h))

Standard Tariff Bill is the customer baseline load (CBL, defined below) for the billing month, billed under the current prices of the customer's standard tariff, (the tariff under which the customer was billed prior to joining the RTP program). The Standard Tariff Bill excludes the Reactive Demand Adjustment.

β is an adjustment to the Standard Tariff Bill. The Company will offer Basic RTP Service with β equal to zero and may offer Premium RTP Service with β equal to 0.05

Incremental Energy Charge = $\Sigma_h P_h^{RTP} * (\text{Actual Load}_h - CBL_h)$

Σ_h indicates a summation across all hours in the billing month.

Actual Load_h is the customer's actual energy use in the hour (kWh).

CBL_h is the baseline hourly energy use. (See below.)

P_h^{RTP} , the real-time price, is calculated as:

$$P_h^{RTP} = \alpha * MC_h + (1 - \alpha) * P_h^{STD}$$

MC_h is the day-ahead forecast of hourly short-run marginal cost of providing energy to Kansas retail customers, including provisions for line losses. Marginal costs include the marginal cost of real power and operating reserves and a proxy for the marginal cost of transmission. (See below for a description of this proxy.)

P_h^{STD} is the hourly effective delivery charge of the customer's Standard Tariff Bill, calculated from the applicable standard (non-RTP) price schedule. It is the change in the Standard Tariff Bill due to a change in usage and includes both delivery and demand charges.

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MONTHLY RATE (continued)

α is the weight of marginal cost in defining retail price, with value of 0.8 for regular RTP service and 0.95 for RTP Premium service.

RTP Service Charge = $223.60 per month for customers whose customer baseline load (CBL) peak demand exceeds five hundred (500) kW for three (3) consecutive months.
$251.55 per month for all other customers.

Reactive Demand Adjustment is the adjustment found in the tariff that served the RTP customer prior to joining RTP. The price of the reactive demand is the current price under that tariff.

CUSTOMER BASELINE LOAD

The customer baseline load (CBL) represents the electricity consumption pattern typical of the RTP customer's operations were they to remain on the standard tariff. The CBL is specific to each individual customer and includes hourly load plus billing aggregates such as peak demand necessary to calculate the base bill under the customer's standard tariff. The CBL is determined in advance of the customer's taking RTP service and is part of the customer's service agreement.

The CBL will be based, whenever possible, on existing load information. The Company reserves the right to adjust the CBL to allow for special circumstances. The CBL is used to ensure revenue neutrality on a customer-specific basis, and must be mutually agreed upon by both the customer and the Company before service commences. The CBL will be in force for the duration of the customer's RTP service agreement.

TRANSMISSION AND DISTRIBUTION

Transmission and distribution charges are currently bundled into Standard Tariff Bill charges.

If the Company is required to either increase the capacity or accelerate its plans for increasing capacity of the transmission or distribution facilities or other equipment necessary to accommodate a customer's increased load, then an additional facilities charge will be assessed.

POWER FACTOR ADJUSTMENT

The Power Factor Adjustment will be billed, where applicable, in accordance with the customer's otherwise applicable, non-RTP, standard tariff. The customer's Standard Tariff Bill does not include any reactive demand charges.

PRICE DISPATCH AND CONFIRMATION

The Company will transmit prices for each day by 4:00 p.m. of the preceding business day. The Company not responsible for failure of customer to receive and act upon the Price Quote. It is customer's responsibility to inform the Company by 5:00 p.m. of failure to receive the Price Quote. The actions taken by customer based on the Price Quote are customer's responsibility.

INTERRUPTIBLE CUSTOMERS

Interruptible customers can participate in RTP service using one (1) of three (3) options:

Option 1: Conversion to Firm Power Status: The customer can terminate their interruptible contract, revert to the applicable standard tariff and join RTP.

Option 2: Retain Interruptible Contract but Add a Buy-through Option: The customer retains their interruptible contract and obtains the privilege of "buying through" their non-interruptible power level at times of interruption at the posted real-time price. The value of the interruptible discount will be reduced by fifty percent (50%). At times of interruptions, the CBL of such a customer will be set to the lesser of the existing CBL value and the customer's non-interruptible power level. The customer will be able to exceed their non-interruptible power level during interruption periods without penalty by purchasing incremental load at the real-time price and will be reimbursed at the same real-time price for reductions below the CBL.

Option 3: Retain Interruptible Contract: The Interruption provisions of the rider will continue to apply as stated in the rider. The marginal cost of real power and operating reserves will not be applied to the interruptible portion of the customer's Baseline Load. At times of interruptions, the CBL of such a customer will be set to the lesser of the existing CBL value and the customer's non-interruptible power level.

PRICE QUOTES FOR FIXED QUANTITIES

To further manage risks, customers will have the option to contract with the Company for short-term power transactions at a price for pre-specified departures from the customer's previously established CBL. The duration of such contracts is not to exceed six (6) months or be shorter than one (1) week. The Company and customer will mutually agree on the pricing structure and quantities to be used for the Price Quote, including but not limited to, hourly prices, prices by time period or seasons, price caps and floors, collars, etc.

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/S/ Susan K. Duffy

PRICE QUOTES FOR FIXED QUANTITIES (continued)

Customer may contract through the Company representative for quotes for fixed power levels at pre-specified fixed quantities. The Company will solicit bids for power from neighboring suppliers that meet customer's schedule, quantities, and pricing structure. Upon agreement by customer a transaction fee of $150 per contract will be applied to recover costs to initiate, administer, and bill for hedging services.

All power is delivered and titled to the Company and may be directed to meet system emergencies should such a need arise. Reasonable advance notice will be made to Customer and a corresponding credit will be applied to Customer's bill in the event of such occurrences.

BILL AGGREGATION SERVICE

Customers will have the choice to aggregate the bills of multiple accounts under the RTP Program for the purposes of the application of the Incremental Energy Charge. Eligible customers will be limited to customers who become active participants in the RTP program who are legally or financially related to one another. The calculation of the aggregated Base Bill will be based on the application of the CBL on a non-aggregated basis for each individual account.

DURATION OF SERVICE AGREEMENT

Each service agreement will be served under RTP for a minimum of one (1) year.

SERVICE AGREEMENT TERMINATION

Written notice of sixty (60) days in advance must be provided by the customer for termination of the service agreement. Once terminated, readmission will not be allowed for a period of one (1) year. The CBL may be reassessed prior to readmission.

RULES AND REGULATIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

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VOLUNTARY LOAD REDUCTION RIDER

AVAILABILITY

This Rider is available to any nonresidential Customer, except those on the Real Time Price Program, that has a peak demand in the past twelve (12) months exceeding five hundred (500) kW and that has a contract with the Company for service under this Rider. Availability is further subject to the economic and technical feasibility of required metering equipment. The decision to execute a contract with any Customer under this Rider is subject to the sole discretion of the Company. The decision to reduce load upon request of the Company is subject to the sole discretion of each eligible Customer.

CONDITIONS

1. Term of Contract: Contracts under this Rider shall extend from the date the contract is signed until the immediate following September 30 after the date the Customer signs the contract. Execution of a contract between the Company and the Customer does not bind the Customer to reduce load in response to any specific Load Reduction request of the Company. However, a Customer's affirmative written response to Load Reduction requests, as described in the Notification Procedure section, determines the Load Reduction periods in which the Company will apply the billing provisions of this Rider for each Customer.

2. Notification Procedure: At its sole discretion, the Company may request that Customers having Voluntary Load Reduction contracts participate in Load Reduction during any period between May 1 and September 30, inclusive. Since the Company may not need maximum participation in every instance, not all Customers with contracts under this Rider must be notified of any specific Load Reduction request. At the time of requesting a period of Load Reduction, the Company also will notify Customers of the credit value per kWh of Load Reduction. After each request, a Customer desiring to participate in the requested Load Reduction must inform the Company in writing (including either fax or electronic mail) of the Customer's willingness to participate in the Load Reduction. Eligibility for a billing credit under this Rider shall be based upon the Company receiving such written notice within two (2) hours of the time of the Company's request.

3. Previous Daily Peaks: The kW loads (on an average, fixed hourly basis) that the Customer used on the Company's system on the most recent non-holiday weekday on which no Voluntary Load Reduction was requested. Holidays are Memorial Day, Independence Day, and Labor Day, or any day celebrated as such.

VOLUNTARY LOAD REDUCTION RIDER

4. Credit Amount: The amount of kWh eligible for Load Reduction credit shall be calculated as ninety percent (90%) of the Previous Daily Peaks corresponding to the hours of the requested Load Reduction, minus the Customer's actual load in each respective hour, and sum across all hours. If these net kWh values, when multiplied by the credit per kWh, result in a negative total credit value for the billing month, no credit shall be applied to the bill. Credits for performance under this Rider shall appear as a part of the Customer's regular monthly billing and shall be applied before any applicable taxes. All other billing, operational, and related provisions of other applicable rate schedules shall remain in effect. Application of a credit for Voluntary Load Reduction shall be independent of the tariff pricing otherwise applicable.

5. Company Equipment: The Customer shall allow the Company to install and maintain the appropriate metering equipment necessary to ensure compliance under the Rider. Such equipment shall be owned and installed by the Company at no cost to the Customer. The Company may provide Customer with access to software for real-time meter information for $75.00 per month. The Customer will provide a personal computer, telephone line, modem, and other items or personnel necessary to make use of the software.

VOLUNTARY LOAD REDUCTION RIDER

FORM OF CONTRACT

This Agreement, made this __________ day of ________________________, _________, by and between Aquila Inc. d/b/a Aquila Networks - WPK, hereinafter referred to as the "Company", and

____
Customer name

______________________________ ______________
Customer Account #

____
Address

Customer Contact	Electronic Mail	Telephone	Fax Telephone
Customer Contact (Alternate)	Electronic Mail	Telephone	Fax Telephone

Hereinafter referred to as the "Customer".

WITNESSETH:

Whereas, the Company has on file with the Corporation Commission of the State of Kansas (Commission) a certain Voluntary Load Reduction Rider Schedule VLR (Rider), and;

Whereas, the Company has determined that the Customer meets the Availability provisions of the Rider, and;

Whereas, the Customer wishes to take electric service from the Company, and the Company agrees to furnish electric service to the Customer under this Rider and pursuant to all other applicable tariffs of the Company, and;

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VOLUNTARY LOAD REDUCTION RIDER

The Company and Customer agree as follows:

1. Electric Service to the Customer's Facilities shall be pursuant to the Voluntary Load Reduction Rider, all other applicable tariffs, and the Company's General Rules and Regulations Applying to Electric Service, as may be in effect from time to time and filed with the Commission.

2. Contracts under this Rider shall extend from the date the contract is signed until the immediate following September 30 after the date the Customer signs the contract. Customer acknowledges that any equipment required, except metering equipment necessary to ensure compliance under the Rider, shall be the obligation of the Customer.

3. Participation in Load Reduction in response to any specific request is voluntary for the Customer. After each individual Load Reduction request directed specifically to the Customer, the Company must be notified in writing (including, but not limited to, fax or electronic mail), within two (2) hours of the time of the Company's request, if the Customer desires to participate in that requested Load Reduction. Eligibility for a billing credit under this Rider shall be based upon the Company receiving such written notice on a timely basis.

4. Customer further acknowledges that this Agreement is not assignable voluntarily by the Customer, but shall nevertheless inure to the benefit of and be binding upon the Customer's successors by operation of law.

5. This Agreement shall be governed in all respects by the laws of the State of Kansas (regardless of conflict of laws provisions), and by the orders, rules and regulations of the Commission, as they may exist from time to time. Nothing contained herein shall be construed as divesting, or attempting to divest, the Commission of any rights, jurisdiction, power or authority vested in it by law.

In witness whereof, the parties have signed this Agreement as of the date first written above.

Aquila Inc. d/b/a Aquila Networks - WPK

____
Customer

By ______________________________ By ______________________________

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By W. Scott Keith (Signature) Director, Regulatory (Title)	

PRIVATE AREA/STREET LIGHTING

AVAILABILITY

To any customer with existing or new pole(s) for lighting of outdoor areas on a dusk to dawn, photo-controlled, unmetered basis from the Company existing distribution system.

NET MONTHLY RATE

For supply of controlled electricity, installation and maintenance of a light fixture(s), pole and lamp renewal as required.

See Unmetered Facilities Table.

Plus

(1) Customer will be responsible for any underground circuits or special wiring not included in the Unmetered Facilities Table.

ENERGY COST ADJUSTMENT

The energy used (kWh used by each fixture) is subject to the Energy Cost Adjustment Clause.

SPECIAL TERMS AND CONDITIONS

A. The following terms and conditions are intended to apply generally and in the absence of any Kansas Corporation Commission approved contractual agreement between the customer and the Company.

1. Standard fixtures available for installation hereunder shall be determined by the Company on the basis of their quality, capital costs, maintenance costs, availability, customer acceptance and other factors. Fixtures furnished in providing this service will be assigned by reference to manufacturer's symbols in the customer's contract for leased lighting.

2. Lamps shall be controlled by a photoelectric controller providing dusk to dawn service.

3. Maintenance of the Company-owned lamp equipment and lamp renewals are performed during normal working hours within a reasonable period following notification by the customer of the need for such service. Glassware is cleaned only at the time of such maintenance. Permission is given Company to enter the customer's premises at all reasonable times for the purpose of inspecting and maintaining its equipment.

4. The customer is responsible for all damages to, or loss of, the Company's property located on his property unless occasioned by Company negligence or by any cause beyond control of the customer.

5. It shall be the customer's responsibility to notify the Company when the lighting system is not working on the customer's premises.

6. The customer will be assessed a special fee if he/she should request an existing fixture be replaced with a high-pressure sodium fixture of equivalent lumen output. This fee is to cover the unamortized cost of the existing fixture, and will be determined at the time of request.

7. The customer will provide the Company, free of charge, the necessary permits, rights of way and excavations or paving cuts necessary for installation and operation of area lighting units.

8. The Company will own, maintain and operate all controlled area lighting equipment and service facilities. Line extensions to serve the area light(s) must be made in accordance with the Company's line extension policy currently on file with the Kansas Corporation Commission.

9. The Company will attempt, circumstances permitting, to service and maintain the equipment within a reasonable length of time from the time the Company is notified of a maintenance requirement. The Company assumes no responsibility for patrolling such equipment to determine when maintenance is needed. However, it is the customer's responsibility to detect and report failures and malfunctions to the Company and, when such failures are due to vandalism, mischief or a violation of traffic laws or other ordinances, to assist the Company in identifying the responsible party.

10. The standard material calculated in the rate for steel street lighting is a thirty (30) foot direct buried pole. The Company will offer larger size poles with or without a breakaway base at the additional cost to be paid by the customer.

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By W. Scott Keith (Signature) Director, Regulatory (Title)	/S/ Susan K. Duffy

B. Special Systems: The Company will provide underground wiring, ornamental poles and other special systems as costs are applicable. The Company reserves the right to approve or disapprove any special system so requested.

C. Relocation of Fixtures: The Company will relocate a Company-owned street lighting pole or standard at the customer's expense if located on private R.W., if on Public R.W., the law of the State of Kansas will govern.

D. Upgrade of Existing Fixtures: The Company shall, upon the request of the customer, upgrade existing street lighting units to provide higher levels of illumination under the following conditions:

1. The existing units must have been in place five (5) or more years.

2. The Company shall replace at the specified option under the rate table for existing Company-owned luminaries and brackets with similar equipment providing higher lumen ratings. The appropriate rates for the fixtures with higher illumination will apply.

E. Disconnection: When a customer requests that a street lighting unit be disconnected before five (5) years have elapsed since the date of installation, the Company may require the customer to reimburse the Company for the life of the value of the street lighting facilities removed plus the cost of removal less the salvage value thereof.

SPECIAL PROVISIONS

A. Residential Subdivision Street Lighting

The Company will furnish, erect, operate and maintain all necessary equipment in accordance with its standard specifications. It is the responsibility of Home Builder's Association or unincorporated communities to pay monthly charges as per terms and conditions of the contract.

In the event when Home Builder's Association, unincorporated communities or any other residential associations or governing group dissolve, the customers related to those lighting areas shall equally share the monthly charges as established as per terms and conditions of the contract.

B. Cities, Municipalities and Governmental Agencies

This Part B does not apply to individual homeowners, Home Builder's Associations or any unincorporated agencies.

If due to any reasons cities, municipalities and governmental agencies decide to install Private Area/Street Lighting to meet their specifications and necessities, a special contract with the new rate will be issued by the Company as dictated by franchise or special agreements. This shall at least cover the cost necessary to provide energy and maintenance of the Private Area/Street Lighting.

TERMINATING NOTICE

All service under this rate shall require a written notice ninety (90) or more days prior to termination by either party. If service is terminated, per customer request, before the two (2) year contract period elapses, the customer must pay the prorated balance of the contract amount. All or part of the payment requirement may be waived by the Company if a successor, in effect, assumes payment responsibility for the predecessor's remaining contractual obligation by continuing Private Area/Street Lighting under Private Area/Street Lighting schedule PAL-SL-I.

GENERAL

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission and to the terms and conditions and applicable standard contract riders included in this electric rate schedule.

DELAYED PAYMENT

As per Schedule DPC.

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MONTHLY RATE – UNMETERED FACILITIES TABLE

			INVESTMENT OPTIONS				
			A	**B***	**C***	**D***	**E**
		Monthly	Cust-0%	Cust-25%	Cust-50%	Cust-75%	Cust-100%
Style/Lamp	Lumens	kWh	WPE-100%	WPE-75%	WPE-50%	WPE-25%	WPE-0%
PRIVATE AREA LIGHT							
On Existing Pole							
100W P.A.L.	7,920	40	$6.42	$5.14	$3.87	$2.65	$1.43
150W P.A.L.	13,500	60	$10.35	$8.17	$6.01	$3.95	$1.88
200W P.A.L.	22,000	80	$11.14	$8.82	$6.53	$4.32	$2.12
On New Pole (Wood)							
100W P.A.L.	7,920	40	$11.78	$9.22	$6.66	$4.23	$1.78
150W P.A.L.	13,500	60	$12.47	$9.79	$7.12	$4.57	$2.01
200W P.A.L.	22,000	80	$12.75	$10.05	$7.36	$4.79	$2.22
FLOOD LIGHTS							
On Existing Pole							
150W Flood	13,500	60	$12.71	$9.98	$7.26	$4.64	$2.03
400W Flood	45,000	160	$21.29	$16.75	$12.21	$7.88	$3.56
1000W Flood M.H.	110,000	402	$24.63	-	-	-	$7.41
On New Pole (Wood)							
150W Flood	13,500	60	$14.66	$11.45	$8.26	$5.22	$2.17
400W Flood	45,000	160	$23.22	$18.21	$13.23	$8.45	$3.69
1000W Flood M.H.	110,000	402	$39.32	-	-	-	$6.56
STREET LIGHT							
On Existing Pole							
100W P.A.L. Fixture	7,920	40	$7.30	$5.80	$4.33	$2.91	$1.50
150W P.A.L. Fixture	13,500	60	$8.09	$6.46	$4.84	$3.29	$1.72
200W P.A.L. Fixture	22,000	80	$9.70	$7.74	$5.77	$3.90	$2.02
On New Pole (Wood)							
100W P.A.L. Fixture	7,920	40	$11.78	$9.21	$6.66	$4.23	$1.78
150W P.A.L. Fixture	13,500	60	$12.47	$9.79	$7.11	$4.57	$2.01
200W P.A.L. Fixture	22,000	80	$12.75	$10.05	$7.36	$4.79	$2.22
STREET LIGHT							
On Existing Pole							
100W Cobra Head	7,920	40	$7.30	$5.80	$4.33	$2.91	$1.50
150W Cobra Head	13,500	60	$8.09	$6.46	$4.84	$3.29	$1.72
200W Cobra Head	22,000	80	$9.70	$7.74	$5.77	$3.90	$2.02
250W Cobra Head	27,000	100	$10.15	$8.13	$6.10	$4.18	$2.25
400W Cobra Head	45,000	160	$10.82	$8.78	$6.74	$4.81	$2.86
On New Pole (Wood)							
100W Cobra Head	7,920	40	$14.05	$10.95	$7.85	$4.90	$1.93
150W Cobra Head	13,500	60	$14.43	$11.29	$8.14	$5.14	$2.16
200W Cobra Head	22,000	80	$14.41	$11.33	$8.24	$5.29	$2.34
250W Cobra Head	27,000	100	$15.57	$12.34	$9.10	$6.00	$2.92
400W Cobra Head	45,000	160	$16.24	$12.98	$9.73	$6.62	$3.52
On New Pole (Steel)							
100W Cobra Head	7,920	40	$22.83	$17.62	$12.43	$7.47	$2.53
150W Cobra Head	13,500	60	$23.20	$17.96	$12.72	$7.73	$2.73
200W Cobra Head	22,000	80	$23.83	$18.55	$13.18	$8.07	$2.96
250W Cobra Head	27,000	100	$26.15	$20.29	$14.46	$8.89	$3.31
400W Cobra Head	45,000	160	$26.79	$20.93	$15.08	$9.50	$3.91

*** Investment Options B, C, and D are not available to new customers after 07/01/2001.**

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SECURITY (DECORATIVE) LIGHTING SERVICE

AVAILABILITY

Available to individuals, municipalities or other governmental subdivisions, school districts, unincorporated communities and for lighting county streets, major highways and public grounds at secondary voltages.

Available for area lighting using street light equipment installed in accordance with the Company street lighting standards, at the voltage and current of Company's established distribution system for such service, for use in lighting private areas and grounds, for protective, safety and decorative purposes.

NET MONTHLY BILL

For supply of controlled electricity, installation and maintenance of a light fixture, pole and lamp renewal as required.

See Unmetered Facilities Table.

(1) Customer will be responsible for any underground circuits or special wiring not included in the Unmetered Facilities Table.

ENERGY COST ADJUSTMENT

The energy used (kWh used by each fixture) is subject to the Energy Cost Adjustment Clause.

SPECIAL TERMS AND CONDITIONS

A. The following provisions are intended to apply generally and in the absence of any Kansas Corporation Commission approved contractual agreement between the customer and the Company.

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1. Standard fixtures available for installation hereunder shall be determined by the Company on the basis of their quality, capital costs, maintenance costs, availability, customer acceptance and other factors. Fixtures furnished in providing this service will be assigned by reference to manufacturer's symbols in the customer's contract for leased lighting.

2. Lamps shall be controlled by a photo-electric controller providing dusk to dawn service.

3. Maintenance of Company-owned lamp equipment and lamp renewals are performed during normal working hours within a reasonable period following notification by the customer of the need for such service. Glassware is cleaned only at the time of such maintenance. Permission is given the Company to enter the customer's premises at all reasonable times for the purpose of inspecting and maintaining its equipment.

4. Trenching of soft soil which extends beyond one hundred seventy-five (175) feet is subject to extra costs. Trenching cost of hard soil will be determined on an individual basis.

5. The customer is responsible for all damages to, or loss of, the Company property located on his property unless occasioned by Company negligence or by any cause beyond control of the customer.

6. It shall be the customer's responsibility to notify the Company when the lighting system is not working on the customer's premises.

7. The customer will provide the Company, free of charge, the necessary permits, rights of way and excavations or paving cuts necessary for installation and operation of area lighting units.

8. The Company will own, maintain and operate all controlled area lighting equipment and service facilities. Line extensions to serve the area light(s) must be made in accordance with Company's line extension policy currently on file with the Kansas Corporation Commission.

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9. The Company will attempt, circumstances permitting, to service and maintain the equipment within a reasonable length of time from the time the Company is notified of a maintenance requirement. The Company assumes no responsibility for patrolling such equipment to determine when maintenance is needed. However, it is the customer's responsibility to detect and report failures and malfunctions to the Company and, when such failures are due to vandalism, mischief or a violation of traffic laws or other ordinances, to assist the Company in identifying the responsible party.

B. Special Systems: The Company will provide underground wiring, ornamental poles and other special systems as costs are applicable. The Company reserves the right to approve or disapprove any special system so requested.

C. Relocation of Fixtures: The Company will relocate a Company-owned street lighting pole or standard at the customer's expense if located on private R.W., if on Public R.W., the law of the State of Kansas will govern.

D. Upgrade of Existing Fixtures: The Company shall, upon the request of the customer, upgrade existing street lighting units to provide higher levels of illumination under the following conditions:

1. The existing units must have been in place five (5) or more years.

2. The Company shall replace at the specified option under the rate table for existing Company-owned luminaries and brackets with similar equipment providing higher lumen ratings. The appropriate rates for the fixtures with higher illumination will apply.

E. Disconnection: When a customer requests that a street lighting unit be disconnected before five (5) years have elapsed since the date of installation, the Company may require the customer to reimburse for the life of the value of the street lighting facilities removed plus the cost of removal less the salvage value thereof.

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/S/ Susan K. Duffy

SPECIAL PROVISIONS

A. Residential Subdivision Street Lighting

The Company will furnish, erect, operate and maintain all necessary equipment in accordance with its standard specifications. It is the responsibility of Home Builder's Association or unincorporated communities to pay monthly charges as per terms and conditions of the contract.

In the event when Home Builder's Association, unincorporated communities or any other residential associations or governing group dissolve, the customers related to those lighting areas shall equally share the monthly charges as established as per terms and conditions of the contract.

B. Cities, Municipalities and Governmental Agencies

This Part B does not apply to individual home owners, Home Builder's Associations or any unincorporated agencies.

If due to any reasons cities, municipalities and governmental agencies decide to install Security (Decorative) Lighting Service to meet their specifications and necessities, a special contract with the new rate will be issued by the Company as dictated by franchise or special agreements. This shall at least cover the cost necessary to provide energy and maintenance of the Security (Decorative) Lighting Service.

TERMINATING NOTICE

All service under this rate shall require a written notice ninety (90) or more days prior to termination by either party. If service is terminated, per customer request, before the two (2) year contract period elapses, the customer must pay the prorated balance of the contract amount. All or part of the payment requirement may be waived by the Company if a successor, in effect, assumes payment responsibility for the predecessor's remaining contractual obligation by continuing Security (Decorative) Lighting under Security (Decorative) Lighting Service schedule DOL-I.

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/S/ Susan K. Duffy

GENERAL

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission and to the terms and conditions and applicable standard contract riders included in this electric rate schedule.

DELAYED PAYMENT

As per Schedule DPC.

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/S/ Susan K. Duffy

AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: 04-DOL-I

Replacing Schedule 01-DOL-I Sheet 6
Which was filed December 17, 2001

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding shall modify the tariff as shown hereon.

MONTHLY RATE – UNMETERED FACILITIES TABLE

			INVESTMENT OPTIONS				
			A	B*	C*	D*	E
Style/Lamp	Lumens	Monthly kWh	Cust-0% WPE-100%	Cust-25% WPE-75%	Cust-50% WPE-50%	Cust-75% WPE-25%	Cust-100% WPE-0%
ACORN							
35W HPS	2,025	14	$17.81	$13.78	$9.78	$5.94	$2.10
100W HPS	7,920	40	$25.23	$19.51	$13.80	$8.34	$2.90
250W HPS	27,000	100	$27.25	$21.20	$15.15	$9.39	$3.62
SINGLE GLOBE							
35W HPS	2,205	14	$13.63	$10.61	$7.59	$4.71	$1.82
70W HPS	5,670	28	$22.24	$17.21	$12.16	$7.37	$2.56
100W HPS	7,920	40	$22.58	$17.50	$12.41	$7.56	$2.72
150W HPS	13,500	60	$22.97	$17.85	$12.72	$7.83	$2.94
MULT GLOBE							
70W HPS (5)	28,350	140	$56.12	$43.48	$30.82	$18.76	$6.69
100W HPS (5)	39,600	200	$57.76	$44.87	$31.99	$19.70	$7.41
150W HPS (5)	67,500	300	$59.79	$46.68	$33.55	$21.04	$8.53
LANTERN							
35W HPS	2,025	14	$16.01	$12.41	$8.83	$5.41	$1.99
100W HPS	7,920	40	$27.38	$21.15	$14.91	$8.98	$3.03
250W HPS	27,000	100	$29.17	$22.66	$16.16	$9.96	$3.75
SHOEBOX							
100W HPS	7,920	40	$32.27	$24.88	$17.47	$10.42	$3.35
250W HPS	27,000	100	$33.93	$26.28	$18.64	$11.36	$4.07
400W HPS	45,000	160	$35.18	$27.45	$19.70	$12.32	$4.93
800W HPS	90,000	320	$44.69	$35.16	$25.64	$16.56	$7.47

* **Investment Options B, C, and D are not available to new customers after 07/01/2001.**

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Signature Title

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/S/ Susan K. Duffy

CONTROLLED PRIVATE AREA LIGHTING
(FROZEN)

AVAILABILITY

To any customer for lighting of outdoor areas on a dusk to dawn, photo-controlled, unmetered basis from Company's existing distribution system.

No additional lamps will be installed under this schedule after the effective date of September 26, 1994.

NET MONTHLY BILL

For supply of controlled electricity, installation and maintenance of mercury vapor light fixture with a four (4) foot bracket on an existing wood distribution pole and for lamp renewal as required for:

Nominal Watt Rating		Monthly kWh			
Mercury Vapor	High Pressure Sodium	Mercury Vapor	High Pressure Sodium	Monthly Rate/Unit	Annual Rate/Unit
175	100	63	40	$ 6.42	$ 77.04
400	200	151	80	$11.14	$133.68
400 (Flood)	150	151	60	$12.71	$152.52
1000 (Flood)	400	355	160	$21.29	$255.48

Plus

1) For each additional standard distribution pole, not longer than thirty-five (35) feet, required for such area lighting supply is $1.42 per month.

2) For each one hundred (100) feet of overhead secondary circuit required is $ .53 per month.

3) Steel standards with maximum mounting height of thirty (30) feet and of the same type as used in street lighting will be furnished upon request provided the customer will be responsible for the placement of the concrete base and anchor bolts at the time of the installation and also for their removal upon termination of the leased lighting agreement. Monthly rental charge for each standard is $6.73.

4) Customer will be responsible for any underground circuits or special wiring.

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ENERGY COST ADJUSTMENT

The energy used (kWh used by each fixture) is subject to the Energy Cost Adjustment Clause.

SPECIAL PROVISIONS

Contracts hereunder are subject to the following special provisions:

1. Standard fixtures available for installation hereunder shall be determined by the Company on the basis of their quality, capital costs, maintenance costs, availability, customer acceptance and such factors. Fixtures furnished in providing this service will be assigned by reference to manufacturer's symbols in the customer's contract for leased lighting.

2. Lamps shall be controlled by a photo-electric controller providing dusk to dawn service.

3. Maintenance of Company-owned lamp equipment and lamp renewals are performed during normal working hours within a reasonable period following notification by the customer of the need for such service, glassware is cleaned only at the time of such maintenance. Permission is given the Company to enter the customer's premises at all reasonable times for the purpose of inspecting and maintaining its equipment.

4. The customer is responsible for all damages to, or loss of, Company property located on his property unless occasioned by Company negligence or by any cause beyond control of the customer.

5. The customer will be assessed a special fee if he/she should request an existing fixture be replaced with a high pressure sodium fixture of equivalent lumen output. This fee is to cover the unamortized cost of the existing fixture, and will be determined at the time of request.

TERM OF CONTRACT

An initial term of three (3) years and for repeating period of one (1) year thereafter until terminated by ninety (90) or more days prior written notice given by either part to the other.

GENERAL

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission and to the terms and conditions and applicable standard contract riders included in this electric rate schedule.

DELAYED PAYMENT

As per Schedule DPC.

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STREET LIGHTING SERVICE
DUSK TO DAWN
(FROZEN)

AVAILABILITY

This schedule is available for street lighting purposes in the residential areas in any community served by the Company.

No additional incandescent lamps will be installed under this rate after the effective date of January 3, 1980.

TYPE OF SERVICE

Open type radial or asymmetric reflectors for incandescent lamps, open suburban type luminaire for mercury vapor lamps on wood poles burning from dusk to dawn; Company to own, maintain and operate the entire street lighting system.

RATE

Incandescent	kWh	Rate	Rate per lamp per year
1000 lumen lamps	34	$2.66	$31.92
Mercury Vapor			
7000 lumen lamps (clear)	63	$6.88	$82.56

(a) Enclosed luminaries will be installed on wood poles by the Company on incandescent lamps of 2500 lumen and above upon request from the city at the location designated by the city at the above rates plus $4.92 per fixture per year. The Company shall not be bound to change more than 10% of the existing open-type fixtures as they existed on October 1, 1970, in any one (1) year.

(b) Where steel standards are requested the above rates will be increased $34.09 per year.

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(c) Underground conductors for the street-lighting system shall be used only where required by the City and at an added charge of $34.08 per standard per year.

(d) The Company shall not be required to extend the present street lighting system of any community over three hundred (300) feet for any one (1) light.

ENERGY COST ADJUSTMENT

The energy used (kWh by each fixture) is subject to the Energy Cost Adjustment Clause.

TERMS OF PAYMENT

As per Schedule DPC.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

VAPOR STREET LIGHTING SYSTEM
ORNAMENTAL SYSTEM
(FROZEN)

AVAILABILITY

This schedule is available to cities contracting for the operation of an ornamental street-lighting system, which system shall be owned, operated and maintained by the Company.

No additional lamps will be installed under this schedule after the effective date of September 26, 1994.

NET MONTHLY BILL

For supply of controlled electricity, installation and maintenance of mercury vapor light fixture with a four (4) foot bracket on an existing wood distribution pole and for lamp renewal as required for:

Nominal Watt Rating		Monthly kWh			
Mercury Vapor	High Pressure Sodium	Mercury Vapor	High Pressure Sodium	Monthly Rate/Unit	Annual Rate/Unit
175	100	63	40	$7.30	$ 87.60
250	150	95	60	$8.09	$ 97.08
400	200	151	80	$9.70	$116.40

Lamps will normally be controlled by a photo-cell operating lamp from dusk to dawn (approximately 4,000 hours per year). The above rates are to be billed in twelve (12) equal monthly installments based upon lamp size indicated. Lamps shall be enclosed in fixtures designated by the Company and supported upon wood poles with up to six (6) foot mast arms. Mounting heights will be at levels recommended by unit manufacturer for proper light distribution.

ENERGY COST ADJUSTMENT

The energy used (kWh used by each fixture) is subject to the Energy Cost Adjustment Clause.

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SPECIAL TERMS AND CONDITIONS

(a) Service under this schedule is for lighting trafficways where the distance between units does not exceed one hundred seventy-five (175) feet and residential areas where spacing does not exceed three hundred (300) feet.

(b) Where lighting fixtures are to be mounted on ornamental metal poles, the annual charge shall be increased:

$18.96 per standard for mounting under 20 feet.
$28.56 per standard for mounting height over 20 feet but under 30 feet.
$36.24 per standard for mounting height over 30 feet.

(c) Where lighting fixture are to be mounted on standard mast arms over six (6) foot in length, the annual charge shall be increased $11.64 per light fixture.

(d) Where lighting standards are located in lighted areas that regulation requires break away bases, the annual charge shall be increased $20.04.

(e) Underground conductor for street lighting system shall be used only where required by the governing body and at the following schedule of added annual charges:

1. Extensions up to one hundred seventy-five (175) feet where no concrete or hard surface road material has to be cut to accommodate the underground circuit $34.08 per lighting standard.

2. Extensions up to one hundred seventy-five (175) feet where concrete or hard surface material has to be cut and replaced to accommodate the underground circuit $66.24 per lighting standard.

(f) Existing bridge or viaduct lighting which is in or contiguous to the district to be lighted under contract shall be served at the same annual rate except where the standard and luminaire are not furnished by the Company, the annual charge shall be reduced $23.88 per standard. The Company will not maintain that portion of the system owned by the customer but will renew bulbs or glassware when burned out or broken.

(g) Where two (2) luminaires are supported from the same standard, the charge above stated shall be reduced $3.01 for each lamp on such standard.

(h) The City may extend a system under contract to take in additional trafficways so long as such extensions are contiguous to existing installations and provided that such extensions meet the requirements under paragraph (a).

(i) The City will be assessed a special fee should they request an existing fixture be replaced with a high pressure sodium fixture of equivalent lumen output. This fee is to cover the unamortized cost of the existing fixture and will be determined at the time of request.

MINIMUM MONTHLY CHARGE

The minimum number and size of street lights shall not be less than specified in the agreement for street lighting service.

GENERAL

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

DELAYED PAYMENT

As per Schedule DPC.

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SUB-TRANSMISSION & TRANSMISSION LEVEL SERVICE

AVAILABLE

Entire Service Area.

APPLICABLE

For all electric service of a single character supplied at one (1) point of delivery at a voltage of 34.5 kilovolts or above, and who have the necessary interval metering installed. At a minimum customers requesting service under the sub-transmission level service shall have an average summer demand of at least five hundred (500) kW and an average summer demand of one thousand (1,000) kW for transmission level customers. This schedule is not applicable to temporary, breakdown, standby, supplementary, resale or shared service.

CHARACTER OF SERVICE

Alternating current, approximately 60 cycles; at any one standard voltage required by Customer as described in Company's Standards for Electric Service.

NET MONTHLY BILL FOR SERVICE AT 34.5 kV VOLTAGE

Customer Charge $111.80 per meter per month

	Winter Bills November 1 to June 30 inclusive	Summer Bills July 1 to October 31 inclusive
Demand Charge		
On-Peak Supply Charge	$5.31 per on-peak supply kW	$6.43 per on-peak supply kW
Off-Peak Supply Charge	$2.24 per kW for all kW in excess of on-peak supply kW	$2.24 per kW for all kW in excess of on-peak supply kW
Network Charge	$3.91 per network kW	$3.91 per network kW
Delivery Charge		
All On-Peak kWh per month	$0.01467 per kWh	$0.01467 per kWh
All Off-Peak kWh per month	$0.00615 per kWh	$0.00615 per kWh

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

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AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: 04-STR

Replacing Schedule 01-STR Sheet 2
Which was filed February 4, 2002

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding shall modify the tariff as shown hereon.

NET MONTHLY BILL FOR SERVICE AT 115 kV VOLTAGE

Customer Charge — $111.80 per meter per month

	Winter Bills November 1 to June 30 inclusive	Summer Bills July 1 to October 31 inclusive
Demand Charge		
On-Peak Supply Charge	$5.15 per on-peak supply kW	$6.24 per on-peak supply kW
Off-Peak Supply Charge	$2.18 per kW for all kW in excess of On-Peak supply kW	$2.18 per kW for all kW in excess of On-Peak supply kW
Network Charge	$1.68 per network kW	$1.68 per network kW
Delivery Charge		
All On-Peak kWh per month	$0.01355 per kWh	$0.01355 per kWh
All Off-Peak kWh per month	$0.00559 per kWh	$0.00559 per kWh

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

MINIMUM BILL

1. The minimum bill shall be based on a demand specified by Company.
2. Where it is necessary to make an unusual extension, reinforce delivery system lines, upgrade or replace existing substations or if in the judgment of Company the revenue to be derived from or the duration of the prospective business is not sufficient under the above stated minimum to warrant the investment, Company may require an adequate minimum bill and establish a contract billing demand to be used in the determination of on-peak supply and network charges, calculated upon reasonable considerations before undertaking to supply the service. In such cases, the customer shall enter into a service agreement with Company as to the character, amount and duration of the business offered.

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BILLING DEMAND

The billing demand established for a customer shall be the higher of the Customer's average kilowatt load during the fifteen (15) minute period of maximum use during the month, determined separately for on-peak and off-peak periods or the demand established by contract. On-peak supply kW is maximum fifteen (15) minute demand established during the on-peak period, subject to ratchet adjustments and contract terms. The network demand is the maximum fifteen (15) minute demand established during the month, subject to ratchets adjustments and contract terms.

RATCHETS

The on-peak supply demand (kW) will be based on the greater of seventy-five percent (75%) of the on-peak summer demand established in the previous eleven (11) months or the current month's on-peak billing demand.

The network demand will be based on the greater of the peak demand, on or off-peak, established in the previous eleven months or the current month's billing demand.

USAGE PERIODS

	Summer	Winter
Weekdays		
On-Peak	12:00 PM - 8:00 PM	12:00 PM - 8:00 PM
Off-Peak	All other hours	All other hours
Weekends & Holidays		
On-Peak	none	none
Off-Peak	All hours	All hours

Holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

POWER FACTOR

The average power factor, expressed to the nearest percent, shall be determined by metering designed to prevent reverse registration. Eight-five percent (85%) lagging shall be considered the baseline power factor. If the average power factor is determined to be below eighty-five percent (85%) for any given month, an additional charge of $0.03 per kilowatt of measured demand for every whole percent less than eighty-five percent (85%) will be added to the monthly bill. If the average power factor is determined to be between eight-five percent (85%) and one hundred percent (100%) for any month a credit of $0.03 per kilowatt of measured demand for every whole percent above eighty-five percent (85%) will be added to the monthly bill.

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DELAYED PAYMENT

As per Schedule DPC.

SERVICE TERM

Not less than one (1) year, or such term as may be specified for a line extension, in accordance with the Agreement for Electric Service ("Service Agreement").

TERMS AND CONDITIONS

The rights and obligations of Company and Customer shall be governed by the Service Agreement. In the event that any provision, term or condition of the Service Agreement is in conflict with or otherwise differs from any provision of the Service Schedules or the General Terms and Conditions for Service or Company's Pricing Schedules, the provision, term or condition of the Service Agreement shall prevail.

MUNICIPAL SERVICE

CHARACTER OF SERVICE

115 volts (or 115/230 volt), single phase, 60 cycle, alternating current.

AVAILABILITY

This schedule is available for the use of the municipality only, for all lighting purposes in city buildings, shelter houses, shops, traffic lights and so forth operated by the municipality but not including street lighting.

Sports field may be lighted under this schedule but the Company will not be required to furnish transformers for sports field lighting.

NET MONTHLY BILL

Customer Charge

$10.06 per meter per month

	Winter Bills November 1 to June 30 inclusive	Summer Bills July 1 to October 31 inclusive
Delivery Charge		
All kWh per month	$0.03035 per kWh	$0.04880er kWh

Minimum

The minimum bill shall be the Customer Charge.

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

TERM OF PAYMENT

As per Schedule DPC.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

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THE STATE CORPORATION COMMISSION OF KANSAS

Index No. 19

AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: 04-WP

Replacing Schedule 01-WP Sheet 1
Which was filed December 17, 2001

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding shall modify the tariff as shown hereon.

Sheet 1 of 1 Sheets

WATER PUMPING SERVICE

AVAILABILITY

This schedule is available for municipal water pumping service.

NET MONTHLY BILL

Customer Charge

$16.21 per meter per month

Delivery Charge

$0.03863 per kWh for kWh on bills dated November 1 to June 30, inclusive.
$0.06099 per kWh for kWh on bills dated July 1 to October 31, inclusive.

Minimum

The minimum shall be the Customer Charge.

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

TERMS OF PAYMENT

As per Schedule DPC.

PRIMARY DISCOUNT

At the option of the customer there will be a discount of 2% on all monthly bills, excluding the Energy Cost Adjustment Clause, provided service is rendered and metered at primary voltage and the customer furnishes and maintains all necessary transformation beyond the point of metering.

TERMS AND CONDITIONS

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AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: 04-IP-I

Replacing Schedule 01-IP-I Sheet 1
Which was filed December 17, 2001

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding shall modify the tariff as shown hereon.

IRRIGATION SERVICE

AVAILABILITY

This schedule is available for irrigation power only. Service under this schedule shall be under contract for an initial period of five years and from year to year thereafter.

CHARACTER OF SERVICE

Alternating current, 60 cycle, 230 volt, 3 phase. Where only single phase service is available, motors of less than ten (10) horsepower may be connected if in the judgment of the Company such service can be rendered without unduly affecting existing service. Not more than one (1) irrigation connection shall be made on any single phase extension.

NET MONTHLY BILL

Demand Charge

Per horsepower contracted per year (nameplate rating)	$29.92

plus

Delivery Charge

For all bills dated November 1 through June 30 inclusive, per kWh	$0.02476
For all bills dated July 1 through October 31 inclusive, per kWh	$0.04097

MINIMUM CHARGE

$29.92 per horsepower contracted per year, which is the Demand charge, plus extension charge, if any. (Minimum charge does not include the delivery charge).

CONTRACT MINIMUM

Ten (10) horsepower

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ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

EXTENSION POLICY

Where the cost of extending service to the irrigation customer exceeds $50.00 per horsepower contracted, the customer will pay in addition to the "minimum charge" set forth above an additional annual minimum charge equal to twenty-one percent (21%) per year of the added investment in such facilities.

PAYMENT

Minimum charges shall be payable
- 50% April 1
- 25% May 1
- 25% June 1

DELAYED PAYMENT

As per Schedule DPC.

TERMS AND CONDITIONS

Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

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TEMPORARY SERVICE

AVAILABILITY

This schedule is available for fairs, carnivals, picnics, and other purposes where service is required for temporary service.

NET MONTHLY BILL

Delivery Charge

$0.13265 per kWh used, plus an amount equal to all the costs of installing and removing equipment to render service.

ENERGY COST ADJUSTMENT

The delivery charges are subject to the Energy Cost Adjustment Clause.

CONNECTION CHARGE

Where the Company deems it advisable the customer will advance the amount of estimated costs of installing and removing said equipment plus the estimated cost of current which will be consumed. Any amount advanced over and above the estimated cost will be refunded to the customer and the customer will pay any amount that may be deficient.

TERMS OF PAYMENT

As per Schedule DPC.

TERMS AND CONDITIONS

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ENERGY COST ADJUSTMENT CLAUSE

Rate Schedule Covered: This Energy Adjustment Clause applies to all rate schedules.

Computation Formula: The rates for energy to which this adjustment is applicable shall be increased or decreased by .001 cents per kilowatt-hour (kWh) for each .001 cents (or major fraction thereof) increase or decrease in the aggregate cost of energy per kWh computed by the following formula:

$$\frac{(F + P + NI + E + C - D)}{(.01)\ S} = \text{Adjustment}$$

Where:

F = Estimated dollar cost of nuclear fuel used[1] and fossil fuel burned[2] during the current month[3] to supply electric energy to customers[8].

P = Estimated total cost of purchased power[4] during the current month[3] to supply electric energy to customers.

NI = Estimated net dollar cost[7] (positive or negative) of interchange received less interchange sales during the current month[3].

E = Emission allowances expensed net of all related revenue (gains)[5] concurrent with the monthly emission of sulfur dioxide[3].

S = Estimated kWh delivered to customers during the current month which equals: (sum of the estimated kWh generated, purchased, and net interchanged during the month) times (1 minus the line loss percentage[6]).

C = Correction to dollar cost which is calculated as:

$$\text{Actual } (F + P + NI + E + C^1) - \text{Estimated } (F + P + NI + E + C^1) \times \frac{\text{Actual } S}{\text{Estimated } S} \text{ (for second prior month)}$$

C^1 = Correction dollars used originally in Energy Cost Adjustment Clause calculation for the second prior month.

D[9] = During December (actual) of each year actual Off-system sales gross profit (“GP”) shall be included in the monthly ECA calculation. The calculation shall be made as follows:
(Year-to-date GP-$344,511) x 25 percent (25%).

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NOTES TO THE FORMULA

1. Costs includable under nuclear fuel are those properly recorded as nuclear in FERC Account Number 518.

2. Costs includable under fossil fuel burned shall include only those costs properly recorded as fossil fuel costs prior to or in the burning cycle in FERC Account Number 151, except that fuel costs should be reduced by the amount of supplier refunds normally credited to FERC Account Number 501. For natural gas or other fuels for which no inventory is maintained, the cost recorded in FERC Account Number 501 and 547are includable as fossil fuel burned. Emission Allowances recorded in FERC Account Number 509 associated with the burning of fossil fuel shall also be includable. Costs of each type of fuel burned shall be computed by the following formula:

$$\frac{(B + A)}{(C + D)} \times E$$

Where:

B = Dollar cost of fuel stocks at the beginning of the current period.

A = Estimated dollar cost of additions to fuel stocks during the current period.

C = Actual units of fuel (tons, barrels, or MCF) in stock at the beginning of the current period.

D = Estimated units of fuel to be added to stocks during the current period.

E = Estimated units of fuel to be burned during the current period.

3. The current month is defined as the month during which the energy to be billed under the adjustment will be delivered.

4. Costs includable under purchased power are those properly recorded as purchased energy costs in FERC Account Number 555, and are exclusive of capacity, demand or other fixed charges.

5. Cost includable under Emission allowances net of all related revenue (gains) are those properly recorded as emission costs in FERC Account Number 509.

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6. Line Loss or unaccounted for losses percentage is the amount of total kWh losses divided by the net kWh generated, purchased, and interchanged during the most recent twelve-month period. If this calculated value is greater than the limit value (as defined in later paragraphs), use of the limit value shall be required in the calculation.

7. Net dollar costs or interchange are energy costs, and are exclusive of capacity, demand, or other fixed charges.

8. In the computational formula, the cost of fuel used to produce steam for industrial customers will be excluded.

9. In the event that actual gross off-system sales gross profit does not exceed $344,511 then factor D shall be equal to zero.

Computation Frequency: This computation must be made monthly.

Settlement Provision: The adjustment computed above will be increased or decreased by the amount (to the nearest .001 cents/kWh) by which the total amount billed to customers under the energy adjustment in the second prior month was greater or less than the actual increased or decreased cost of energy experienced during that month. The actual increased cost of energy will be calculated using the formula:

$$\text{Actual }(F + P + E + NI + C^1) - \text{Estimated }(F + P + NI + E + C^1) \times \frac{\text{Actual S}}{\text{Estimated S}}$$

for second prior month where components are defined as above, except that actual rather than estimated data will be used to compute the current period portion of the formula; and the fuel cost factor of (F) will be reduced by any supplier refunds or BTU credit adjustments received.

Reporting Requirements: The Company shall submit to the Kansas Corporation Commission on or before the fifteenth (15^{th}) day of each month an energy adjustment report, in a format prescribed by the Kansas Corporation Commission, showing the calculations for the next month's energy adjustment rate.

In the event that the operating statistics of the Company shall fall outside the limits as outlined below, the Company will inform the Kansas Corporation Commission of the circumstances surrounding the deviation in operating statistics, and the Kansas Corporation Commission may, at its discretion, require the Company to make the calculation at the limit values. These limits are:

AQUILA INC d/b/a AQUILA NETWORKS-WPK
(Name of Issuing Utility)

Schedule: 04-ECA

Replacing Schedule 01-ECA-I Sheet 4
Which was filed June 12, 2002

ENTIRE SERVICE AREA
(Territory to which schedule is applicable)

No supplement or separate understanding shall modify the tariff as shown hereon.

	Summer Period May - September		Winter Period October - April	
Statistics	Limits	Alternative* Fuel Ratios	Limits	Alternative* Fuel Ratios
Thermal Efficiency (Heat rate)	Max. Of 12,100 BTU/kWh		Max. Of 12,200 BTU/kWh	
Percentage of BTU from:				
Coal	16% to 100%	30%	16% to 100%	25%
Oil	0% to 25%	15%	0% to 75%	42%
Gas	0% to 84%	55%	0% to 84%	33%
Nuclear	-% to -%	-%	-% to -%	-%
Line Loss	Maximum of 14%		Maximum of 14%	

*These alternative fuel ratios must be used in calculating the fuel cost, if actual performance falls outside the limit values.

Assessment for Estimating Accuracy: In the event that the estimated total energy costs per kWh for any three (3) consecutive months exceed by more than five percent (5%) the actual cost per kWh for those same months, The Company shall submit an explanation. If the Company cannot show that the estimate was realistic and the actual costs was the lowest overall cost that could have been incurred, the Kansas Corporation Commission may, at its discretion, assess the Company, for the purpose of recovering administrative costs of handling the adjustment, in an amount not to exceed the difference between the amount billed to customers under the estimated rate and the actual increase in energy costs for those billing periods.

Issued March 18, 2005
Month Day Year

Effective Upon Commission Approval
Month Day Year

By W. Scott Keith Director, Regulatory
Signature Title

04-AQLE-1065-RTS
Approved
Kansas Corporation Commission
March 30, 2005
/S/ Susan K. Duffy

PARALLEL GENERATION SERVICE

AVAILABLE

Electric service is available under this schedule at points on the Company's distribution system.

APPLICABLE

To Residential or General Service customers who contract for service supplied at one (1) point of delivery where part of all of the electrical requirements, as defined in the Definitions and Conditions section, of the customer can be supplied from customer owned generation sources, and where such sources are connected for parallel operation of the customer's system with the Company's system. Customer sources may include but are not limited to windmills, water wheels, solar conversion and geothermal devices.

Prior to commencement of service, a contract for service shall be entered into, specifying the maximum kW load the Company is to supply and setting out the type and size of electric generating facilities, the type of protective relay equipment, and other technical and safety aspects of parallel operation.

The schedule is not applicable to resale or redistribution of electric service.

CHARACTER OF SERVICE

Service shall be alternating current 60 cycles, at the voltage and phase of the Company's existing distribution system having capacity of receiving the customer's excess power.

NET MONTH BILL

Rate

1. For capacity and energy supplied by the Company to Customer, the Company's rate schedules and terms and conditions normally applicable to the customer absent parallel generation shall apply.

2. For capacity and energy supplied by Customer to the Company, the Company shall pay:

   One hundred fifty-percent (150%) of the average system cost of energy[a] per kWh multiplied by the kWh Supplied by the Customer

   [a] This calculation shall be based on the monthly cost formula included in the Energy Cost Adjustment clause.

Minimum Bill

The minimum bill shall be the same as in the tariff under which service is received.

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DEFINITIONS AND CONDITIONS

1. The Company will supply, own and maintain all necessary meters and associated equipment utilized for billing. In addition, and for purposes of monitoring customer generation and load, Company may install at its expense, load research metering. The customer shall supply, at no expense to the Company, a suitable location for meters and associated equipment used for billing and for load research.

2. The Company shall have the right to require the customer, at certain times and as electrical operating conditions warrant, to limit the production of electrical energy from the generating facility to an amount no greater than the load at the customer's facility of which the generating facility is a part.

3. The Company will install, own and maintain a disconnecting device located near the electric meter or meters. Interconnection facilities shall be accessible at all times to Company personnel.

4. The customer shall furnish, install, operate and maintain in good order and repair, and without cost to the Company, such relays, locks and seals, breakers, automatic synchronizer, and other control and protective apparatus as shall be designated by the Company as being required as suitable for the operation of the generator in parallel with the Company's system.

5. The customer shall be required to reimburse the Company for any equipment or facilities required as a result of the installation by the customer of generation in parallel with the Company service.

6. The customer shall notify the Company prior to the initial energizing and start-up testing of the customer-owned generator, and the Company shall have the right to have a representative present at said test.

7. The customer's equipment shall not produce electrical energy with a third harmonic content greater than ten percent (10%) nor a fifth harmonic content greater than five percent (5%) or cause measurable interference with neighboring customers.

8. This schedule is available to residential customers providing electric energy and capacity to the Company from small power production facilities with a design capacity of twenty-five (25) kilowatts (kW) or less, where part or all of the electrical requirements of the customer can be supplied from such customer-owned capacity; and is available to non-residential customers providing electric energy and capacity to Company from small power production facilities with a design capacity of one hundred (100) kW or less, where part or all of the electrical requirements of the customer can be supplied from such customer-owned capacity.

9. Service will be rendered under Company's Rules and Regulations as filed with the Kansas Corporation Commission.

10. All provisions of this rate schedule are subject to changes made by order of the regulatory authority having jurisdiction.

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