BEFORE THE

STATE CORPORATION COMMISSION OF

THE STATE OF KANSAS

DOCKET NO. 08-KEPE-597-RTS

DIRECT TESTIMONY
OF
DAVID A. NAYLOR, P.E.

On Behalf of

KANSAS ELECTRIC POWER COOPERATIVE, INC.

DECEMBER 21, 2007

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DAVID A. NAYLOR, P.E.
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KANSAS ELECTRIC POWER COOPERATIVE, INC.

Q: PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is David A. Naylor. My business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q: BY WHOM ARE YOU EMPLOYED?

A: I am employed by C. H. Guernsey & Company, Engineers • Architects • Consultants, Oklahoma City, Oklahoma.

Q: PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A: I received a Bachelor of Science Degree in Electrical Engineering from the University of Oklahoma (OU) in 1994. Upon graduation, I was employed as an Electrical Engineer in the Rates Department at C.H. Guernsey and Company (GUERNSEY). Since joining GUERNSEY, I have advanced to the position of Senior Engineer in the Analytical Services Group. I serve as a consultant to electric utility clients in a number of areas including contract negotiations, power supply studies, cost and rate analysis and engineering economic analysis. A copy of my resume is attached as Exhibit DAN-1.

Q: HAVE YOU TESTIFIED BEFORE THIS COMMISSION?

A: No.

Q: WHERE HAVE YOU TESTIFIED?

A: As shown in Exhibit DAN-1, I have testified before the Public Utility Commission of Texas (PUCT) and the Oklahoma Corporation Commission (OCC).

Q: ARE YOU A REGISTERED PROFESSIONAL ENGINEER?

A: Yes. I am a registered Professional Engineer in the state of Oklahoma, No. 19807.

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of Kansas Electric Power Cooperative, Inc. (KEPCo). KEPCo is a not-for-profit generation and transmission cooperative (G&T) headquartered in Topeka, KS. KEPCo is the wholesale power supplier for its 19 distribution rural electric cooperative members (Members).

PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to present the (1) development of the functional cost of service used to determine the Rate Revenue Requirement, (2) KEPCo

Board of Trustee's (Board's) decision regarding KEPCo's High Voltage Discount, Rural Energy Credit, and Economic Development Rider and (3) Rate Revenue Requirement which will serve as the basis for the rate design.

Q: ARE YOU SPONSORING ANY EXHIBITS IN SUPPORT OF YOUR DIRECT TESTIMONY?

A: Yes. I am sponsoring Exhibits DAN-1 through DAN-9.

DEVELOPMENT OF THE FUNCTIONALIZED COST OF SERVICE

Q: WHAT IS THE PURPOSE OF THE FUNCTIONALIZED COST OF SERVICE?

A: The functionalized cost of service (COS) serves as the basis for KEPCo's Rate Revenue Requirement which will be used in the rate design. KEPCo's services can be functionalized into five basic areas: (1) Production Demand, (2) Production Energy, (3) Transmission, and (4) Delivery Point, and (5) KEPCo Services Inc. (KSI). The COS determines KEPCo's cost for each of these areas. Even though KSI is treated as a separate cost function, no KSI expenses or revenues are included in the Rate Revenue Requirement.

The Rate Revenue Requirement developed from the COS is the starting point for the proposed KEPCo rate design, as described in Mr. Stover's testimony.

Q: WHAT TEST YEAR HAS KEPCO USED IN ITS COS?

A: KEPCo's COS is based on the twelve-month period ending December 31, 2006.

Q: WERE ANY POST-TEST YEAR ADJUSTMENTS MADE?

A: Yes. The following adjustments were made to the test year:

(1) Weather normalization of the Members' billing units. Weather normalization required modifying the Member's billing units to reflect "normal weather." Adjusting the Members' billing units required corresponding adjustments to KEPCo's purchased power expenses as well as KEPCo's revenues it received from its Members. These adjustments are discussed in Dr. Bowser's testimony.

(2) Accounting adjustments. Accounting adjustments were made for changes that are known, measurable and of a continuing nature. These adjustments are discussed in Ms. Wells' testimony.

(3) Purchased Power adjustments. Purchased Power adjustments reflect the updated rates and pro forma adjustments for KEPCo's purchased power agreements. These adjustments are discussed in Dr. Bowser's testimony.

(4) Rate adjustments. Rate adjustments reflect an increase to the Members' rates such that KEPCo earns a margin equal to a 1.20 debt service coverage (DSC) ratio. KEPCo's Board approved a financial plan that defined several financial objectives. This plan determined that it was necessary for KEPCo to realize a 1.20 DSC to meet those financial objectives. This plan is described in Mr. Solomon's testimony.

Q: WHAT DID YOU DO WITH THE POST-TEST YEAR ADJUSTMENTS?

A: I took the post-test year adjustments developed by Dr. Bowser and Ms. Wells and the DSC requirement determined by Mr. Solomon and calculated an Adjusted Test Year Member Revenue Requirement as shown in Exhibit DAN-2. Exhibit DAN-2 presents an income statement for the unadjusted test year along with each of the adjustments described above. A summary of the adjustments are shown below in Table 1. The Member Revenue Requirement is $107,876,815. Because Members are paid the Economic Development Rider, the Rural Energy Credit, and the High Voltage Discount, the amount charged to Members must be increased to realize the Member Revenue Requirement. The Rate Revenue Requirement, discussed further below, includes the adjustments for these items.

Description	Unadjusted Test Year	Accounting Adjustments	Weather Normalization	Purchased Power Adjustments	Rate Adjustment	Adjusted Test Year
Member Revenues	110,707,844	35,828	(8,231,125)	-	5,364,268	107,876,815
Other Revenues	66,475	-	-	-	-	66,475
Total Oper. Revenues	110,774,319	35,828	(8,231,125)	-	5,364,268	107,943,289
Operating Expenses	101,695,276	(121,179)	(7,120,536)	(1,139,095)	-	93,314,466
Interest & Other Deducts	8,904,085	(463,197)	-	-	-	8,440,888
Total Oper. Expenses	110,599,361	(584,376)	(7,120,536)	(1,139,095)	-	101,755,354
Operating Margin	174,958	620,204	(1,110,589)	1,139,095	5,364,268	6,187,935
Non-Oper. Revenues	884,482	(252,468)	-	-	-	632,014
Total Margin	1,059,440	367,736	(1,110,589)	1,139,095	5,364,268	6,819,950
DSC	0.95					1.20

Table 1 – Summary of Adjustments to Test Year

Q: PLEASE DESCRIBE THE DEVELOPMENT OF THE FUNCTIONALIZED COS.

A: The first step was to determine the basic functions of KEPCo. As described above, this resulted in five areas – Production Demand, Production Energy, Transmission, Delivery Point, and KSI. Costs or revenues specifically associated with any of these functions are directly assigned to that function.

Allocation factors are then developed for costs and revenues which cannot be directly assigned. These include allocation factors based on KEPCo's gross plant in service, net plant in service, rate base, labor, purchased power, and revenue.

Exhibit DAN-3 contains the allocation factors used in the COS.

The Rate Base allocation factor is developed in Exhibit DAN-4. KEPCo's rate base is calculated as the plant in service less accumulated depreciation plus working capital. KEPCo's intangible and general plant are allocated among the functions using the Labor allocation factor. KEPCo's production plant is directly assigned to the Production Demand function. KEPCo's transmission plant is directly assigned to the Transmission function. KEPCo's accumulated depreciation is assigned on the same basis as the associated plant (i.e., accumulated depreciation for the production plant is directly assigned to the Production function). Working capital includes fuel stock, materials and supplies, prepayments and cash. Cash working capital was calculated as 1/8 of KEPCo's operation and maintenance (O&M) expenses, excluding administrative and general (A&G) expenses.

The development of the Labor allocation factor is shown in Exhibit DAN-5. It includes the expenses associated with labor (i.e., payroll, benefits, etc.) which KEPCo booked into each of its O&M accounts. The labor expense is assigned on the same basis as the underlying O&M expense.

The other allocation factor used is the Purchased Power allocation factor. Shown on Exhibit DAN-6, each of KEPCo's purchased power expenses were assigned to either Production Demand, Production Energy, or Transmission on the basis of the charges incurred. For example, charges billed by a third party to KEPCo using a capacity charge were assigned to the Production Demand function. Any purchase power charges which were a fixed monthly fee (i.e., did not vary with usage) were also assigned to the Production Demand function. Charges billed to KEPCo using an energy or fuel charge were assigned to the Production Energy function. Charges billed to KEPCo for transmission were assigned to the Transmission function.

Once the allocation factors are developed, the costs are assigned or allocated to the various functions.

Q: HOW WERE THE OPERATING EXPENSES ALLOCATED?

A: The complete COS is shown in Exhibit DAN-7. Direct assignment was used to the extent possible. The remaining costs were allocated using one of the allocation factors discussed above to reflect a reasonable cost assignment among the functions.

Q: HOW WERE EXPENSES ASSIGNED TO THE PRODUCTION FUNCTIONS?

A: KEPCo's production O&M expenses (accounts 517 - 557, excluding account 555, purchased power expenses) were allocated between Production Demand and Production Energy using a Federal Energy Regulatory Commission (FERC) approved methodology in which the fuel and some of the maintenance expenses are assigned to the energy, or variable, component. The remaining costs are assigned to the demand, or fixed, component. This is also the same methodology used by KEPCo in its last rate case, Docket No. 01-KEPE-1106-RTS, filed in 2001.

KEPCo's Purchased Power expenses (account 555) were allocated using the Purchased Power Allocation Factor.

Q: HOW WERE EXPENSES ASSIGNED TO THE TRANSMISSION FUNCTION?

A: KEPCo's O&M expenses booked to transmission accounts (accounts 560 - 573) were directly assigned to the Transmission function.

Q: HOW WERE EXPENSES ASSIGNED TO THE DELIVERY POINT FUNCTION?

A: KEPCo's O&M expenses booked to accounts 901 – 916 were directly assigned to the Delivery Point function. These are expenses typically classified as customer expenses and vary based on the number of delivery points – not on the demand or energy served from the delivery point. Therefore, the cost recovery is based on the number of delivery points.

Q: HOW WERE KEPCO'S A&G EXPENSES ALLOCATED?

A: KEPCo's A&G expenses, accounts 920 – 935, were allocated using the A&G allocation factor. The A&G allocation factor is a modified Labor allocation factor. A comparison is shown in Table 2.

Description	Total	Production Demand	Production Energy	Transmission	Delivery Point
Labor	100.0%	58.4%	0.0%	21.4%	20.3%
A&G	100.0%	29.2%	29.2%	21.4%	20.3%

Table 2 – Comparison of Allocation Factors

Using the normal Labor allocation factor would result in no A&G expenses being allocated to the Production Energy function. However, in discussion with KEPCo staff, a portion of their time is devoted to both demand-related and energy-related tasks. Therefore, a portion of their A&G expenses should be allocated to the Production Energy function. To recognize this, the Labor allocation percentage assigned to Production Demand (58.4% as shown above in Table 2) was split equally between the Production Demand and Production Energy functions, resulting in 29.2% assigned to each function.

Q: HOW WERE KEPCO'S DEPRECIATION AND AMORTIZATION EXPENSES ALLOCATED?

A: KEPCo's depreciation expense associated with Wolf Creek was directly assigned to the Production Demand function. KEPCo's general plant depreciation expense was allocated using the Labor allocation factor (same as KEPCo's general plant). KEPCo's amortization expense is allocated among the functions using KEPCo's Gross Plant allocation factor.

Q: HOW WAS KEPCO'S INTEREST EXPENSE ALLOCATED?

A: KEPCo's interest expense is allocated among the functions using KEPCo's Rate Base allocation factor.

Q: HOW WERE KEPCO'S OTHER REVENUES ALLOCATED?

A: KEPCo's operating revenues include Member revenues, Non-Member sales, and other operating revenues. KEPCo's non-member sales (less than $65,000 in the test year), are a result of KEPCo's scheduling arrangements in which Westar must accommodate KEPCo's hydroelectric power allocation. Since these revenues are energy related, KEPCo's non-member sales are directly assigned to the Production Energy function.

KEPCo's other operating revenues and non-operating revenues are allocated among the functions based on KEPCo's Rate Base allocation factor.

Q: HOW WERE THE OPERATING MARGINS ALLOCATED AMONG THE FUNCTIONS?

A: KEPCo's Operating Margin is allocated using the Revenue allocation factor. KEPCo's Board treated margin as a cost and wanted a portion of this cost to be recovered from each function. The procedure used to allocate the margin in the COS reflects the concept that the margin is a percent of revenue and should be the same for each component, as shown in Table 3. Since we are calculating the revenue requirement, I used Operating Expenses as a proxy for revenues to avoid a circular argument.

Description	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point
Operating Expenses	101,755,354	40,630,836	43,974,292	14,547,753	2,602,473
Operating Margin	6,187,935	2,470,838	2,674,160	884,676	158,261
Margin as % of Revenue	6.1%	6.1%	6.1%	6.1%	6.1%

Table 3 – Margin as a Percent of Revenues

Allocating the margin as a percent of revenue matches the manner in which KEPCo allocates capital credits to its Members.

Q: WERE ANY COSTS OR REVENUES ALLOCATED TO THE KSI FUNCTION?

A: No. As described by Ms. Wells, no costs or revenues associated with KSI are included in the Member Revenue Requirement. This is also shown in Exhibit DAN-7.

Q: WHAT IS THE ALLOCATION OF THE MEMBER REVENUE REQUIREMENT TO EACH FUNCTION?

A: The allocation is shown in Table 4. The COS results in 83% of the costs allocated to Production Demand and Production Energy functions and 17% to the Transmission and Delivery Point functions.

Description	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point
Operating Expenses	101,755,354	40,630,836	43,974,292	14,547,753	2,602,473
Non-Operating Revenues	(632,014)	(517,231)	(52,651)	(43,999)	(18,134)
Non-Member Sales	(64,089)	-	(64,089)	-	-
Other Operating Revenues	(2,386)	(1,953)	(199)	(166)	(68)
Subtotal Member Revenue Requirement	101,056,865	40,111,652	43,857,354	14,503,588	2,584,271
Total Margin	6,819,950	2,988,069	2,726,810	928,675	176,395
Total Member Revenue Requirement	**$ 107,876,815**	**$ 43,099,721**	**$ 46,584,165**	**$ 15,432,263**	**$ 2,760,666**
Percent of Total	100.0%	40.0%	43.2%	14.3%	2.6%
Annual Energy (MWh)	1,698,150	1,698,150	1,698,150	1,698,150	1,698,150
Average Rate ($/MWh)	$ 63.53	$ 25.38	$ 27.43	$ 9.09	$ 1.63

Table 4 – Allocation of Member Revenue Requirement

Q: WHAT IS THE OVERALL RATE INCREASE WITH THIS MEMBER REVENUE REQUIREMENT?

A: The Member Revenue Requirement results in a 5.3% average rate increase when compared to the weather normalized 2006, shown in Table 5.

	Weather Normalized Test Year	Adjusted Test Year
Member Net Revenue Requirement	$ 102,465,876	$ 107,876,815
Member Usage (MWh)	1,698,150	1,698,150
Average Rate ($/MWh)	$ 60.34	$ 63.53
Percent Increase (Decrease) in Average Rate		5.3%

Table 5 – Percent Increase in Average Rate

KEPCO'S DISCOUNTS, RIDERS, AND CREDITS

Q: PLEASE DESCRIBE KEPCO'S CURRENT DISCOUNTS, RIDERS AND CREDITS.

A: Included in KEPCo's current Schedule M-9 is a Primary Metering Discount, High Voltage Discount (HVD), Economic Development Rider (EDR), and a Rural Energy Credit (REC). KEPCo's proposed Schedule M-10 also includes the HVD, EDR, and REC.

The Primary Metering Discount provides a discount if a Member delivery point is metered on the primary side of the substation.

The HVD provides a discount for delivery of power at voltages greater than 12.5 kV. The higher the voltage, the greater the discount.

The EDR provides a credit to the demand charge for new loads with a demand of 50 kW or more and a minimum 50% load factor. The credit is reduced each year over a period of five years.

The REC provides a credit to the energy charge for new loads of 10 kW or more and a minimum 36% load factor. The credit is reduced each year over a period of six years.

Q: DID THE KEPCO BOARD REQUEST A REVIEW OF THESE DISCOUNTS, RIDERS, AND CREDITS?

A: The Board requested we review the HVD, the EDR, and the REC. The Board did not request a review of the Primary Metering Discount and no change is being proposed.

The reviews were presented at KEPCo's July 2007 Board meeting. Ultimately, the Board decided not to make any changes to the HVD, the EDR, and the REC.

Q: PLEASE DESCRIBE YOUR REVIEW OF THE HIGH VOLTAGE DISCOUNT.

A: An analysis, summarized in Table 6, was presented to the KEPCo Board showing that KEPCo paid its Members an average of $0.75/kW-Mo for delivery at a higher voltage level.

Voltage Level (kV)	Discount ($/kW)	12-Mo NCP kW Normalized	Credits ($)
34.5	0.59	1,535,756	906,096
69.0	0.72	879,886	633,518
115.0	1.30	518,397	673,916
		2,934,039	$ 2,213,530
Average Discount ($/kW)			$ 0.75

Table 6 – Average High Voltage Discount Paid by KEPCo

In comparison, KEPCo pays $0.65/kW-Mo to Westar (for all delivery points) and did pay $0.20/kW-Mo to KCP&L (for 34.5 kV to Primary). After further discussion, the KEPCo Board voted to maintain the current discount levels for the HVD.

Q: PLEASE DESCRIBE YOUR REVIEW OF THE ECONOMIC DEVELOPMENT RIDER AND THE RURAL ENERGY CREDIT.

A: A two-part analysis was prepared to compare the costs of the EDR and REC under the existing rates to the proposed rates. The proposed rates are discussed in Mr. Stover's testimony.

The first part was a cross-over analysis. This determined the number of years before the net revenues collected from the qualifying load exceeded the costs of supplying the load (i.e., crossed over). A detailed comparison between the existing and proposed rates is included in Exhibit DAN-8 with the results summarized in Figure 1, Figure 2, and Table 7. The proposed rates provide a cross-over sooner than under the existing rates – 2.4 years versus 4.0 years for the EDR and 4.9 years versus 6.4 years for the REC.

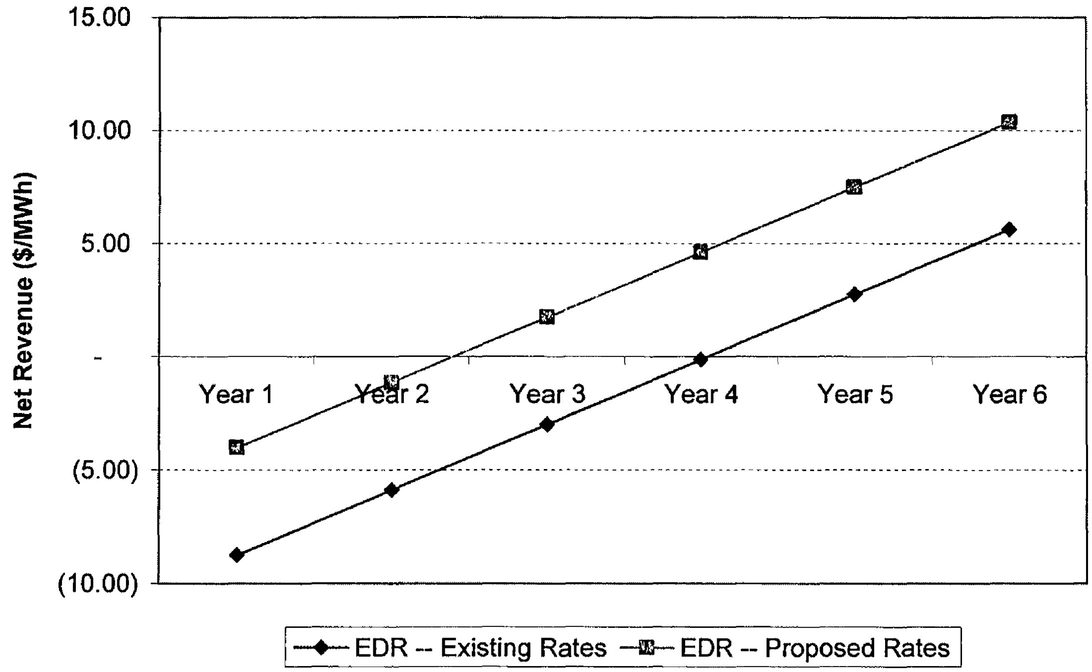

Figure 1 – Net Revenue ($/MWh) Comparison for EDR

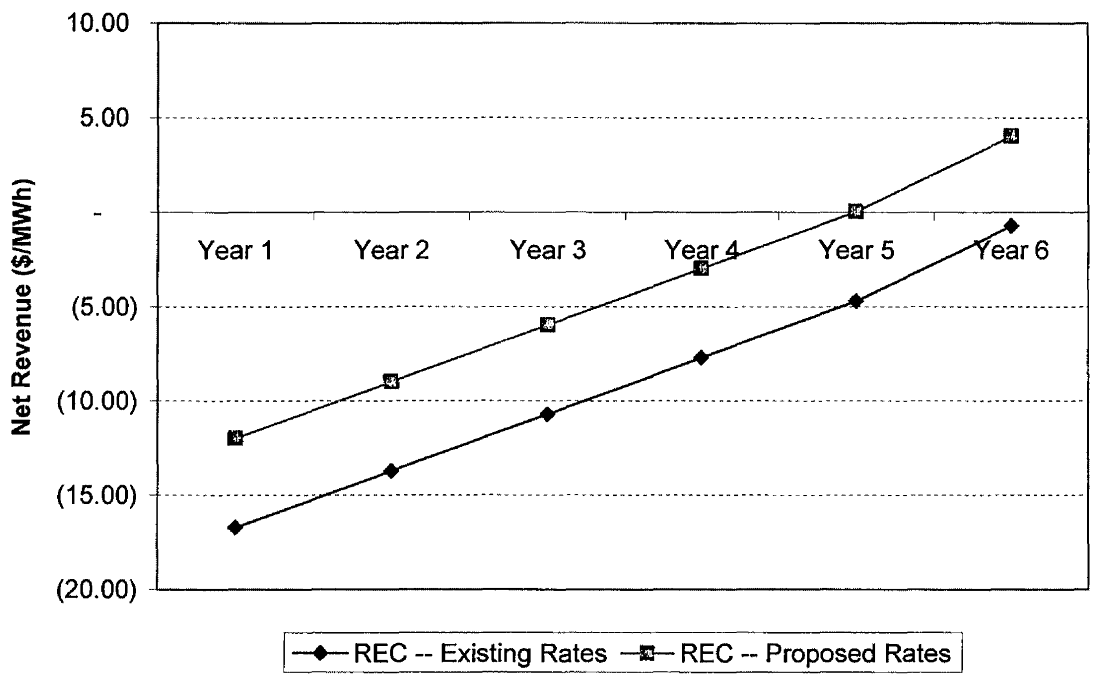

Figure 2 – Net Revenue ($/MWh) Comparison for REC

	Crossover (Yrs) for EDR	Crossover (Yrs) for REC
Existing Rate	4.0	6.4
Proposed Rate	2.4	4.9

Table 7 – Crossover for EDR and REC

The second part was a breakeven analysis. This analysis calculated the percent increase or decrease to be made to the credits such that the revenues equaled the costs over the applicable time credits were provided (i.e., five years for the EDR and six years for the REC).

The complete analysis is included in Exhibit DAN-9 and is summarized in Table 8.

	Economic Development Rider Proposed Rates	**Rural Energy Credit** Proposed Rates
Percent Increase (Decrease) in Credits to Breakeven	20.2%	-34.9%

Table 8 – Breakeven Analysis of EDR and REC

If it were the desire of the KEPCo Board to set the level of credits in the EDR and REC such that the revenues equaled the costs over the effective time period, the credits would need to be increased 20.2% for the EDR and decreased 34.9% for the REC, under the proposed rate structure.

However, as discussed earlier, the KEPCo Board decided to retain the current level of credits and make no adjustments to either the EDR or REC.

KEPCO'S RATE REVENUE REQUIREMENT

Q: PLEASE DESCRIBE THE REVENUE REQUIREMENT TO BE RECOVERED THROUGH KEPCO'S RATES.

A: From the COS, the Member Revenue Requirement was determined to be $107,876,815. However, the credits associated with the HVD, EDR, REC, Revenue Credit Adjustment, WAPA Credits, and Decommissioning Adjustment must be added to the Member Revenue Requirement to determine the Rate Revenue Requirement. The Revenue Credit Adjustment, WAPA Credits, and Decommissioning Adjustment also remained unchanged from the test year.

Shown in Table 9, KEPCo's rates must earn $111,902,560 before applying the credits, which results in an average rate before credits of $65.90/MWh.

Total Member Revenue Requirement	$	107,876,815
Rural Energy Credit		1,892,651
Economic Development Rider		342,204
Decomissioning Adjustment		(405,597)
Revenue Credit Adjustment		34,124
WAPA Credits		(38,199)
High Voltage Discount		2,200,563
Total Credits	$	4,025,745
Total Rate Revenue Requirement	$	111,902,560
Energy Sales (MWh)		1,698,150
Average Rate ($/MWh)	$	65.90

Table 9 – KEPCo's Rate Revenue Requirement

Q: WHAT IS THE ALLOCATION OF THE RATE REVENUE REQUIREMENT TO EACH FUNCTION?

A: The allocation is shown in Table 10.

Description	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point
Operating Expenses	101,755,354	40,630,836	43,974,292	14,547,753	2,602,473
Non-Operating Revenues	(632,014)	(517,231)	(52,651)	(43,999)	(18,134)
Non-Member Sales	(64,089)	-	(64,089)	-	-
Other Operating Revenues	(2,386)	(1,953)	(199)	(166)	(68)
Subtotal Member Revenue Requirement	101,056,865	40,111,652	43,857,354	14,503,588	2,584,271
Total Margin	6,819,950	2,988,069	2,726,810	928,675	176,395
Total Member Revenue Requirement	**$ 107,876,815**	**$ 43,099,721**	**$ 46,584,165**	**$ 15,432,263**	**$ 2,760,666**
Rural Energy Credit	1,892,651		1,892,651		
Economic Development Credit	342,204	342,204			
Decomissioning Adjustment	(405,597)		(405,597)		
Revenue Credit Adjustment	34,124		34,124		
WAPA Credits	(38,199)		(38,199)		
High Voltage Discount	2,200,563	-	-	2,200,563	-
Subtotal Credits	4,025,745	342,204	1,482,978	2,200,563	-
Total Rate Requirement	**$ 111,902,560**	**$ 43,441,925**	**$ 48,067,143**	**$ 17,632,826**	**$ 2,760,666**
Annual Energy (MWh)	1,698,150	1,698,150	1,698,150	1,698,150	1,698,150
Average Rate ($/MWh)	$ 65.90	$ 25.58	$ 28.31	$ 10.38	$ 1.63

Table 10 – Allocation of Rate Revenue Requirement

The total Rate Revenue Requirement is the starting point for the rate design as discussed by Mr. Stover.

Q: IN YOUR OPINION, IS THIS ALLOCATED RATE REVENUE REQUIREMENT REASONABLE?

A: Yes. The allocated rate revenue requirement is reasonable.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A: Yes, it does.

EDUCATION:

B.S., Electrical Engineering (*magna cum laude*), The University of Oklahoma, 1994
NewEnergy Strategist University Training, Atlanta, Georgia; June 7-11, 2004
Modeling and Analysis of Modern Power Systems, The University of Texas at Arlington, 1995

REGISTRATIONS:

Registered Professional Engineer – Oklahoma - 19807

PROFESSIONAL ACTIVITIES / HONORS:

Member, Institute of Electrical and Electronics Engineers

EXPERIENCE RECORD:

1995 - Present C. H. Guernsey & Company, Oklahoma City, Okla.

Mr. Naylor's areas of responsibility include production cost modeling and system optimization of transactions and resources using NewEnergy Associates' PROMOD IV®; development and evaluation of solicitation packages for competitively procuring power supply in the emerging electric utility competitive generation market; development and presentation of transmission cost of service studies and unbundled cost of service studies resulting in unbundled tariff development, including transmission tariffs responsive to FERC rules; analysis of electric utility transition and providing training to utility executives on the emerging utility structures and analysis of power supply issues. These studies (including analysis for cost minimization and allocation among multiple parties) and presentations have been conducted in numerous states across the nation.

While attending the University of Oklahoma, Mr. Naylor was Teaching Assistant in the "Electromagnetic Fields II" course. He also served as Summer Intern: Design Technician and Junior Design Technician in the Transmission Design Department at Arkansas Electric Cooperative Corporation, Little Rock, Arkansas.

PUBLICATIONS / PRESENTATIONS:

"Power Markets Update," presented at OML/MESO Annual Meeting; Tulsa, Okla, September 18, 2002.

"Zambia Energy Regulation Power Markets Workshop," Livingstone, Zambia, August 26-30, 2002 (coordinated through Institute of International Education, Washington, D.C.).

"Electric Transmission in Oklahoma," presented at OML/MESO Annual Meeting; Oklahoma City, Okla., September 13, 2001.

SPECIFIC CONSULTING EXPERIENCE:

Billing, Metering, Data Collection and Processing

Mr. Naylor also audits substantial (over $10 million per month) wholesale power invoices and participates in associated power billing dispute resolutions.

- Magic Valley Electric Cooperative, Texas
- Rayburn Country Electric Cooperative, Texas

Resource Planning and Procurement

Mr. Naylor participates in the procurement of power supply for both demand- and supply-side resources, including the development and evaluation of the solicitation packages as well as contract negotiations and dispute resolutions involved in the power supply procurement process. These solicitation packages range from requests for all-requirements to block purchases. Mr. Naylor also participates in long-range system planning analysis, including evaluation of future resources and power pool feasibility. Mr. Naylor utilizes NewEnergy Associates' PROMOD IV ® to develop production costs and optimization models to analyze the impacts of various transactions and resources on a utility's system.

- Chermac Energy Corporation, Oklahoma – Avoided cost calculations for potential wind farm; Cause No. PUD200500059 and Cause No. PUD200500177.
- Golden Spread Electric Cooperative, Texas – Asset Evaluation.
- Grand River Dam Authority, Oklahoma – Power Supply Solicitation and Eavluation.
- Magic Valley Electric Cooperative, Texas – Pooling Feasibility Analysis
- Matanuska Electric Association, Alaska – Preliminary Power Supply Planning Study
- Oglethorpe Power Corporation, Georgia – Allocation of energy costs and revenues among members
- Rayburn Country Electric Cooperative, Texas – Load forecasting, and resource reporting and resource integration
- South Plains Electric Cooperative, Texas – Determining resource requirements
- South Texas Electric Cooperative, Medina Electric Cooperative, and Magic Valley Electric Cooperative, Texas – Consolidation Analysis
- South Texas Electric Cooperative, Texas – Power Supply Solicitation and Evaluation
- Twelve Member-Systems of Oglethorpe Power Corporation, Georgia

Industry Restructuring and Competition

Mr. Naylor has been actively involved in the Texas Stakeholder Process for the implementation of electric industry restructuring. He has remained involved in the market design issues as new market structures are implemented in the Texas market. Mr. Naylor is also involved in Federal market design issues through proceedings at the Federal Energy Regulatory Commission.

- Texas Electric Cooperatives Statewide Association

Financial Forecasting and Analysis

Mr. Naylor has developed and analyzed financial forecasts to determine the impacts of equity management plans, rate changes, and corporate cash flows. These forecasts have been used in regulatory filings as well as in implementing corporate policies.

Cost of Service and Rates (Expert Testimony)

Mr. Naylor develops and analyzes wholesale tariffs and rate structures (Transmission Cost of Service (TCOS)) on behalf of clients. He provides regulatory testimony as an expert witness in these areas and has filed testimony in the following Transmission Cost of Service filings before the Public Utility Commission of Texas.

- Bandera Electric Cooperative, Texas – TCOS (Docket Nos. 25421, 26937)
- Big Country Electric Cooperative, Texas – TCOS (Docket No. 25718)
- Bluebonnet Electric Cooperative, Texas - TCOS
- Brazos Electric Power Cooperative, Texas – Unbundled COS and Rate Design
- Central Texas Electric Cooperative, Texas - TCOS
- Coleman County Electric Cooperative, Texas - TCOS
- Concho Valley Electric Cooperative, Texas - TCOS
- Deseret G&T Cooperative, Utah – Unbundled COS and Open Access Transmission Tariff
- DeWitt Electric Cooperative, Texas - TCOS
- Fannin County Electric Cooperative, Texas - TCOS (Docket No. 24312)
- Farmers Electric Cooperative, Texas - TCOS
- Garkane Power Association, Utah – Transmission Rate and Third-Party Wheeling Negotiations
- Golden Spread Electric Cooperative, Texas / Big Country and Coleman County Electric Cooperative – Asset Transfer Study
- Golden Spread Electric Cooperative, Texas – Transmission Equalization Study
- Grayson-Collin Electric Cooperative, Texas – TCOS (Docket No. 27881)

- Kansas Electric Power Cooperative, Kansas – Unbundled COS and Rate Design
- Lamar County Electric Cooperative Assn., Texas - TCOS
- Magic Valley Electric Cooperative, Texas – TCOS (Docket No. 26181)
- Medina Electric Cooperative, Texas – TCOS (Docket No. 30007)
- Northwest Iowa Power Cooperative, Iowa – Unbundled Transmission Tariff and COS
- Rayburn Country Electric Cooperative, Texas – TCOS (Docket No. 21265)
- San Bernard Electric Cooperative, Texas – TCOS (Docket No. 34672)
- South Texas Electric Cooperative, Texas – TCOS (Docket No. 22534)
- Southwest Texas Electric Cooperative, Texas - TCOS
- Taylor Electric Cooperative, Texas – TCOS (Docket No. 29756)
- Trinity Valley Electric Cooperative, Texas – Delivery Services COS (Docket No. 21825)
- Tri-State G&T Association, Colorado – Unbundled COS and Open Access Transmission Tariff

<u>Education and Training - International</u>

- "Zambia Energy Regulatory Power Markets Workshop," Livingston, Zambia, August 26-30, 2002 (coordinated through Institute of International Education).

<u>Expert Testimony - Other</u>

- Cause No. PUD 2000500059 and Cause No. PUD 200500177 before the Oklahoma Corporation Commission on behalf of Chermac Energy, regarding avoided cost calculations – 2005.
- Docket NO. 33687 before the Public Utility Commission of Texas on behalf of Texas Electric Cooperatives, Inc., regarding Entergy Gulf States' Transition to Competition Plan – 2007.

Kansas Electric Power Cooperative, Inc.
Revenue Requirement
Test Year Ending December 31, 2006

Line No.	Description	Unadjusted Test Year	Accounting Adjustments	Subtotal Adjusted Test Year	Weather Normalization	Weather Normalized Test Year	Purchased Power Adjustments	Normalized Test Year	Rate Adjustment	Adjusted Test Year
1	**Operating Revenues**									
2	Member Revenues	110,707,844	35,828	110,743,672	(8,231,125)	102,512,546	-	102,512,546	5,364,268	107,876,815
3	Non-Member Sales	64,089	-	64,089	-	64,089	-	64,089		64,089
4	Other Operating Revenues	2,386	-	2,386	-	2,386	-	2,386	-	2,386
5	**Total Operating Revenues**	**110,774,319**	**35,828**	**110,810,146**	**(8,231,125)**	**102,579,021**	**-**	**102,579,021**	**5,364,268**	**107,943,289**
6										
7	**Operating Expenses**									
8	Production -- Operations & Maintenance	10,579,829	67,251	10,647,080	-	10,647,080	-	10,647,080		10,647,080
9	Production -- Fuel	2,405,782	-	2,405,782	-	2,405,782	-	2,405,782		2,405,782
10	Purchased Power	68,052,774	76,732	68,129,506	(7,120,536)	61,008,970	(1,139,095)	59,869,875		59,869,875
11	Transmission Expense	7,230,261	(114,059)	7,116,202	-	7,116,202	-	7,116,202		7,116,202
12	Customer Accounts Expense	200,443	(3,831)	196,611	-	196,611	-	196,611		196,611
13	Customer Service & Information Expense	120,470	(51,498)	68,971	-	68,971	-	68,971		68,971
14	Sales	529,262	(7,651)	521,611	-	521,611	-	521,611		521,611
15	Administrative and General Expense	4,219,524	64,591	4,284,115	-	4,284,115	-	4,284,115		4,284,115
16	Depreciation and Amortization Expense	8,356,932	(152,713)	8,204,218	-	8,204,218	-	8,204,218	-	8,204,218
17	Subtotal Operating Expenses	101,695,276	(121,179)	101,574,097	(7,120,536)	94,453,561	(1,139,095)	93,314,466	-	93,314,466
18										
19	**Interest & Other Deductions**									
20	Interest on Long-Term Debt	8,604,186	(458,308)	8,145,878	-	8,145,878	-	8,145,878		8,145,878
21	Interest-Other	298,135	(4,889)	293,246	-	293,246	-	293,246		293,246
22	Interest Charged to Construction	(63,943)	-	(63,943)	-	(63,943)	-	(63,943)		(63,943)
23	Other Deductions	65,707	-	65,707	-	65,707	-	65,707	-	65,707
24	Total Interest & Other Deductions	8,904,085	(463,197)	8,440,888	-	8,440,888	-	8,440,888	-	8,440,888
25										
26	**Total Operating Expenses**	**110,599,361**	**(584,376)**	**110,014,985**	**(7,120,536)**	**102,894,449**	**(1,139,095)**	**101,755,354**	**-**	**101,755,354**
27										
28	**Operating Margin**	**174,958**	**620,204**	**795,162**	**(1,110,589)**	**(315,428)**	**1,139,095**	**823,667**	**5,364,268**	**6,187,935**
29										
30	**Non-Operating Revenues**									
31	Interest and Dividend Income	875,646	(252,468)	623,178	-	623,178	-	623,178		623,178
32	Other Non-Operating Revenues	(33,376)	-	(33,376)	-	(33,376)	-	(33,376)		(33,376)
33	Other Capital Credits	42,212	-	42,212	-	42,212	-	42,212	-	42,212
34	**Total Non-Operating Revenues**	**884,482**	**(252,468)**	**632,014**	**-**	**632,014**	**-**	**632,014**	**-**	**632,014**
35										
36	**Total Margin**	**1,059,440**	**367,736**	**1,427,176**	**(1,110,589)**	**316,587**	**1,139,095**	**1,455,682**	**5,364,268**	**6,819,950**
37										
38	**TIER**	**1.12**		**1.18**		**1.04**		**1.18**		**1.84**
39	Principal Payment	10,464,348	698,146	11,162,494	-	11,162,494	-	11,162,494	-	11,162,494
40	**DSC**	**0.95**		**0.92**		**0.86**		**0.92**		**1.20**

Kansas Electric Power Cooperative, Inc.
Allocation Factors
Test Year Ending December 31, 2006

Line No.	Description	Total	Production Demand	Production Energy	Transmission	Delivery Point	KSI
1	Demand	100.0%	100.0%				
2	Energy	100.0%		100.0%			
3	Transmission	100.0%			100.0%		
4	Delivery Point	100.0%				100.0%	
5	KSI	100.0%					100.0%
6							
7	KEPCo Gross Plant	100.0%	64.2%	0.0%	24.4%	11.4%	0.0%
8	Total Gross Plant	100.0%	97.0%	0.0%	2.0%	1.0%	0.0%
9	Total Net Plant	100.0%	91.1%	0.0%	6.0%	2.9%	0.0%
10	Rate Base	100.0%	81.8%	8.3%	7.0%	2.9%	0.0%
11							
12	Labor	100.0%	58.4%	0.0%	21.4%	20.3%	0.0%
13	A&G	100.0%	29.2%	29.2%	21.4%	20.3%	0.0%
14	CWC	100.0%	32.5%	52.0%	14.5%	1.0%	0.0%
15	Pur Power-Pre Adj	100.0%	31.5%	61.4%	7.1%		
16	Purchased Power	100.0%	28.6%	63.5%	7.9%		
17							
18	Revenue	100.0%	39.9%	43.2%	14.3%	2.6%	0.0%

Kansas Electric Power Cooperative, Inc.
Rate Base Calculation
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Allocation Factor	Total	Production Demand	Production Energy	Transmission	Delivery Point	KSI
1		**Plant in Service**							
2		Intangible Plant							
3	301.00	Organization	Labor	-	-	-	-	-	-
4	302.00	Franchises and Consents	Labor	-	-	-	-	-	-
5	303.00	Miscellaneous Intangible Plant	Labor	1,070,204	624,619	-	228,580	217,005	-
6		Total Intangible Plant		1,070,204	624,619	-	228,580	217,005	-
7									
8		Nuclear Plant							
9	320.00	Land and Land Rights	Demand	(20,618,535)	(20,618,535)	-	-	-	-
10	321.00	Structures and Improvements	Demand	63,537,184	63,537,184	-	-	-	-
11	322.00	Reactor Plant Equipment	Demand	101,406,279	101,406,279	-	-	-	-
12	323.00	Turbogenerator Units	Demand	26,609,896	26,609,896	-	-	-	-
13	324.00	Accessory Electric Equipment	Demand	21,284,050	21,284,050	-	-	-	-
14	325.00	Miscellaneous Power Plant Equipment	Demand	9,748,769	9,748,769	-	-	-	-
15	326.00	Retirement Costs	Demand	4,631,744	4,631,744	-	-	-	-
16		Total Nuclear Plant		206,599,388	206,599,388	-	-	-	-
17									
18		Other Production Plant							
19	340.00	Land and Land Rights	Demand	-	-	-	-	-	-
20	341.00	Structures and Improvements	Demand	78,560	78,560	-	-	-	-
21	342.00	Fuel Holders, Producers and Accessories	Demand	-	-	-	-	-	-
22	343.00	Prime Movers	Demand	-	-	-	-	-	-
23	344.00	Generators	Demand	3,563,447	3,563,447	-	-	-	-
24	345.00	Accessory Electric Equipment	Demand	1,796,966	1,796,966	-	-	-	-
25	346.00	Miscellaneous Power Plant Equipment	Demand	-	-	-	-	-	-
26		Total Other Production Plant		5,438,973	5,438,973	-	-	-	-
27									
28		Transmission Plant							
29	350.00	Land and Land Rights	Transmission	45	-	-	45	-	-
30	352.00	Structures and Improvements	Transmission	33,000	-	-	33,000	-	-
31	353.00	Station Equipment	Transmission	1,897,079	-	-	1,897,079	-	-
32	354.00	Tower and Fixtures	Transmission	-	-	-	-	-	-
33	355.00	Poles and Fixtures	Transmission	7,437	-	-	7,437	-	-
34	356.00	Overhead Conductors and Devices	Transmission	210,063	-	-	210,063	-	-
35	357.00	Underground Conduit	Transmission	-	-	-	-	-	-
36	358.00	Underground Conductors and Devices	Transmission	-	-	-	-	-	-
37	359.00	Roads and Trails	Transmission	-	-	-	-	-	-
38		Total Transmission Plant		2,147,624	-	-	2,147,624	-	-
39									
40		General Plant							
41	389.00	Land and Land Rights	Labor	320,133	186,844	-	68,376	64,913	-

Kansas Electric Power Cooperative, Inc.
Rate Base Calculation
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Allocation Factor	Total	Production Demand	Production Energy	Transmission	Delivery Point	KSI
42	390.00	Structures and Improvements	Labor	1,895,053	1,106,038	-	404,756	384,259	-
43	391.00	Office Furniture and Equipment	Labor	1,010,081	589,529	-	215,739	204,814	-
44	392.00	Transportation Equipment	Labor	306,210	178,718	-	65,402	62,090	-
45	393.00	Stores Equipment	Labor	-	-	-	-	-	-
46	394.00	Tools, Shop and Garage Equipment	Labor	62,345	36,387	-	13,316	12,642	-
47	395.00	Laboratory Equipment	Labor	196,459	114,662	-	41,961	39,836	-
48	396.00	Power Operated Equipment	Labor	16,110	9,403	-	3,441	3,267	-
49	397.00	Communication Equipment	Labor	5,930,427	3,461,262	-	1,266,655	1,202,510	-
50	398.00	Miscellaneous Equipment	Labor	-	-	-	-	-	-
51	399.00	Other Tangible Property	Labor	-	-	-	-	-	-
52		Total General Plant		9,736,818	5,682,842	-	2,079,646	1,974,330	-
53									
54		**Total Plant In Service**		**224,993,008**	**218,345,822**	**-**	**4,455,851**	**2,191,334**	**-**
55									
56		KEPCO Plant In Service (excl Nuclear)		17,323,416	11,121,815	-	4,227,270	1,974,330	-
57									
58		Accumulated Depreciation							
59	108.00	Accum Depreciation of Electric Utility Plant	KEPCo Gross Plant	(5,657,350)	(3,632,079)	-	(1,380,510)	(644,762)	-
60	108.20	Accum Depreciation of Nuclear Production Plant	Demand	(128,179,752)	(128,179,752)	-	-	-	-
61	108.80	Retirement Work in Progress	KEPCo Gross Plant	14,003,468	8,990,374	-	3,417,135	1,595,959	-
62	111.00	Accumulated Amortization of Electric Utility Plant	KEPCo Gross Plant	(998,065)	(640,769)	-	(243,549)	(113,748)	-
63		Total Accumulated Depreciation		(120,831,700)	(123,462,225)	-	1,793,076	837,449	-
64									
65		**Total Net Plant In Service**		**104,161,307**	**94,883,597**	**-**	**6,248,927**	**3,028,784**	**-**
66									
67		Working Capital							
68	120.00	Nuclear Fuel (Net)	Energy	4,921,775	-	4,921,775	-	-	-
69	151.00	Fuel Stock	Energy	37,287	-	37,287	-	-	-
70	154.00	Plant Materials and Operating Supplies	KEPCo Gross Plant	2,906,204	1,865,813	-	709,174	331,217	-
71	163.00	Stores Expense Undistributed	KEPCo Gross Plant	39,985	25,671	-	9,757	4,557	-
72	165.10	Prepayments - Insurance	Labor	83,282	48,607	-	17,788	16,887	-
73	165.20	Other Prepayments	KEPCo Gross Plant	327,226	210,083	-	79,850	37,294	-
74		Cash Working Capital	CWC	10,103,267	3,284,089	5,252,614	1,468,164	98,399	-
75		Total Working Capital		18,419,025	5,434,263	10,211,676	2,284,732	488,354	-
76									
77		**Total Rate Base**		**122,580,332**	**100,317,860**	**10,211,676**	**8,533,659**	**3,517,137**	**-**

Kansas Electric Power Cooperative, Inc.
Labor Allocations
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Allocation Factor	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point	KSI
1		**Operating Expenses**							
2		Nuclear Power Production Expense							
3	517.00	Operation Supervision and Engineering	Demand	-	-	-	-	-	-
4	518.00	Nuclear Fuel Expense	Energy	-	-	-	-	-	-
5	519.00	Coolants and Water	Demand	-	-	-	-	-	-
6	520.00	Steam Expenses	Demand	-	-	-	-	-	-
7	521.00	Steam from Other Sources	Demand	-	-	-	-	-	-
8	522.00	Steam Transferred - Credit	Demand	-	-	-	-	-	-
9	523.00	Electric Expenses	Demand	-	-	-	-	-	-
10	524.00	Miscellaneous Nuclear Power Expenses	Demand	79,928	79,928	-	-	-	-
11	525.00	Rents	Demand	-	-	-	-	-	-
12		Subtotal Operations Expense		79,928	79,928	-	-	-	-
13									
14	528.00	Maintenance Supervision and Engineering	Energy	-	-	-	-	-	-
15	529.00	Maintenance of Structures	Demand	-	-	-	-	-	-
16	530.00	Maintenance of Reactor Plant Equipment	Energy	-	-	-	-	-	-
17	531.00	Maintenance of Electric Plant	Energy	-	-	-	-	-	-
18	532.00	Maintenance of Miscellaneous Nuclear Plant	Demand	-	-	-	-	-	-
19		Subtotal Maintenance Expense		-	-	-	-	-	-
20		Total Nuclear Power Production Expense		79,928	79,928	-	-	-	-
21									
22		Other Power Production Expense							
23	546.00	Operation Supervision and Engineering	Demand	8,226	8,226	-	-	-	-
24	547.00	Fuel	Energy	-	-	-	-	-	-
25	548.00	Generation Expenses	Demand	33,274	33,274	-	-	-	-
26	549.00	Miscellaneous Other Power Generation Expenses	Demand	-	-	-	-	-	-
27	550.00	Rents	Demand	-	-	-	-	-	-
28		Subtotal Operations Expense		41,499	41,499	-	-	-	-
29									
30	551.00	Maintenance Supervision and Engineering	Demand	-	-	-	-	-	-
31	552.00	Maintenance of Structures	Demand	-	-	-	-	-	-
32	553.00	Maintenance of Generating and Electric Equipment	Demand	33,807	33,807	-	-	-	-
33	554.00	Maint of Miscellaneous Other Power Generation Plant	Demand	-	-	-	-	-	-
34		Subtotal Maintenance Expense		33,807	33,807	-	-	-	-
35		Total Other Power Production Expense		75,307	75,307	-	-	-	-
36									
37		Other Power Supply Expense							
38	555.00	Purchased Power	Purchased Power	-	-	-	-	-	-
39	556.00	System Control and Load Dispatching	Demand	219,588	219,588	-	-	-	-
40	557.00	Other Expenses	Demand	444,904	444,904	-	-	-	-
41		Total Other Power Supply Expense		664,492	664,492	-	-	-	-

Kansas Electric Power Cooperative, Inc.
Labor Allocations
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Allocation Factor	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point	KSI
42									
43		Transmission Expense							
44	560.00	Operation Supervision and Engineering	Transmission	114,191	-	-	114,191	-	-
45	561.00	Load Dispatching	Transmission	-	-	-	-	-	-
46	562.00	Station Expenses	Transmission	-	-	-	-	-	-
47	563.00	Overhead Line Expenses	Transmission	-	-	-	-	-	-
48	564.00	Underground Line Expenses	Transmission	-	-	-	-	-	-
49	565.00	Transmission of Electricity by Others	Transmission	-	-	-	-	-	-
50	566.00	Miscellaneous Transmission Expenses	Transmission	25,363	-	-	25,363	-	-
51	567.00	Rents	Transmission	-	-	-	-	-	-
52	568.00	Maintenance Supervision and Engineering	Transmission	36,754	-	-	36,754	-	-
53	569.00	Maintenance of Structures	Transmission	-	-	-	-	-	-
54	570.00	Maintenance of Station Equipment	Transmission	123,673	-	-	123,673	-	-
55	571.00	Maintenance of Overhead Lines	Transmission	-	-	-	-	-	-
56	572.00	Maintenance of Underground Lines	Transmission	-	-	-	-	-	-
57	573.00	Maintenance of Miscellaneous Transmission Plant	Transmission	-	-	-	-	-	-
58		Total Transmission Expense		299,981	-	-	299,981	-	-
59									
60		Customer Accounts Expense							
61	901.00	Supervision	Delivery Point	-	-	-	-	-	-
62	902.00	Meter Reading Expenses	Delivery Point	-	-	-	-	-	-
63	903.00	Customer Records and Collection Expenses	Delivery Point	83,461	-	-	-	83,461	-
64	904.00	Uncollectible Accounts	Delivery Point	-	-	-	-	-	-
65	905.00	Miscellaneous Customer Accounts Expenses	Delivery Point	-	-	-	-	-	-
66		Total Customer Accounts Expense		83,461	-	-	-	83,461	-
67									
68		Customer Service & Information Expense							
69	907.00	Supervision	Delivery Point	-	-	-	-	-	-
70	908.00	Customer Assistance Expenses	Delivery Point	68,971	-	-	-	68,971	-
71	909.00	Informational and Instructional Advertising Expenses	Delivery Point	-	-	-	-	-	-
72	910.00	Misc Customer Service and Informational Expenses	Delivery Point	-	-	-	-	-	-
73		Total Customer Service & Information Expense		68,971	-	-	-	68,971	-
74									
75		Sales							
76	911.00	Supervision	Delivery Point	-	-	-	-	-	-
77	912.00	Demonstrating and Selling Expenses	Delivery Point	121,418	-	-	-	121,418	-
78	913.00	Advertising Expenses	Delivery Point	10,939	-	-	-	10,939	-
79	916.00	Miscellaneous Sales Expenses	Delivery Point	-	-	-	-	-	-
80		Total Sales Expense		132,357	-	-	-	132,357	-
81									
82		**Subtotal Labor Expense**		**1,404,497**	**819,727**	**-**	**299,981**	**284,789**	**-**

Kansas Electric Power Cooperative, Inc.
Labor Allocations
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Allocation Factor	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point	KSI
83									
84		Administrative and General Expense							
85	920.00	Administrative and General Salaries	A&G	1,099,412	320,833	320,833	234,819	222,927	-
86	921.00	Office Supplies and Expenses	A&G	-	-	-	-	-	-
87	922.00	Administrative Expenses Transferred - Credit	A&G	-	-	-	-	-	-
88	923.00	Outside Services Employed	A&G	-	-	-	-	-	-
89	924.00	Property Insurance	A&G	-	-	-	-	-	-
90	925.00	Injuries and Damages	A&G	-	-	-	-	-	-
91	926.00	Employee Pensions and Benefits	A&G	-	-	-	-	-	-
92	927.00	Franchise Requirements	A&G	-	-	-	-	-	-
93	928.00	Regulatory Commission Expenses	A&G	129,443	37,774	37,774	27,647	26,247	-
94	929.00	Duplicate Charges - Credit	A&G	-	-	-	-	-	-
95	930.10	General Advertising Expenses	A&G	-	-	-	-	-	-
96	930.20	Miscellaneous General Expenses	A&G	-	-	-	-	-	-
97	931.00	Rents	A&G	-	-	-	-	-	-
98	935.00	Maintenance of General Plant	A&G	-	-	-	-	-	-
99		Total Administrative and General Expense		1,228,856	358,607	358,607	262,466	249,174	-
100									
101		**Total Labor Expense**		**2,633,352**	**1,178,335**	**358,607**	**562,447**	**533,964**	**-**

Kansas Electric Power Cooperative, Inc.

Purchased Power & Transmission by Others Expenses
Test Year Ending December 31, 2006

Line No.	Acct No.	Description		Test Year with Accounting Adjustments	Weather Normalization	Weather Normalized Test Year	Purchased Power Adjustments	Adjusted Test Year
1		**Demand ($)**						
2	555.00	Westar Energy	D	11,768,879	(2,764,724)	9,004,155	-	9,004,155
3	555.00	Aquila Networks - WPE	T	2,782,560	-	2,782,560	-	2,782,560
4	555.00	Kansas City Power & Light	D	744,319	(18,044)	726,275	(726,275)	-
5	555.00	Kansas City Power & Light - Transmission	T	144,759	(3,539)	141,220	1	141,221
6	555.00	Empire District Electric	D	568,400	-	568,400	(568,400)	-
7	555.00	City of St. Marys	D	-	-	-	-	-
8	555.00	Sunflower Electric Power	D	3,711,893	(185,199)	3,526,694	(37,718)	3,488,976
9	555.00	Sunflower Electric Power - Transmission	T	63,045	-	63,045	14,930	77,976
10	565.00	Southwest Power Pool		5,813,449	-	5,813,449	-	5,813,449
11	555.00	Southwestern Power Administration	D	3,624,920	-	3,624,920	-	3,624,920
12	555.00	Western Area Power Administration	D	558,891	-	558,891	3	558,894
13								
14		Total Demand ($)		29,781,115	(2,971,505)	26,809,610	(1,317,458)	25,492,151
15								
16		**Energy ($)**						
17	555.00	Westar Energy	E	29,257,145	(3,494,578)	25,762,567	-	25,762,567
18	555.00	Aquila Networks - WPE	T	1,723,443	(96,547)	1,626,896	-	1,626,896
19	555.00	Kansas City Power & Light	E	1,054,930	(33,480)	1,021,450	1,282,759	2,304,209
20	555.00	Kansas City Power & Light - Transmission	T	33,426	(953)	32,473	(32,473)	-
21	555.00	Empire District Electric	E	48,854	-	48,854	(48,854)	-
22	555.00	City of St. Marys	E	7,315	-	7,315	-	7,315
23	555.00	City of St. Marys - Transmission	T	454	-	454	-	454
24	555.00	Sunflower Electric Power	E	7,281,595	(523,472)	6,758,123	241,427	6,999,550
25	565.00	Southwest Power Pool		838,126	-	838,126	-	838,126
26	555.00	Southwestern Power Administration	E	2,877,800	-	2,877,800	(1,264,493)	1,613,307
27	555.00	Western Area Power Administration	E	1,158,370	-	1,158,370	(3)	1,158,367
28								
29		Total Energy ($)		44,281,457	(4,149,031)	40,132,426	178,364	40,310,790
30								
31		**Subtotal Purchased Power & Transmission by Others ($)**		74,062,572	(7,120,536)	66,942,036	(1,139,095)	65,802,941
32	555.00	Amortization of Outage Replacement Power ($)	E	(827,550)	-	(827,550)	-	(827,550)
33		**Total Purchased Power & Transmission by Others ($)**		**73,235,022**	**(7,120,536)**	**66,114,486**	**(1,139,095)**	**64,975,391**
34								
35	555.00	Total Purchased Power ($)		66,583,447	(7,120,536)	59,462,911	(1,139,095)	58,323,817
36	555.00	Purchased Power Demand ($)	D	20,977,302	(2,967,967)	18,009,335	(1,332,390)	16,676,945
37	555.00	Purchased Power Transmission ($)	T	4,747,686	(101,039)	4,646,647	(17,541)	4,629,106
38	555.00	Purchased Power Energy ($)	E	40,858,459	(4,051,530)	36,806,929	210,836	37,017,765
39								
40	565.00	Transmission by Others ($)		6,651,575	-	6,651,575	-	6,651,575
41								
42	555.00	Purchased Power Demand (%)		31.5%		30.3%		28.6%
43	555.00	Purchased Power Transmission (%)		7.1%		7.8%		7.9%
44	555.00	Purchased Power Energy (%)		61.4%		61.9%		63.5%
45	555.00	Total Purchased Power (%)		100.0%		100.0%		100.0%

Kansas Electric Power Cooperative, Inc.
Detailed Revenue Requirement
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Adjusted Test Year	Allocation Factor	Production Demand	Production Energy	Transmission	Delivery Point	KSI
1		**Operating Revenues**							
2	447.10	Member Revenues	107,876,815		43,099,721	46,584,165	15,432,263	2,760,666	-
3	447.20	Non-Member Sales	64,089	Energy	-	64,089	-	-	-
4	454.00	Other Operating Revenues	2,386	Rate Base	1,953	199	166	68	-
5		**Total Operating Revenues**	**107,943,289**		**43,101,674**	**46,648,452**	**15,432,429**	**2,760,734**	-
6									
7		**Operating Expenses**							
8		Nuclear Power Production Expense							
9	517.00	Operation Supervision and Engineering	955,028	Demand	955,028	-	-	-	-
10	518.00	Nuclear Fuel Expense	2,382,257	Energy	-	2,382,257	-	-	-
11	519.00	Coolants and Water	608,208	Demand	608,208	-	-	-	-
12	520.00	Steam Expenses	3,026,040	Demand	3,026,040	-	-	-	-
13	521.00	Steam from Other Sources	-	Demand	-	-	-	-	-
14	522.00	Steam Transferred - Credit	-	Demand	-	-	-	-	-
15	523.00	Electric Expenses	251,742	Demand	251,742	-	-	-	-
16	524.00	Miscellaneous Nuclear Power Expenses	2,920,317	Demand	2,920,317	-	-	-	-
17	525.00	Rents	-	Demand	-	-	-	-	-
18		Subtotal Operations Expense	10,143,592		7,761,335	2,382,257	-	-	-
19									
20	528.00	Maintenance Supervision and Engineering	838,256	Energy	-	838,256	-	-	-
21	529.00	Maintenance of Structures	319,556	Demand	319,556	-	-	-	-
22	530.00	Maintenance of Reactor Plant Equipment	1,187,253	Energy	-	1,187,253	-	-	-
23	531.00	Maintenance of Electric Plant	571,859	Energy	-	571,859	-	-	-
24	532.00	Maintenance of Miscellaneous Nuclear Plant	(174,065)	Demand	(174,065)	-	-	-	-
25		Subtotal Maintenance Expense	2,742,859		145,491	2,597,368	-	-	-
26		Total Nuclear Power Production Expense	12,886,450		7,906,825	4,979,625	-	-	-
27									
28		Other Power Production Expense							
29	546.00	Operation Supervision and Engineering	26,807	Demand	26,807	-	-	-	-
30	547.00	Fuel	23,525	Energy	-	23,525	-	-	-
31	548.00	Generation Expenses	33,274	Demand	33,274	-	-	-	-
32	549.00	Miscellaneous Other Power Generation Expenses	2,650	Demand	2,650	-	-	-	-
33	550.00	Rents	-	Demand	-	-	-	-	-
34		Subtotal Operations Expense	86,255		62,730	23,525	-	-	-
35									
36	551.00	Maintenance Supervision and Engineering	-	Demand	-	-	-	-	-
37	552.00	Maintenance of Structures	-	Demand	-	-	-	-	-
38	553.00	Maintenance of Generating and Electric Equipment	80,156	Demand	80,156	-	-	-	-
39	554.00	Maint of Miscellaneous Other Power Generation Plant	-	Demand	-	-	-	-	-
40		Subtotal Maintenance Expense	80,156		80,156	-	-	-	-
41		Total Other Power Production Expense	166,411		142,887	23,525	-	-	-
42									

Kansas Electric Power Cooperative, Inc.
Detailed Revenue Requirement
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Adjusted Test Year	Allocation Factor	Production Demand	Production Energy	Transmission	Delivery Point	KSI
43		Other Power Supply Expense							
44	555.00	Purchased Power	58,323,817	Purchased Power	16,676,945	37,017,765	4,629,106	-	-
45	556.00	System Control and Load Dispatching	817,068	Demand	817,068	-	-	-	-
46	557.00	Other Expenses	728,991	Demand	728,991	-	-	-	-
47		Total Other Power Supply Expense	59,869,875		18,223,004	37,017,765	4,629,106	-	-
48									
49		Transmission Expense							
50	560.00	Operation Supervision and Engineering	114,191	Transmission	-	-	114,191	-	-
51	561.00	Load Dispatching	-	Transmission	-	-	-	-	-
52	562.00	Station Expenses	14,021	Transmission	-	-	14,021	-	-
53	563.00	Overhead Line Expenses	-	Transmission	-	-	-	-	-
54	564.00	Underground Line Expenses	-	Transmission	-	-	-	-	-
55	565.00	Transmission of Electricity by Others	6,651,575	Transmission	-	-	6,651,575	-	-
56	566.00	Miscellaneous Transmission Expenses	41,459	Transmission	-	-	41,459	-	-
57	567.00	Rents	-	Transmission	-	-	-	-	-
58	568.00	Maintenance Supervision and Engineering	38,597	Transmission	-	-	38,597	-	-
59	569.00	Maintenance of Structures	-	Transmission	-	-	-	-	-
60	570.00	Maintenance of Station Equipment	256,359	Transmission	-	-	256,359	-	-
61	571.00	Maintenance of Overhead Lines	-	Transmission	-	-	-	-	-
62	572.00	Maintenance of Underground Lines	-	Transmission	-	-	-	-	-
63	573.00	Maintenance of Miscellaneous Transmission Plant	-	Transmission	-	-	-	-	-
64		Total Transmission Expense	7,116,202		-	-	7,116,202	-	-
65									
66		Customer Accounts Expense							
67	901.00	Supervision	-	Delivery Point	-	-	-	-	-
68	902.00	Meter Reading Expenses	-	Delivery Point	-	-	-	-	-
69	903.00	Customer Records and Collection Expenses	196,611	Delivery Point	-	-	-	196,611	-
70	904.00	Uncollectible Accounts	-	Delivery Point	-	-	-	-	-
71	905.00	Miscellaneous Customer Accounts Expenses	-	Delivery Point	-	-	-	-	-
72		Total Customer Accounts Expense	196,611		-	-	-	196,611	-
73									
74		Customer Service & Information Expense							
75	907.00	Supervision	-	Delivery Point	-	-	-	-	-
76	908.00	Customer Assistance Expenses	68,971	Delivery Point	-	-	-	68,971	-
77	909.00	Informational and Instructional Advertising Expenses	-	Delivery Point	-	-	-	-	-
78	910.00	Misc Customer Service and Informational Expenses	-	Delivery Point	-	-	-	-	-
79		Total Customer Service & Information Expense	68,971		-	-	-	68,971	-
80									
81		Sales							
82	911.00	Supervision	-	Delivery Point	-	-	-	-	-
83	912.00	Demonstrating and Selling Expenses	485,297	Delivery Point	-	-	-	485,297	-
84	913.00	Advertising Expenses	36,315	Delivery Point	-	-	-	36,315	-

Kansas Electric Power Cooperative, Inc.
Detailed Revenue Requirement
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Adjusted Test Year	Allocation Factor	Production Demand	Production Energy	Transmission	Delivery Point	KSI
85	916.00	Miscellaneous Sales Expenses	-	Delivery Point	-	-	-	-	-
86		Total Sales Expense	521,611		-	-	-	521,611	-
87									
88		Subtotal Operating Expenses for CWC	80,826,133		26,272,716	42,020,915	11,745,308	787,194	-
89									
90		Administrative and General Expense							
91	920.00	Administrative and General Salaries	1,819,545	A&G	530,984	530,984	388,629	368,948	-
92	921.00	Office Supplies and Expenses	198,764	A&G	58,004	58,004	42,453	40,303	-
93	922.00	Administrative Expenses Transferred - Credit	(5,237)	A&G	(1,528)	(1,528)	(1,119)	(1,062)	-
94	923.00	Outside Services Employed	317,848	A&G	92,755	92,755	67,888	64,450	-
95	924.00	Property Insurance	-	A&G	-	-	-	-	-
96	925.00	Injuries and Damages	-	A&G	-	-	-	-	-
97	926.00	Employee Pensions and Benefits	11,956	A&G	3,489	3,489	2,554	2,424	-
98	927.00	Franchise Requirements	-	A&G	-	-	-	-	-
99	928.00	Regulatory Commission Expenses	381,683	A&G	111,384	111,384	81,522	77,394	-
100	929.00	Duplicate Charges - Credit	-	A&G	-	-	-	-	-
101	930.10	General Advertising Expenses	7,601	A&G	2,218	2,218	1,623	1,541	-
102	930.20	Miscellaneous General Expenses	1,466,845	A&G	428,058	428,058	313,297	297,431	-
103	931.00	Rents	20,080	A&G	5,860	5,860	4,289	4,072	-
104	935.00	Maintenance of General Plant	65,032	A&G	18,978	18,978	13,890	13,187	-
105		Total Administrative and General Expense	4,284,115		1,250,200	1,250,200	915,026	868,688	-
106									
107		Depreciation and Amortization Expense							
108	403.20	Depreciation Expense - Nuclear Production Plant	2,759,808	Demand	2,759,808	-	-	-	-
109	403.70	Depreciation Expense - General Plant	944,903	Labor	551,488	-	201,818	191,597	-
110	405.00	Amortization of Other Electric Plant	4,499,508	KEPCo Gross Plant	2,888,731	-	1,097,973	512,804	-
111		Total Depreciation and Amortization Expense	8,204,218		6,200,027	-	1,299,790	704,401	-
112									
113		Subtotal Operating Expenses	93,314,466		33,722,943	43,271,115	13,960,125	2,360,283	-
114									
115		Interest on Long-Term Debt							
116	427.00	Interest on Long-Term Debt	8,145,878	Rate Base	6,666,461	678,600	567,091	233,726	-
117	427.30	Interest Charged to Construction - Credit	(63,943)	Rate Base	(52,330)	(5,327)	(4,452)	(1,835)	-
118		Total Interest on Long-Term Debt	8,081,935		6,614,131	673,274	562,639	231,891	-
119									
120		Other Interest Expense							
121	428.00	Amortization of Debt Discount and Expense	120,542	Rate Base	98,649	10,042	8,392	3,459	-
122	431.00	Other Interest Expense	172,704	Rate Base	141,339	14,387	12,023	4,955	-
123		Total Other Interest Expense	293,246		239,988	24,429	20,415	8,414	-
124									
125		Other Deductions							
126	426.10	Donations	5,681	Rate Base	4,650	473	396	163	-

Kansas Electric Power Cooperative, Inc.
Detailed Revenue Requirement
Test Year Ending December 31, 2006

Line No.	Acct No.	Description	Adjusted Test Year	Allocation Factor	Production Demand	Production Energy	Transmission	Delivery Point	KSI
127	426.20	Life Insurance	55,122	Rate Base	45,111	4,592	3,837	1,582	-
128	426.30	Penalties	281	Rate Base	230	23	20	8	-
129	426.40	Expenditures for Certain Civic, Political, and Related Activities	4,623	Rate Base	3,783	385	322	133	-
130		Total Other Deductions	65,707		53,773	5,474	4,574	1,885	-
131									
132		**Total Operating Expenses**	**101,755,354**		**40,630,836**	**43,974,292**	**14,547,753**	**2,602,473**	**-**
133									
134		**Operating Margin**	**6,187,935**	Revenue	**2,470,838**	**2,674,160**	**884,676**	**158,261**	**-**
135									
136		**Non-Operating Revenues**							
137	419.00	Interest and Dividend Income	623,178	Rate Base	509,999	51,914	43,384	17,881	-
138	417.00	Revenues from Nonutility Operations	206	Rate Base	168	17	14	6	-
139	421.00	Miscellaneous Nonoperating Income	(33,582)	Rate Base	(27,483)	(2,798)	(2,338)	(964)	-
140	424.00	Other Capital Credits	42,212	Rate Base	34,546	3,517	2,939	1,211	-
141		**Total Non-Operating Revenues**	**632,014**		**517,231**	**52,651**	**43,999**	**18,134**	**-**
142									
143		**Total Margin**	**6,819,950**		**2,988,069**	**2,726,810**	**928,675**	**176,395**	**-**
144									
145		**TIER**	**1.84**						
146		Principal Payment	11,162,494						
147		**DSC**	**1.20**						

Kansas Electric Power Cooperative, Inc.

Evaluation of Economic Development & Rural Energy Credit Riders -- Proposed Rates

Red Text represents Input values

Description	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Economic Development Credit ($/kW)	5.25	4.20	3.15	2.10	1.05	-
Rural Energy Credit ($/MWh)	20.00	17.00	14.00	11.00	8.00	4.00
Weighted Rate Demand Charge ($/kW)	11.20	11.20	11.20	11.20	11.20	11.20
Weighted Rate Energy Charge ($/MWh)	21.13	21.13	21.13	21.13	21.13	21.13
Schedule M-9 Rates						
Production Demand Rate ($/kW)	9.00	9.00	9.00	9.00	9.00	9.00
Production Energy Rate ($/MWh)	32.80	32.80	32.80	32.80	32.80	32.80
Proposed Rates						
Production Demand Rate ($/kW)	9.00	9.00	9.00	9.00	9.00	9.00
Production Energy Rate ($/MWh)	37.54	37.54	37.54	37.54	37.54	37.54
Economic Development Rider						
Load (kW)	50.0	50.0	50.0	50.0	50.0	50.0
Load Factor	50.0%	50.0%	50.0%	50.0%	50.0%	50.0%
Tariff Diversity Factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
M-9 (kW)	50.0	50.0	50.0	50.0	50.0	50.0
Energy (MWh)	219	219	219	219	219	219
Economic Development Credit	3,150	2,520	1,890	1,260	630	-
Demand Costs -- Weighted	6,722	6,722	6,722	6,722	6,722	6,722
Energy Costs -- Weighted	4,627	4,627	4,627	4,627	4,627	4,627
Tariff Revenue -- Existing Rates	12,583	12,583	12,583	12,583	12,583	12,583
Tariff Revenue -- Proposed Rates	13,620	13,620	13,620	13,620	13,620	13,620
Net Revenue -- Existing Rates	(1,916)	(1,286)	(656)	(26)	604	1,234
Net Revenue -- Proposed Rates	(878)	(248)	382	1,012	1,642	2,272
Net Revenue -- Existing Rates ($/MWh)	(8.75)	(5.87)	(2.99)	(0.12)	2.76	5.64
Net Revenue -- Proposed Rates ($/MWh)	(4.01)	(1.13)	1.74	4.62	7.50	10.37

Crossover Calculation	Slope	Y-Intercept	Cross-over (Yrs)
Existing Rate	2.877	(11.623)	4.0
Proposed Rate	2.877	(6.888)	2.4

Kansas Electric Power Cooperative, Inc.

Evaluation of Economic Development & Rural Energy Credit Riders -- Proposed Rates

Red Text represents Input values

Description	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Economic Development Credit ($/kW)	5.25	4.20	3.15	2.10	1.05	-
Rural Energy Credit ($/MWh)	20.00	17.00	14.00	11.00	8.00	4.00
Weighted Rate Demand Charge ($/kW)	11.20	11.20	11.20	11.20	11.20	11.20
Weighted Rate Energy Charge ($/MWh)	21.13	21.13	21.13	21.13	21.13	21.13
Schedule M-9 Rates						
Production Demand Rate ($/kW)	9.00	9.00	9.00	9.00	9.00	9.00
Production Energy Rate ($/MWh)	32.80	32.80	32.80	32.80	32.80	32.80
Proposed Rates						
Production Demand Rate ($/kW)	9.00	9.00	9.00	9.00	9.00	9.00
Production Energy Rate ($/MWh)	37.54	37.54	37.54	37.54	37.54	37.54
Rural Energy Credit						
Load (kW)	10.0	10.0	10.0	10.0	10.0	10.0
Load Factor	36.0%	36.0%	36.0%	36.0%	36.0%	36.0%
Tariff Diversity Factor	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
M-9 (kW)	10.0	10.0	10.0	10.0	10.0	10.0
Energy (MWh)	32	32	32	32	32	32
Rural Energy Credit	631	536	442	347	252	126
Demand Costs -- Weighted	1,344	1,344	1,344	1,344	1,344	1,344
Energy Costs -- Weighted	666	666	666	666	666	666
Tariff Revenue -- Existing Rates	2,114	2,114	2,114	2,114	2,114	2,114
Tariff Revenue -- Proposed Rates	2,264	2,264	2,264	2,264	2,264	2,264
Net Revenue -- Existing Rates	(527)	(432)	(338)	(243)	(149)	(22)
Net Revenue -- Proposed Rates	(378)	(283)	(188)	(94)	1	127
Net Revenue -- Existing Rates ($/MWh)	(16.71)	(13.71)	(10.71)	(7.71)	(4.71)	(0.71)
Net Revenue -- Proposed Rates ($/MWh)	(11.97)	(8.97)	(5.97)	(2.97)	0.03	4.03

Crossover Calculation	Slope	Y-Intercept	Cross-over (Yrs)
Existing Rate	3.143	(20.043)	6.4
Proposed Rate	3.143	(15.308)	4.9

Kansas Electric Power Cooperative, Inc.
Evaluation of Economic Development & Rural Energy Credit Riders

Line No	Description	Reference	Economic Development Rider: Existing Rates	Economic Development Rider: Proposed Rates	Rural Energy Credit: Existing Rates	Rural Energy Credit: Proposed Rates
1	Assumed Load (kW)	Input	1.0	1.0	1.0	1.0
2	Assumed Load Factor	Input	50.0%	50.0%	36.0%	36.0%
3	Assumed Load (MWh)	L1 * L2 * 8.760	4.380	4.380	3.154	3.154
4	Term of Rider (years)	Input	5.0	5.0	6.0	6.0
5						
6	KEPCo Revenues Received					
7	Tariff Demand Charge ($/kW-Mo)	Input	9.00	9.00	9.00	9.00
8	Energy Charge ($/MWh)	Input	32.80	37.54	32.80	37.54
9						
10	Demand Revenues over Term	L1 * L7 * L4 * 12	540	540	648	648
11	Energy Revenues over Term	L3 * L8 * L4	718	822	621	710
12	Total Revenues	L10 + L11	1,258	1,362	1,269	1,358
13						
14	Rider Payments					
15	Rider Payments (rate) - Year 1	Input	5.25	5.25	20.00	20.00
16	Rider Payments (rate) - Year 2	Input	4.20	4.20	17.00	17.00
17	Rider Payments (rate) - Year 3	Input	3.15	3.15	14.00	14.00
18	Rider Payments (rate) - Year 4	Input	2.10	2.10	11.00	11.00
19	Rider Payments (rate) - Year 5	Input	1.05	1.05	8.00	8.00
20	Rider Payments (rate) - Year 6	Input	-	-	4.00	4.00
21	Total EDR Payments	sum(L15:L20) * 12 * L1	189	189		
22	Total REC Payments	sum(L15:L20) * L3			233	233
23						
24	Purchased Power Costs					
25	Demand Charge ($/kW-Mo)	Input	5.48	11.20	5.48	11.20
26	Energy Charge ($/MWh)	Input	35.28	21.13	35.28	21.13
27						
28	Demand Costs over Term	L1 * L25 * L4 * 12	329	672	394	807
29	Energy Costs over Term	L3 * L26 * L4	773	463	667	400
30	Total Purchased Power Costs	L28 + L29	1,101	1,135	1,062	1,206
31						
32	Total Costs	L21(EDR) + L22(REC) + L30	1,290	1,324	1,295	1,440
33						
34	Net Revenues (Costs)	L12 - L32	(32)	38	(27)	(82)
35	Net Revenues (Costs) ($/kW-Yr)	L34 / L1	(31.83)	38.15	(26.54)	(81.52)
36	Net Revenues (Costs) ($/MWh)	L34 / L3	(7.27)	8.71	(8.42)	(25.85)
37						
38	Breakeven %					
39	Total Rider Payments	sum(L15:L20)	15.75	15.75	74.00	74.00
40	Breakeven Rider Payments (EDR)	L39 + L35/12	13.10	18.93		
41	Breakeven Rider Payments (REC)	L39 + L36			65.58	48.15
42	Breakeven %	L40(EDR); L41(REC) / L39 - 1	-16.8%	20.2%	-11.4%	-34.9%