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Kansas Corporation Commission
/S/ Susan K. Duffy

BEFORE THE
STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

DOCKET NO. 08-KEPE-597-RTS

DIRECT TESTIMONY
OF
CARL N. STOVER, P.E.

ON BEHALF OF
KANSAS ELECTRIC POWER COOPERATIVE, INC.

December 21, 2007

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Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Carl N. Stover; my business address is 5555 North Grand Boulevard, Oklahoma City, Oklahoma 73112-5507.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION WITH THE FIRM?

A. I am employed by C. H. Guernsey & Company, Engineers • Architects • Consultants. I served as President and CEO of the firm from 1989 to 2005 and as Chairman of Board from 2005 to present. My consulting activities include rate and financial analysis on behalf of our clients before state and regulatory commissions. I am also involved in long range system planning, development of financial forecasts, and engineering feasibility studies related to power supply planning and contract negotiations.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a Bachelor of Science degree in Electrical Engineering and a Master of Science degree in Industrial Engineering. I am a Registered Professional

Engineer, licensed in the states of Colorado, Iowa, Kansas, Oklahoma, Texas, and Wyoming. I am a member of the Power Engineering Society and the Engineering Management Society of the Institute of Electrical and Electronics Engineers.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE STATE REGULATORY COMMISSIONS ON MATTERS RELATED TO COST OF SERVICE, RATE DESIGN, AND POWER SUPPLY PLANNING?

A. Yes. I have appeared before regulatory commissions in the states of Arkansas, Colorado, Iowa, Kansas, New Mexico, Oklahoma, Texas, Utah, and Wyoming. Exhibit CNS-1 attached to this testimony contains a summary of the retail rate proceedings in which I have been involved.

Q. HAVE YOU BEEN INVOLVED IN WHOLESALE RATE PROCEEDINGS?

A. Yes. I have been involved in a number of proceedings before state and federal regulatory agencies that involved cost of service and rate design issues related to wholesale rates. A summary of the wholesale rate proceedings in which I have participated also can be found in Exhibit CNS-1.

Q. HAVE YOU PUBLISHED OR PRESENTED PAPERS CONCERNING PLANNING, RATE DESIGN, COST OF SERVICE, ETC.?

A. Yes. Exhibit CNS-1 also lists my papers and presentations.

Q. WHOM DO YOU REPRESENT IN THIS PROCEEDING?

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

I. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe:

1. The development of the proposed Schedule M-10, All Requirements Member Wholesale Electric Service tariff (M-10) found in Section 18 of KEPCo's filing, under which KEPCo will sell power to its Members.

2. The proposed Demand Cost Adjustment (DCA) which, along with the existing Energy Cost Adjustment (ECA), will provide a mechanism for KEPCo to flow through to the Members any changes in the cost of purchased power.

3. The proposed interim rate and/or energy adder which is intended to be in place for a limited period of time or the expedited treatment of this filing, that will help ensure that KEPCo is able to maintain adequate debt service coverage (DSC) for 2008.

4. The proposed rate phase-in proposed for the M-10 tariff.

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

A. Yes. Exhibit CNS-2 consists of a number of different schedules that I will reference in my testimony.

Q. WERE THE SCHEDULES INCLUDED IN EXHIBIT CNS-2 PREPARED EITHER DIRECTLY BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. WHAT INFORMATION DID YOU RELY ON IN THE PREPARATION OF THE SCHEDULES IN EXHIBIT CNS-2?

A. I used information provided by Dr. Bowser, Ms. Wells, and the cost of service (COS) analysis developed by Mr. Naylor.

II. RATEMAKING PROCESS

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE PROPOSED M-10 TARIFF AND HOW THE KEPCO BOARD OF TRUSTEES (BOARD) DECIDED ON THE PROPOSED M-10 RATE DESIGN.

A. Mr. Parr outlined in his testimony the reasons for the filing of the M-10 tariff and the process that the Board went through in adopting the tariff. For my part, the process began with a workshop presentation to the Board in February 2007 at which time the key elements of the ratemaking process were outlined to the Board. Those elements included:

1. Selection of the historical test year
2. Development of weather normalized billing units for the test year
3. Development of test year adjustments including
   a. Expenses
   b. Purchased Power Cost
   d. Revenue
4. Development of margin requirement
5. Determination of appropriate costs to reflect existing programs including:
   a. High Voltage Discount
   b. Rural Energy Credit
   c. Economic Development
6. Determination of Member revenue requirement
7. Development of cost of service analysis with revenue requirements defined by:
   a. Cost Function
   b. Cost Classification

8. Determination of revenue requirements for each cost function and classification to be recovered from rates
9. Definition of billing units for recovery of cost
10. Development of M-10 rate tariff

The objective was to identify a process that would allow the Board to understand all activities involved in the ratemaking process and have the data to understand the issues and make the required decisions. An important part of the process was to explain that rate making is not a precise science, that a great deal of judgment is involved, and that decisions made related to one part of the rate design will impact other elements of the rate design. This is extremely important in developing rates for a G&T like KEPCo because the Board represents the ultimate rate payers (i.e., the retail member consumers served by the Members). The Members are responsible for developing not only the wholesale rate but also the retail rates that will recover the KEPCo wholesale power cost in a fair and equitable manner from their respective retail member consumers. The Members must therefore always consider the impact of the KEPCo wholesale rate on their respective retail rates. The Directors are responsible for weighing the different factors and making the final decisions that will impact their retail member consumers.

Q. DID YOU PARTICIPATE IN THE SERIES OF MEMBER MEETINGS DESCRIBED BY MR. PARR?

A. Yes. I believe there were a total of nine board meetings in which I participated. The rate study meeting would typically be from 1 P.M. to 5 P.M. on the first day of the monthly KEPCo Board meeting, so I would estimate that the Board invested at least thirty-six hours in discussing wholesale rate design. On occasion there was further discussion on the second day of the Board meeting in which I did not participate. I mention this to emphasize the level of commitment made by the entire Board (not just a sub-committee of the Board) in discussing and understanding issues. I have developed wholesale rates for many G&Ts and, based on my experience, the effort expended by the KEPCo Board in the development of the M-10 tariff exceeded what I typically encounter.

Q. WERE THERE ISSUES THAT WERE PARTICULARLY DIFFICULT TO DEAL WITH?

A. I think the most difficult issues involved the treatment of the Purchased Power Agreement between KEPCo and Westar Energy, Inc. (Westar Agreement) that Mr. Parr has described. The Westar Agreement was being negotiated during the period that the KEPCo wholesale rate was being developed. The Board recognized the importance of having a wholesale rate that tracked cost as much as possible. They also recognized that it was important that any change in the wholesale rate design consider the impact on the Member consumer, and, more importantly, the impact on the retail rate design serving the ultimate retail customer.

All discussions up until the November Board meeting assumed the new Westar Agreement would be reflected in the test year adjustments. The Board made a series of decisions given that assumption. As Mr. Parr explained, in November it became apparent that the proposed Westar Agreement being considered could not be reflected as a test year adjustment in development of the M-10 tariff. Given the delays in FERC approval described by Mr. Parr, there was a concern that the Westar Agreement would not meet the KCC standards for known and measurable cost adjustments. The Board then decided to consider the M-10 tariff based on the existing Westar wholesale rate design and associated power cost and to use the proposed DCA and existing ECA to provide for any changes in the purchased power cost associated with Westar when the proposed Westar Agreement is implemented.

Q. IS THE PROPOSED M-10 TARIFF THEREFORE BASED ON THE EXISTING WESTAR WHOLESALE RATE AND RATE DESIGN?

A. Yes.

III. M-10 REVENUE REQUIREMENT FOR RATE DESIGN

Q. PLEASE DESCRIBE THE DETERMINATION OF THE REVENUE REQUIREMENT FOR THE M-10 RATE.

A. Referencing the outline of the ratemaking process presented above, CY2006 was selected as the test-year period. Dr. Bowser developed the weather normalized billing units described in his testimony; Dr. Bowser and Ms. Wells developed the adjustments to test-year expenses described in their testimonies. Dr. Bowser also identified the transmission component of the purchased power cost. Mr. Solomon established the justification for the 1.20 DSC, and Ms. Wells then identified the net margins needed to meet the 1.20 DSC. The Member revenue requirement totaled $107,876,815. Mr. Naylor defined the credits associated with the various Member programs (and the associated cost) that he describes in his testimony, which resulted in the total Rate Requirement of $111,902,560. Mr. Naylor then developed the cost of service study which included functionalization of the revenue requirement and classification of costs. The results of all of these activities are shown on Table 10 of Mr. Naylor's testimony. The Table 10 results provided the starting point for the development of the rate design and are shown as Exhibit CNS-2, Schedule A-1.0. (Note: further references to schedules are to those schedules contained in Exhibit CNS-2.)

Q. HOW DO THE FUNCTIONS SHOWN ON SCHEDULE A-1.0 COMPARE WITH THE FUNCTIONS REFLECTED IN THE CURRENT M-9 RATE?

A. The functions are the same except for the addition of the Delivery Point function.

Q. WHY IS A DELIVERY POINT FUNCTION ADDED?

A. KEPCo delivers capacity and energy to the Members through delivery points and there are costs associated with determining the amount of power delivered and the billing to Members for the service received. As Mr. Naylor explained, these costs vary as a function of the number of delivery points and not by the amount of power delivered. The cost of billing for a 1-MVA delivery point is the same as a 10-MVA delivery point. The recommendation was made, and the Board accepted the concept of removing these costs from the power supply and transmission functions and establishing a delivery point function.

Q. OTHER THAN THE ADDITION OF THE DELIVERY POINT FUNCTION WERE THERE ANY OTHER CHANGES?

A. No. The cost functions and the corresponding rate functions are the same as approved in the development of KEPCo's M-9 tariff. The M-10 tariff functions include:

1. Power Supply Function
2. Transmission Function
3. Delivery Point Function

Q. IS THERE ANY CHANGE IN THE CLASSIFICATION OF COSTS?

A. No. The Power Supply function has costs that are classified as fixed (demand) and variable (energy), and the Transmission function has all costs classified as fixed (demand) which is the same as the current M-9 classifications. The Delivery

Point function classifies all costs to the number of delivery points. Schedule A-1.0 shows both the functionalization and classification of costs based on the COS developed by Mr. Naylor.

Q. WERE ANY ADJUSTMENTS MADE TO THE CLASSIFICATION OF REVENUE REQUIREMENT IN THE DEVELOPMENT OF THE M-10 TARIFF?

A. Yes. A portion of the Power Supply fixed cost was transferred to the Power Supply variable cost to be recovered as a part of the energy charge.

Q. WHAT AMOUNT WAS TRANSFERRED?

A. A total of $15,673,493 was transferred. This corresponded to $9.23/MWh, or approximately 39.8% of the total Power Supply fixed cost reflected in the COS.

Q. IS THE CONCEPT OF TRANSFERRING A PORTION OF THE POWER SUPPLY FIXED COST TO THE POWER SUPPLY VARIABLE TO BE RECOVERED IN THE ENERGY RATE NEW OR DIFFERENT FOR KEPCO?

A. No. There is a similar reclassification of power supply cost reflected in the current M-9 rate design.

Q. WHAT IS THE JUSTIFICATION FOR THE RECLASSIFICATION OF POWER SUPPLY FIXED COST?

A. The justification is based on the following thinking:

1. KEPCo designs its power supply portfolio to serve the total Member load at the lowest possible cost. The power supply portfolio consists of a variety of resources to serve the base load, intermediate load, and peaking load requirements. The resources used to serve base load will typically have a high fixed cost and a low energy cost, whereas the resources used to serve the peak load will have a low fixed cost and a high energy cost. The power supply portfolio is designed to serve the total composite load requirements at the lowest cost.

2. The power supply portfolio that is optimum to serve the composite load will likely not be the optimum portfolio to serve a specific retail load. For example, a Wolf Creek nuclear resource would not be the optimum resource to serve a low load factor agricultural load such as an irrigation pump or corn dryer. A peaking resource such as the Sharpe peaking unit would not be the optimum resource to serve a high load factor industrial load like an ethanol plant.
3. The KEPCo Board has the responsibility to approve rates that allocate the revenue requirement associated with the power supply portfolio to all of the ultimate retail customers in a fair and equitable manner. This means that, as a part of the KEPCo wholesale rate design, the Board needs to allocate the cost associated with the optimum power supply portfolio designed to serve the average load to users who do not have average system usage characteristics.

Q. HOW DID THE BOARD DEAL WITH THIS ISSUE?

A. There are number of ways to deal with this issue. One is subjective and requires the Board to consider how different fixed cost reallocations will impact the retail customer. This involves evaluating different Power Supply pricing curves as reflected by the wholesale rate. The second approach is more quantitative and considers the extent to which fixed costs have been incurred in order to realize lower variable cost. Wolf Creek would be a good example. KEPCo was willing to make the large capital investment and incur the higher annual fixed costs in order to realize lower energy costs. This was a decision based on the need to serve the total load profile of all retail customers. The reality is that the retail customer with the high load factor will benefit more from a resource with low energy cost than the customer with a low load factor. The Board is faced with the question of how to fairly allocate the cost associated with the optimum system power supply portfolio to all users. In particular, should the additional fixed costs incurred to realize the lower energy cost be allocated to the energy component and would this be a fairer way to recover cost from all users?

Q. DID YOU DEVELOP AN ANALYSIS OF ADDITIONAL COSTS INCURRED BY KEPCO TO REALIZE THE LOWER ENERGY COST BENEFITS?

A. Yes. The analysis is characterized as a capital substitution or peaking unit process. The process involves comparing the fixed cost associated with a specific unit or a total portfolio with the fixed cost of a peaking unit. The concept is that the peaking unit reflects a resource used to serve only capacity requirements and that the difference reflects the additional cost incurred in order to realize the benefits of the lower energy cost. This is not a precise process and requires a number of assumptions. However, it is a way to provide some quantification of the issue of cost recovery.

Schedule B-1.0 shows the development of the analysis for KEPCo. KEPCo has 70 MW of Wolf Creek base load resources. The capital cost associated with the Wolf Creek resource totals $206.6 million and the annual fixed cost (debt service and O&M), is approximately $299.23/kW/year. Assuming a peaking unit at $525/kW and estimated O&M of approximately $30.24/year, the annual cost is approximately $75.29/kW/year. The difference is $224/kW/year, which when applied to the owned Wolf Creek capacity of 70 MW results in $15.7 million/year.

Q. HOW MUCH OF THE PRODUCTION DEMAND COST DID THE BOARD DECIDE TO REALLOCATE TO THE ENERGY FUNCTION TO BE RECOVERED IN THE PRODUCTION ENERGY CHARGE?

A. The Board decided to reallocate $15,673,493 to the Production Energy function. This corresponded to $9.23/MWh, or 39.8% of the total Production Demand cost.

Q. WHAT IS THE RESULTING REVENUE REQUIREMENT FOR EACH COMPONENT OF THE PROPOSED RATE GIVEN THE REALLOCATION?

A. Schedule C-1.0 shows the revenue requirement for each component of the rate.

Q. WERE THERE OTHER FACTORS TO CONSIDER IN THE FINAL DETERMINATION OF THE APPROPRIATE FIXED COST REALLOCATION?

A. Yes. It is clear that the CapSub is not a precise process; there are many assumptions that must be made. At best the process establishes one reference point in the ratemaking process. Another consideration is the impact on the ultimate consumer and in particular consumers with different load factors. The Board did not want to cause a significant impact on either high or low factor consumers. To assist in this evaluation the Board compared the pricing curve for the M-9 and M-10 tariffs. Schedule D-1.0 shows the Power Supply pricing curve in the M-9 rate as compared to the proposed M-10 rate. Schedule D-1.0 shows the impact on the average Power Supply rate at different load factors. Based on this comparison the Board felt that the M-10 design did maintain the desired rate continuity.

IV. DETERMINATION OF BILLING UNITS

Q. SCHEDULE C-1.0 SHOWS THE REVENUE REQUIREMENT FOR EACH COMPONENT OF THE RATE. PLEASE DESCRIBE THE BILLING UNITS USED TO RECOVER THE REVENUE REQUIREMENT.

A. As I explained previously, two of the Board's objectives in the development of the M-10 rate were to maintain rate continuity and minimize any adverse customer impact associated with changes in the rate design. The Board decided to maintain the current rate design with separate base and excess demand charges for recovery of Production Demand cost, a Production Energy charge, a Transmission demand charge, plus the new Delivery Point charge. The Base and Excess billing units were updated to reflect usage during the Test Year. The underlying concepts for the development of the Base and Excess billing are the same as approved by the Commission in the M-9 rate proceeding. Dr. Bowser developed the updated billing units. The billing units are shown on Schedule C-1.0. The energy billing units are simply the weather normalized usage developed by Dr. Bowser and the delivery points are the number of delivery points in place to serve the Members.

V. M-10 RATE DESIGN

Q. PLEASE DESCRIBE THE DEVELOPMENT OF THE M-10 RATE.

A. I have described the functionalization of cost and the classification of cost including the reclassification of fixed cost. The only remaining issue was the determination of the appropriate Production Base Demand Charge and Production Excess Demand Charge. Because of the importance of the load management program, the Board wanted to maintain the Production Excess Demand charge at the same level as the current M-9 rate. They felt that changes to the Excess Demand Charge could have an adverse impact on the future effectiveness of the load management program. With the Production Excess Demand Charge set at the existing $9.00/kW-Month this forced the Production Base Demand Charge to a value of $7.901/kW-Month. The sum of the revenue under the Base and Excess Demand charges must equal the total Production Demand revenue requirement. The Production Energy Charge is $37.535/MWh with all but $14.342/MWh coming from KEPCo's ECA, the Transmission Charge is $4.585/kW, and the Delivery Point Charge is $902.178. Schedule E-1.0 shows each component of the proposed M-10 rate.

Q. **THERE IS A SUBSTANTIAL INCREASE IN THE TRANSMISSION CHARGE. WHY DID THIS OCCUR?**

A. Dr. Bowser identified the transmission component of the test year purchased power cost. The transmission cost is recovered from the transmission component of the rate. The change in the transmission rate simply reflects the increase in transmission-related costs that have occurred over the last six years.

VI. DEMAND COST ADJUSTMENT (DCA) AND ENERGY COST ADJUSTMENT (ECA)

Q. WHAT IS THE PURPOSE OF THE DCA AND ECA FACTORS?

A. KEPCo currently has in place an ECA in the M-9 tariff. The purpose of the ECA is to provide for a tracking of changes in fuel and purchased power energy costs. The DCA is being added to provide for a recovery of changes in the demand component of purchased power. With the ECA and DCA, KEPCo will be able to track any changes, either increases or decreases, in the purchased power cost associated with providing service to its Members.

Q. WHY IS IT REASONABLE TO ADOPT THE DCA?

A. The Commission has already recognized the rationale for an automatic tracking mechanism for the variable component of the costs over which KEPCo does not have direct control (i.e., fuel and the variable cost of purchased power). The rationale is that any decreases in unit rates are automatically flowed through to the Members and any increases are recovered from the Members without incurring the delays and costs associated with a rate proceeding. The concept is that with the provisions for reconciling variable costs with the ECA there is greater possibility of KEPCo earning the margin approved by the Commission and the Member paying only the rates needed to recover the costs associated with providing service.

The DCA provides for this same mechanism for the fixed cost component of the purchased power cost. KEPCo currently purchases power from six different suppliers. The suppliers can change not only the rate charged but also the rate design. The proposed Westar Agreement is a good example. The proposed Westar rate change will result in an overall lower cost to KEPCo and its Members, but it does so by increasing the demand rate and decreasing the energy rate. By adopting both the ECA and DCA there will be full recognition of changes in both components of the wholesale rate in terms of the KEPCo rate to its Members.

Q. ARE ANY CHANGES BEING PROPOSED IN THE ECA?

A. Yes. The ECA is being expanded to include coal as a fuel component for KEPCo. There are currently no KEPCo-owned generation resources that use coal as a resource, however, with the addition of resources described by Mr. Parr there will be coal generation in the KEPCo power supply portfolio. With the proposed change in the ECA there will be provisions for a full reconciliation of all fuel costs associated with the KEPCo resources.

Q. WILL THE PROPOSED DCA PROVIDE FOR ANY RECOVERY OF THE FIXED COSTS ASSOCIATED WITH KEPCO-OWNED RESOURCES?

A. No. The proposed DCA will provide for recovery of only the fixed costs associated with purchased power cost. These are the costs over which, like the fuel, KEPCO does not have direct control.

Q. PLEASE IDENTIFY THE CURRENT WHOLESALE SUPPLIERS WHOSE RATES WILL BE REFLECTED IN THE PROPOSED DCA.

A. The current wholesale suppliers include:

Westar Energy

Sunflower Electric Power Corporation

Kansas City Power & Light

Southwestern Power Administration

Western Area Power Administration

City of St. Marys

Q. ARE THESE THE SAME ENTITIES WHOSE ENERGY RATES ARE REFLECTED IN THE ECA?

A. Yes.

Q. PLEASE DESCRIBE THE DCA.

A. The proposed M-10 rate includes as a part of the total cost for the test year purchased power demand cost. Schedule F-1.0 shows the components for the six suppliers in the amount of $16.7 million. Given the test year weather normalized demand billing units of 3,307,974 kW months, the average purchased power demand cost embedded in the M-10 rate design is $5.04/kW. The intent is that the DCA will provide for a tracking of any changes from this value. If for a twelve-month period the annualized average purchased power demand cost actually incurred is $5.14/kW, then there will be a $0.10/kW DCA adjustment applied to the Member demand billing in the following year. If for a twelve-month period the annualized average purchased power demand cost actually incurred is $4.94/kW, then there will be a $0.10/kW credit applied to the Member demand billing for the next twelve months.

Q. PLEASE DESCRIBE THE DIFFERENCE IN THE RECOVERY MECHANISM FOR THE ECA AND THE DCA.

A. There are really no major differences except for timing. The ECA provides for reconciliation each month, resulting in changes in the effective energy rate charged each month to the Member and in turn to the retail member consumer. When discussing adding a DCA, the Members wanted to minimize changes in the monthly demand rate. One of the primary reasons is that, with demand-side management programs, the retail customers are making decisions each month with regard to controlling loads. Monthly changes in demand rates could create some uncertainty and confusion for the ultimate retail customers. Therefore, the Members elected to implement the DCA and change the demand rate (it may increase or decrease) only once each year. The change would be made effective with the billing for January each year.

Q. DOES THIS MEAN THAT IF PURCHASED POWER DEMAND RATES INCREASE THERE WILL BE DELAY IN THE RECOVERY OF THOSE COSTS?

A. Yes, with one exception. I previously mentioned that because of the anticipated magnitude of the changes in the proposed Westar Agreement demand rate, KEPCo would request that the DCA to track changes in the proposed Westar Agreement rate be made as soon as the Westar Agreement becomes effective. In addition, KEPCo would request that the recovery of the initial Westar adjustment be recovered in only the Base Demand rate.

Q. WHY IS THERE NO ADJUSTMENT APPLIED TO THE EXCESS DEMAND RATE WITH THE INITIAL WESTAR RATE CHANGE?

A. The Excess Demand rate is the primary price signal mechanism for the demand side management programs. As I indicated, the Members are seeking stability in the pricing signals so the economics associated with these programs are not changing. The Board is concerned that the change in the initial Westar rate will have a significant impact on the demand side management programs if recovery is reflected in the Production Excess Demand Charge.

Q. PLEASE PROVIDE AN EXAMPLE OF HOW THE DCA WILL BE IMPLEMENTED.

A. The DCA will track changes in the demand component of the purchased power cost for all six suppliers. The concept is that changes in the purchased power demand cost from the base value embedded in the rates of $5.04/kW will recovered or credited to the Members. Changes in the purchased power demand rates can occur at any time during the years. For example the Westar change will typically occur in June. Therefore for Westar, there will be five months billed under one demand rate and seven months billed under another demand rate. As I explained, the DCA is computed once each year to reflect purchased demand rates at the end of the year. The intent is that the DCA will become effective with the KEPCO billing to its Members for usage beginning January of each year with bills rendered in February. The DCA calculation will be based on the actual usage for the twelve months ending 12/31. The purchased power demand cost for the year will be defined as the actual calendar year purchased power demand times the purchased power demand rate in effect as of 12/31. The reason to annualize based on year end demand rates is to make the DCA more forward looking, In the case of Westar the demand value used in the normalization process will be the actual demand paid for the January – May period. Hopefully this will help to mitigate the impact of the lag.

Schedule G-1.0 provides an example of the process. Each year, the annualized purchased power demand cost incurred per kW of Member billing demand is compared with the base value plus or minus an adjustment for prior period over or under recover.. In the example, in year 1, if the difference is $0.39/kW. This values is applied in year 2; which given the year 2 billing units produces $1,372,844. The same process is repeated in each year.

Q. IS IT THE INTENT TO PROVIDE A RECONCILIATION IN THE DCA MECHANISM?

A. Yes. It will be important that there be a reconciliation because of the lag in cost recovery (or there could be a credit), and because a major component of the purchased demand cost is changing potentially every June. At the end of the year there will be a comparison of dollars actually recovered with the dollars actually paid in the demand component of purchased power. Any differences will then be netted with differences in the current year to determine the DCA to be reflected in the next year. The reconciliation process is shown in the example described above and is the "R" term in calculation. Schedule G-1.0 shows a summary for the three years in the example. The total actual purchased power cost is $56.28 million. The amount recovered in the base demand component of $5.04/kW is $53,08 million, the amount recovered in DCA is $2.91 million, and the amount carried forward to year 4 is $287,018. The sum of the base recover, the DCA recovery, and the carry forward amount equal to the actual cost of $56.28 million.

VII. INTERIM RATE ADJUSTMENT/ENERGY ADDER/EXPEDITED RELIEF

Q. PLEASE EXPLAIN THE PROPOSED INTERIM RATE ADJUSTMENT/ENERGY ADDER.

A. As Mr. Parr has explained, KEPCo is very concerned about the ability to maintain adequate DSC to meet mortgage requirements in CY2008. It is absolutely essential that KEPCo realize sufficient margins to meet DSC requirements. It is anticipated that the M-10 will not be effective until September 1, 2008. KEPCO is proposing three alternatives to ensure that KEPCO CY2008 DSC is at an acceptable level:

1. An interim rate of \$2.0/MWh be in place for the period 6/1/2007 – 8/31/2008, or
2. A\$2.00/MWh energy adder to the energy charge resulting from the rate application for the period 9/1/2008 – 12/31/2008, or
3. An expedited treatment of KEPCo's rate Application such that the rates could go into effect July 1,2008.

Based on forecasted energy usage, either the \$2.00/MWh interim adjustment or the \$2.00/MWh adder is expected to produce approximately \$1.2 million. As Mr. Parr has explained, this is the amount necessary to ensure that KEPCo will maintain the required DSC. If the either of the first two alternatives are approved, i.e. the interim rate or the energy adder proposals, KEPCO will refund to the Members revenues in excess of that required to realize a 1.10 DSC for calendar year 2008.

VIII RATE PHASE-IN

Q. PLEASE DESCRIBE THE PROPOSED RATE PHASE-IN.

A. As I have indicated in previous testimony, one of the concerns of the Board is to mitigate rate impact associated with the implementation of the M-10 rate. Therefore the Board is proposing a one year phase-in of the M-10. The phase-in essentially means that in the first year the maximum amount paid by a Member will be equal to the average increase for all Members. Schedule H-1.0 shows the average percentage increase for each Member based on weather normalized test year billing units. If a Member is projected to have an increase greater than the system average a credit is applied that will result in an increase equal to the system average.

Q. COULD YOU PROVIDE AN EXAMPLE OF THE APPICATION OF THE PHASE-IN.

A. Referring to Schedule H-1.0. Brown-Atchison is projected to have an increase of 8.0% as compared to the system average of 5.3%. If the limit is 5.3%, then the projected increase for Brown-Atchison must be reduced by $127,034. The reduction is accomplished with a demand credit which, given the test year billing units, is equivalent to $0.80/kW.

Q. **WHAT IS THE ESTIMATED IMPACT OF THE PHASE-IN FOR THE TOTAL KEPCO SYSTEM?**

A. Schedule H-1.0 reflects an impact of $443,337. This means that the actual revenue collected will be $443,337 less than projected (based on test year usage).

Q. **IS THIS ONE OF THE FACTORS CONTRIBUTING TO THE CONCERN OF KEPCO BEING ABLE TO MEET ITS DSC REQUIREMENTS?**

A. Yes.

Q. **IS THE PHASE-IN CONCEPT AND METHODOLOGY PROPOSED THE SAME CONCEPT AND METHODOLOGY APPLIED WHEN THE M-9 TARIFF WAS APPROVED?**

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Collaborative Business Strategies." Panel Discussion Presenter, Texas Electric Cooperatives' 61st Annual Meeting; Austin, Texas, July 31, 2001.

"Restructuring Issues for the G&T," Presented for G&T Accounting and Finance Association's 2000 Conference; Breckenridge, Colorado; June 19, 2000.

"Rate Design in a Restructured Environment," presented for NRECA's 2000 Management Internship Program; Lincoln, Nebraska; January 10-11 and April 10-11, 2000.

"Financial Strategy and Rate Design for a Competitive World," presented for NRECA's Financial Planning and Strategies Workshop; Lincoln, Nebraska; April 4-5, 2000.

"The Restructuring of the Electric Power Industry in Oklahoma and in the Southwest," Panel Discussion Participant; Institute for Energy Economics and Policy, et al; Sarkeys Energy Center, The University of Oklahoma, Norman; December 10, 1999.

"Application of Leadership Skills," presentation for Dr. Jerry Holmes' engineering students at The University of Oklahoma, Norman; April 22 and December 2, 1999.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Planning; Lincoln, Nebraska; April 14-15, 1999.

"Rate Design in a Restructured Environment," NRECA's 1999 Management Internship Program; Lincoln, Nebraska; January 14-15, April 28-29, and May 13-14, 1999.

"Rate Design and the Changing Electric Industry," WREA Annual Meeting; Cheyenne, Wyoming; September 24, 1998.

"Rate Design and the Changing Electric Industry," CFC's Annual Meeting; Colorado Springs, Colorado; July 3, 1998.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Program; Lincoln, Nebraska, May 20-21, 1998.

"Rate Issues and Strategy for the Changing Utility Industry," NRECA's Management Internship Program; Lincoln, Nebr., January 7-8, April 9-10, April 30-May 1, 1998.

"Identifying Revenues and Costs Associated with Marketing Solutions," NRECA's Strategic Marketing Planning for Management Conference; Lincoln, Nebr., June 4, 1997.

"Financial Strategy and Rate Issues for the Changing Utility Industry," NRECA's Advanced Financial Program; Lincoln, Nebraska, April 10-11, 1997.

"Rate Issues and Strategy for the Changing Utility Industry," NRECA's Management Internship Program; Lincoln, Nebr., January 9-10, April 23-24, and May 8-9, 1997.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Application of Market-Based Rates in a Competitive Utility Industry," presented to NRECA's Tech Advantage '97 Annual Meeting; Las Vegas, Nevada; March 15, 1997.

"Preparing for the Future Cooperative Electric Service in Texas," presented to Texas Electric Cooperatives' Managers' Conference; Austin, Texas; December 5, 1996.

"Industry Restructuring Implications for Cooperatives," presented to Texas Electric Cooperatives' Government Relations Committee; Austin, Texas; July 1, 1996.

"Identifying Revenues and Costs Associated with Marketing Solutions," NRECA's Strategic Marketing Planning for Management Conference; Lincoln, Nebr., June 3-7, 1996.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; April 3-4 and July 24-25, 1996.

"Power Supply Issues in the U.S. and Abroad - Increasing Competition and Deregulation," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rates and Related Issues," for Management and Technical Issues Conference for International Guests at 1996 NRECA Annual Meeting; Houston, Texas; March 23, 1996.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 15-16, March 4-5, and April 15-16, 1996.

"The Economics of Serving Large Loads," Electric Cooperatives of South Carolina's Competitive Strategies Workshop, Columbia, S.C., August 15-16, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA's Summer School; New Orleans, La., June 30-August 1, and Hilton Head, S.C., July 18-19, 1995.

"Evolving Cooperative Structures," CFC's Cooperative Financing Forum; Chicago, Ill.; July 11, 1995.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 20-21, 1995.

"Takeover Workshop," Texas Electric Cooperatives, Inc.; Lubbock and Cleburne, Texas; April 6-7, 1995.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; April 4-5 and May 9, 1995.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 22-23, 1995.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 9, April 24, and May 8, 1995.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Competing for Retail Loads," NRECA's 1994 G&T Legal Seminar; New Orleans, La., November 10, 1994.

"The Power in the Partnership: Changing the Co-Op Power Supply," TEC 54th Annual Meeting; Fort Worth, Texas, August 2, 1994.

"Competitive Strategies: The Economics of Serving Large Loads," NRECA G&T Rates Conference; Lincoln, Nebr., June 14-15, 1994.

"Competing in the '90s and Beyond," 1994 NRECA G&T Rates Conference; San Antonio, Texas; June 5-8, 1994.

"Implementation of Demand-Side Component of IRP," Georgia EMC in coordination with NRECA; Ga., April 27, 1994.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; March 29-30, 1994

"The Transmission Access Revolution," Special G&T Director's Update Program for Brazos Electric Power Cooperative, DFW Airport Marriott Hotel, Texas; March 21-22, 1994.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 9-10, 1994.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 17, April 22, and May 16, 1994

"Buy-Out and Refinancing of REA Loans: Factors to Consider in Evaluation Analysis," Texas Electric Cooperatives, Inc.; Austin, Texas; December 3, 1993.

"Transmission Access Revolution," NRECA's 1993 G&T Director's Update Conference; Nashville, Tenn.; December 2, 1993.

"Update on Current Issues — Texas RECs and PUCT," Texas Electric Cooperatives, Inc.; Austin, Texas; November 15, 1993.

"Coordination of IRP and Marketing Strategy with G&T Wholesale Rate Design," NRECA's G&T Rates & G&T Marketing Conference; Lexington, Ky.; June 8, 1993.

"Implementation of Demand-Side Component of IRP," NRECA's Finance for Marketing Professionals Workshop; Lincoln, Nebr.; April 27-28, 1993.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 14-15, April 14-15 and May 10, 1993

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 10-11, June 30-July 1, and September 29-30, 1993.

"Rates as a Marketing Tool," NRECA's G&T Marketing Seminar; Denver, Colo.; September 10, 1992.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"The Co-Op Power Picture in Texas," TEC's 52nd Annual Meeting; Houston, Texas; July 28, 1992.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; March 3-4, June 3-4, and November 18-19, 1992.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 9-10 and May 5-6, 1992.

Rate Training Course presented for members of Bangladesh REB coordinated through NRECA; Oklahoma City, Okla.; October 28-November 8, 1991.

"Ratemaking Activities for Rural Electric Cooperatives," TEC's Seminar on Electric Cooperatives; Austin, Texas; October 18, 1991.

"Rate Analysis: Determination of Revenue Requirements," NRECA's Accounting and Finance Conference; Albuquerque, N. Mex.; August 18-21, 1991.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Work-shop; Lincoln, Nebr.; May 1-2, June 25-26, and November 6-7, 1991.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 17-18 and May 8-9, 1991.

"Development of a Rate Strategy for the Cooperative System," 1991 Rural Electric Expo for NRECA; New Orleans, La.; February 2-3, 1991.

"Innovative Rate Forms," 1991 NRECA Engineering and Operations Conference; New Orleans, La.; January 31, 1991.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; January 9-10, 1991.

"Rate Analysis," NRECA MIP Advanced Planning and Analysis Workshop; Lincoln, Nebr.; October 3-4, 1990.

"Making Sense of Your System's Rate Structure," NRECA 1990 Member Services Communication Conference; Charlotte, N.C.; July 31, 1990.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 18 and May 11, 1990.

"Cost of Service Major Points," TEC Accounting Association Annual Meeting; San Antonio, Texas; April 20, 1990.

"Rate Design for Large Power Service and Options for Marketing and Incentive Rates," TEC Engineering Association; Austin, Texas; September 27, 1989.

"Service to Large Industrial Customers," NRECA's Rural Electric Management Council; Fargo, N. Dak.; May 17, 1989.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 24-25 and May 15-16, 1989.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Revenue Requirements and Cost of Service Considerations at the PUC," TEC Engineering Association; Austin, Texas; April 28, 1988.

"Course 495.3 - Rate Issues and Philosophies," NRECA's Management Internship Program; University of Nebraska, Lincoln; April and May, 1988.

"Course 495.3 - Rate Issues and Philosophies," 1987 Wisconsin Electric Cooperative Association; Wisconsin Rapids, Wis.; December 1-3, 1987.

"Marketing: Distribution Benefits Through Sale of Surplus Power and Jointly Designed Marketing Rates," 1987 NRECA Engineering and Operations Conference; Denver, Colo.; November 20, 1987.

"Cost Bases for Incentive Rates Applicable to Industrial Loads," 1987 Conference on Industrial Energy Technology; Houston, Texas; September 16-17, 1987.

"Considerations in Cooperative Consolidations," with Martin Lowery at NRECA's 1987 Accounting and Finance Conference; Lexington, Ky.; September 9, 1987.

"Rates to Attract Attractive Loads," Association of Louisiana Electric Cooperatives, in coordination with AHP Systems, Inc.; Baton Rouge, La.; July 1-2, 1987.

"Course 495.3 - Rate Issues and Philosophies," NRECA's 1987 Summer School; Lake of the Ozarks, Mo.; July 20-22; and Williamsburg, Va.; August 13-15, 1987.

"Rate Issues and Philosophies," NRECA's Management Internship Program; Lincoln, Nebr.; April 24-25 and May 15-16, 1987.

"Rates to Attract Attractive Loads," Wisconsin Electric Cooperative Association in Coordination with AHP Systems, Inc.; Stephens Point, Wis.; February 12, 1987.

"Rate Design for Attracting and Maintaining Loads," NRECA's Management Internship Program; Lincoln, Nebr.; October 1, 1986.

"Rate Seminar," Indiana Statewide Association of REC, Inc., (Co-Presenter: David Hedberg); Indianapolis, Ind.; September 25, 1986.

"Preconference Workshop: Basic Issues in Rate Design," NRECA's 1986 National Accounting and Finance Conference; Tampa, Fla.; September 9, 1986.

"Course 495.2 - Rate Issues and Philosophies," NRECA's 1986 Summer Schools; Myrtle Beach, S.C.; Nashville, Tenn.; and Taos, N. Mex.; July 1986.

"Cost of Service and Rate Design Issues Affecting Industrial Customers in Retail Rate Proceedings," Public Utility Commission of Texas 1986 Industrial Energy Technology Conference; Houston, Texas; June 1986.

"The Importance of the Impact of Rates," NRECA's Management Services Conference -- Preparing Now to Prevent a Takeover or Sellout; Denver, Colo.; April 17-18, 1986; and New Orleans, La.; May 14-15, 1986.

PAPERS AND PRESENTATIONS
CARL N. STOVER, JR.

"Energy Cost for Industrial Customers," (Co-Author: M.K. Moore) ACEC Research & Management Foundation's Industrial Energy Management Forum; Tempe, Ariz., March 26, 1986.

"Analysis of Financial and Operating Ratios," REA National Conference; San Antonio, Texas; July 10, 1985.

"Coordination of Wholesale/Retail Rate Design for Effective Marketing Strategy," NRECA's National Marketing Conference; Kansas City, Mo., June 5, 1985.

"Development of Rate Schedules for an Electric Utility," CAST/CSEE/NRECA Workshop; Kunming, Republic of China; May 14-19, 1984.

"Development of a Rate Analysis," NRECA Management Quarterly; Washington, D.C.; Volume 24, No. 3; Summer 1983.

"Cost Allocation Considerations for Rural Distribution Systems," NARUC Biennial Regulatory Information Conference; Columbus, Ohio; October 19, 1978.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Transactions on Industry Application; Volume 1A-13, No. 2; 1977.

"Design of Irrigation Rates Under Load Management Program," (Co-Authors: S.P. Patwardhan and B.E. Smith), presented at IEEE Rural Power Conference; Kansas City, Mo.; May 16, 1977.

"Cost Allocation Considerations and Methods for Electric Rate Analysis and Design for Rural Distribution Systems," IEEE Rural Electric Power Conference; Omaha, Nebr.; April 1975.

"A Financial Forecasting Model for Rural Electric Distribution Systems," IEEE PES Summer Power Meeting and Energy Resources Conference; Anaheim, Calif.; July 1974.

"A Planning Model for the Analysis of Long Range Distribution System Design Alternatives," IEEE PES Summer Meeting and EHV/UHV Conference; Vancouver, Canada; July 1973.

"Transmission Substation Control Using On-Site Computer Directed Simulation and Closed Loop Control," (Co-Author: H.E. Michel).

"The Development of Design Objectives for Electric Utility Rate Schedules," Master's Thesis; University of Oklahoma, Norman; 1969.

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

ARKANSAS (Arkansas Public Service Commission)
Ozarks Electric Cooperative Corporation, Fayetteville (Docket 86-162-U)

COLORADO (Colorado Public Utilities Commission)
Delta-Montrose Electric Association, Delta
Empire Electric Association, Inc., Cortez
Gunnison County Electric Association, Inc., Gunnison
Holy Cross Electric Association, Inc., Glenwood Springs
Intermountain Rural Electric Association, Sedalia
La Plata Electric Association, Inc., Durango
Moon Lake Electric Association, Inc., Roosevelt, UT
Poudre Valley Rural Electric Association, Inc., Ft. Collins
San Isabel Electric Association, Inc., Pueblo
San Luis Valley Rural Electric Cooperative, Inc., Monte Vista
San Miguel Power Association, Inc., Nucla
United Power, Inc., Brighton
White River Electric Association, Inc., Meeker

ILLINOIS
Egyptian Electric Cooperative Association, Steeleville
Southeastern Illinois Electric Cooperative, Inc., Eldorado
Southern Illinois Electric Cooperative, Dongola

INDIANA (Indiana Public Service Commission)
Clark County Rural Electric Membership Corporation, Sellersburg

KANSAS (Kansas Corporation Commission)
Ark Valley Electric Cooperative Association, Inc., Hutchinson
C.&W. Rural Electric Cooperative Association, Inc., Clay Center
C.M.S. Electric Cooperative, Inc., Meade
D.S.&O. Rural Electric Cooperative Association, Inc., Solomon
Great Plains Electric Cooperative, Inc.
Lane-Scott Electric Cooperative, Inc., Dighton
Lyon County Electric Cooperative, Inc., Emporia
N.C.K. Electric Cooperative, Inc., Belleville
Ninnescah Rural Electric Cooperative Association, Inc., Pratt
Northwest Kansas Electric Cooperative Association, Inc., Bird City
Norton-Decatur Cooperative Electric Company, Inc., Norton
Sedgwick County Electric Cooperative Association, Inc., Cheney
Smoky Hill Electric Cooperative Association, Inc., Ellsworth
Sumner-Cowley Electric Cooperative, Inc., Wellington
Victory Electric Cooperative Association, Inc., Dodge City
Western Cooperative Electric Association, Inc., WaKeeney

LOUISIANA (Louisiana Public Service Commission)
Teche Electric Cooperative, Inc., et. al. (Docket U-19943)

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

NEBRASKA
McCook Public Power District, McCook
Nebraska Electric G&T Cooperative, Inc., Columbus
Panhandle Rural Electric Membership Corporation, Alliance
Twin Valleys Public Power District, Cambridge

OKLAHOMA (Oklahoma Corporation Commission)
Caddo Electric Cooperative, Binger
Canadian Valley Electric Cooperative, Seminole
Central Rural Electric Cooperative, Stillwater
Cimarron Electric Cooperative, Kingfisher
Cookson Hills Electric Cooperative, Inc., Stigler
Cotton Electric Cooperative, Walters
East Central Oklahoma Electric Cooperative, Inc., Okmulgee
Harmon Electric Association, Inc., Hollis
Indian Electric Cooperative, Inc., Cleveland
Kay Electric Cooperative, Blackwell
Kiwash Electric Cooperative, Inc., Cordell
Lake Region Electric Cooperative, Inc., Hulbert
Northeast Oklahoma Electric Cooperative, Inc., Vinita
Northfork Electric Cooperative, Sayre
Northwestern Electric Cooperative, Inc., Woodward
Oklahoma Electric Cooperative, Norman
Oklahoma Gas & Electric Company, Cause No. 29450
People's Electric Cooperative, Ada
Red River Valley Rural Electric Association, Marietta
Rural Electric Cooperative, Inc., Lindsay
Southwest Rural Electric Association, Inc., Tipton
Sun Oil vs. Arkansas Louisiana Gas Company
Verdigris Valley Electric Cooperative, Inc., Collinsville

SOUTH DAKOTA
West Central Electric Cooperative, Inc., Murdo

TEXAS (Public Utility Commission of Texas)
B-K Electric Cooperative, Inc. (4701)
Bailey County Electric Cooperative Association (2915, 5003, 7900)
Bandera Electric Cooperative, Inc. (2786, 4279)
Bluebonnet Electric Cooperative, Inc. (266, 4070, 7415, 12126)
Cap Rock Electric Cooperative, Inc. (4749, 6778, 8283)
Central Texas Electric Cooperative, Inc. (3170, 6363, 7661, 10325, 12127)
Cherokee County Electric Cooperative Association (817)
City of Austin (6560 - in behalf of Bergstrom AFB
Coleman County Electric Cooperative, Inc. (4875, 13335)
Comanche County Electric Cooperative, Inc. (5272, 8272)
Concho Valley Electric Cooperative, Inc. (3550, 4797, 6540, 9056, 13334)
Cooke County Electric Cooperative Association (9240)

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

TEXAS (Continued)
CoServ Electric (formerly Denton County Elec. Coop., Inc.) (3470, 4189, 5165, 9892, 21669)
Deaf Smith Electric Cooperative, Inc. (4481, 5019, 8354)
Deep East Texas Electric Cooperative, Inc. (3393, 6308)
Department of Defense (Bergstrom AFB v. City of Austin (6560)
DeWitt County Electric Cooperative, Inc. (667, 3702, 4919, 6618)
Dickens Electric Cooperative, Inc. (4299, 7556, 9563, 11513)
Erath County Electric Cooperative Association (4643, 8990)
Fannin County Electric Cooperative, Inc. (3747, 4940, 9992)
Farmers Electric Cooperative, Inc. (3780, 4422, 5259, 6475)
Fort Belknap Electric Cooperative, Inc. (4396, 6558, 9944)
Gate City Electric Cooperative, Inc. (4987)
Grayson-Collin Electric Cooperative, Inc. (3945, 6510)
Greenbelt Electric Cooperative, Inc. (5038, 9930, 10405)
Guadalupe Valley Electric Cooperative, Inc. (398, 3397, 4516, 6338, 7550)
Hamilton County Electric Cooperative Association (5971)
Hill County Electric Cooperative, Inc. (7154)
Houston Lighting and Power Company (5779 and 8425)
Hunt-Collin Electric Cooperative, Inc. (3091, 4750)
Jackson Electric Cooperative, Inc. (2753, 4710, 10561)
Johnson County Electric Cooperative, Inc. (4353, 4961, 8288, 11347)
Kaufman County Electric Cooperative, Inc. (3926, 5612, 8096)
Kimble Electric Cooperative, Inc. (2308)
Lamb County Electric Cooperative, Inc. (3270)
Lighthouse Electric Cooperative, Inc. (2995, 4612, 8097)
Limestone County Electric Cooperative, Inc. (3931)
Lone Wolf Electric Cooperative, Inc. (5878)
Lyntegar Electric Cooperative, Inc. (2988, 4564)
Magic Valley Electric Cooperative, Inc. (1991, 3212, 5477, 20314)
Medina Electric Cooperative, Inc. (4113, 11048)
Midwest Electric Cooperative, Inc. (2717, 3711, 6983)
Navarro County Electric Cooperative, Inc. (3116)
Navasota Valley Electric Cooperative, Inc. (7355)
New Era Electric Cooperative, Inc. (4625)
North Plains Electric Cooperative, Inc. (2934, 4958, 5214)
Nueces Electric Cooperative, Inc. (3936, 5203)
Pedernales Electric Cooperative, Inc. (2247, 3437, 5109)
Rayburn Country Electric Cooperative, Inc. (7361)
Rio Grande Electric Cooperative, Inc. (521, 3681)
Rita Blanca Electric Cooperative, Inc. (2527, 8422)
Rusk County Electric Cooperative, Inc. (3383)
San Bernard Electric Cooperative, Inc. (2699, 3692, 4534, 5467, 6218)
San Miguel Electric Cooperative, Inc. (4127, 5351)
South Plains Electric Cooperative, Inc. (2936, 4822, 6985)
Southwest Texas Electric Cooperative, Inc. (5335)
Stamford Electric Cooperative, Inc. (4095, 8077)
Swisher Electric Cooperative, Inc. (3062, 6796)

RETAIL ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

TEXAS (Continued)
Taylor Electric Cooperative, Inc. (3679, 5767, 9159)
Victoria County Electric Cooperative Company (770, 3949, 6680)
Wharton County Electric Cooperative, Inc. (4541, 6685)

UTAH (Utah Public Service Commission)
Empire Electric Association, Inc., Cortez, CO
Moon Lake Electric Association, Inc., Roosevelt

WYOMING (Wyoming Public Service Commission)
Big Horn Rural Electric Company (9076)
Bridger Valley Electric Association, Inc. (9447)
Carbon Power & Light, Inc. (9022)
Garland Power & Light, Inc. (9575)
Hot Springs Rural Electric Association, Inc. (9553, 10010-CR-89-2)
Niobrara Electric Association, Inc. (9572)
Riverton Valley Electric Association, Inc. (9451)
Sheridan-Johnson Rural Electrification Association (9392)
Shoshone River Power, Inc. (9656)
Wheatland Rural Electric Association (9574)
Wyrulec Company (9097)

MUNICIPAL UTILITY RATE ANALYSIS AND DESIGN
Altus, OK
Blackwell, OK
Braman, OK
Bryan, TX
Chanute, KS
Chathan, IL
Cody, WY
Cushing, OK
Fredericksburg, TX
(7661, Certification - Central Texas EC)
Lamar, MO v. Southwestern Power Admin.
Larned, KS
Oklahoma Municipal Power Authority, OK
Osborne, KS
Ponca City, OK
Raton, NM
Riverton, IL
Stillwater, OK
Torrington, WY
Vernon, TX
Wellington, KS

WHOLESALE ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

ARKANSAS (Arkansas Public Service Commission)
Arkansas Electric Cooperative Corporation — Docket Nos. U-3071 and 83-023-U

COLORADO
Tri-State G&T Association, Inc. — Docket No. 98A-511E

ILLINOIS
Southern Illinois Power Cooperative

IOWA
Corn Belt Power Cooperative, Inc.
Northwest Iowa Power Cooperative, Inc.

LOUISIANA
Cajun Electric Power Cooperative, Inc. — Docket No. U-17735

NEW MEXICO
Plains Electric G&T Cooperative, Inc. — Merger with Tri-State G&T Assn.

NORTH CAROLINA
North Carolina Electric Membership Corporation

NORTH DAKOTA
Basin Electric Cooperative, Inc.
Central Power Electric Cooperative, Inc.

SOUTH DAKOTA
Rushmore Electric Power Cooperative, Inc.

TEXAS (Public Utility Commission)

Brazos Electric Cooperative, Inc.	Docket Nos. 4079, 8868, 12757, 13100
Central and South West Corporation and American Electric Power Company, Inc.	Docket No. 19265
Golden Spread Electric Cooperative, Inc.	Docket Nos. 13444, 14980, 16738
Lower Colorado River Authority	Docket Nos. 366, 1521, 2503, 3522, 3838, 6027, 7512, 8032, 8400, and 9427
South Texas Electric Cooperative, Inc.	Docket Nos. 4128, 5077, 5387, 5440, and 8952
Southwestern Electric Service Company	Docket No. 2817
Southwestern Public Service Company	Docket Nos. 4387 and 6055
Texas Electric Service Company	Docket Nos. 527, 1903, 2606, 3250, 4097, 5200

WHOLESALE ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.

TEXAS (Continued)	
Texas Power & Light Company	Docket Nos. 3006, 3780 and 4321
Texas Utilities Electric Company	Docket Nos. 5640, 9300 and 13100
Texland Electric Cooperative, Inc.	Docket No. 3896
West Texas Utilities Company	Docket No. 4716
UTAH	
Deseret G&T Cooperative, Inc. PacifiCorp / ScottishPower Merger	Docket No. 98-2035-04
FEDERAL POWER COMMISSION (Federal Energy Regulatory Commission)	
Gulf States Utilities Company	Docket Nos. EL87-051 and ER88-477
Central and South West Services, Inc.	Docket No. ER84-031
Central Power & Light Company	Docket Nos. ER77-331, ER81-387 and ER86-721
El Paso Electric Company	Docket Nos. ER76-409, ER77-488, ER79-526, ER81-426, ER84-236 and ER86-368
Golden Spread Electric Cooperative, Inc.	Docket Nos. ER87-396, EL89-050 and EL95-24
Oklahoma Gas & Electric Company	Docket Nos. ER77-127, ER77-215 ER78-423, ER80-421, ER82-256 and ER84-541
Public Service Company Colorado	Docket Nos. ER76-381, ER76-687, ER78-507 and ER80-407
Public Service Company Oklahoma	Docket Nos. ER77-422, ER78-511 and ER82-545
Southwestern Public Service Co.	Docket Nos. ER84-604, ER85-477 and EL89-051
West Texas Utilities Company	Docket Nos. ER80-038, ER82-023, ER82-708, ER83-694, ER84-236, ER85-081, and ER87-065

**WHOLESALE ELECTRIC RATE ANALYSIS/DESIGN EXPERIENCE
CARL N. STOVER, JR.**

TRANSMISSION WHEELING/INTERCONNECTION ANALYSIS

Central and South West Services, Inc.	Docket No. EL79-008 and ER82-545, et.al.
LCRA Wheeling Case before the Texas PUC	Docket No. 6995

POWER SUPPLY PLANNING

A. System Resource Planning:

Golden Spread Electric Cooperative, Inc.: Notice of Intent (PUCT Docket No. 13444)
Golden Spread Electric Cooperative, Inc.: Exempt Wholesale Generation Contract Certification (PUCT Docket No. 15100)

B. Long-Range Power Cost - 20-Year Forecast:

Golden Spread Electric Cooperative, Inc.	Southwestern Public Service Company
Kim-Wood Electric Cooperative, Inc.	Southwestern Public Service Company
Mid-Tex G&T Electric Cooperative, Inc.	West Texas Utilities Company and Brazos Electric Cooperative
Magic Valley Electric Coop., Inc./ Rio Grande Electric Cooperative, Inc.	South Texas Electric Coop., Inc./ Central Power & Light Company
Magic Valley Electric Cooperative, Inc.	City of Brownsville/Central Power & Light Co.

C. Other Power Supply Planning Projects:

Golden Spread Electric Cooperative, Inc., TX	Mustang Station
Magic Valley Electric Cooperative, Inc., TX	Magic Valley Station

Kansas Electric Power Cooperative, Inc.
Unbundled Cost of Service
Test Year Ending December 31, 2006

Line No.	Description	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point
1	Operating Expenses	101,755,354	40,630,836	43,974,292	14,547,753	2,602,473
2	Non-Operating Revenues	(632,014)	(517,231)	(52,651)	(43,999)	(18,134)
3	Non-Member Sales	(64,089)	-	(64,089)	-	-
4	Other Operating Revenues	(2,386)	(1,953)	(199)	(166)	(68)
5	Subtotal Member Revenue Requirement	101,056,865	40,111,652	43,857,354	14,503,588	2,584,271
6	Percent of Total	100.0%	39.7%	43.4%	14.4%	2.6%
7	Total Margin	6,819,950	2,988,069	2,726,810	928,675	176,395
8	**Total Member Revenue Requirement**	**$ 107,876,815**	**$ 43,099,721**	**$ 46,584,165**	**$ 15,432,263**	**$ 2,760,666**
9	Percent of Total	100.0%	40.0%	43.2%	14.3%	2.6%
10						
11	Rural Energy Credit	1,892,651		1,892,651		
12	Economic Development Credit	342,204	342,204			
13	Decomissioning Adjustment	(405,597)		(405,597)		
14	Revenue Credit Adjustment	34,124		34,124		
15	WAPA Credits	(38,199)		(38,199)		
16	High Voltage Discount	2,200,563			2,200,563	
17						
18	**Total Rate Requirement**	**$ 111,902,560**	**$ 43,441,925**	**$ 48,067,143**	**$ 17,632,826**	**$ 2,760,666**
19						
20	Annual Energy (MWh)	1,698,150	1,698,150	1,698,150	1,698,150	1,698,150
21	Average Rate ($/MWh)	$ 65.90	$ 25.58	$ 28.31	$ 10.38	$ 1.63

Kansas Electric Power Cooperative, Inc.
Capital Substitution / Peaker Equivalent
Test Year Ending December 31, 2006

Line No.	Description	Reference	Amount
1	KEPCo Financing Assumptions		
2	Number of Years -- Nuclear Financing	Input	40
3	Number of Years -- Peaking Financing	Input	25
4	Interest Rate	Input	7.0%
5	Payments per Year	Input	1
6			
7	Baseload Resource Costs		
8	Wolf Creek Booked Cost	KEPCo YE2006 Gross Plant	206,599,388
9	Wolf Creek Capacity (MW)	Input	70
10	Wolf Creek Capital Cost ($/kW)	L8 / L9	2,951
11			
12	Wolf Creek Debt Service ($/kW-Year)	PMT (L4 / L5, L2 * L5, L10)	$221.38
13	Wolf Creek Fixed O&M ($/kW-Year)	Input	77.85
14	Wolf Creek Fixed Cost ($/kW-Yr)	L12 + L13	299.23
15			
16	Peaking Resource Costs		
17	Peaking Capital Cost ($/kW)	Input	525.00
18			
19	Peaking Principal Payment ($/kW-Year)	PMT (L4 / L5, L3 * L5, L17)	$45.05
20	Peaking Fixed O&M ($/kW-Year)	Input	30.24
21	Peaking Fixed Cost ($/kW-Yr)	L19 + L20	75.29
22			
23	Reallocation of Cost		
24	Fixed Costs to Reallocate ($/kW)	L14 - L21	223.94
25	Wolf Creek Capacity (MW)	L9	70
26	Demand costs to be reallocated	L9 * L25	15,676,006
27	Total All Resource Demand Costs	CNS-2, Schedule B-2.0	39,380,635
28	**Equivalent Tilt (%)**	**L26 / L27**	**39.8%**
29			
30	Total Energy (MWh)	CNS-2, Schedule A-1.0	1,698,150
31	Reallocated ($/MWh)	L26 / L30	9.23

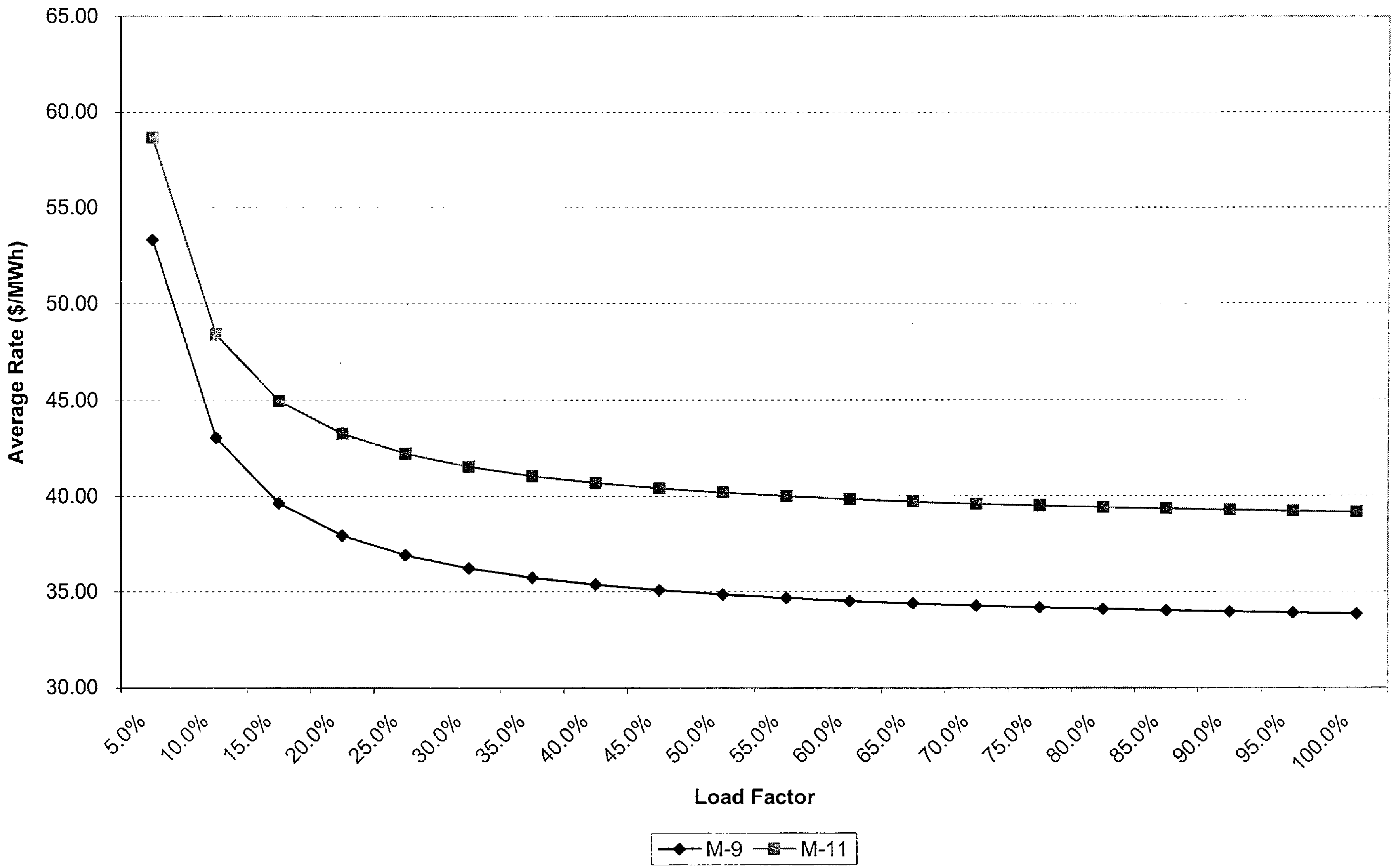
Kansas Electric Power Cooperative, Inc.
Calculation of Demand Costs
Test Year Ending December 31, 2006

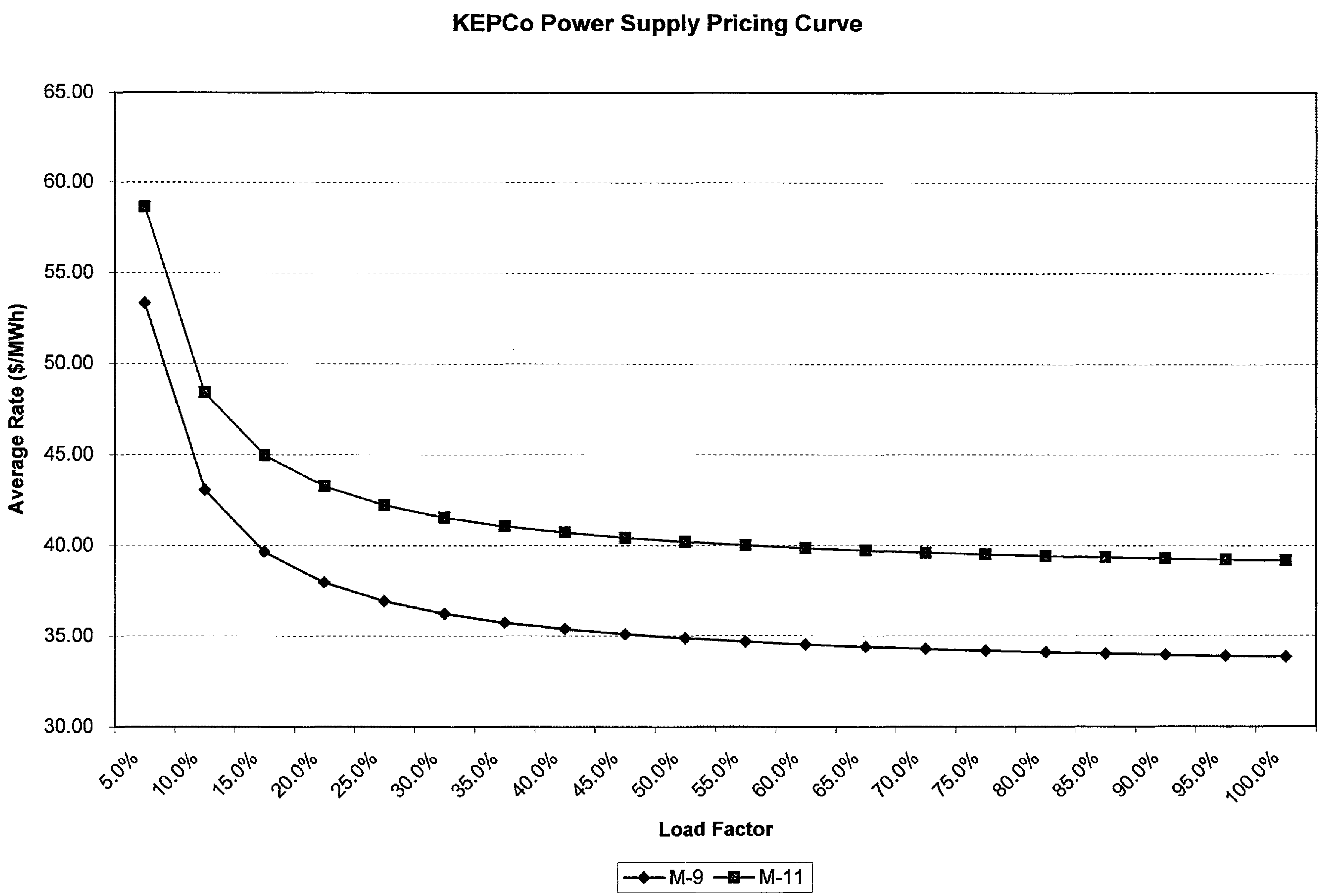
Line No.	Description	Reference	Amount
1	Total KEPCo Demand Costs		
2	Owned Resources O&M	Exhibit DAN-7	9,595,771
3	Interest	Exhibit DAN-7	6,907,893
4	Depreciation & Amortization	Exhibit DAN-7	6,200,027
5	Subtotal Owned Resources	SUM (L2:L4)	22,703,690
6	Purchased Power Demand	Exhibit DAN-7	16,676,945
7	Total Resources	SUM (L5:L6)	39,380,635

Kansas Electric Power Cooperative, Inc.
Unbundled Cost of Service with Reallocated Demand Costs
Test Year Ending December 31, 2006

Line No.	Description	Adjusted Test Year	Production Demand	Production Energy	Transmission	Delivery Point
1	Operating Expenses	101,755,354	40,630,836	43,974,292	14,547,753	2,602,473
2	Non-Operating Revenues	(632,014)	(517,231)	(52,651)	(43,999)	(18,134)
3	Non-Member Sales	(64,089)	-	(64,089)	-	-
4	Other Operating Revenues	(2,386)	(1,953)	(199)	(166)	(68)
5	Subtotal Member Revenue Requirement	101,056,865	40,111,652	43,857,354	14,503,588	2,584,271
6	Percent of Total	100.0%	39.7%	43.4%	14.4%	2.6%
7	Total Margin	6,819,950	2,988,069	2,726,810	928,675	176,395
8	**Total Member Revenue Requirement**	**$ 107,876,815**	**$ 43,099,721**	**$ 46,584,165**	**$ 15,432,263**	**$ 2,760,666**
9	Percent of Total	100.0%	40.0%	43.2%	14.3%	2.6%
10						
11	Reallocation (% of total resources)		39.8%			
12	Reallocation Adjustment	-	(15,673,493)	15,673,493		
13						
14	**Total Member Revenue Requirement**	**$ 107,876,815**	**$ 27,426,228**	**$ 62,257,657**	**$ 15,432,263**	**$ 2,760,666**
15	Percent of Total	100.0%	25.4%	57.7%	14.3%	2.6%
16						
17	Rural Energy Credit	1,892,651	-	1,892,651	-	-
18	Economic Development Credit	342,204	342,204	-	-	-
19	Decomissioning Adjustment	(405,597)	-	(405,597)	-	-
20	Revenue Credit Adjustment	34,124	-	34,124	-	-
21	WAPA Credits	(38,199)	-	(38,199)	-	-
22	High Voltage Discount	2,200,563	-	-	2,200,563	-
23						
24	**Total Rate Requirement**	**$ 111,902,560**	**$ 27,768,432**	**$ 63,740,636**	**$ 17,632,826**	**$ 2,760,666**
25						
26	Billing Units	1,698,150	3,307,974	1,698,150	3,845,968	3,060
27	Billing Units	MWh	CP kW-Mo	MWh	NCP kW-Mo	Delivery Points
28	Average Rate ($/Billing Unit)	$ 65.897	$ 8.394	$ 37.535	$ 4.585	$ 902.178

KEPCo Power Supply Pricing Curve




KEPCo Power Supply Pricing Curve
65.00
60.00
55.00
50.00
45.00
40.00
35.00
30.00
Average Rate ($/MWh)
5.0%
10.0%
15.0%
20.0%
25.0%
30.0%
35.0%
40.0%
45.0%
50.0%
55.0%
60.0%
65.0%
70.0%
75.0%
80.0%
85.0%
90.0%
95.0%
100.0%
Load Factor
M-9
M-11

Kansas Electric Power Cooperative, Inc.
Pricing Curve Calculation
Test Year Ending December 31, 2006

M-9 Excess Demand Rate ($/kW-Mo)	$	9.00
M-9 Energy Rate ($/MWh)		9.57
M-9 ECA ($/MWh)		23.23
Total M-9 Energy Rate ($/MWh)	$	32.80
M-11 Excess Demand Rate ($/kW-Mo)	$	9.00
M-11 Energy Rate ($/MWh)		14.90
M-11 ECA ($/MWh)		23.23
Total M-11 Energy Rate ($/MWh)	$	38.12

Load Factor	M-9	M-11
5.0%	53.34	58.67
10.0%	43.07	48.40
15.0%	39.64	44.97
20.0%	37.93	43.26
25.0%	36.90	42.23
30.0%	36.22	41.55
35.0%	35.73	41.06
40.0%	35.36	40.69
45.0%	35.08	40.41
50.0%	34.85	40.18
55.0%	34.66	39.99
60.0%	34.51	39.83
65.0%	34.38	39.70
70.0%	34.26	39.59
75.0%	34.17	39.49
80.0%	34.08	39.41
85.0%	34.00	39.33
90.0%	33.94	39.26
95.0%	33.88	39.20
100.0%	33.82	39.15

Kansas Electric Power Cooperative, Inc.
Unbundled Cost of Service with Reallocated Demand Costs and Base & Excess Demand Charges
Test Year Ending December 31, 2006

Line No.	Description	Adjusted Test Year	Base Demand	Excess Demand	Production Demand	Production Energy	Transmission	Delivery Point
1	Operating Expenses	101,755,354	27,260,386	13,370,450	40,630,836	43,974,292	14,547,753	2,602,473
2	Non-Operating Revenues	(632,014)	(517,231)		(517,231)	(52,651)	(43,999)	(18,134)
3	Non-Member Sales	(64,089)	-		-	(64,089)	-	-
4	Other Operating Revenues	(2,386)	(1,953)	-	(1,953)	(199)	(166)	(68)
5	Subtotal Member Revenue Requirement	101,056,865	26,741,203	13,370,450	40,111,652	43,857,354	14,503,588	2,584,271
6	Percent of Total	100.0%	26.5%	13.2%	39.7%	43.4%	14.4%	2.6%
7	Total Margin	6,819,950	2,988,069	-	2,988,069	2,726,810	928,675	176,395
8	**Total Member Revenue Requirement**	**$ 107,876,815**	**$ 29,729,271**	**$ 13,370,450**	**$ 43,099,721**	**$ 46,584,165**	**$ 15,432,263**	**$ 2,760,666**
9	Percent of Total	100.0%			40.0%	43.2%	14.3%	2.6%
10								
11	Reallocation (% of total resources)				39.8%			
12	Reallocation Adjustment	-	(15,673,493)	-	(15,673,493)	15,673,493		
13								
14	**Total Member Revenue Requirement**	**$ 107,876,815**	**$ 14,055,779**	**$ 13,370,450**	**$ 27,426,228**	**$ 62,257,657**	**$ 15,432,263**	**$ 2,760,666**
15	Percent of Total	100.0%			25.4%	57.7%	14.3%	2.6%
16								
17	Rural Energy Credit	1,892,651	-	-	-	1,892,651	-	-
18	Economic Development Credit	342,204	342,204	-	342,204	-	-	-
19	Decomissioning Adjustment	(405,597)	-	-	-	(405,597)	-	-
20	Revenue Credit Adjustment	34,124			-	34,124	-	-
21	WAPA Credits	(38,199)			-	(38,199)	-	-
22	High Voltage Discount	2,200,563	-	-	-	-	2,200,563	-
23								
24	**Total Rate Requirement**	**$ 111,902,560**	**$ 14,397,983**	**$ 13,370,450**	**$ 27,768,432**	**$ 63,740,636**	**$ 17,632,826**	**$ 2,760,666**
25								
26	Billing Units	1,698,150	1,822,368	1,485,606	3,307,974	1,698,150	3,845,968	3,060
27	Billing Units	MWh	Base kW-Mo	Excess kW-Mo	CP kW-Mo	MWh	NCP kW-Mo	Delivery Points
28	Unit Rate ($/Billing Unit)	$ 65.897	$ 7.901	$ 9.000	$ 8.394	$ 37.535	$ 4.585	$ 902.178
29								
30	Fuel and Purchased Power Energy Costs					$ 39,385,348		
31	ECA Average Rate ($/MWh)					$ 23.193		
32	Non-ECA Energy Average Rate ($/MWh)					$ 14.342		

Kansas Electric Power Cooperative, Inc.
Supplier Demand Rates
Test Year Ending December 31, 2006

Supplier	Demand Costs	Billing Units (kW-Mo)	Average Rate ($/kW-Mo)
Westar Energy	$ 9,004,155	1,613,748	$ 5.580
Kansas City Power & Light	$ -	-	$ -
Empire District Electric	$ -	-	$ -
City of St. Marys	$ -	-	$ -
Sunflower Electric Power	$ 3,488,976	345,059	$ 10.111
Southwestern Power Administration	$ 3,624,920	1,200,000	$ 3.021
Western Area Power Administration	$ 558,894	162,942	$ 3.430
Total	$ 16,676,945	3,321,749	$ 5.021

	Base	Excess	Total
M-11 Billing Units	1,822,368	1,485,606	3,307,974
Test Purchased Demand			$16,676,945
Average Rate			5.04

Kansas Electric Power Cooperative, Inc.
Example of DCA Calculation

Assume M-10 effective 2008 such that DCA is in place.
Assume that adjustment has already been for initial Westar rate change.
Assume hypothetical changes in purchased power demand cost and Member billing demand.

Line No.	Description	Reference	Units	Base	(A) Year 1	(B) Year 2	(C) Year 3	(D) Total Years 1,2,3,
1	Purchased Power Demand Cost Actually Paid For Period	DC	$	16,676,946	17,677,563	18,738,217	19,862,510	56,278,289
2	Annualized Purchased Power Demand Cost	ADC	$	16,676,946	18,000,000	19,000,000	20,000,000	
3	Member Billing Demand for Period	D	kW mon	3,307,974	3,407,213	3,509,429	3,614,712	
4	Base Demand Cost	BD	$/kW	5.04000				
5	BD	L4	$/kW		5.040	5.040	5.040	
6	**DC**	L1	$		17,677,563	18,738,217	19,862,510	56,278,289
7	ADC	L2	$		18,000,000	19,000,000	20,000,000	
8	D	L3	$		3,407,213	3,509,429	3,614,712	
9	D*BD	L8 * L5	$		17,172,352	17,687,523	18,218,148	53,078,023
10	D*DCAa	L8 * L12	$		-	1,372,844	1,540,404	2,913,248
11	R	L1-L9-L10+Prior Year R	$		505,211	183,060	287,018	287,018
12	DCAa		$/kW			0.39	0.43	
13	DCAe	(L7-L9+L11)/L8	$/kW		0.39	0.43	0.57	
14	Total							56,278,289
15	Power Cost To Recover		$		17,677,563	18,738,217	19,862,510	56,278,289
16	Power Cost in Base		$		17,172,352	17,687,523	18,218,148	53,078,023
17	DCA Recovery		$		-	1,372,844	1,540,404	2,913,248
18	Carry Forward		$					287,018
19	Total		$		17,172,352	19,060,367	19,758,552	56,278,289

Kansas Electric Power Cooperative, Inc.
One Year Phase-in for Members Over the Average Increase
Test Year Ending December 31, 2006

			Without Phase-In				First Year Credit		
			M-9 Weather Normalized Rates	M-10 Proposed Rates	Difference	% Difference	Credit Calculation		
Member	Total MWh	Total kW-Mo	Total ($)	Total ($)	Total ($)	(%)	(%)	($)	($/kW)
Brown-Atchison	78,842	159,498	$ 4,669,376	$ 5,043,119	$ 373,744	8.0%	2.72%	$ 127,034	$0.80
Radiant	61,232	110,287	$ 3,385,443	$ 3,603,626	$ 218,183	6.4%	1.16%	$ 39,311	$0.36
Ninnescah	66,141	120,188	$ 3,996,975	$ 4,257,571	$ 260,596	6.5%	1.24%	$ 49,413	$0.41
CMS	107,364	149,796	$ 5,657,898	$ 5,987,250	$ 329,351	5.8%	0.54%	$ 30,413	$0.20
Bluestem	92,950	174,687	$ 5,661,242	$ 6,022,825	$ 361,583	6.4%	1.10%	$ 62,468	$0.36
Prairie Land	24,122	37,154	$ 1,345,822	$ 1,430,371	$ 84,549	6.3%	1.00%	$ 13,441	$0.36
DS&O	117,763	233,607	$ 7,226,448	$ 7,651,465	$ 425,016	5.9%	0.60%	$ 43,202	$0.18
Rolling Hills	124,596	250,459	$ 7,725,154	$ 8,187,841	$ 462,686	6.0%	0.71%	$ 54,523	$0.22
Twin Valley	34,902	74,332	$ 2,151,180	$ 2,275,236	$ 124,057	5.8%	0.48%	$ 10,398	$0.14
Caney Valley	55,806	121,071	$ 3,563,666	$ 3,757,589	$ 193,923	5.4%	0.16%	$ 5,634	$0.05
Sumner-Cowley	73,185	150,816	$ 4,570,979	$ 4,816,271	$ 245,292	5.4%	0.08%	$ 3,781	$0.03
Lyon-Coffey	96,843	192,971	$ 6,079,036	$ 6,403,945	$ 324,909	5.3%	0.06%	$ 3,719	$0.02
Flint Hills	75,415	160,209	$ 4,806,149	$ 5,049,764	$ 243,614	5.1%			
Sedgwick	110,179	242,072	$ 6,750,645	$ 7,084,615	$ 333,970	4.9%			
Victory	125,355	169,301	$ 6,687,234	$ 7,012,702	$ 325,468	4.9%			
Ark Valley	85,804	169,769	$ 5,217,376	$ 5,436,061	$ 218,685	4.2%			
Butler	111,602	254,699	$ 7,109,280	$ 7,390,643	$ 281,363	4.0%			
Leavenworth-Jefferson	112,830	240,267	$ 7,036,316	$ 7,313,415	$ 277,100	3.9%			
Heartland	143,222	296,810	$ 8,825,656	$ 9,155,420	$ 329,764	3.7%			
Total KEPCo	1,698,150	3,307,993	$ 102,465,876	$ 107,879,729	$ 5,413,853	5.3%			
One Year Credit								$ 443,337	