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Kansas Corporation Commission
/S/ Susan K. Duffy

BEFORE THE CORPORATION COMMISSION
OF THE STATE OF KANSAS

STATE CORPORATION COMMISSION

JUN 1 5 2010

Susan Talbott

IN THE MATTER OF THE APPLICATION	]	
OF KANSAS CITY POWER & LIGHT	]	Docket No. 10-KCPE-415-RTS
COMPANY TO MODIFY ITS TARIFFS	]	
TO CONTINUE THE IMPLEMENTATION	]	
OF ITS REGULATORY PLAN	]	

DIRECT TESTIMONY OF

ANDREA C. CRANE

RE: REVENUE REQUIREMENTS
AND COST OF CAPITAL

ON BEHALF OF

THE CITIZENS' UTILITY RATEPAYER BOARD

June 15, 2010

*****PUBLIC VERSION*****

***** Schedule ACC-9 and Schedule ACC-35 Redacted*****

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 199 Ethan Allen Highway, Ridgefield, Connecticut 06877.

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

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I have been President of the firm since 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in over 300 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, West Virginia and the District of Columbia. These proceedings involved electric, gas, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony is included in Appendix A.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On or about December 17, 2009, Kansas City Power & Light Company ("KCP&L" or "Company") filed an Application with the Kansas Corporation Commission ("KCC" or "Commission") seeking a rate increase of $55.225 million. The Company's request would result in an increase of approximately 9.7% over retail sales revenue at present rates. The Company's filing is based on a test year ending September 30, 2009, with pro forma adjustments extending in some cases through

September 30, 2010.

The Columbia Group, Inc. was engaged by The State of Kansas, Citizens' Utility Ratepayer Board ("CURB"), to review the Company's Application and to provide recommendations to the KCC regarding the Company's cost of capital and revenue requirement claims. Brian Kalcic is also filing testimony on behalf of CURB addressing rate design issues. CURB did not engage an expert to review the Company's new depreciation study or to examine other issues in this case relating to depreciation rates or KCP&L's claim for unrecovered general plant costs. Therefore, I have not made any adjustments relating to these issues in my revenue requirement recommendation. However, CURB may provide Cross Answering Testimony on these issues or address these issues further in its Brief in this case. Thus, at this time, the KCC should not conclude that CURB supports the Company's new depreciation rates or its adjustment relating to unrecovered general plant costs.

Q. What are the most significant issues in this rate proceeding?

A. The most significant issues in the Company's filing are: a) its projected utility plant-in-service additions, especially additions to plant-in-service associated with the Iatan Unit 2 generating facility; b) incremental operating costs and depreciation expense associated with Iatan Unit 2; c) proposed increases in salaries and wages; d) proposed increases in incentive compensation and other employee benefit costs; e) proposed increases in generation and distribution maintenance costs; and f) the Company's request for a return on equity of 11.25%. The Company's filing represents the fourth case to be filed pursuant to the Regulatory Plan that was agreed to by the Company and the KCC Staff in Docket No. 04-KCPE-1025-GIE.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing and other documentation in this case, my conclusions are as follows:

1. The twelve months ending September 30, 2009 is a reasonable test year to use in this case to evaluate the reasonableness of the Company's claim.
2. The Company has a cost of equity of 9.39% and an overall cost of capital of 8.06% (see Schedule ACC-2).[1]
3. KCPL has pro forma test year rate base of $1,731,941,171 (see Schedule ACC-9).
4. The Company has pro forma operating income at present rates of $135,075,508 (see Schedule ACC-17).
5. KCPL has a pro forma revenue deficiency of $7,379,627 (see Schedule ACC-1). This is in contrast to the Company's claimed revenue requirement

[1] Schedules ACC-1, ACC-45, and ACC-46 are summary schedules, ACC-2 to ACC-8 are cost of capital schedules, ACC-9 to ACC-16 are rate base schedules, and ACC-17 to ACC-44 are operating income schedules.

deficiency of $55,225,000.

6. CURB's recommendations do not include any adjustments to the Company's claims for new depreciation rates or to its claim for unrecovered general plant. CURB will review adjustments proposed by other parties relating to these issues and may adopt such adjustments in Cross Answering Testimony or in its Brief.

IV. BACKGROUND OF THE REGULATORY PLAN

Q. Please provide a brief description of the Regulatory Plan[2] under which the Company has operated for the past few years.

A. On May 18, 2004, KCP&L filed an Application requesting that the KCC open a docket to address various issues relating to the continued provision of regulated utility service. The KCC subsequently opened KCC Docket No. 04-KCPE-1025-GIE. The most significant issue addressed in that proceeding was the perceived need for additional generating capacity and the best way to finance that additional capacity. Other issues included the need for environmental upgrades, investments in the Company's transmission and distribution systems, and establishment of Demand Side Management ("DSM") and other energy efficiency programs.

The KCC, at the request of the Company, established a workshop forum to address these various issues. As a result of that process, the Company entered into a

[2] Throughout this testimony, I will use the term "Regulatory Plan" to refer to the provisions of the Stipulation and Agreement in Docket No. 04-KCPE-1025-GIE, as well as the provisions outlined in the associated appendices.

Regulatory Plan that identified investments to be made by KCP&L over the next five years and established a regulatory mechanism designed to maintain the financial integrity of the Company during this period. The Regulatory Plan was agreed to by the Company, Staff, Sprint, and the Kansas Hospital Association. CURB was not a signatory to the Settlement Agreement for the Regulatory Plan. The Regulatory Plan was approved by the KCC on August 5, 2005.

Q. Please briefly outline the provisions of the Regulatory Plan.

A. Pursuant to the Regulatory Plan, KCPL agreed to undertake a series of capital investments, including the addition of 800-900 MWs of new coal-fired generation and 100 MWs of new wind generation. The Company also agreed to make certain investments with regard to transmission and distribution facilities and environmental upgrades, and to introduce several programs to address Demand Response, Efficiency, and Affordability issues.

The Regulatory Plan required KCP&L to file a base rate case on or before May 1, 2006. That case (KCC Docket No. 06-KCPE-828-RTS) was filed on January 31, 2006 and was resolved by a Stipulation approved by the KCC on December 4, 2006. The Regulatory Plan permitted, but did not require, KCP&L to file base rate cases in 2007 and 2008. Pursuant to this provision, KCP&L filed base rate cases on March 1, 2007 and September 5, 2008 (KCC Docket Nos. 07-KCPE-905-RTS and 09-KCPE-246-RTS, respectively). Both of these cases were resolved by Stipulation.

The Regulatory Plan also required the Company to file a base rate case on or before August 15, 2009, with new rates to be effective June 1, 2010 ("2010 Case"). It was anticipated that the 2010 Case would be the last filing made pursuant to the Regulatory Plan. Given various delays that have occurred in the construction of Iatan Unit 2, the 2010 Case was not filed until December 17, 2009 and rates are not expected to become effective until the fall of 2010 or later, depending upon the in-service date of Iatan Unit 2.

The Regulatory Plan recognized that it was important for KCP&L to maintain an investment grade rating during the construction process. In order to assist KCP&L to maintain this rating, the Regulatory Plan contained a provision for "an amortization accounting [adjustment] to be referred to as a Contribution in Aid of Construction ("CIAC")."[3] Pursuant to the Regulatory Plan, the CIAC was an amount that would be treated as an additional amortization expense and added to KCP&L's cost of service for ratemaking purposes if required in order to meet the cash flow requirements of the rating agencies. The Regulatory Plan provided that the accumulated CIAC would be treated as an increase to the depreciation reserve and deducted from rate base in future KCP&L proceedings beginning with rates effective as a result of the 2010 Case. The CIAC provision equated to a prepayment of the new generating facilities by ratepayers if required to meet cash flow objectives.

[3] Stipulation and Agreement, Docket No. 04-KCPE-1025-GIE, page 6.

Q. Please summarize the Stipulation that was agreed to in the Company's last base rate case.

A. In its last case, the Company requested a rate increase of \$71.63 million, including \$11.2 million in CIAC. The Stipulation in that case provided for a total revenue increase of \$59.0 million. The Stipulation provided that \$18.0 million of that increase "will be treated for accounting purposes as a pre-tax payment on plant on behalf of consumers. The \$18 million pre-tax payment shall be treated as an increase to KCPL's depreciation reserve and will be assigned to primary plant accounts in the next rate case."

The Stipulation in that case also permitted the Company to create a regulatory asset for depreciation expense and carrying costs associated with the Iatan Unit 1 Air Quality Control System ("ACQS") and Iatan common plant that went into service but which was not yet included in rate base. The Stipulation deferred to the 2010 Case certain recommendations made by the parties regarding prudence disallowances. Finally, the Stipulation specified the accounting treatment for several types of costs, such as rate case costs, Surface Transportation Board litigation expenses, SO_2 emission allowance proceeds, and pension costs. Other issues addressed in the Stipulation included depreciation rates, asset retirement obligations and costs of removal, and Allowance for Funds Used During Construction ("AFUDC") on Iatan Unit 2.

Q. How successful has the Company been in meeting the requirements of the Regulatory Plan since the Regulatory Plan was approved on August 5, 2005?

A. On May 4, 2010, KCP&L filed a reconciliation of the estimated costs included in the Regulatory Plan and the actual costs incurred to date, including the most recent estimate of actual costs to complete Iatan Unit 2. As shown in the chart below, several components of the Company's Regulatory Plan were significantly over-budget, were delayed, or were not undertaken at all. The Regulatory Plan as filed totaled $1.231 billion on a total KCP&L basis, while actual costs, based on current estimates for Iatan Unit 2, are approximately $1.7 billion. However, the original estimate included total KCP&L costs for DSM programs, while the actuals provided by the Company were on a Kansas jurisdictional basis.[4] In addition, the Regulatory Plan included one project, the La Cygne Unit 1 Flue Gas Desulfurization ("FGD") and Baghouse, which was not undertaken by the Company. Therefore, in order to provide a more meaningful comparison, it is necessary to adjust the $1.231 billion included in the Regulatory Plan to a) reflect the Kansas-jurisdictional estimate for DSM programs and b) remove the estimate for the La Cygne Unit 1 FGD and Baghouse. With these modifications, the original estimate declines to $1.139 billion. Thus, actual costs for the components of the Regulatory Plan that were completed are approximately 50% over-budget.

[4] Actual costs for the other projects were reported on a total KCP&L basis.

Project	Estimate ($000)	Actual ($000)	Notes:
Iatan Unit 2	$733,666	$1,091,000-$1,113,000	
Wind Generation	$130,838	$161,795	
Environmental – La Cygne Unit 1 SCR	$37,317	$40,370	
Environmental-Iatan Unit 1 AQCS	$170,956	$329,000	
Environmental-La Cygne Unit 1 FGD and Baghouse	$63,540	NA	Project Not Undertaken
Asset Management	$42,326	$42,300	
DSM Programs	$52,782	$26,413	Regulatory Plan had total KCP&L estimate of $52,782; actual reflects Kansas share
Total	$1,231,425	$1,690,878-$1,712,878	
Total w/adjusted DSM Estimate	$1,202,431		
Total w/ adjusted DSM Estimate and Excluding La Cygne Unit 1 FDG and Baghouse	$1,138,891		

Moreover, the Iatan Unit 2 project, which was originally envisioned to be complete by June 1, 2010, will not be in-service until the fall of 2010, and perhaps even later.

Q. How is the Company justifying these cost overruns, especially with regard to

Iatan Unit 2?

A. Now, five years after the Regulatory Plan was approved by the KCC, the Company is testifying that the estimates included in the Regulatory Plan were given a very low likelihood of being met. We are hearing for the first time about the Cost Estimate Classification System developed by the Association for the Advancement of Cost Engineers ("AACE"), which classifies cost estimates based upon the level of project development at the time of the estimate. The KCC is now being told that the project was so ill-defined when the Regulatory Plan was approved that the cost estimates included in the Regulatory Plan, at least for Iatan Unit 2, could not be relied upon. I will address this argument later in my testimony. However, it is unfortunate that the Company did not provide this information to the Commission when the KCC was being asked to approve the Regulatory Plan. While CURB was not a signatory to the Regulatory Plan, it did participate in discussions that preceded the execution of the Regulatory Plan. During those discussions, it was certainly CURB's impression that the cost estimates were "good" numbers. While cost estimates are just that – estimates not actuals – it was certainly CURB's impression that there was a sound basis for the estimates associated with Iatan Unit 2. Moreover, the Regulatory Plan provided a regulatory compact between KCP&L and the ratepayers of Kansas. Given the significant cost overruns and project delays, particularly with regard to Iatan Unit 2, I believe that this regulatory compact has been breached. At a minimum, this should make the KCC, and the signatory parties to the Regulatory Plan, reluctant to enter into any similar agreement in the future with KCP&L.

V. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that the Company is requesting in this case?

A. The Company utilized the projected capital structure and cost rates for Great Plains Energy, Inc. ("GPE"), the parent holding company, at August 31, 2010. As shown on page 6 Dr. Hadaway's testimony, the Company's claim was composed of the following:

	Percent	Cost Rate	Weighted Cost
Common Equity	46.17%	11.25%	5.19%
Equity Linked Convertible Debt	4.53%	13.588%	0.62%
Preferred Stock	0.61%	4.29%	0.03%
Long Term Debt	48.68%	6.84%	3.33%
Total	100.00%		8.75%

A. Capital Structure

Q. Are you recommending any adjustments to this capital structure or cost of capital?

A. Yes, I am recommending adjustments to the Company's capital structure and its cost of equity claims.

Q. What adjustments are you recommending to the Company's capital structure?

A. The Company's capital structure includes an equity-linked convertible debt instrument at an interest rate of 13.588%, a portion of which is tax deductible. However, this financing instrument is more expensive than either the Company's debt or equity cost claim. I am recommending that this equity-linked convertible debt be excluded from the Company's capital structure for ratemaking purposes.

Q. What is the basis for your adjustment?

A. This capital is more expensive than either KCP&L's debt or equity capital. The Company has provided CURB with confidential documentation relating to the issuance of this financing instrument. I have concluded that the Company issued this equity-linked convertible debt to avoid a potential downgrade of its credit rating. However, the Company has been operating pursuant to a Regulatory Plan that provided a specific mechanism to provide sufficient revenues so that the Company could maintain an investment grade rating. That mechanism was referred to as a Contribution in Aid of Construction ("CIAC") in the Regulatory Plan. The Regulatory Plan provided for payments of CIAC by ratepayers over the life of the Regulatory Plan sufficient to permit the Company to maintain an investment grade rating. The Stipulations and Agreements approved by the parties during the rate cases included in the Regulatory Plan contained approximately $66.25 million in prepayments that were designed for this purpose.

The Regulatory Plan made it clear that if the Company's investment grade rating was jeopardized in spite of the CIAC or prepayments collected from ratepayers, then the parties "are under no obligation to recommend any further cash flow or rate relief to satisfy the obligations under this section. KCPL also recognizes and agrees that Kansas is only responsible for and will only provide cash flow for its share of the necessary cash flows as set out in this section. Therefore, if KCPL is unable to meet the BBB+ credit ratio guidelines because of inadequate cash flows from its Missouri operations, because of imprudent or unreasonable costs, because of inadequate cash flows from the non-regulated subsidiary of GPE or any risk associated with GPE that is unrelated to KCPL's regulated operations, KCPL will not argue for or receive increased cash flows from Kansas in order to meet the BBB+ credit ratio guidelines."

Thus, the Regulatory Plan suggests that, apart from providing for CIAC, it is incumbent upon the Company and its shareholders to take the appropriate steps necessary to maintain the investment grade rating. As acknowledged by KCP&L in the Regulatory Plan, "KCPL further understands that it is incumbent upon the Company to take prudent and reasonable actions that do not place its investment grade debt rating at risk and that this Agreement heightens rather than lessens such obligation. KCPL further understands that its Kansas jurisdictional customers will not support any negative impact from KCPL's failure to be adequately insulated from the Great Plains business risks as perceived by the debt rating agencies."

Q. Has KCP&L provided any documentation to demonstrate that the need to issue equity-linked convertible debt was the direct result of actions taken in Kansas that were inconsistent with the provisions of the Regulatory Plan?

A. No, it has not. KCP&L has been a signatory to each Stipulation and Agreement in the Kansas rate cases that have occurred during the period of the Regulatory Plan. The Company should not have signed these agreements if it felt that they did not provide sufficient revenues for KCP&L to maintain its investment grade rating. Therefore, shareholders, rather than ratepayers, should be responsible for any additional financing costs that may be necessary in order to ensure than an investment grade rating is maintained. In addition, it should be noted that during this period the Company completed a major acquisition that undoubtedly had an impact on its financing needs. The Company's shareholders and management obviously believed that the Company had sufficient financing ability to pursue this acquisition. Moreover, the Company's financial integrity has undoubtedly been impacted by continued delays and cost overruns associated with Iatan Unit 2. To the extent that these delays and overruns put further pressure on the Company's credit indices, shareholders and not ratepayers should be responsible. Accordingly, there is nothing in the record in this case to support the inclusion of high cost, equity-linked convertible capital in the Company's capital structure and I recommend that this capital be excluded for ratemaking purposes.

Q. How did you determine a pro forma capital structure for KCP&L?

A. In order to calculate a pro forma capital structure for KCP&L, I eliminated the equity-linked convertible debt and recalculated the capital ratios based on the projected balances at August 31, 2010, per the Company's workpapers. As shown in Schedule ACC-2, this results in the following capital structure:

	Percent
Common Equity	48.37%
Preferred Stock	0.64%
Long Term Debt	50.99%
Total	100.00%

B. Cost of Equity

Q. How did you develop your recommended cost of equity?

A. The KCC has traditionally relied upon the Discounted Cash Flow Model ("DCF") as the primary mechanism to determine cost of equity for a regulated utility. Therefore, in determining an appropriate return on equity for KCPL, I have relied primarily upon the DCF. The DCF method is based on the following formula:

$$\text{Return on Equity} = \frac{D_1}{P_0} + g$$

where "D_1" is the expected dividend, "P_0" is the current stock price, and "g" is the expected growth in dividends.

The DCF methodology is generally applied to a comparable group of investments, usually to a group of companies that provide the same utility service as the utility service for which rates are being set. In order to determine a comparable group of companies, I utilized the same comparable group as that selected by the Company's witness, Dr. Samuel Hadaway.

To determine an appropriate dividend yield for comparable companies - i.e., the expected dividend divided by the current price - I calculated the dividend yield of each of the comparable companies under two scenarios. First, I calculated the dividend yield using the average of the stock prices for each company over the past three months. The use of a dividend yield using a three-month average price mitigates the effect of stock price volatility for any given day. The three-month average is also consistent with the methodology used by Dr. Hadaway. Based on the average stock prices over the past three months, and the current dividend for each company, I determined an average dividend yield of 4.84% for the comparable group, as shown in Schedule ACC-5.

I also calculated a current dividend yield at May 20, 2010, which showed an average dividend yield of 4.99% for the comparable group. This calculation is also shown in Schedule ACC-5. As a check of reasonableness, I also reviewed the dividend yields as reported in the May 2010 edition of the AUS Utility Reports, which showed an average yield for electric companies of 4.3%. Based on these determinations, I recommend that a dividend yield of 4.84% be used in the DCF calculation. This recommended dividend yield is lower than the average historic dividend yield of 5.19% shown in Schedule 5 to Dr. Hadaway's testimony due to the use of more recent data. My recommended dividend yield will be increased by ½ of my recommended growth rate, as determined below, to reflect the fact that the DCF model is prospective and dividend yields may grow over the next year. Increasing the dividend yield by ½ of the prospective growth rate is commonly referred to as the "half year convention."

Q. How did you determine an appropriate growth rate?

A. The actual growth rate used in the DCF analysis is the dividend growth rate. In spite of the fact that the model is based on dividend growth, it is not uncommon for analysts to examine several growth factors, including growth in earnings, dividends, and book value.

Various growth rates for the companies within my comparable group are shown in Schedule ACC-6 and group averages are summarized below:

Past 5 Years – Earnings	6.4%
Past 5 Years – Dividends	2.8%
Past 5 Years - Book Value	4.5%
Past 10 Years – Earnings	2.8%
Past 10 Years – Dividends	0.5%
Past 10 Years - Book Value	3.5%
Estimated Next 5 Years - Earnings	5.4%
Estimated Next 5 Years - Dividends	4.3%
Estimated Next 5 Years - Book Value	4.3%

Q. Why do you believe that it is reasonable to examine historic growth rates as well as projected growth rates when evaluating a utility's cost of equity?

A. I believe that historic growth rates should be considered because security analysts have been notoriously optimistic in forecasting future growth in earnings. At least part of this problem in the past has been the fact that firms that traditionally sold securities were the same firms that provided investors with research on these securities, including forecasts of earnings growth. This resulted in a direct conflict of interest since it has traditionally been in the best interest of securities firms to provide optimistic earnings forecasts in the hope of selling more stock. Therefore, earnings growth forecasts should be analyzed cautiously by state regulatory commissions.

The continued unreliability of analysts' future forecasts has been confirmed with the economic problems faced by the financial community in late 2008 and 2009. Many firms, including Value Line, incorrectly forecasted steady growth for companies whose stock prices have now fallen dramatically, and in some cases for firms that have now required bailouts from other firms or the federal government. Although Value Line does not sell stock, its forecasts appear to be just as optimistic as many of the securities firms. The KCC needs only to examine actual results in 2008 and 2009 to realize that earnings forecasts should be viewed with a healthy dose of skepticism.

Q. Based upon your review, what growth rate do you recommend be utilized in the DCF calculation?

A. Based on my review of this data, I believe that a growth rate of no greater than 5.0% should be utilized. This recommended growth rate is greater than the ten year growth rates in earnings, dividends, or book value. It is also higher than either the five-year growth rates or the projected growth rates in dividends and book value per Value Line.

Q. What cost of equity is produced by the DCF methodology?

A. My analysis indicates a cost of equity using the DCF methodology of 9.94%, as shown below:

Dividend Yield	4.84%
Growth in Dividend Yield (1/2 X 5.00% X 4.84%)	0.12%
Expected Growth	5.00%
Total	9.96%

Q. Did you also calculate a cost of equity based on the CAPM methodology?

A. Yes, I did.

Q. Please provide a brief description of the CAPM methodology.

A. The CAPM methodology is based on the following formula:

Cost of Equity = Risk Free Rate + Beta (Risk Premium)

or

$$\text{Cost of Equity} = R_f + B(R_m - R_f)$$

The CAPM methodology assumes that the cost of equity is equal to a risk-free rate plus some market-adjusted risk premium. The risk premium is adjusted by Beta, which is a measure of the extent to which an investor can diversify his market risk. The ability to diversify market risk is a measure of the extent to which a particular stock's price changes relative to changes in the overall stock market. Thus, a Beta of

1.00 means that changes in the price of a particular stock can be fully explained by changes in the overall market. A stock with a Beta of 0.60 will exhibit price changes that are only 60% as great as the price changes experienced by the overall market. Utility stocks have traditionally been less volatile than the overall market, i.e., their stock prices do not fluctuate as significantly as the market as a whole, and therefore their Betas have generally been less than 1.0.

Q. How did you calculate the cost of equity using the CAPM?

A. My CAPM analysis is shown in Schedule ACC-7. First, I used a risk-free rate of 4.24% for the yield on long-term U.S. Government bonds. Over the past year, this rate has ranged from 3.99% to 4.85%. In addition, I used the average Beta for the proxy group. This resulted in an average Beta of 0.70, as shown in Schedule ACC-8. Finally, since I am using a long-term U.S. Government bond rate as the risk-free rate, the risk premium that should be used is the historic risk premium of stocks over the rates for long-term government bonds. According to the 2008 Ibbotson Valuation Yearbook, *Market Results for Stocks, Bonds, Bills, and Inflation, 1926-2007,* the risk premium of using geometric mean returns is 4.9%.

Q. Turning to the issue of the risk premium, what is the difference between a geometric and an arithmetic mean return?

A. An arithmetic mean is a simple average of each year's percentage return. A geometric mean takes compounding into effect. As a result, the arithmetic mean overstates the historic return to investors. For example, suppose an investor starts with $100. In year 1, he makes 100% or $100. He now has $200. In year 2, he loses 50%, or $100. He is now back to $100.

The arithmetic mean of these transactions is 100% - 50% or 50%/ 2 = 25% per year. The geometric mean of these transactions is 0%. In this simple example, it is clear that the geometric mean more appropriately reflects the real return to the investor, who started with $100 and who still has $100 two years later. The use of the arithmetic mean would suggest that the investor should have $156.25 after two years ($100 X 1.25 X 1.25), when in fact the investor actually has considerably less. Therefore, a geometric mean return is a more appropriate measure of the real return to an investor, if it is used as I am using it here, i.e., to develop an historic relationship between long-term risk free rates and market risk premiums. Some utilities have criticized me in the past for using a geometric, rather than an arithmetic mean return, arguing that the arithmetic mean should be used when estimating future returns. However, in my case, I am not using the mean to develop an expected outcome, I am simply using the mean returns to develop an historic relationship. Therefore, the geometric mean is the appropriate measure, as illustrated in the above example.

Q. What is the Company's cost of equity using a CAPM approach?

A. Given a long-term risk-free rate of 4.24%, a Beta of 0.70, and a risk premium of 4.9%, the CAPM methodology produces a cost of equity of 7.67%, as shown on Schedule ACC-7.

Risk Free Rate + Beta (Risk Premium) = Cost of Equity

4.24% + (0.70 X 4.9%) = 7.67%

Q. Based on your analysis of the DCF and CAPM results, what cost of equity are you recommending in this case?

A. The DCF methodology and the CAPM methodology suggest that a return on equity of 7.67 % to 9.96% would be appropriate. Since I recognize that the Commission has generally relied primarily upon the DCF, I have weighted my results with a 75% weighting for the DCF methodology and a 25% weighting for the CAPM methodology. This results in a cost of equity of 9.39%, as shown below:

DCF Result	9.96% X 75% =	7.47%
CAPM	7.67% X 25% =	1.92%
Total		9.39%

This weighting methodology is consistent with the methodology that I have used in prior cases before the KCC, as well as in other jurisdictions that have expressed a preference for the DCF model.

Q. Why is your recommendation substantially lower than the cost of equity recommended by Dr. Hadaway?

A. My recommendation is substantially lower than Dr. Hadaway's primarily because he used unrealistic growth projections. Dr. Hadaway calculated three DCF results. His first DCF model used a constant growth based only on analysts' estimated growth rates. This resulted in an average growth rate of 6.01%, which I believe is overly optimistic.

Dr. Hadaway's second DCF analysis used long-term projected GDP growth as his growth rate. This methodology resulted in an average growth rate of 6.20%. Dr. Hadaway claims that the long-term GDP "is the most general measure of economic growth in the U.S. economy."[5] While it may be true that GDP is the most general measure of economic growth in the U.S. economy, it does not follow that GDP is an appropriate rate to utilize for utility dividends in a DCF model. Moreover, Dr. Hadaway developed his GDP growth rate of 6.20% by averaging historic GDP growth over 10, 20, 30, 40, 50, and 60 years. However, as shown on Schedule SCH-4 to Dr. Hadaway's testimony, the ten-year average of 4.8% and the twenty-year average of 5.1% are both well below the growth rates of 6.1% to 7.1% that occurred in the remaining periods reviewed. The use of a GDP growth rate that is heavily dependent upon periods of very high economic growth, especially the 11.0% plus

[5] Testimony of Dr. Hadaway, page 36.

growth rates that occurred during the 1972 to 1983 period, is particularly inappropriate. There is no evidence that GDP growth is the appropriate growth rate to use for utility dividends and this is especially true of GDP growth from thirty years ago.

Dr. Hadaway's third DCF analysis employed a two-stage DCF, using the Value Line projected dividend for the first stage and the long-term projected GDP for the second stage. Dr. Hadaway's two-stage model is again flawed due to the use of excessive projected earnings growth rates and the use of the GDP.

D. Overall Cost of Capital

Q. What is the overall cost of capital that you are recommending for KCP&L?

A. As shown on Schedule ACC-2, I am recommending an overall cost of capital for KCPL of 8.06 %, as shown below:

	Percent	Cost Rate	Weighted Cost
Common Equity	48.37%	9.39%	4.54%
Preferred Stock	0.64%	4.29%	0.03%
Long Term Debt	50.99%	6.84%	3.49%
Total	100.00%		8.06%

VI. RATE BASE ISSUES

Q. What test year did the Company utilize to develop its rate base claim in this proceeding?

A. The Company selected the test year ending September 30, 2009. However, its rate base claim reflects an assortment of dates. The Company reflected investment, accumulated depreciation, and deferred income taxes at September 30, 2010. However, some rate base components reflect values as of August 31, 2010 (e.g. deferred security costs) while others are based on balances at September 30, 2009 (e.g. customer advances), the end of the test year in this case, or are based on average monthly balances during the test year (e.g. prepayments).

A. Utility Plant In Service

Q. Please describe the Company's claim for utility plant in service.

A. The Company has included utility plant-in-service additions and retirements through September 30, 2010 in its claim. KC&L's claim starts with utility plant-in-service at September 30, 2009, the end of the test year in this case. The Company then made adjustments to reflect a revision to its ownership interest in certain plant associated with Iatan Unit 1; to reflect the retirement of additional amounts relating to leasehold improvements at its former headquarters building; and to reflect post-test year plant additions relating to Iatan 1 plant, Iatan common plant, and Iatan 2. The Company also included normal ongoing additions and retirements through September 30, 2010 in its rate base claim.

Q. Did the Stipulation in the Company's last base rate case address the issue of Iatan Unit 2 and the final rate case to be filed as part of the Regulatory Plan?

A. Yes, it did. The Regulatory Plan required the Company to file its last base rate case pursuant to the Regulatory Plan on August 15, 2009. However, in the Stipulation in KCC Docket No. 09-KCPE-246-RTS, the parties recognized that this filing date was no longer appropriate, due to delays in the construction of Iatan Unit 2. In addition, the parties recognized that it would be difficult to review final cost information in time to have rates approved concurrent with the in-service date of the unit. Therefore, in the Stipulation in KCC Docket No. 09-KCPE-246-RTS, the parties agreed to collaborate "in order to establish a procedure for the next rate case that addresses the in-service, process, and timing problems realized with this proceeding." As a result of that collaboration, on September 9, 2009, the parties submitted a "Joint Report Regarding the Timing and Process For Kansas City Power & Light Company's Final Rate Proceeding Under Its Five Year Regulatory Plan" ("Joint Report"). In the Joint Report, the parties agreed that a) budgeted cost numbers for Iatan Unit 2 would be used to set rates in this proceeding, b) rates set in this proceeding would be subject to true-up in a subsequent abbreviated proceeding within twelve months, c) issues of prudence disallowances would be addressed in the 2010 Case, subject to true-up for actual costs in the abbreviated case, and d) in their testimony in the 2010 Case, the parties would identify what portion of the rate increase is not subject to true-up and potential refund, based on review of invoices as of the end of the month approximately 60 days prior to the filing date for testimony.

Q. How much has the Company included for Iatan Unit 2 in its rate base claim in this case?

A. In this case, the Company has included Iatan Unit 2 costs of $1.029 billion, which represents KCP&L's share of construction costs, AFUDC, and property taxes capitalized during construction.

Q. Are you recommending any adjustment to the Company's claim for utility plant- in- service?

A. Yes, I am recommending two adjustments, both relating to the Company's claim for Iatan Unit 2. First, I am recommending an adjustment to reflect a more recent estimate for property taxes that are being capitalized prior to the in-service date of Iatan Unit 2. Second, I am recommending that the KCC disallow 25% of the project cost overruns, or $33.6 million, on the basis of imprudence.

Q. Please describe your first adjustment to the Iatan Unit 2 costs.

A. As noted, the Company's claim for Iatan Unit 2 includes property taxes that will be capitalized during the construction period. In the response to KCC-95, the Company stated that it now has a better estimate for the amount of property taxes that will be capitalized as part of the project. Therefore, at Schedule ACC-10, I have reduced the Company's estimate for Iatan Unit 2 costs to reflect the updated property tax amount identified by the Company in that response.

Q. Turning to the issue of prudence, what is the standard in Kansas for prudence disallowances?

A. It should be noted that I am not an attorney and my comments are not meant to provide any legal guidance to the KCC. The legal issues regarding prudence disallowances will be addressed in CURB's Brief in this case.

However, it is my understanding that the KCC does have the authority to disallow utility investment on the basis that such investment was imprudent. Specifically, K.S.A. 66-128e states in part:

> Nothing in this act shall limit the commission's authority to adjust revenue requirements of any public utility if the commission determines the revenue requirement requested results in whole or in part from inefficiency or a lack of prudence.

K.S.A. 66-128g outlines the "factors which shall be considered by the commission in making the determination of 'prudence' or lack thereof in determining the reasonable value of electric generating property...". These factors include a comparison of the original cost estimates made by the owners of the facility under consideration with the final cost of such facility.[6]

In this case, not only was a cost estimate for a new generating facility presented to the KCC, but the KCC approved a Regulatory Plan to support the Company's proposed construction activities. In my view, this Regulatory Plan resulted in a regulatory compact between shareholders and ratepayers. The Regulatory Plan contained several ratemaking provisions that went above and beyond the normal ratemaking framework. It provided for a series of annual rate filings during the construction period. It provided for payment of CIAC, which was to be used to maintain the Company's financial integrity during the construction period. It permitted the Company to retain proceeds from the sales of SO_2 emission allowances until after construction of Iatan Unit 2 was complete. It provided for a true-up of pension costs during this period and permitted carrying costs on the resulting regulatory asset or liability. In approving this Regulatory Plan, the KCC relied upon the cost estimates contained in the plan, especially the cost estimate for Iatan Unit 2.[7]

The Company now contends that the cost estimate for Iatan Unit 2 should not have been relied upon by the parties. Frankly, I find this an insulting position for the Company to take. KCP&L is now attempting to tie the validity of the Iatan Unit 2 cost estimate to the estimate classification system provided by the Association for the Advancement of Cost Engineers ("AACE"). According to testimony provided by Mr. Meyer in this case, the AACE classifies cost estimates into one of five

[6] K.S.A. 66-128g(a)(4).

[7] Order Approving the Stipulation and Agreement, KCC Docket No. 04-KCPE-1025-GIE, August 5, 2005, paragraphs 9, 11.

categories. On page 4 of his testimony, Mr. Meyer stated that:

> A Class 1 estimate is based upon a fully-developed project definition, while at the other end of the spectrum, a Class 5 estimate is often developed quickly and based on very preliminary and limited information. As a result, an estimate that fits the definition of a Class 5 estimate is not generally regarded within the industry as being very accurate.

It appears that the Company is now stating that the cost estimates that the parties and the KCC relied upon in the Regulatory Plan were not intended to be "very accurate." Moreover, Mr. Meyer goes on to state that "Conceptual phase estimates are not expected to be highly accurate; rather, they are regarded as merely providing a cost order of magnitude for a project."

Nowhere in the Regulatory Plan does it state that the cost estimates constitute an "order of magnitude" estimate. While the signatory parties undoubtedly realized that there could be some variation from the estimates provided in the plan, we are now faced with costs for the Regulatory Plan that are significantly above the estimates upon which the Regulatory Plan was based, while the cost variance for Iatan Unit 2, by far the largest component of the Regulatory Plan, exceeds its estimate by approximately 50%. Moreover, according to "KCP&L's Summarized Comparison of Regulatory Plan Estimates to Current Forecasted Total Project Costs", submitted by the Company on May 4, 2010, the total cost for Iatan Unit 2 may even exceed the amount included in its rate base claim in this case.

It is interesting to note that Mr. Meyer states on page 13, lines 23-25 of his testimony that "...during 2006, KCP&L, with the help of Burns & McDonnell and Schiff, identified several risks that had the potential of increasing the overall cost of the Project" and that the largest risk included "the management, coordination and execution of a very large and complex construction project, and KCP&L needed to significantly ramp up its internal and external capabilities in order to manage such an undertaking." Although I am not an engineer, it seems apparent even to me that construction of a coal-fired generating unit would require the management, coordination and execution of a very large and complex construction project and that any utility involved in such a project would need to ramp up its internal and external capabilities in order to manage such an undertaking. Perhaps KCP&L simply was not adequately prepared for this project when it negotiated the Regulatory Plan with the signatory parties to the plan.

Q. What do you recommend?

A. I recommend that the KCC disallow 25% of the cost overrun for Iatan Unit 2 on the basis of lack of prudence. My adjustment is shown in Schedule ACC-11. This recommendation is based on the fact that the Regulatory Plan was approved based on the Company's representations with regard to cost. That Regulatory Plan provided for extraordinary ratemaking treatment over a five-year period in order to assist the Company in completing the construction of Iatan Unit 2, while maintaining its financial integrity. The KCC had the right to expect that the cost estimate provided by the Company was more than just an "order of magnitude" estimate. At no time during that process did the Company reveal that this estimate should be interpreted as a Class 4 or Class 5 estimate pursuant to the AACE Cost Classification system discussed in Mr. Meyer's testimony. In fact, Mr. Meyer acknowledges on page 5, lines 11-14 of his testimony that the AACE Cost Classification system, which he now proposes to utilize to defend the Company's original cost estimate, was not specifically used for the Iatan Unit 2 project.

In addition, the Company claims that one of the reasons for the higher than anticipated costs is that the Regulatory Plan contemplated an 800 MW unit generating station while an 850 MW station was actually constructed.[8] However, the Company ignores the fact that KCP&L's share of Iatan Unit 2 is much less than projected in the Regulatory Plan. The Regulatory Plan envisioned that KCP&L would acquire 500 MWs of generation, or 62.5% based on an 800 MW facility. However, KCP&L actually owns 54.7% of Iatan Unit 2, or 465 MWs. Thus, Kansas ratepayers are not only paying more, but they are paying more for less capacity.

Q. Why do you believe that a 25% adjustment of the cost overrun is reasonable?

A. I recognize that it was reasonable to assume that there would be some variation between the actual costs of Iatan Unit 2 and the estimates contained in the Regulatory

[8] KCP&L's Summarized Comparison of Regulatory Plan Estimates to Current Forecasted Total Project Costs, submitted May 4, 2010, paragraph 13.

Plan. Given the preferential ratemaking treatment afforded to shareholders by the Regulatory Plan, one may conclude that it would be reasonable to have this risk shared 50/50 between ratepayers and shareholders. However, I am recommending that ratepayers be allocated more than 50% of this variance, given the fact that at least some of these cost overruns may have been outside of the Company's control.

Q. If the Company can demonstrate that 100% of the cost overruns were due to factors outside of the Company's control, would you then recommend that ratepayers bear 100% of the cost overruns?

A. No, I would not. Regardless of the factors that are ultimately found to be responsible for these costs overruns, I still believe that shareholders should bear a portion of these costs, given the fact that the Company entered into a regulatory compact through the Regulatory Plan. Similarly, while I recognize that the scope of the final Iatan Unit 2 project may have changed somewhat from what was included in the original estimate, I still recommend that actual costs be compared with costs reflected in the Regulatory Plan. Since rates were established over the past five years based on the Regulatory Plan, then the costs in the Regulatory Plan should be the foundation to which actual costs are compared when determining if some or all of any cost overruns should be disallowed.

Q. How did you quantify your adjustment?

A. As shown in Schedule ACC-11, I began with the Company's claim in this case for Iatan Unit 2, based on its currently budgeted costs. I then reduced those costs by the property tax adjustment discussed above. I then calculated the difference between the current adjusted Iatan Unit 2 budgeted cost and the Iatan Unit 2 estimate included in the Regulatory Plan. My adjustment is based on 25% of that difference.

Q. Given that the Iatan Unit 2 cost estimate will be trued-up in the abbreviated case, subject to any prudence disallowance, what level of Iatan Unit 2 cost should the KCC consider final and not subject to further disallowance?

A. In the Joint Report submitted on September 9, 2009 in KCC Docket No. 04-KCPE-1025-GIE, the parties agreed to identify the amount of any rate increase in this case that is final and not subject to true-up in the abbreviated case. As stated on page 7 of the Joint Report, the parties agreed to base "their recommendations on review of actual costs (invoices paid) as of the end of the month approximately 60 days prior to the date Staff/Intervener testimony is filed." Based on the audit conducted by Staff, I understand that Staff has verified total project costs through March 31, 2010 of $401,803,705 for Iatan Unit 1, of $1,655,108,528 for Iatan Unit 2, and of $57,827,169 for common plant.[9] As noted in the Joint Report, these costs are not subject to true-up in the abbreviated case, except for potential prudence

[9] These costs are subject to allocation among the owners of the units and subject to further allocation among the regulatory jurisdictions.

disallowances made by the KCC and possible clarification of errors that may not be identified until the abbreviated case.

B. Accumulated Depreciation

Q. How did the Company develop its claim for accumulated depreciation?

A. The Company's claim for accumulated depreciation is based on its balance for accumulated depreciation at September 30, 2009, adjusted to reflect additions to the depreciation reserve through September 30, 2010. The Company developed its post-test year adjustment by first reflecting adjustments relating to retirements of remaining leasehold improvements associated with its former headquarters location at 1201 Walnut Street, changes in the reserve related to changes in the ownership interest in Iatan 1, removal of other post-test year retirements, and additions to the reserve through September 30, 2010. The reserve additions were developed by a) assuming a full year of depreciation reserve additions on test year-end plant balances, b) assuming one-half year of depreciation reserve additions on non-Iatan Unit 2 plant additions, and c) assuming two months of depreciation reserve additions on Iatan Unit 2. In addition, the Company made another adjustment to increase the reserve by $33 million, to reflect additional prepayment on plant that was contributed by ratepayers pursuant to stipulations in prior cases.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending one adjustment to the Company's depreciation reserve claim. Since I am recommending adjustments to the Company's utility plant-in-service claim for Iatan Unit 2, as discussed above, it is necessary to make a corresponding adjustment to the depreciation reserve. Therefore, I have made an adjustment to eliminate, from the depreciation reserve, depreciation expense on plant that I have also eliminated from the Company's rate base.

Q. How did you quantify your adjustment?

A. I calculated a composite depreciation rate for Iatan Unit 2 plant, based on the Company's proposed adjustment to accumulated depreciation. I then applied this composite rate to my recommended utility plant-in-service adjustment, to develop an annualized depreciation expense. Consistent with the Company's methodology to reflect two months of depreciation reserve additions in rate base, my adjustment is based on eliminating two months of the annualized depreciation expense from the reserve. My adjustment, which is shown in Schedule ACC-12, reduces the reserve for depreciation, and therefore increases the Company's rate base.

C. Cash Working Capital

Q. What is the Company's cash working capital claim in this case?

A. KCP&L has included a cash working capital claim of ($34,515,150), which includes the impact of post-test year adjustments. Excluding the cash working capital associated with post-test year adjustments, the Company's cash working capital claim is ($33,303,408). Thus, the Company has a negative cash working capital requirement. This negative cash working capital requirement is primarily the result of the fact that the Company sells its accounts receivables, minimizing the revenue lag for a large percentage of the Company's sales.

Q. Are you recommending any adjustments to the Company's claim for cash working capital?

A. Yes, I am recommending one adjustment. In its filing, the Company included a cash working capital requirement associated with fuel and purchased power costs. As a result of the Stipulation in Docket No. 07-KCPE-905-RTS, the Company is permitted to recover these costs through an Energy Cost Adjustment ("ECA") clause. In fact, these costs are recovered on a dollar-for-dollar basis from ratepayers. Since the Company's request for an ECA was accepted by the KCC in that case, I am recommending that the KCC eliminate fuel and purchased power costs from the cash working capital calculation.

The ECA is typically based on two factors: estimated fuel and purchased power costs for the current period and an actual cost adjustment true-up factor. Therefore, in any given month, there is likely to be either an under-recovery or over-recovery of fuel and purchased power costs. Consequently, in any particular month, the revenue received by KCP&L may be reimbursing the Company for fuel and power purchased in the past, or it may be providing funds for fuel and power that is still to be purchased in the future.

Because of the special nature of purchased fuel and purchased power adjustment clauses, these costs are frequently excluded from the cash working capital calculation. This is because it is very difficult at any point in time to determine if the Company is being compensated for prior costs, current costs, or future costs. Therefore, I am recommending that the cash working capital associated with fuel and purchased power costs be removed from the cash working capital calculation. This adjustment is shown in Schedule ACC-13.

Q. Have you updated the Company's cash working capital claim for the impact of the operating expense adjustments that you are recommending?

A. No, I have not. However, I do recommend that the KCC update the Company's cash working capital claim to reflect the level of expenses ultimately found to be appropriate and authorized by the KCC.

D. <u>Materials And Supplies</u>

Q. How did the Company develop its claim for material and supplies?

A. The Company's claim is based on a 13-month test year average balance, except for certain accounts that the Company stated showed trends, for which an end of test year balance was used.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending that the thirteen month test year balance be utilized for all accounts. The purpose of using an average balance for materials and supplies is that materials and supplies are composed of many items that fluctuate from month-to-month. The use of a multi-month average mitigates the impact of these monthly variations.

The Company's methodology results in a hybrid approach, whereby KCP&L has selectively used an end of month balance for some items and an average balance for others. However, the Company's approach would require a complete examination of every component of materials and supplies in each rate case. It would also introduce a new controversy into the rate case process as parties debate whether a new "trend" has emerged in a particular account.

The use of a multi-month average is the generally accepted method for determining materials and supplies in a base rate case. It has worked well, given the nature of materials and supplies, the number of items included in this rate base component, and the fluctuations in monthly balances.

Q. What do you recommend?

A. I recommend that the Company's allowance for materials and supplies be based on the average balance for the thirteen months ending September 2009, the end of the test year in this case. My adjustment is shown in Schedule ACC-14.

E. FAS 87 Pension Regulatory Asset

Q. Please describe the Company's claim for a regulatory asset relating to the pension plan.

A. As described later in my testimony, the Regulatory Plan permitted the Company to establish a regulatory asset or liability for the difference between the Company's annual pension expense pursuant to Financial Accounting Standard ("FAS") 87 and the pension expense recovered annually from ratepayers during the term of the Regulatory Plan. Pursuant to the Regulatory Plan, this regulatory asset or liability is amortized over a five-year period and the unamortized balance is included in the Company rate base. In its filing, KCP&L included a regulatory asset of $7,978,163 in rate base.

Q. Did the Company subsequently revise its claim for a regulatory asset?

A. Yes, it did. Subsequent to its filing, KCP&L revised its pension expense claim twice, which in turn resulted in a revision to its claim for the associated regulatory asset. Specifically, revisions made by the Company to its pension expense claim now result in a regulatory asset of $21,295,558, 46.0757% of which is allocated to Kansas. Thus, the Company is now claiming a regulatory pension asset of $9,812,075 in rate base. At Schedule ACC-15, I have made an adjustment to the Company's regulatory pension asset to reflect KCP&L's revised claim.

Q. Do you have any other comments regarding the regulatory pension asset?

A. Yes. As discussed in Section IX of this testimony, the current ratemaking treatment for pension costs was approved for the duration of the Regulatory Plan. Specifically, the Regulatory Plan include a tracking mechanism that allows the Company guaranteed dollar for dollar recovery of these costs. This tracking mechanism was intended to mitigate the Company's risk during the construction of Iatan Unit 2 by transferring the risk of pension expense fluctuations from shareholders to ratepayers. I am generally opposed to tracking mechanisms of this sort, since such mechanisms are rarely balanced with appropriate reductions in the cost of equity charged to ratepayers. However, as discussed in Section IX, if the KCC decides to continue a tracking mechanism for KCP&L's pension costs, it should adopt the same mechanism it approved for Kansas Gas Service ("KGS"), Westar Energy, Inc. ("Westar"), and Empire District Electric Company ("Empire"). That mechanism does not include carrying costs on any associated regulatory asset or liability. Therefore, once the current regulatory asset is fully amortized, there should be no regulatory pension asset included in rate base in future rate cases.

F. Accumulated Deferred Income Taxes

Q. Are you recommending any adjustment to the Company's claim for accumulated deferred income taxes?

A. Yes, I am recommending one adjustment. As discussed above, over the course of the Regulatory Plan, the Company has been collecting prepayments on plant from ratepayers. Such prepayments were approved in the Regulatory Plan as a way to strengthen the Company's financial integrity during the period of construction of Iatan Unit 2. The Regulatory Plan requires that "[t]he accumulated CIAC amounts will be treated as increases to the depreciation reserve and be deducted from rate base in any future KCPL rate proceedings....". In its filing, the Company included an adjustment to increase its depreciation reserve by $66.25 million, consistent with the terms of the Regulatory Plan. This adjustment has the effect of decreasing rate base by $66.25 million. However, the Company also included an adjustment to reduce its deferred income tax reserve by $25,134,888, which has the effect of increasing rate base by this amount. Therefore, the net impact on ratepayers is that they are effectively only receiving the benefit of a prepayment of $41.12 million.

Q. Why does the Company contend that an adjustment to the deferred income tax reserve is appropriate?

A. The Company contends that such an adjustment is appropriate because it had to pay income taxes on the $66.25 million that it received from ratepayers over this period.

This is because the Company did not record any expense to offset the receipt of the $66.25 million.

Q. Does the Regulatory Plan provide for the deferred income tax reserve adjustment now being proposed by the Company?

A. No, it does not. The Regulatory Plan is based on the assumption that all amounts collected from ratepayers will be used to reduce the cost to ratepayers of Iatan Unit 2 once that unit goes into service. The Regulatory Plan does not permit the Company to reduce this benefit for the impact of deferred income taxes. The impact of the Company's deferred income tax reserve adjustment is that ratepayers are losing the benefit of approximately one-third of the prepayments that have made over the course of the Regulatory Plan. There was never any provision for ratepayers to have their benefit reduced in this manner.

Q. What did the Company state in the last case regarding the manner in which the prepayment on plant would be handled at the end of the Regulatory Plan?

A. In the last case, Company witness Chris B. Giles submitted Testimony in Support of Joint Stipulation and Agreement on June 22, 2009. In Schedule CBG-2 to that testimony, Mr. Giles presented an "Explanation and Example of Application of Pre-Tax Payment on Plant Amounts in the Context of KCP&L's Next Rate Case." That example is based on the assumption that the prepayment would total $74 million by

January 1, 2011. Mr. Giles stated that "the total cumulative amount of pre-tax payment on plant on behalf of customers of $74 million would be added to the accumulated depreciation reserve as of the date rates resulting from the fourth and final rate case under the Regulatory Plan are effective (January 1, 2011 in this example). The effect of this would be to lower rate base as if customers had already paid for this amount of plant investment, and therefore no return on this $74 million would be forthcoming to the Company as part of rates going forward. In addition, there would be no depreciation expense related to this customer-paid plant amount ($74 million in this example) included in KCP&L's future revenue requirements. This is a permanent reduction to the depreciation reserve and so will have the impact of never allowing the Company to earn a return on or a return of (depreciation expense) a portion of its rate base equivalent to the amount of accumulated pre-tax payment on plant on behalf of customers." (emphasis added)

The Company's adjustment clearly violates its representation that ratepayers would receive full benefit for the pre-tax prepayments they made over the course of the Regulatory Plan.

Q. Did you previously address this issue?

A. Yes, in my testimony in KCC Docket No. 09-KCPE-246-RTS, I stated that "...additional revenues collected pursuant to the Stipulations in the last two base rate cases should also be reflected as a rate base deduction. Any amounts raised from ratepayers due to cash flow requirements should be deducted from rate base on a pre-tax basis so that ratepayers receive full value for the funds that they have contributed."[10]

Q. What do you recommend?

A. The Regulatory Plan required ratepayers to provide additional amounts to the Company over the course of the Regulatory Plan, with the understanding that ratepayers would receive the full value of those prepayments once Iatan Unit 2 went into service. That understanding was confirmed by the Company witness Chris Giles in his testimony in Support of Joint Stipulation and Agreement in KCC Docket No. 09-KCPE-246-RTS. The Company's adjustment to increase rate base through an adjustment to the deferred income tax reserve is in direct violation of the Regulatory Plan and the representations made by Mr. Giles. It is also blatantly unfair to ratepayers. Accordingly, I recommend that the KCC reject the Company's attempt to reduce the value of the prepayments made by ratepayers during the course of the Regulatory Plan. The Company's adjustment to the deferred income tax reserve should be rejected, as shown in Schedule ACC-16.

Q. In addition to your concerns about the prepayment of plant issue, is it possible that additional adjustments to the deferred income tax reserve should be made,

[10] Direct Testimony of Andrea C. Crane, page 68, KCC Docket No. 09-KCPE-246-RTS (emphasis added).

consistent with some of the other rate base recommendations you are making in this case?

A. Yes, it is. The calculation of deferred income tax adjustments is complex and requires information about various tax and book depreciation rates and other timing differences. To the extent that any of my rate base adjustments impact upon the Company's deferred income tax calculations, there may be other adjustments to the deferred income tax reserve that would be appropriate. If the Company believes that further adjustments to the reserve are necessary, and provides the necessary supporting data, I will review the information provided by the Company and make additional reserve adjustments, if appropriate.

G. Summary of Rate Base Issues

Q. What is the impact of all of your rate base adjustments?

A. My recommended adjustments reduce the Company's rate base claim from $1,793,576,755 as reflected in its filing, to $1,731,941,171, as summarized on Schedule ACC-9.

VII. OPERATING INCOME ISSUES

A. Pro Forma Sales Revenue

Q. Are you recommending any adjustment to the Company's claim for pro forma sales revenue?

A. Yes, I am recommending one adjustment. Shortly before the filing of this testimony, the Company informed the parties that it had overstated certain customer counts, resulting in an overstatement to the customer charges reflected in its pro forma revenue claim. It is my understanding that the Company double-counted certain customers during months when it was switching from its summer to winter rates. KCP&L has notified the parties that the impact of this error was to understate pro forma revenue at present rates by $2,664,560. Accordingly, at Schedule ACC-18, I have made an adjustment to reflect decrease revenue by $2,664,560 relating to this error.

B. Forfeited Discount Revenue

Q. What are forfeited discounts?

A. Forfeited discounts are amounts that the Company earns from ratepayers for late payment of utility charges. According to Schedule 1.25 of the Company's tariff, KCP&L charges customers a late payment charge of 2% when a bill becomes delinquent. Non-residential customers may request a 14-day extension of the date upon which an unpaid bill becomes delinquent. In that case, a 1% monthly charge will be applied to the non-residential customer's bill.

Q. How did the Company determine its pro forma revenue claim for forfeited discounts?

A. As discussed on page 42 of Mr. Weisensee's testimony, the Company developed its claim for forfeited discounts by computing a Kansas-specific forfeited discount factor and applying that factor to its weather-normalized revenues. The forfeited discount factor was based on actual experience during the test year. The Company used a forfeited discount factor of 0.2611%.

Q. Are you recommending any adjustment to the Company's claim for forfeited discount revenue?

A. Yes. As shown in the workpapers to Adjustment R-21, the monthly rate of forfeited discounts as a percentage of sales ranged from 0.2053% to 0.4762% during each month of the test year except for June 2009, when the rate was 0.1142%. It appears that the Kansas rate for June 2009 was abnormally low. Therefore, I have made an adjustment to normalize forfeited discount revenue to account for the abnormally low rate in the month of June.

Q. How did you quantify your adjustment?

A. I utilized the test year data, but eliminated the Kansas retail revenue and the Kansas forfeited discounts in the month of June 2009. This resulted in a forfeited discount rate of 0.2808%. I then applied this rate to the Company's weather-normalized pro forma sales. My adjustment is shown in Schedule ACC-19.

Q. Have you also made an adjustment to include incremental forfeited discount revenue associated with your proposed rate increase?

A. Yes, I have. I have included my recommended rate for forfeited discounts in my revenue multiplier, as shown in Schedule ACC-44. This has the effect of adjusting my revenue requirement recommendation to reflect the fact that forfeited discount revenue will increase as sales revenue increases.

C. Salary and Wage Expense

Q. How did the Company develop its salary and wage expense claim in this case?

A. KCP&L's claim is based on actual headcount at September 30, 2009 and "actively recruited positions as of that day". In addition, the Company included an adjustment to annualize headcount for Iatan Unit 1 and Unit 2. KCP&L included management payroll increases of 3.0% effective March 1, 2010. In addition, the Company included union increases of 3.25% to 3.75% effective February 1, March 1, and April 1, 2010 for various unions. In addition to payroll costs, the Company also made adjustments to include overtime costs, temporary and summer employees, and certain additional increases relating to step increases, shift differentials, and other payroll provisions.

The Company's claim also includes its share of payroll costs for the Wolf Creek Nuclear Operating Company ("WCNOC"). In its filing, KCP&L has included 2010 increases of 4.0% for executives of WCNOC, of 3.75% for WCNOC management employees, and of 3.50% for union employees of WCNOC.

Q. Are you recommending any adjustments to the Company's salary and wage claim?

A. Yes, I am recommending one adjustment relating to employee vacancies. The Company included an adjustment of approximately $4.9 million relating to 77 vacant positions. These 77 vacancies do not include vacant positions at Iatan Unit 1 and Unit 2, since employees levels at Iatan were separately adjusted by KCP&L. While the Company claims that it has only included vacancies that are "actively recruited positions" as of September 30, 2009, the Company's methodology still ignores the fact that it is normal and customary for a company the size of KCP&L to have significant vacancies at any given point in time.

As shown in the Company's Manpower Reports, provided in response to CURB-6, KCP&L has consistently had a large number of vacant positions. During the test year, the Company had an average of 91 vacant positions, as one would expect in a company of this size.

It is normal and customary for companies to have unfilled positions at any given time as a result of terminations, transfers, and retirements. Moreover, even though the Company claims that it only included vacancies for which they are actively recruiting, such recruiting is a normal, ongoing function of the company. KCP&L is always actively recruiting because it does not generally have a full complement of employees. If utility rates are set based on a full complement of employees, and if these employee positions remain vacant, then ratepayers will have paid rates that are higher than necessary, to the benefit of shareholders. Therefore, when setting rates, I recommend that the KCC consider the fact that, at any given time, some positions are likely to be vacant.

Q. How did you quantify your adjustment?

A. I have eliminated the Company's adjustment relating to the 77 additional employees, as shown in Schedule ACC-20. I have reduced the revenue requirement impact of my adjustment by the percentage of costs allocated to joint partners and by the percentage of payroll that is capitalized. It should be noted that I have not made any adjustment to the Company's claim for additional positions at Iatan Unit 1 and Unit 2, since the test year did not represent a normal level of activity at these facilities.

D. Incentive Compensation Expense

Q. Please describe the Company's claims for incentive compensation program costs.

A. The Company included costs for several incentive compensation plans in its filing. These amounts include what the Company characterizes as short-term incentive plans, including: $1,929,000 for the Rewards Plan available to union employees, $10,284,421 for the ValueLink Plan available to management employees, and $3,092,150 for short-term incentives for officers. In addition, the Company has included $3,875,375 for long-term incentives for officers, mostly in the form of restricted stock. Thus, over one-third of the Company's total claim for incentive compensation costs is related to incentives for a small group of officers and key executives.

While the Company claims that the specific parameters of each plan are confidential, there are similarities among the plans. The Rewards Plan has both a Company component and a Division component. The Company component is comprised of financial goals, customer-service goals, internal goals (which also include a financial component), and safety goals. The Division component is based on similar goals but does not contain a customer-service component.

The Value Link plan also includes Company and Division goals, comprised of financial, customer-service, internal and safety components, as well as an individual factor. The short-term incentive plan for officers is similar in that it is composed of financial goals, key business objectives, and an individual performance factor. The long-term incentive plan for officers appears to be based solely on financial objectives.

Q. Do you believe that it is appropriate to recover all of these incentive compensation costs from regulated ratepayers?

A. No, I do not. I have several concerns about these types of programs, most of which are based, at least in part, on a utility's ability to achieve certain financial goals. Providing employees with a direct financial interest in the profitability of the Company is an objective that benefits shareholders, but it does not benefit ratepayers. Incentive compensation awards that are based on earnings criteria may violate the principle that a utility should provide safe and reliable utility service at just and reasonable rates. This is because these plans require ratepayers to pay higher compensation costs as a consequence of higher corporate earnings, generating an upward spiral that does not directly benefit ratepayers, but does directly benefit shareholders, as well as the management personnel responsible for establishing such programs -- to whom much of the incentive compensation is granted.

Incentive compensation plans tied to corporate performance result in greater enrichment of company personnel as a company's earnings reach or exceed targets that are predetermined by management. It should be noted that it is the job of regulators, not the shareholders or company management, to determine what constitutes a just and reasonable rate of return award to shareholders in a regulated environment. Regulators make such a determination by establishing a reasonable rate of return award on rate base in a base rate case proceeding.

Allowing a utility to charge for additional return that is then distributed to employees as part of a plan devised to divide extraordinary profits violates all sense of fairness to the ratepayers of the regulated entity. It is certain to result in burdensome and unwarranted rates for its ratepayers, and also violates the principles of sound utility regulation, particularly with regard to the requirement for "just and reasonable" utility rates.

Q. Are KCP&L employees being well compensated, separate and apart from these employee incentive plans?

A. Yes, they are. Over the past several years, the Company's non-union employees have consistently received increases ranging from 3.0% to 3.8%. Union employees have also experienced wage increases in the 3.0% to 3.75% range. Moreover, there is no indication that KCP&L is having difficulty attracting quality employees to its workforce. The Company's salary and wage levels appear reasonable, even if the incentive compensation plans are not taken into account. In fact, the 2009 and 2010 salary and wage increases included in the Company's filing are generous given the difficult economic environment experienced in 2009 and the fact that employees in many companies are being forced to take pay cuts or to forgo payroll increases altogether.

Q. Don't most of these incentive plans have customer-service or safety components that provide a direct benefit to customers?

A. While customers do benefit from good customer service, and while everyone benefits from safe utility practices, it is does not necessarily follow that ratepayers should pay "extra" for good and safe utility service. Given the increasing emphasis on incentive compensation, one has to wonder what an employee's base salary is supposed to cover – showing up? A review of the incentive criteria suggests that employees and officers are being rewarded for results that should be part of their basic job description – to provide safe and reliable utility service at the lowest reasonable cost.

Q. Are these awards in some cases based on industry peer group statistics?

A. Yes, at a minimum, the Company's officer compensation plans are benchmarked against a peer group. However, the problem with tying these awards to industry peer groups is that no company wants to be below the average of the group. Studies of peer groups performed by Mercer and other human resource consulting firms put compensation on a continuing upward spiral as each company that falls below the mean or median attempts to increase their position among their peers. For that reason, awards that rely upon industry peer groups can result in inflated salaries that continue to escalate as the companies below the average attempt to raise their standing in the group.

Q. Do you believe that the incentive compensation program costs claimed by KCP&L should be passed through to ratepayers?

A. No, I do not. I have several concerns about these types of programs, many of which are based, at least in part, on a utility's ability to achieve certain earnings goals. First, it should be noted that 36% of the overall cost of these plans involve incentive compensation awards for a small group of officers and executives. In addition to these awards, the Company's revenue requirement claim also includes substantial base salaries for officers, including $800,000 annually for Mr. Chesser, the Company's Chairman and Chief Executive Officer. In fact, the Company's Proxy Statement demonstrates that each of the Named Executive Officers ("NEOs") earned over $1 million in compensation in 2009, with total compensation ranging from $1.24 million for Ms. Curry (Senior Vice President-Human Resources and Corporate Secretary) to $4.78 million for Mr. Chesser. I am not recommending any disallowance relating to the test year cost for officer and executive salaries. Thus, my revenue requirement recommendation already reflects a generous allowance for officers and executives. If the Company wants to further reward officers and executives it can do so, but these additional costs should be borne by shareholders, not ratepayers.

Q. What is your recommendation with regard to incentive compensation plan costs?

A. I am recommending that the KCC deny the Company's request to recover these costs from ratepayers. Many of these incentives are driven by financial benchmarks. Other benchmarks relate to service parameters that should be the hallmark of safe and reliable utility service. Moreover, the prospective incentive plan payments are not known or measurable, since they are based on future levels of operating income and other variables that cannot be quantified with certainty until the end of each year. My recommendation will require the Company to establish incentive compensation plans that shareholders are willing to finance. As long as ratepayers are required to pay the costs of these incentive plans, then there is no incentive for the Company to control these costs. This is especially true since the management of the Company and its stockholders are primary beneficiaries of such plans. Therefore, I recommend that the KCC reject the Company's claim to recover these incentive compensation costs from ratepayers. My adjustment relating to incentive compensation costs for employees, as well as short-term incentives for officers, is shown in Schedule ACC-21. My adjustment to eliminate long-term incentive compensation plan costs for officers and other key executives is shown in Schedule ACC-22.

Q. Have other states rejected claims for incentive compensation costs?

A. Yes. In a 2000 base rate case involving Middlesex Water Company, Board Staff argued in its Initial Brief that,

> Staff is persuaded by the arguments of the RPA that, at this time, the incentive compensation expenses should be not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also indicated that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RPA's position that it is inappropriate for the Company to request recovery of bonuses in rates at this time.[11]

While the Administrative Law Judge ("ALJ") in that case recommended that Middlesex be permitted to recover 50% of its incentive compensation costs in rates, the BPU rejected the ALJ's recommendation and instead ordered that 100% of these costs be disallowed.[12]

Moreover, in an earlier decision, the BPU found that including employee incentives in utility rates is especially troublesome during difficult economic times, finding that,

> We are persuaded by the arguments of Staff and Rate Counsel that, at this time, the incentive compensation or "bonus" expenses should not be recovered from ratepayers. The current economic condition has impacted ratepayers' financial situation in numerous ways, and it is evident that many ratepayers, homeowners and businesses alike, are having difficulty paying their utility bills and otherwise remaining profitable. These circumstances, as well as the fact that the bonuses are significantly impacted by the Company achieving financial performance goals, render it inappropriate for the Company to request recovery of such bonuses in rates at this time. Especially in the current economic climate, ratepayers should not be paying additional

[11] I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Staff Initial Brief, page 37.

[12] I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Order Adopting in Part/Modifying in Part/Rejecting in Part Initial Decision, at 25-26 (June 6, 2001).

> costs to reward a select group of Company employees for performing the job they were arguably hired to perform in the first place.[13]

It is indisputable that ratepayers are once again facing very difficult economic conditions. Consumers and regulators are examining management bonus plans with renewed interest. Now, more than ever, ratepayers deserve relief from costs that are designed to benefit the Company and its shareholders, but which may not provide a direct benefit to ratepayers. Accordingly, I recommend that the KCC adopt my recommendation and exclude incentive compensation costs from the Company's regulated revenue requirement.

E. Payroll Tax Expense

Q. Have you also made an adjustment to the Company's payroll tax expense claim?

A. Yes, I have made an adjustment to eliminate the payroll taxes associated with my adjustments relating to salary and wage expense and incentive compensation costs. To quantify this adjustment, I utilized the Company's average Social Security and Medicare tax rate of 7.375%, which was provided in the workpapers to Adjustment CS-53, and applied that rate to my recommended expense adjustments for salaries and wages and incentive compensation. My payroll tax expense adjustment is shown in Schedule ACC-23.

[13] I/M/O the Petition of Jersey Central Power & Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, BRC Docket No. ER91121820J, Final Decision and Order Accepting in Part and Modifying in Part the Initial Decision at 4 (June 15, 1993).

F. Employee Benefits Expense - 401K Match

Q. Please describe the Company's 401K matching benefit.

A. KCP&L offers a 401K retirement savings plan for its employees. This plan has historically included a company match on a portion of the contributions made by participating employees. As described in the response to CURB-19, KCP&L revised its 401K plan for non-union employees on January 1, 2008. Prior to that date, the Company provided a 50% match on up to 6% of base pay. The revised plan provides for a 100% match of up to 6% of base pay plus overtime, bonuses, and incentives. However, the revised 401K plan also includes a reduced pension benefit and therefore non-union employees had an option to remain with the prior 401K and pension benefit plans or to adopt the new plans. The revised 401K plan does not apply to union employees. Aquila employees who became KCP&L employees as of the merger on July 14, 2008 are only eligible for the new 401K plan.

Q. How did the Company develop its 401K matching expense claim in this case?

A. Because of changes made to the plan, the Company stated that it was difficult to determine a meaningful historic average for 401K matching costs. Therefore, the Company based its claim on the actual average match for the pay period ending September 30, 2009. This resulted in a factor of 2.879%. The Company then applied this factor to its claim for payroll, overtime and additional compensation, and incentive compensation costs.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, since I am recommending adjustments to the Company's salary and wage claim and to its incentive compensation cost claim, it is necessary to make a corresponding adjustment to its claim for 401K matching costs. To quantify my adjustment, I applied the Company's pro forma matching rate of 2.879% to my recommended adjustments for payroll and incentive compensation costs. My adjustment to the Company's claim associated with the 401K plan is shown in Schedule ACC-24. It is unclear if long-term stock awards for officers are included in the Company's calculation of amounts eligible for the 401K match. To be conservative, I have not included long-term incentive awards in the calculation of my adjustment to KCP&L's 401K matching plan costs.

G. <u>Pension Expense</u>

Q. How did the Company develop its pension expense claim in this case?

A. The Company's pension expense claim was based on preliminary 2010 information from Towers Watson, the firm that performs the actuarial studies on the Company's behalf. In its filing, the Company reflected total KCP&L pension costs of $40,912,247, approximately 21% of which are capitalized. In addition, KCP&L included a regulatory asset of $17,315,334 relating to the difference between the amount recovered in rates and its pension costs pursuant to FAS 87. This ratemaking treatment was approved for the duration of the Regulatory Plan. The Company also included an amortization expense associated with the regulatory asset, which is being amortized over five years.

Q. Are you recommending any adjustment to the Company's claim for pension costs?

A. Yes, I am recommending two adjustments. First, as noted, the Company's pension expense claim was based on preliminary information from the Company's actuary. KCP&L provided an updated 2010 pension expense claim in late April 2010, based on a final report from its actuaries. At that time, the Company indicated that it was revising its total pension cost claim to $47,882,590 and revising its claim for a regulatory asset to $21,962,222. A meeting was subsequently held with the Company on April 30, 2010 to review its workpapers and other supporting documentation. I participated in that meeting by phone. As a result of questions raised during that meeting, the Company subsequently revised its pension cost claim again to $46,882,590 and its regulatory asset claim to $21,295,558 (see Schedule ACC-15).

My first adjustment updates the Company's claim to reflect the revised actuarial report received from Towers Perrin, and the further revision made by KCP&L as a result of our April 30th meeting with the Company. This adjustment is shown in Schedule ACC-25.

Q. What is your second expense adjustment to the Company's claim for pension costs?

A. My second adjustment eliminates all Supplemental Executive Retirement Plan ("SERP") costs embedded in the Company's revised pension expense claim.

Q. **What are SERP costs?**

A. These costs relate to supplemental retirement benefits for officers and key executives that are provided by the Company. These SERP benefits are in addition to pension benefits received by officers and key executives pursuant to the normal pension plan benefits offered to all other employees. These additional retirement benefits generally exceed various limits imposed on retirement programs by the Internal Revenue Service ("IRS") and therefore are referred to as "non-qualified" plans. According to the Company's Proxy Statement, its SERP provides,

> ...an amount substantially equal to the difference between the amount that would have been payable under the Pension Plan in the absence of tax laws limiting pension benefits and earnings that may be considered in calculating pension benefits, and the amount actually payable under the Plan...Messrs. Chesser and Marshall are credited with two years of service for every one year of service earned under our Pension Plan.

Q. What are the test year SERP costs that the Company has included in its claim?

A. As shown in the revised workpapers for its pension expense adjustment, KCP&L has included $1,174,964 of GPE SERP costs in its filing, a portion of which are capitalized. None of the GPE SERP costs have been allocated to entities other than KCP&L. The Company has also included WCNOC SERP costs of $496,778, 47% of which are allocated to KCP&L.

Q. Do you believe that these SERP costs should be recovered from the Company's ratepayers?

A. No, I do not. As noted above, the officers of the Company are already well compensated. Moreover, these officers and key executives that receive SERP benefits also receive pension benefits pursuant to the Company's regular pension plan. Ratepayers are already paying for retirement benefits for these officers and executives through the FAS 87 pension costs included in the Company's revenue requirement for the regular pension plan. If KCP&L wants to provide further retirement benefits to select officers and key executives, then shareholders, not ratepayers, should fund these excess benefits. Therefore, I recommend that the Company's claim for SERP costs be disallowed. This adjustment is also shown in Schedule ACC-25.

Q. Did you adjust the Company's pension regulatory asset to reflect the impact of the pension expense adjustments that you are recommending?

A. As discussed earlier in my testimony, I recalculated the Company's claimed regulatory asset to reflect the revision to the 2010 pension estimate provided by the

Company on May 4, 2010. The associated adjustment to the regulatory asset is shown in Schedule ACC-15.

I did not revise the pension regulatory asset to reflect my recommendation to eliminate SERP costs from the Company's pension expense recovered from ratepayers. Since my adjustment impacts prospective rates, it would not impact the regulatory asset recorded prior to the effective date of rates in this case. Therefore, I felt that no adjustment to the pension regulatory asset relating to SERP costs should be made in this case.

Q. Did you adjust the annual amortization expense associated with the change in the pension regulatory asset?

A. Yes, I did. Since the Company's updated 2010 pension claim impacts the pension regulatory asset, it also impacts the amortization of that asset. Therefore, at Schedule ACC-26, I made an adjustment to increase the Company's annual amortization expense, based on the revised pension regulatory asset. My adjustment reflects a five year amortization period, as stated in the Regulatory Plan.

H. Other Benefits Expense

Q. How did the Company determine its other benefits expense claim in this case?

A. According to page 56 of Mr. Weisensee's Testimony, the Company "annualized those costs based on projected costs included in the 2010 Budget." Other benefits include medical expense costs, educational assistance, long-term disability costs, and group and accident insurance costs. Medical costs accounts for the vast majority of costs included in Other Benefits Expense.

KCP&L is self-insured for its health care costs. The health insurance plans are funded through contributions by both KCP&L and its employees, and actual costs depend on the number and magnitude of claims made during the year. In its filing, the Company included projected 2010 costs of approximately $23.0 million in its claim, including its share of costs for employees at the WCNOC facility. This claim reflects an increase of more than 15% over the actual test year costs of $19.9 million.

Q. Did the Company demonstrate that its adjustment was based on known and measurable changes to the test year?

A. No, it did not. The Company's claim is based on budgeted 2010 amounts, which do not represent known and measurable changes to the test year. As noted, the Company is self-insured for a large portion of its medical benefit costs. Therefore, to a large extent, actual costs will depend upon the level of services required in any given year and the unit cost of those services. The actual amount of claims paid will not only be impacted by the general level of health care costs, but it will also be impacted by the degree to which employees seek medical care and the severity of the illnesses experienced by employees. For these reasons, the Company's post-test year claim does not represent a known and measurable change to the test year.

Q. What do you recommend?

A. Since the Company is largely self-insured, the projected costs included by KCP&L in its claim are speculative and do not represent known and measurable changes to the test year. Therefore, I recommend that the KCC utilize the actual test year costs to determine pro forma Other Benefits Expense costs in this case. At Schedule ACC-27, I have made an adjustment to reflect the actual test year costs for Other Benefits Expense.

I. Bad Debt Expenses

Q. How did the Company quantify its bad debt expense claim in this case?

A. As discussed in the testimony of Mr. Weisensee at pages 43-44, the Company calculated its bad debt expense claim by applying a state-specific net bad debt write-off factor to its pro forma jurisdictional revenue claim. To determine its bad debt factor, the Company used the net bad debt write-offs (accounts written off less recoveries of accounts previously written off) for the test year and the retail revenues for the period April 2008 to March 2009. The Company also included a pro forma adjustment at proposed rates to reflect incremental bad debts associated with the incremental revenues associated with this base rate case.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending that the bad debt factor be based on actual revenues received during the test year, instead of on revenues received for the twelve-month period ending March 2009. In determining an appropriate bad debt factor, regulatory commissions generally match the time period over which revenues are received with the time period over which bad debts are written off. While there is invariably a lag between when a specific revenue is booked and when that revenue is written-off, attempting to match the specific timing of revenues and write-offs adds unnecessary complexity to the analysis. Moreover, new base rates went into effect August 1, 2009, making it more difficult to precisely match net write-offs with the billing months that gave rise to those write-offs.

The Company's methodology is also internally inconsistent because it applies its proposed bad debt factor to pro forma revenue, rather than to revenue that has already been recognized on its books and records of account. Thus, the Company's pro forma adjustment at present rates is not based on revenue actually received during the test year, but on prospective, normalized revenue. Moreover, the additional adjustment at proposed rates similarly was developed by applying the bad debt factor to prospective revenue that reflects the full rate increase being requested in this case. Therefore, while the Company reflected a revenue lag in developing its bad debt factor, it did not take this revenue lag into effect when applying that factor to pro forma revenues.

Q. What do you recommend?

A. I recommend that the Company's bad debt expense allowance be determined by using a consistent time period for both actual net write-offs and revenues. Therefore, I have used net write-offs and revenues during the actual test year to determine a pro forma bad debt factor. This methodology results in a bad debt expense factor of 0.3764% instead of the 0.3871% utilized by KCPL. I have applied my bad debt expense factor to the Company's claimed pro forma revenue at present rates in order to quantify the revenue requirement impact of my recommendation. My adjustment is shown in Schedule ACC-28.

Q. Did you also make an adjustment to bad debt expense associated with the Company's proposed rate increase?

A. Yes, I did. At Schedule ACC-29, I have eliminated bad debt expense associated with the Company's proposed rate increase. To quantify my adjustment, I applied the Company's proposed bad debt rate of 0.3871% to the Company's requested increase of $55.225 million. I am recommending a rate increase that is significantly lower than the rate increase proposed by KCP&L and it is unlikely that the KCC will approve the full increase being requested by the Company. Therefore, including a bad debt expense allowance based on the Company's request is likely to overstate its prospective bad debt expense and the Company's adjustment should therefore be rejected.

Q. How did you account for bad debt expense associated with your proposed rate increase?

A. In order to account for bad debt expense associated with my proposed rate increase, I have included a bad debt expense factor in my revenue multiplier. Thus, the bad debt expense included in my recommendation is matched to the overall level of the rate increase that I am recommending in this case.

J. Wolf Creek Refueling Outage Expense

Q. How did the Company develop its claim associated with costs for the Wolf Creek refueling outage?

A. As discussed on page 46 of Mr. Weisensee's Testimony, the Wolf Creek nuclear generating station has a refueling outage approximately every 18 months. In its filing, KCP&L included refueling costs based on projected costs for the refueling outage that occurred in the fall of 2009. The Company claimed that it was appropriate to include refueling outage costs for the fall 2009 outage, since "that will be the level of expense recognized for the final quarter of 2009 and all of 2010."

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am. In the response to CURB-73, the Company provided the actual refueling outage costs for the fall 2009 outage. The outage lasted from October 10, 2009 to

November 31, 2009 and the actual cost was $21,491,571, or $532,483 less than the amount included in the Company's claim. Therefore, at Schedule ACC-30, I have made an adjustment to reflect the actual outage costs incurred by the Company for the fall 2009 refueling outage. To quantify my adjustment, I have utilized the same 18 month amortization period as was proposed by Mr. Weisensee in his testimony.

K. SO_2 Emission Allowance Proceeds

Q. How are proceeds from the sale of SO_2 emission allowances being handled for ratemaking purposes?

A. Pursuant to the Regulatory Plan, KCP&L was permitted to establish a regulatory liability for the sales proceeds relating to SO_2 emission allowances during the period the Regulatory Plan was in effect. The Regulatory Plan originally stated that this regulatory liability "will be amortized over the same time period used to depreciate environmental assets. Such amortization shall be reflected in rates beginning with the rates resulting from the 2009 rate filing."

In the Stipulation and Agreement in KCC Docket No. 07-KCPE-905-RTS ("905 S&A"), the parties reaffirmed the ratemaking treatment for SO_2 emission allowances during the term of the Regulatory Plan. However, the 905 S&A stated that the "regulatory liability will be amortized over a time period to be determined in the 2009 rate filing. Such amortization will be reflected in rates beginning with the rates resulting from the 2009 rate filing." In the Stipulation and Agreement in KCC

Docket No. 09-KCPE-246-RTS ("246 S&A"), the parties again reaffirmed the ratemaking treatment for SO_2 emission allowances during the term of the Regulatory Plan and stated that the "regulatory liability will be amortized over a time period to be determined in Company's next rate case, with such amortization reflected in rates beginning with the rates resulting from that case."

Q. How were coal premiums handled in the Regulatory Plan?

A. In the Regulatory Plan, the signatories discussed the fact that KCP&L purchases coal from vendors under contracts that indicate the sulfur content, and that KCP&L pays a premium over the contract price for coal that has a lower sulfur content that the content specified per the contract. The Regulatory Plan permitted the Company to record these premiums as an offset to the regulatory liability associated with the SO_2 emission allowance proceeds. This treatment was continued in subsequent stipulations that were signed during the course of the Regulatory Plan. However, the maximum annual amount that KCP&L was permitted to credit against the regulatory liability has increased from $327,000 as stated in the Regulatory Plan to a current cap of $5 million.

Q. What ratemaking treatment is the Company's proposing in this case for proceeds relating to the sale of SO_2 emission allowances?

A. The Company has included a regulatory liability of $36.9 million on a Kansas-jurisdictional basis. It is proposing to amortize this regulatory liability over a period of 22 years, which KCP&L states corresponds to the remaining depreciable life of the Company's environmental equipment. In addition, the Company is proposing that this credit be returned through the ECA, instead of through base rates. Finally, the Company is requesting that the KCC continue the ratemaking treatment for SO_2 emission allowance proceeds whereby a regulatory asset is established for such proceeds, and whereby coal premiums are credited against the regulatory liability.

Q. Are you recommending any adjustment to the Company's proposed treatment for SO_2 emission allowance proceeds?

A. Yes, I am recommending several adjustments. First, I am recommending that the current regulatory liability be returned to ratepayers over a period of ten years. While the Regulatory Plan originally specified that the regulatory liability would be returned over the period used to depreciate environmental assets, that provision was changed in subsequent stipulations where the parties agreed to determine an appropriate amortization period in this case.

As shown in the response to CURB-59, the overwhelming majority of the SO_2 emission allowance proceeds included in the regulatory liability were received in 2005-2007. It is unreasonable to ask ratepayers to wait for up to 22 years for the return of these proceeds. Therefore, I am recommending that the regulatory liability associated with the SO_2 emission allowance proceeds be amortized over a period of ten years. The ten-year amortization period provides a better balance between the period of time over which the majority of these proceeds were received and the period over which the proceeds will be returned to ratepayers. In addition, the use of a ten-year period will provide greater rate relief to ratepayers now, when it is most needed. The revenue requirement associated with the investment in new plant is at its highest in this case, due to the fact that at this time there is virtually no depreciation reserve to offset the investment in the new generating facility. The use of a ten-year amortization period will not only provide a better match with the period of time over which most of the emission allowance proceeds were received, but it will also provide a significant financial benefit to ratepayers by returning these proceeds more quickly. My adjustment is shown in Schedule ACC-31.

Q. What is your second adjustment?

A. As shown in KCP&L's workpapers to CS-26, the Company only included 63.7% of its annual amortization of SO_2 emissions allowance proceeds in its revenue requirement claim, on the basis that 36.3% should be allocated to non-wholesale operations. However, the entire regulatory liability has been accrued to retail rates over the period of the Regulatory Plan, and there is no rationale or mechanism for returning any of this liability to non-retail ratepayers. Therefore, 100% of this regulatory liability should be returned to retail ratepayers. Based on informal discussions with KCP&L, I understand that the Company concurs with my conclusion that its adjustment should be allocated entirely to retail ratepayers. As shown on Schedule ACC-31, I have not reflected any allocation to non-retail customers in quantifying my adjustment.

Q. What is your final adjustment?

A. The Company is proposing that the amortization of the regulatory liability flow through the ECA, instead of being returned through base rates. I disagree. The regulatory liability has been a rate base component of the Company's distribution rates since the Regulatory Plan was initially approved. In addition, the regulatory liability will continue to be a component of the Company's rate base, and therefore a component of its distribution rates, until the amortization is complete. Accordingly, it would be unreasonable to reflect the amortization credit through the ECA while the regulatory liability continues to be reflected in base rates. Therefore, I recommend that the regulatory liability be returned to ratepayers through its distribution revenue requirement. I have included this amortization in calculating my revenue requirement recommendation in this case as discussed above.

Q. Would you be opposed to the Company returning <u>future</u> sales proceeds relating to SO_2 emission allowances through the ECA?

A. No, I would not. However, the Company is requesting approval to continue the regulatory treatment authorized pursuant to the Regulatory Plan and to continue to defer future sales proceeds. If these sales proceeds are deferred, then I believe they should be returned to ratepayers through base rates. If however, the Company decides to return any sales proceeds immediately to ratepayers, then I would not object if such proceeds were returned through the ECA.

L. Production Maintenance Expenses

Q. How did the Company determine its claim for production maintenance expenses in this case?

A. The Company included an adjustment of $2,904,692 relating to production maintenance expenses in its revenue requirement claim, as shown in its workpapers to Adjustment CS-42. KCP&L has utilized actual test year costs for its production maintenance expense accounts, except for the steam production maintenance accounts. For steam production maintenance accounts, KCP&L utilized a seven-year average of maintenance costs, adjusted to reflect cost increases based on Handy Whitman Index factors.

Q. Please describe your adjustment relating to the Company's production maintenance expense claim.

A. I am recommending that the actual test year level of production maintenance costs be used for all accounts, including steam production maintenance, to determine the Company's revenue requirement is this case. My recommendation is based on two factors. First, while the Company's historic steam maintenance costs have fluctuated from year-to-year, the actual test year costs appear reasonable in light of these fluctuations. Historic costs decreased from 2003 to 2004, increased in 2005, declined again in 2006, increased in 2007 and 2008, and declined in the test year. As shown below, the actual test year cost was actually below the level of costs experienced in 2003. Moreover, the actual test year cost was relatively close to the seven-year average for steam maintenance costs.

Test Year	$26,517,598
2008	$29,753,040
2007	$27,086,136
2006	$22,860,355
2005	$25,367,568
2004	$24,690,941
2003	$26,740,373
Average	$26,145,144

Second, the Company has not provided any support for its claim that historic costs should be increased by the Handy Whitman Index factors. While these factors may provide some general guidance regarding typical cost movement, there is no indication that such factors are appropriate for determining utility rates. The Company has not provided any studies or other supporting documentation to demonstrate that the use of the Handy Whitman Index factors provides an appropriate methodology for use in setting utility rates. Given the fact that these costs have fluctuated over the past seven years, that the test year costs were close to the seven-year average, and that the Company has not supported its proposal to adjust historic costs by the Handy Whitman Index factors, I recommend that the actual test year costs be used as the basis for the Company's revenue requirement. My adjustment is shown in Schedule ACC-32.

M. Distribution Maintenance Expenses

Q. Please describe your adjustment to the Company's distribution maintenance expense claim.

A. KCP&L included a post-test year adjustment of $1,114,843 in its filing relating to distribution maintenance costs. Once again, the Company utilized a five-year average, adjusted by a price escalation factor. The Company's claim for distribution maintenance expenses does not include costs associated with storm damage, which have been accounted for separately.

Q. Did the Company utilize the Handy Whitman Index as its price escalation factor for distribution maintenance costs?

A. No, it did not. While in past cases, KCP&L has proposed using the Handy Whitman Index to escalate costs for distribution maintenance, in this case it is only proposing to use the Handy Whitman Index to escalate steam production maintenance costs, as discussed earlier. Instead of using the Handy Whitman Index, the Company proposes to escalate costs for distribution maintenance based on "KCP&L-specific vegetation management contractor rates."

Q. Please describe your recommended adjustment to the Company's claim.

A. Consistent with my recommendation regarding steam production maintenance costs, I am recommending that the KCC reject the Company's proposal to utilize a price escalator to determine pro forma costs and instead utilize the actual test year costs. As shown below, the actual test year costs appear reasonable relative to actual historic costs over the past five years.

Test Year	$15,192,700
2008	$15,444,941
2007	$14,476,932
2006	$12,968,707
2005	$16,973,764
Average	$15,011,409

Moreover, the actual costs incurred since 2005 already reflect actual contractor rates, to the extent that contractors are used for vegetative management services. The Company's methodology, whereby another price escalation factor would be included in its revenue requirement, is nothing more than a speculative inflation adjustment that is neither known nor measurable. Moreover, this adjustment would sever the relationship between the historic test year costs and prospective rates. For all these reasons, I recommend that the KCC reject the Company's proposal to utilize a price-escalated historic average and instead reflect the actual test year costs in the Company's revenue requirement. My adjustment is shown in Schedule ACC-33.

N. Rate Case Expenses

Q. How did the Company develop its rate case expense claim in this case?

A. The Company's claim includes amortization costs for three rate cases, including the current case. As shown in the workpapers to Adjustment CS-80, KCP&L has included the annual amortization of the following rate case costs: $871,309 for costs incurred in KCC Docket No. 07-KCPE-905-RTS, $2,313,299 for costs incurred in KCC Docket No. 09-KCPE-246-RTS, and $2,020,307 for the current case. Each of these cases is being amortized over a four-year period. The Company has not included costs for KCC Docket No. 06-KCPE-828-RTS in its claim, since these costs will be fully amortized by December 31, 2010. KCP&L incurred rate case costs of $1,224,160 in that proceeding. It should be noted that these amounts are the Kansas-jurisdictional share of the Company's rate case costs. Since KCP&L has filed concurrent cases in Kansas and Missouri, it is also recovering significant rate case costs in the Missouri jurisdiction.

In addition to claims for Kansas rate cases, the Company has also included costs relating to a transmission rate case at the Federal Energy Regulatory Commission ("FERC"). KCP&L is proposing to amortize costs associated with the FERC case over one year.

Q. Are you recommending any adjustment to the Company's claim for rate case costs?

A. Yes, I am recommending two adjustments. First, I am recommending an adjustment to the Company's claim for costs associated with KCC Docket No. 09-KCPE-246-RTS, which is the Company's last base rate case. In that case, KCP&L estimated total rate case costs of approximately $800,000 for the Kansas jurisdiction. In this case, the Company is seeking to recover $2,314,299 relating to that case, an increase of almost 200% from the original claim.

Q. What were some of the factors that led to the higher than projected costs in the last case?

A. The most significant factor was the issue of costs associated with Iatan Unit 1 environmental upgrades and with Iatan Unit 2. During the course of the proceeding, there were serious concerns raised regarding the use of budgeted vs. actual cost data, the allocation of common plant between Iatan Units 1 and 2, and other accounting requirements regarding the booking of common plant. In addition, the Iatan Unit 2 schedule continued to slip while the Iatan Unit 2 costs continued to escalate.

Given these issues, it is not surprising that the Company's actual rate case costs were significantly higher than projected. Not only did the Company engage additional witnesses to address issues with regard to Iatan Unit 1 and Unit 2, but the hourly rates for some of these individuals were, in my opinion, excessive.[14] Accordingly, I recommend that shareholders be responsible for a portion of the rate case costs incurred in the last proceeding. At this time, I am not recommending any adjustment to costs being claimed for the current case. Although the estimated amount for this case is high relative to the costs for KCC Docket Nos. 06-KCPE-828-RTS and 07-KCPE-905-RTS, one would expect this case to have higher costs, given that it is the last case envisioned pursuant to the Regulatory Plan.

Q. What specific adjustment are you recommending to rate case costs?

A. I am recommending that 50% of the actual rate case costs claimed for KCC Docket No. 09-KCPE-246-RTS be disallowed. My adjustment results in recovery of rate case costs for that proceeding of $1,157,150, which is still 44% higher than the Company's original cost estimate. My adjustment is shown in Schedule ACC-34.

[14] Specific hourly rates are confidential.

Q. How does your recommendation compare to the rate case cost estimate that was included in the Stipulation in Docket No. 09-KCPE-246-RTS?

A. The Stipulation in that case permitted the Company to establish a regulatory asset for its rate case costs, and notes that "KCP&L currently estimates the Kansas jurisdictional regulatory asset will be approximately $1.0 million at July 31, 2009...." Thus, my recommended allowance of $1,157,150 is 15.7% higher than KCP&L's estimate reflected in the Stipulation, lending further support for the reasonableness of my recommendation.

Q. What is your second adjustment to the Company's claim for rate case costs?

A. I am recommending that the Company's claim for recovery of certain FERC-jurisdictional costs be denied. According to page 60 of Mr. Weisensee's testimony, "FERC does not allow a deferral and amortization of these costs; rather, costs must be expensed as incurred. Therefore, we included the 2010 budgeted FERC transmission rate case expense in this rate proceeding."

Q. What is the basis for your adjustment?

A. The fact that FERC does not permit the Company to defer and amortize these costs is no reason to require Kansas-jurisdictional customers to pay these costs. If the Company attempted to recover Missouri rate case costs from Kansas ratepayers, that claim would undoubtedly be denied. Whether or not the Company can recover costs that are incurred for the benefit of another jurisdiction in that other jurisdiction is irrelevant in determining whether the costs should be recovered in Kansas. KCP&L has not provided any rationale for why these costs should be recovered in Kansas-jurisdictional rates, other than its claim that such costs cannot be recovered elsewhere. Accordingly, the Company's claim should be denied. My adjustment to eliminate these FERC transmission costs from the Company's Kansas-jurisdictional revenue requirement is also shown in Schedule ACC-34.

O. Credit Card Expense

Q. Please describe the Company's claim for credit card processing costs.

A. In its filing, the Company included an adjustment to its credit card processing costs to reflect an increase in the number of customers using credit cards to pay their bills. The Company's claim is based on a projected acceptance rate in August 2010 of 8.2%.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, it appears that the acceptance rate estimated by KCPL may be overly optimistic. In its workpapers to Adjustment CS-77, the Company indicated that the actual average acceptance rate in the test year was only 5.3%. The acceptance rate in September 2009, the end of the test year in this case, was 6.3%. Therefore, I am recommending a reduction to the Company's claim to reflect a lower acceptance rate than the rate used by the Company in its filing. It should be noted that since the Company began accepting credit card payments, KCP&L has consistently over-estimated the acceptance rates developing its pro forma claims for credit card processing costs.

Q. How did you quantify your adjustment?

A. I have used the September 2009 acceptance rate of 6.3% to quantify my adjustment. I did not make any adjustment to the Company's claim for per unit costs associated with credit card processing. My adjustment is shown in Schedule ACC-35.

P. Membership Dues Expense

Q. Are you recommending any adjustment to the Company's claim for membership dues?

A. Yes, I am. On page 61 of Mr. Weisensee's Testimony, he stated that "In deference to Staff's past practice in rate cases under the Regulatory Plan and as allowed under K.S.A. 66-101f(a), we have eliminated from cost of service 50% of utility dues...." However, the Company's adjustment does not include the elimination of 50% of its dues to the Edison Electric Institute ("EEI"). While the Company did eliminate a portion of these dues that are specifically related to lobbying activities, 100% of the remaining dues expense is included in its revenue requirement.

Therefore, I have made an adjustment to eliminate 50% of the EEI dues from the Company's claim. This adjustment is consistent with the Company's treatment of other dues and membership expenses. My adjustment is shown in Schedule ACC-36.

Q. <u>Lobbying Expenses</u>

Q. Are you recommending any adjustment to the Company's claim for lobbying expenses?

A. Yes, I am recommending that lobbying costs be disallowed. The Company indicated that it was its intent to remove all lobbying costs from its cost of service. However, in the response to KCC-46, the Company identified $18,072 in lobbying-related payroll costs that were inadvertently included in its claim. On Schedule ACC-37, I have made an adjustment to eliminate these costs.

Q. Are lobbying costs an appropriate expense to include in a regulated utility's cost of service?

A. No, they are not. Lobbying costs are not necessary for the provision of safe and adequate utility service. Moreover, the lobbying activities of a regulated utility may be focused on policies and positions that enhance shareholders but may not benefit, and may even harm, ratepayers. Regulatory agencies generally disallow costs involved with lobbying, since most of these efforts are directed toward promoting the interests of the utilities' shareholders rather than its ratepayers. Ratepayers have the ability to lobby on their own through the legislative process. Moreover, lobbying activities have no functional relationship to the provision of safe and adequate electric service. If the Company were to immediately cease contributing to these types of efforts, utility service would in no way be disrupted. Clearly, these costs should not be borne by ratepayers. For all these reasons, I recommend that lobbying activities be disallowed.

R. Meals and Entertainment Expense

Q. Are you recommending any adjustment to the Company's meals and entertainment expense claim?

A. Yes, I am. The Company has included in its filing approximately $855,000 of meals and entertainment expenses that are not deductible on the Company's income tax return. The IRS limits the deductibility of meals and entertainments expenses to 50%. These are costs that the IRS has determined are not appropriate deductions for federal tax purposes. If these costs are not deemed to be reasonable business expenses by the IRS, it seems reasonable to conclude that they are not appropriate business expenses to include in a regulated utility's cost of service. Accordingly, at Schedule ACC-38, I have made an adjustment to eliminate these costs from the Company's revenue requirement. While there may be certain costs for meals that should be borne by ratepayers, there are also clearly costs included in this category which should be entirely excluded from the Company's revenue requirement. Therefore, my recommendation to use the 50% IRS criteria provides a reasonable balance between shareholders and ratepayers and should be adopted by the KCC.

S. Interest on Customer Deposits

Q. How did the Company determine its claim for interest on customer deposits?

A. The Company's filing includes interest on customer deposits based on the average level of customer deposits during the test year and on an interest rate of 1.0%. Since interest costs are booked below-the-line, these costs were not included in the Company's actual test year operating costs. Therefore KCP&L made an adjustment to move these costs above-the-line. Such an adjustment is appropriate, since customer deposits are subtracted from rate base as non-investor supplied capital. Since ratepayers receive a rate base deduction for customer deposits, the Company should be given the opportunity to recover the associated interest costs.

Q. Are you recommending any adjustment to the Company's claim for interest on customer deposits?

A. Yes, I am. In its filing, the Company reflected an interest rate on customer deposits of 1.0%. I understand that this is the interest rate approved by the KCC for 2009. However, in December 2009, the KCC issued an order specifying an interest rate of 0.5% on customer deposits during 2010. Therefore, at Schedule ACC-39, I have made an adjustment to reflect the currently-approved KCC rate for interest on customer deposits. I am not recommending any adjustment to the amount of customer deposits included in the Company's rate base claim upon which the interest rate is applied.

T. **Property Tax Expense**

Q. How did the Company develop its property tax expense claim in this case?

A. As discussed on page 69 of Mr. Weisensee's Testimony, the Company's claim was based on actual 2009 assessed property values and on projected 2009 tax levy rates.

Q. Are you recommending any adjustment to the Company's property tax claim?

A. Yes, I am. In its filing, the Company indicated that it would know the amount of its actual 2008 property tax expense by the end of 2009. In response to KCC-180, the Company updated its claim to reflect actual 2009 property taxes. Therefore, at Schedule ACC-40, I have made an adjustment to incorporate this update in my revenue requirement recommendation.

U. **Depreciation Expense**

Q. Are you recommending an adjustment to the Company's depreciation expense claim?

A. Yes, I am recommending one adjustment. As discussed previously, I am recommending an adjustment to utility plant-in-service relating to Iatan Unit 2. Therefore, at Schedule ACC-41 I have made an adjustment to exclude annual depreciation expense associated with my recommended plant disallowance. To quantify my adjustment, I used the composite depreciation rate for the Company's Iatan Unit 2 plant additions as shown in its Adjustment RB-20.

Q. Are you recommending any adjustment to the Company's proposed depreciation rates?

A. No. As discussed earlier in this testimony, CURB did not engage a consultant to undertake a review of the Company's proposed depreciation rates. Therefore, I have not made any adjustment to the depreciation rates being proposed by the Company in this case. Nor have I made any adjustment to the Company's claim for unrecovered general plant. However, the fact that I have not included any adjustments should not be taken as support by CURB for the Company's proposed depreciation rates or its claim for unrecovered general plant. CURB will review testimony that may be submitted by Staff and other parties on these issues and may recommend adjustments to the Company's depreciation claims after reviewing the testimony filed by other parties in this case.

V. Interest Synchronization and Taxes

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Schedule ACC-42. It is consistent (synchronized) with my recommended rate base, capital structure, and cost of capital recommendations. I am recommending a lower rate base and a higher debt ratio than the rate base and debt ratio included in the Company's filing. The net result of these adjustments is a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under my recommendations. Therefore, my recommendations result in an interest synchronization adjustment that reflects a higher income tax burden for the Company, and a decrease to pro forma income at present rates.

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Schedule ACC-43, I have used a composite income tax factor of 39.58%, which includes a state income tax rate of 7.05% and a federal income tax rate of 35%. These are the state and federal income tax rates contained in the Company's filing. My revenue multiplier, which is shown in Schedule ACC-44, reflects these same income tax rates. In addition, the revenue multiplier includes uncollectible costs at a rate of 0.3764% and forfeited discount revenue at a rate of .28077% , which are the bad debt and forfeited discount rates recommended earlier in my testimony.

VIII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in this testimony?

A. My adjustments show that KCPL has a revenue deficiency at present rates of $7,379,627, as summarized on Schedule ACC-1. My recommendations result in revenue requirement adjustments of $47,845,373 to the Company's requested revenue requirement increase of $55,225,000.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-45, I have quantified the revenue requirement impact of the rate of return, rate base, and expense recommendations contained in this testimony.

Q. Have you developed a pro forma income statement?

A. Yes, Schedule ACC-46 contains a pro forma income statement, showing utility operating income under several scenarios, including the Company's claimed operating income at present rates, my recommended operating income at present rates, and operating income under my proposed rate increase. My recommendations will result in an overall return on rate base of 8.06%.

IX. TRACKING MECHANISMS FOR PENSIONS AND OPEB COSTS

Q. How have pension costs traditionally been treated for ratemaking purposes?

A. Until a few years ago, pension costs were generally treated the same way as other components of a utility's revenue requirement. When the KCC approved new rates for a utility, it included test year pension costs, subject to known and measurable adjustments, in the utility's revenue requirement.

As part of the Regulatory Plan, the KCC approved a new approach for KCP&L. In order to reduce the Company's risk during the period of the Iatan Unit 2 construction, the KCC approved a mechanism that has allowed the Company to defer the difference between its actual pension costs each year and the amount recovered in rates. This regulatory asset or liability, which has received rate base treatment, is being amortized over a five-year period.

The Regulatory Plan also permitted KCP&L to establish a regulatory asset for contributions to the pension fund made in excess of the FAS 87 expense for one of the following reasons: (1) if the minimum required contribution is greater than the FAS 87 expense level, (2) to avoid Pension Benefit Guarantee Corporation ("PBGC") variable premiums, and (3) to avoid the recognition of a minimum pension liability. The Regulatory Plan provided for rate base treatment of this regulatory asset.

The Regulatory Plan stated that "non-KCPL parties reserve the right to propose a different methodology for addressing FASB 87 pension expense in the first

KCPL rate case proceeding after 2010. In the event that the Commission addresses FASB 87 pension expense in a general investigation, KCPL agrees to cooperate in such investigation and be bound by the results thereof in rate proceedings subsequent to 2010."

Q. What has KCP&L proposed in this case?

A. In this case, the Company has proposed to expand the situations whereby KCP&L would be granted rate recognition of contributions in excess of the FAS 87 expense. Therefore, the Company is seeking rate recognition for excess contributions for the following reasons, in addition to those listed in the Regulatory Plan: (i) to avoid pension benefit restrictions under the Pension Protection Act of 2006 ("PPA") that would cause an inability of the Company to pay pension benefits to recipients according to the normal provisions of the plan; (ii) to avoid at-risk status under the PPA that would result in acceleration of minimum contributions; and (iii) to reduce Pension Benefit Guarantee Corporation variable premiums.

Q. Has the Company also proposed to implement a tracking mechanism for Other Post Employment Benefit ("OPEB") costs?

A. Yes, it has. As discussed on page 57 of Mr. Weisensee's Testimony, the Company is seeking to establish a tracking mechanism for OPEB costs as well. Specifically, it is proposing to establish a regulatory asset or regulatory liability for the difference between the actual annual OPEB expense and the annual amount recovered in rates.

Q. Have there been further developments with regard to recovery of pension and OPEB costs since the Regulatory Plan was approved by the KCC?

A. Yes, since the Regulatory Plan was approved, there has been a major development with regard to these costs. On March 29, 2007, the KCC initiated a generic docket (KCC Docket No. 07-GIMX-1041-GIV) to examine the appropriate ratemaking treatment for pension and OPEB costs. This docket was initiated in response to a request by several utility companies, including KCP&L. Specifically, the utilities requested KCC authorization to:

> Establish a regulatory asset or regulatory liability to track the difference between the amounts recognized in rates and the pension and OPEB costs recorded for financial reporting purposes pursuant to Generally Accepted Accounting Principles ("GAAP"), and
>
> Recognize for ratemaking purposes the companies' contributions to their pension and OPEB plans in excess of costs recorded for financial reporting purposes.

On March 18, 2009, Staff filed its Report and Recommendations in the generic proceeding. Staff recommended that the KCC permit the utilities to establish a regulatory asset or liability for the difference between pension and OPEB costs recovered in rates and amounts recorded for financial reporting purposes. KCC Staff also recommended that the utilities be required to fund the amount of pension and OPEB costs recovered annually in rates. The KCC Staff recommended that any deferrals be amortized over a five-year period without carrying costs. Moreover, the KCC Staff recommended that the KCC reject the utilities' request to establish a regulatory asset for the difference between the annual amount of pension and OPEB contributions and the amounts booked pursuant to GAAP.

On April 17, 2007, CURB filed Initial Comments in the generic docket. I assisted CURB with the preparation of those comments. CURB recommended that the KCC deny the utilities' request to establish regulatory assets or liabilities relating to pension and OPEB costs. As noted in CURB's comments, "[p]ermitting the establishment of a regulatory asset or regulatory liability would constitute single-issue ratemaking, would provide a disincentive for the companies to control these costs, would weaken regulatory oversight, would shift risk from the companies completely to ratepayers, and has not been justified by Staff." However, CURB also recommended that if the KCC adopted Staff's recommendation to permit a regulatory asset or liability to be established for the difference between amounts collected in rates and the amounts booked pursuant to GAAP, then it should also adopt Staff's recommendation to require the utilities to fund the amount collected in rates. In addition, CURB argued that if such a mechanism was adopted, the KCC should also adopt Staff's recommendation that the KCC reject the utilities' request to include any regulatory asset or liability in rate base. The Initial Comments and Reply Comments filed by CURB are incorporated herein by reference.

Discussions were subsequently held between Staff, CURB, and the utilities to determine if resolution of these issues was possible. As a result of those discussions, Applications for Accounting Orders were subsequently filed by KGS and by Westar[15] Energy, Inc. and Kansas Gas and Electric Company (collectively "Westar"), on August 13, 2009 and August 14, 2009 respectively. These utilities requested authorization to implement a tracking mechanism for the difference between the pension and OPEB costs included in rates and the costs booked pursuant to GAAP, but agreed that any resulting regulatory asset or liability would not accrue carrying costs and that the associated unamortized balances would not be included in rate base in the companies' next rate proceeding. Both utilities also agreed to fund the amount of pension and OPEB costs reflected in rates, to the extent such funding was deductible for federal income tax purposes. Both KGS and Westar also agreed to establish a regulatory liability for any amounts not funded due to IRS limitations with regard to tax deductibility.

In addition, in their Applications for Accounting Orders, both parties requested authorization to establish a second regulatory asset if the amounts actually funded exceeded the annual costs booked pursuant to GAAP. However, KGS and Westar agreed that this second regulatory asset would not accrue carrying costs or be included in rate base in a future case, but would only be used to meet the funding requirements for its first tracker. On September 11, 2009, the KCC issued orders

[15] Westar filed on behalf of Westar Energy, Inc. and the Kansas Gas and Electric Company.

approving the Applications for Accounting Orders submitted by KGS and Westar. On January 12, 2010, CURB, Staff, Westar, and KGS filed a Stipulation and Agreement proposing that the KCC adopt the terms and conditions outlined in the KGS and Westar Accounting Orders on a permanent basis.

Moreover, in the recent Empire District Electric Company ("Empire") base rate case, KCC Docket No. 10-EPDE-314-RTS, Empire proposed a tracking mechanism for its pension and OPEB costs that contained some of the components being requested by KCP&L in this case. Specifically, Empire's proposal: 1) did not require any specific level of funding in order to record a regulatory asset for the difference between pension and OPEB amounts collected in rates and amounts booked pursuant to GAAP, 2) included rate base treatment for the regulatory asset or liability resulting from the difference between pension and OPEB amounts collected in rates and amounts booked pursuant to GAAP, 3) provided for ratemaking recovery of a second regulatory asset related to the difference between amounts funded and the annual pension and OPEB costs booked pursuant to GAAP, and 4) provided for rate base treatment of this second regulatory asset. In the Stipulation and Agreement in KCC Docket No. 10-EPDE-314-RTS, Empire agreed to modify its proposal to be consistent with the mechanisms approved for Westar and KGS.

Q. What is your recommendation with regard to KCP&L's proposal in this case?

A. I continue to oppose pension and OPEB tracker mechanisms, for the reasons expressed in the Initial Comments and Reply Comments filed by CURB in KCC Docket No. 07-GIMX-1041-GIV. However, if the KCC determines that some tracking mechanism is appropriate, then it should adopt the mechanisms approved for KGS, Westar, and Empire. These mechanisms have substantial ratepayer safeguards that are not found in KCP&L's current or proposed mechanisms. First, the KGS, Westar, and Empire mechanisms require that utilities actually fund amounts collected in rates in order to record a regulatory asset for differences between pension and OPEB amounts collected in rates and amounts booked pursuant to GAAP. This is an important safeguard and will ensure that amounts collected from ratepayers for pension and OPEB costs are actually used for that purpose.[16] Second, the KGS, Westar, and Empire mechanisms do not include rate base treatment for the regulatory asset or liability resulting from the difference between pension and OPEB amounts collected in rates and amounts booked pursuant to GAAP. Since the funding requirement will match the amount collected in rates, the regulatory asset or liability generated will have no cash impact on the Company and therefore there is no rationale for including any such regulatory asset or liability in rate base. Third, the KGS, Westar, and Empire mechanisms do permit the recording of a second regulatory asset relating to excess contributions, but this regulatory asset has no

[16] While the Regulatory Plan has a funding requirement for pension costs, the Company's proposal does not appear to have a funding requirement for OPEB costs.

ratemaking implications and therefore receives no rate base treatment or carrying costs. This provision allows the companies to apply "excess" contributions to meet their regulatory funding requirements in future years, but avoids the possibility of utilities basing funding decisions on discretionary criteria that may not benefit ratepayers. Therefore, if the KCC revises the pension tracker that was adopted for the duration of the Regulatory Plan, and adopts an OPEB tracking mechanism for KCP&L, it should adopt the same mechanisms as those approved for KGS, Westar, and Empire. Given the KCC's generic investigation, which was initiated by the utilities including KCP&L, it would be reasonable to implement uniform tracking mechanisms for all Kansas utilities.

Q. Could changes in KCP&L's pension tracker be implemented with this rate case?

A. The language of the Regulatory Plan states that non-KCP&L parties may propose changes in the pension tracker with the first rate case proceeding after 2010. That may be interpreted as this current case or the next case, depending on the interpretation of "after 2010". However, the Regulatory Plan does not bind non-signatory parties, including CURB, from proposing changes in the ratemaking treatment for pension and OPEB costs <u>at any time</u>. Moreover, I have been advised by counsel that the KCC itself is not bound by the terms of the Regulatory Plan, and may make changes to specific aspects of the Regulatory Plan at any time.

In its Order Approving Stipulation and Agreement in KCC Docket No. 04-KCPE-1025-GIE, the KCC noted that the Regulatory Plan does not bind the Commission, and noted that even "KCP&L acknowledged that the Commission's approval of the Agreement would not require the Commission to make any specific determinations or grant any approvals in subsequent dockets."[17] In approving the Regulatory Plan, the KCC noted that "[t]he proposed treatment regarding the specific matters contained in the Agreement appears reasonable at this time, but is subject to future Commission review to ensure that they result in just and reasonable rates and reflect the provision of efficient and sufficient service. K.S.A. 66-101b."[18] In addition, the KCC itself was not a signatory party to the Regulatory Plan and therefore would not be bound by language addressing the "non-KCP&L parties." Thus, the KCC has the authority in this case to extend the pension tracking mechanism recently approved for Westar, KGS, and Empire to KCP&L, or to find that no tracking mechanism is appropriate.

However, if for any reason the KCC decides that no change to the pension tracker should be made in this case, then the KCC should reject the revisions being proposed by KCP&L in this case and instead adopt, as part of the abbreviated rate case to be filed subsequent to this case, the uniform pension tracking mechanism adopted for the other utilities in Kansas. It should be noted that I have not made any quantitative adjustment to the Company's claims in this case for pension expense or

[17] Order Approving Stipulation and Agreement, KCC Docket No. 04-KCPE-1025-GIE, paragraph 32.
[18] Id., paragraph 61.

for the associated regulatory asset associated with changes in the tracking mechanism, as I presume that any changes would only be effective prospectively.

With regard to OPEB costs, the KCC should deny the Company's request to establish a tracking mechanism for these costs, for the reasons stated by CURB in Docket No. 07-GIMX-1041-GIV. However, if the KCC decides to adopt a tracking mechanism for OPEB costs, it should be consistent with the mechanisms adopted for Westar, KGS, and Empire.

X. ENVIRONMENTAL COST RECOVERY RIDER

Q. Please describe the Environmental Cost Recovery ("ECR") Rider that the Company is requesting in this case.

A. As described in the testimony of Mr. Rush at pages 9-11, the Company is requesting an ECR rider to recover the capital and operating costs associated with environmental improvement projects undertaken by the Company between base rate case. KCP&L is proposing to recover the return on incremental investment, depreciation expense, related operating and maintenance costs, and income taxes through an annual ECR rider. When new rates are established, these costs would be rolled into base rates.

Q. Do you support the establishment of an ECR for KCP&L?

A. No, I do not. The Company is at the end of a five-year Regulatory Plan during which rates to Kansas customers were increased by $116 million, not including any increases that may be approved as a result of this case or the abbreviated case to be filed next year. This Regulatory Plan was intended to provide the Company with sufficient revenue to acquire additional generating capacity and to undertake various environmental projects, some of which were never completed in spite of the significant rate increases borne by Kansas customers. Now that ratepayers are nearing the end of the Regulatory Plan, it is unreasonable to require them to continue to fund annual rate increases for additional environmental projects.

While the Company may be required to undertake additional environmental investments over the next few years, this investment should be handled like any other investment that is required to provide safe and adequate electric utility service. Between base rate cases, the risk of recovery should be on shareholders, who are given a premium return on equity for taking on such risk. The Company does not begin to recover other types of investment until it files for new base rates and investment in environmental projects should be given the same regulatory treatment. Requiring the Company to recover these costs in a base rate also provides a better forum for CURB, KCC Staff, and other interveners to review these costs and to determine whether the costs are just and reasonable. While the Company will argue that parties have the ability to review these costs in an ECR proceeding, the reality is that such proceedings are conducted in a relatively short period of time and many interveners to not have the resources to undertake a comprehensive review outside of a base rate case.

Q. Would the Company's proposal to implement an ECR rider shift additional risk onto ratepayers?

A. Yes, it would. The Company's proposed mechanism would shift risk from shareholders, where it properly belongs, onto ratepayers without any commensurate reduction in the Company's return on equity. In addition, the Company's proposal would result in single-issue ratemaking and would allow KCP&L to increase rates even if the Company was earning its authorized rate of return.

Permitting these costs to be recovered between base rate cases will also reduce the Company's incentive to control and manage these costs. If the Company is required to file a base rate case to recover these costs, it is likely to work harder to keep costs down between base rate cases by investing in the most efficient projects and by managing construction of such projects effectively.

An ECR rider also results in rate uncertainty for ratepayers. Ratepayers are nearing the end of a Regulatory Plan where they have seen significant annual increases. Adopting an ECR for KCP&L would continue the trend of annual rate increases for Kansas ratepayers. These constant rate changes make it difficult for customers to anticipate their electric charges or to assess the accuracy of their bills.

Rate stability can be especially important to residential and small commercial customers. Adoption of an ECR rider also puts the KCC in the position of approving rate increases without any idea of the potential magnitude of those increases. The KCC has not examined important issues such as gradualism, rate stability, and the avoidance of rate shock, issues which should be thoroughly explored prior to implementing the adjustment mechanism proposed by KCP&L.

Q. Doesn't Westar have a similar ECR rider surcharge mechanism?

A. Yes, it does. It should be noted that CURB opposed the adoption of an ECR rider for Westar as well, for some of the same reasons outlined above. However, one difference with KCP&L is that this utility has had rate increases each year since the Regulatory Plan was adopted. Ratepayers have the right to expect some rate relief from these annual increases at the end of the Regulatory Plan.

Q. Given your concerns with the ECR rider, what do you recommend?

A. I recommend that the KCC reject the Company's proposal. The ECR rider results in single-issue ratemaking, provide a disincentive for utility management to control costs, and shifts risk from shareholders to ratepayers. Given the increases that KCP&L ratepayers have experienced under the Regulatory Plan, and will continue to experience in 2010 and possibly in 2011, now is not the time to implement a new mechanism that will result in further annual rate increases. Instead, investment in environmental projects should be treated no differently from other investment that is necessary to provide safe and adequate utility service, and should be recovered only through a base rate case where all parties can undertake a thorough review of the costs. Accordingly, the Company's request for an ECR rider should be denied.

XI. ALLOCATION OF OFF-SYSTEM SALES MARGINS

Q. How are off-system sales margins currently treated for ratemaking purposes?

A. Off-system sales margins are allocated based on an unused energy allocator. Such margins are returned to customers through the ECA mechanism. This allocation was agreed to by the Company when it received approval to implement an ECA.

Q. Is the Company proposing a change in the allocation methodology in this case?

A Yes, it is. KCP&L is proposing to change the allocation factor from unused energy to an allocation based on the allocation of steam production plant.

Q. What is the Company's rationale for this proposed change in allocation?

A. The Company now claims that the unused energy allocator is not an appropriate allocator. Instead, KCP&L claims that the off-system sales margins should be allocated in proportion to the fixed costs of the generating units used to generate the electricity sold, which the Company claims primarily comes from its coal-fired steam generating stations.

Q. Do you agree with the Company's proposal to change the allocator used for off-system sales margins?

A. No, I do not. While the coal-fired steam generating stations may be the source of much of the energy used for off-system sales, the Company's proposed allocator does not provide any meaningful information about the availability of this energy to be used for off-system sales. If a particular unit is producing at full capacity but if its output is being used entirely to serve native load, then there is no opportunity for that unit to participate in the off-system sales market. Accordingly the use of the unused energy allocator provides a better measure of the degree to which energy is available to be sold in the off-system sales market.

Moreover, it appears that the Company's real concern is that different allocators for off-system sales margins are used by regulatory agencies in Kansas vs. Missouri. Thus, KCP&L could find itself allocating more (or less) than 100% of its off-system sales margins. However, instead of proposing to adopt an unused energy allocator in Missouri, KCP&L is proposing to put the burden on the KCC to change the allocation methodology previously approved in Kansas.

Q. Was the unused energy allocator a condition of approving the Company's ECA mechanism?

A. Yes, it was. While CURB initially opposed the Company's proposal to adopt an ECA, CURB did sign the Stipulation and Agreement in KCC Docket No. 07-KCPE-

905-RTS, which provided for the implementation of an ECA. However, an integral part of that agreement was the use of an unused energy allocator for off-system sales. Specifically, the Stipulation an Agreement in that case provided that "KCPL agrees to utilize its UE1 [Unused Energy Allocator] to allocate off-system margins to Kansas retail ratepayers within the context of its ECA tariff." Now that the ECA is in operation, KCP&L is attempting to change the rules agreed upon by the parties.

Q. What would be the impact on Kansas ratepayers if the Company's proposal is adopted?

A. As shown in the response to CURB-64, the change in the allocation methodology would reduce the percentage of the credit allocated to Kansas. Based on data from KCC Docket No. 09-KCPE-246-RTS, Kansas would be allocated 44.32% of off-system sales margins if the steam production allocator is used, instead of the 47.11% resulting from the unused energy allocator.

Q. What do you recommend?

A. I am recommending that the Company's proposal be rejected, and that off-system sales margins continue to be allocated on the basis of unused energy. This is the allocator that was agreed to as part of the implementation of the ECA. If the Company wants to reexamine the conditions of that settlement, then the parties should also be free to reexamine the ECA and to recommend that it be terminated.

The Company's proposal would significantly reduce the benefit received by Kansas ratepayers from off-system sales. Moreover, the Company's proposed allocator provides no meaningful information about the extent to which specific units are available to make off-system sales. The KCC should not take second place to regulatory agencies in Missouri. If the Company requires uniform allocators in each state, then it should propose to adopt the unused energy allocator in Missouri for off-system sales margins, instead of putting the burden on Kansas ratepayers. Therefore, the KCC should maintain the current allocation methodology for off-system sales margins.

Q. Does this conclude your testimony?

A. Yes, it does.

<u>VERIFICATION</u>

STATE OF CONNECTICUT)

COUNTY OF FAIRFIELD) ss:

Andrea C. Crane, being duly sworn upon her oath, deposes and states that she is a consultant for the Citizens' Utility Ratepayer Board, that she has read and is familiar with the foregoing testimony, and that the statements made herein are true to the best of her knowledge, information and belief

Andrea C. Crane

Andrea C. Crane

Subscribed and sworn before me this 11TH day of June, 2010.

Notary Public Marjorie M. Lexis

My Commission Expires: December 31, 2013