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Kansas Corporation Commission
/S/ Susan K. Duffy

BEFORE THE CORPORATION COMMISSION

OF THE STATE OF KANSAS

STATE CORPORATION COMMISSION

AUG 0 3 2007

Docket Room

IN THE MATTER OF THE APPLICATION	]	
OF KANSAS CITY POWER & LIGHT	]	KCC Docket No. 07-KCPE-905-RTS
COMPANY TO MODIFY ITS TARIFFS	]	
TO BEGIN 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

August 3, 2007

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Appendix A - List of Prior Testimonies
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1 **I. STATEMENT OF QUALIFICATIONS**

2 **Q. Please state your name and business address.**

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

5

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

7 A. I am Vice President of The Columbia Group, Inc., a financial consulting firm that specializes
8 in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and
9 undertake various studies relating to utility rates and regulatory policy. I have held several
10 positions of increasing responsibility since I joined The Columbia Group, Inc. in January
11 1989.

12

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

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

19

20 **Q. Have you previously testified in regulatory proceedings?**

21 A. Yes, since joining The Columbia Group, Inc., I have testified in approximately 250

1 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii,
2 Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma,
3 Pennsylvania, Rhode Island, South Carolina, Vermont, West Virginia and the District of
4 Columbia. These proceedings involved gas, electric, water, wastewater, telephone, solid
5 waste, cable television, and navigation utilities. A list of dockets in which I have filed
6 testimony is included in Appendix A.
7
8 **Q. What is your educational background?**
9 A. I received a Masters degree in Business Administration, with a concentration in Finance,
10 from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A.
11 in Chemistry from Temple University.
12
13 **II. <u>PURPOSE OF TESTIMONY</u>**
14 **Q. What is the purpose of your testimony?**
15 A. On or about March 1, 2007, Kansas City Power & Light Company ("KCPL" or "Company")
16 filed an Application with the Kansas Corporation Commission ("KCC" or "Commission")
17 seeking a rate increase of $47.06 million. This rate increase request included $34.22 million
18 related to a traditional revenue requirement deficiency and another $12.84 million in
19 additional cash flow that the Company claims is necessary to maintain its investment grade
20 credit rating. The Company's request would result in an increase of approximately 10.8%
21 over retail sales revenue at present rates. The Company's filing is based on a test year ending

1 December 31, 2006, with pro forma changes through September 30, 2007.

2 The Columbia Group, Inc. was engaged by The State of Kansas, Citizens' Utility
3 Ratepayer Board ("CURB") to review the Company's Application and to provide
4 recommendations to the KCC regarding the Company's cost of capital and revenue
5 requirement claims.

6

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

8 A. The most significant issues in the Company's filing are a) its projected utility plant-in-
9 service increases, b) proposed increases in salaries and wages, c) increased pension costs and
10 amortization of associated regulatory assets; d) proposed increases in generation,
11 transmission, and distribution maintenance costs, e) the Company's request for an 11.25%
12 return on equity, and f) the Company's request for an additional increase of $12.84 million to
13 maintain certain credit ratios. KCPL is also requesting approval for an Energy Cost
14 Adjustment ("ECA") mechanism. The Company's filing represents the second case to be
15 filed pursuant to the Regulatory Plan that was agreed upon by the Company and the KCC
16 Staff in Docket No. 04-KCPE-1025-GIE.

17

18 **III. SUMMARY OF CONCLUSIONS**

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

21 A. Based on my analysis of the Company's filing and other documentation in this case, my

1 conclusions are as follows:

2 1. The twelve months ending December 31, 2006 is a reasonable test year to use in this
3 case to evaluate the reasonableness of the Company's claim.

4 2. The Company has a cost of equity of 9.59% and an overall cost of capital of 7.90%
5 (see Schedule ACC-2).[1]

6 3. KCPL has pro forma test year rate base of $1,079,691,945 (see Schedule ACC-9).

7 4. The Company has pro forma operating income at present rates of $87,113,121 (see
8 Schedule ACC-17).

9 5. KCPL has a pro forma revenue requirement surplus of $3,053,110 (see Schedule
10 ACC-1). This is in contrast to the Company's claimed revenue requirement
11 deficiency of $34,220,000.

12 6. If the KCC decides to permit the Company to increase rates in order to meet the bond
13 coverage ratios outlined in the Stipulation in Docket No. 04-KCPE-1025-GIE, then
14 an increase of $16,436,781 would be necessary (see Schedule ACC-46). This
15 increase would partially offset the revenue requirement decrease of $3,053,110
16 referenced above, resulting in a net revenue increase of $13,383,671.

17 7. Any additional increase granted by the KCC relating to cash flow requirements
18 should be applied as a rate base deduction beginning in the rate case filed in 2009, as

[1] Schedules ACC-1, ACC-44, 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-43 are operating income schedules.

required in the Stipulation in Docket No. 04-KCPE-1025-GIE. The rate base deduction should equal the full, pre-tax amount of any such increase.

8. The KCC should reopen the Regulatory Plan to reexamine the Company's generation resource plan in view of new developments, such as the lower-than-projected wind capacity factor, the Company's recent Settlement Agreement in Missouri with the Sierra Club and other parties, and the Company's proposed acquisition of Aquila. The KCC should also reexamine its approval of a cash flow mechanism that effectively cedes control over Kansas jurisdictional rates to credit rating agencies.

IV. BACKGROUND OF THE REGULATORY PLAN

Q. Can you briefly describe the Regulatory Plan[2] that was approved by the KCC for KCPL?

A. Approximately three years ago, the KCC opened a docket to address the Company's future electric supply requirements and related pricing issues. The KCC, at the request of the Company, established a workshop forum to address various issues, including Integrated Resource Planning and related financial issues.

As a result of that process, the Company entered into a Regulatory Plan that addressed certain financial and policy issues over the next five years, during the period of construction of new generating capacity at Iatan. The Regulatory Plan was agreed to by the Company, Staff, Sprint, and the Kansas Hospital Association. CURB was not a signatory to

1 the Settlement Agreement for the Regulatory Plan.

2

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

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

9 The Regulatory Plan provided for KCPL to file a base rate case on or before May 1,
10 2006. That case was resolved by a Stipulation approved by the KCC on December 4, 2006.
11 The Regulatory Plan permitted, but did not require, KCPL to file base rate cases in 2007 and
12 2008. This case is the first optional base rate case to be filed pursuant to the Regulatory
13 Plan. The Regulatory Plan also requires the Company to file a base rate case on or before
14 August 15, 2009, with new rates to be effective June 1, 2010. The Regulatory Plan
15 recognized that it was important for KCPL to maintain an investment grade rating during the
16 construction process. In order to assist KCPL to maintain this rating, the Regulatory Plan
17 contained a provision for "an amortization accounting [adjustment] to be referred to as a
18 Contribution in Aid of Construction ("CIAC")."[3] Pursuant to the Regulatory Plan, the CIAC
19 was an amount that would be treated as an additional amortization expense and added to

[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.

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

1 KCPL's cost of service for ratemaking purposes if required in order to meet the cash flow
2 requirements of the rating agencies. The Regulatory Plan provides that the accumulated
3 CIAC will be treated as an increase to the depreciation reserve and deducted from rate base
4 in future KCPL proceedings beginning in 2009. In essence, the CIAC provision equates to a
5 prepayment of the new generating facilities by ratepayers if required to meet cash flow
6 objectives.
7
8 **Q. Please summarize the Stipulation that was agreed to in the Company's last base rate**
9 **case.**
10 A. In its last case, the Company requested a rate increase of $42.27 million. The Company did
11 not request any CIAC in that case, nor did the Company request an ECA.
12 The Stipulation in that case provided for a total revenue increase of $29 million. The
13 Stipulation provided that $4 million of this increase "will be treated for accounting purposes
14 as a pre-tax payment on plant on behalf of customers. The $4 million pre-tax payment shall
15 be treated as an increase to KCPL's depreciation reserve and will be assigned to primary
16 plant accounts in a future rate case." In addition, KCPL agreed to propose an ECA
17 mechanism "in its next rate filing that will be filed no later than March 1, 2007." The
18 Stipulation also specified the accounting treatment for several types of costs, such as rate
19 case costs, talent assessment costs, enhanced security costs, pension costs, and certain
20 litigation costs. Other issues addressed in the Stipulation included depreciation rates, asset
21 retirement obligations and cost of removal, decommissioning, SO_2 emission allowances, and

1 Allowance for Funds Used During Construction ("AFUDC") on Iatan 2.

2

3 **Q. What are the credit ratios that are addressed in the Regulatory Plan?**

4 A. The Regulatory Plan addresses three credit ratios that should be considered by the signatory
5 parties: total debt to total capitalization, funds from operations interest coverage, and funds
6 from operation as a percentage of average total debt. The Regulatory Plan states that KCPL
7 will address the first ratio through its issuance of securities. Thus, the Regulatory Plan states
8 that the CIAC mechanism will be used, if necessary, to achieve the objectives for the other
9 two ratios, funds from operations interest coverage and funds from operation as a percentage
10 of average total debt.

11

12 **V. <u>COST OF CAPITAL AND CAPITAL STRUCTURE</u>**

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

15 A. The Company utilized the following capital structure and cost of capital in its filing:

16

17

18

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7

	Percent	Cost Rate	Weighted Cost
Common Equity	53.43%	11.25%	6.01%
Preferred Stock	1.33%	4.29%	0.06%
Long Term Debt	45.24%	6.09%	2.76%
Total	100.00%		8.83%

8

9 **A. Capital Structure**

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

11 A. Yes, I am recommending adjustments to the Company's capital structure, its cost of debt,

12 and its cost of equity claims.

13

14 **Q. How did the Company determine its capital structure claim in this case?**

15 A. KCPL's claim is based on the projected capital structure of its parent company, Great

16 Plains Energy ("GPE") at September 30, 2007.

17

18 **Q. Has the Company provided further information about its capital structure?**

19 A. Yes, it has. In response to KCC-320, the Company provided its updated projected capital

20 structure at September 30, 2007. The details of this response are confidential.

21 However, I have reflected this updated capital structure at Schedule ACC-2.

1 **B. Cost of Debt**

2 **Q. What cost of debt have you included in your overall cost of capital recommendation?**

3 A. I have used the Company's pro forma cost for long-term debt as updated in the response to
4 KCC-320.

5

6 **C. Cost of Equity**

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

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

12–13
$$\text{Return on Equity} = \frac{D_1}{P_0} + g$$

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

16 The DCF methodology is generally applied to a comparable group of investments,
17 usually to a group of companies that provide the same utility service as the utility service for
18 which rates are being set. In order to determine a comparable group of companies, I utilized
19 the same comparable group as that selected by the Company.

20 To determine an appropriate dividend yield for comparable companies - i.e., the
21 expected dividend divided by the current price - I calculated the dividend yield of each of the

1 comparable companies under two scenarios. First, I calculated the dividend yield using the
2 average of the stock prices for each company over the past three months. The use of a
3 dividend yield using a three-month average price mitigates the effect of stock price volatility
4 for any given day. The three-month average is also consistent with the methodology used by
5 KCPL witness Dr. Samuel Hadaway. Based on the average stock prices over the past three
6 months, and the current dividend for each company, I determined an average dividend yield
7 of 4.07% for the comparable group, as shown in Schedule ACC-5.

8 I also calculated a current dividend yield at July 12, 2007, which showed an average
9 dividend yield of 4.21% for the comparable group. This calculation is also shown in
10 Schedule ACC-5. Based on these determinations, I recommend that a dividend yield of
11 4.21% be used in the DCF calculation. This recommended dividend yield is consistent with
12 Dr. Hadaway's findings of a 4.19% average dividend and a 4.15% median dividend for the
13 comparable group. My recommended dividend yield will be increased by ½ of my
14 recommended growth rate, as determined below, to reflect the fact that the DCF model is
15 prospective and dividend yields may grow over the next year. Increasing the dividend yield
16 by ½ of the prospective growth rate is commonly referred to as the "half year convention."
17

18 **Q. How did you determine an appropriate growth rate?**

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

1 Various growth rates for the companies within my comparable group are shown in
2 Schedule ACC-6 and group averages are summarized below:
3

Past 5 Years - Earnings	(0.9%)
Past 5 Years - Dividends	0.2%
Past 5 Years - Book Value	2.5%
Past 10 Years - Earnings	0.1%
Past 10 Years - Dividends	(0.8%)
Past 10 Years - Book Value	2.4%
Estimated Next 5 Years - Earnings	5.3%
Estimated Next 5 Years - Dividends	4.4%
Estimated Next 5 Years - Book Value	3.8%

4
5
6 **Q. Why do you believe that it is reasonable to examine historic growth rates as well as**
7 **projected growth rates when evaluating a utility's cost of equity?**
8 A. I believe that historic growth rates should be considered because security analysts have been
9 notoriously optimistic in forecasting future growth in earnings. At least part of this problem
10 in the past has been the fact that firms that traditionally sell securities are the same firms that
11 provide investors with research on these securities, including forecasts of earnings growth.
12 This results 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.

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 5.3% should be utilized. This recommended growth rate is equal to the projected five-year growth rate in earnings per Value Line. Moreover, my recommended growth rate is higher than the actual average growth rates over the past five or ten years in earnings, dividends or book value. It is also higher than the projected five-year growth rates for dividends or book value.

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

A. My analysis indicates a cost of equity using the DCF methodology of 9.62%, as shown below:

Dividend Yield	4.21%
Growth in Dividend Yield (1/2 X 5.30% X 4.21%)	0.11%
Expected Growth	5.30%
Total	9.62%

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

1 changes experienced by the overall market. Utility stocks have traditionally been less volatile
2 than the overall market, i.e., their stock prices do not fluctuate as significantly as the market
3 as a whole, and therefore their Betas have generally been less than 1.0.
4
5 **Q. How did you calculate the cost of equity using the CAPM?**
6 A. My CAPM analysis is shown in Schedule ACC-7. First, I used a risk-free rate of 5.14%
7 for the yield on long-term U.S. Government bonds, which was the rate at July 17, 2007
8 per the Statistical Release by the Federal Reserve Board. Over the past year, this rate has
9 ranged from 4.58% to 5.29%. In addition, I used the average Beta for the proxy group.
10 This resulted in an average Beta of 0.89, as shown in Schedule ACC-8. Finally, since I
11 am using a long-term U.S. Government bond rate as the risk-free rate, the risk premium
12 that should be used is the historic risk premium of stocks over the rates for long-term
13 government bonds. According to the 2006 Ibbotson Associates' publication, *2006*
14 *Yearbook: Stocks, Bonds, Bills, and Inflation*, the risk premium of using geometric mean
15 returns is 4.9%.
16
17 **Q. What is the difference between a geometric and an arithmetic mean return?**
18 A. An arithmetic mean is a simple average of each year's percentage return. A geometric mean
19 takes compounding into effect. As a result, the arithmetic mean overstates the historic
20 return to investors. For example, suppose an investor starts with $100. In year 1, he makes
21 100% or $100. He now has $200. In year 2, he loses 50%, or $100. He is now back to

1 $100.

2 The arithmetic mean of these transactions is 100% - 50% or 50%/ 2 = 25% per year.
3 The geometric mean of these transactions is 0%. In this simple example, it is clear that the
4 geometric mean more appropriately reflects the real return to the investor, who started with
5 $100 and who still has $100 two years later. The use of the arithmetic mean would suggest
6 that the investor should have $156.25 after two years ($100 X 1.25 X 1.25), when in fact the
7 investor actually has considerably less. Therefore, a geometric mean return is a more
8 appropriate measure of the real return to an investor, if it is used as I am using it here, i.e., to
9 develop an historic relationship between long-term risk free rates and market risk premiums.
10 Some utilities have criticized me in the past for using a geometric, rather than an arithmetic
11 mean return, arguing that the arithmetic mean should be used when estimating future returns.
12 However, in my case, I am not using the mean to develop an expected outcome, I am simply
13 using the mean returns to develop an historic relationship. Therefore, the geometric mean is
14 the appropriate measure, as illustrated in the above example.
15
16 **Q. Did Dr. Hadaway also utilize a geometric mean in his risk premium analysis?**
17 A. Yes, he did. In at least one of his risk premium analyses, Dr. Hadaway relied upon the
18 geometric mean returns as reported by Value Line.
19
20 **Q. What is the Company's cost of equity using a CAPM approach?**
21 A. Given a long-term risk-free rate of 5.14%, a Beta of 0.89, and a risk premium of 4.9%, the

1 CAPM methodology produces a cost of equity of 9.50%, as shown on Schedule ACC-7.

2

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

4 5.14% + (0.89 X 4.9%) = 9.50%

5

6 **Q. Based on your analysis of the DCF and CAPM results, what cost of equity are you**

7 **recommending in this case?**

8 A. The DCF methodology and the CAPM methodology suggest that a return on equity of 9.50 %

9 to 9.62% would be appropriate. Since I recognize that the Commission has generally relied

10 primarily upon the DCF, I have weighted my results with a 75% weighting for the DCF

11 methodology and a 25% weighting for the CAPM methodology. This results in a cost of

12 equity of 9.59%, as shown below:

13	DCF Result	9.62% X 75% =	7.22%
14	CAPM	9.50% X 25% =	2.38%
15	Total		9.59%

16 **Q. Why is your recommendation substantially lower than the cost of equity recommended**

17 **by Dr. Hadaway?**

18 A. My recommendation is substantially lower than Dr. Hadaway's primarily because he used

19 unrealistic growth projections. In addition, he discarded his primary DCF result on the basis

20 that the result was too low, ignoring completely in his analysis the constant state, DCF model

21 that utilized utility earnings projections as the growth rate.

1 Dr. Hadaway calculated three DCF results. His first DCF model used a constant
2 growth that was developed by averaging four different growth rates: 1) Value Line earnings
3 projections, 2) Zack's earnings projections, 3) a sustainable growth ("b" times "r") estimate
4 based on Value Line's projected retention rates and rates for return, and 4) a long-term
5 estimate of nominal growth in Gross Domestic Product ("GDP"). His second DCF result
6 used only the GDP growth rate. The third DCF model was a two-stage approach using Value
7 Line earnings projections in stage one and projected GDP growth in stage two.

8 It is interesting to note that Dr. Hadaway's more traditional constant state model
9 yielded a cost of equity of 9.3% to 9.5%, below my DCF result of 9.62%, even though 25%
10 of his model's growth rate was based on long-term GDP. It was only by making the
11 unrealistic long-term GDP growth rate the primary growth indicator in the other two versions
12 of the DCF model that Dr. Hadaway was able to increase the Company's cost of equity
13 claim.

14 Dr. Hadaway claims that the long-term GDP "is the most general measure of
15 economic growth in the U.S. economy."[4] While it may be true that GDP is the most general
16 measure of economic growth in the U.S. economy, it does not follow that GDP is an
17 appropriate rate to utilize for utility dividends in a DCF model. Moreover, Dr. Hadaway
18 used a GDP growth rate of 6.6%, which he developed by averaging historic GDP growth
19 over 10, 20, 30, 40, 50, and 58 years. However, as shown on Schedule SCH-5 to Dr.

4 Testimony of Dr. Hadaway, page 33.

1 Hadaway's testimony, the ten-year average of 5.4% and the twenty-year average of 5.7% are
2 both well below the growth rates of over 7.0% that occurred in the remaining periods
3 reviewed. Thus, his long-term result relied heavily upon GDP in the period from 1971 to
4 1984, a period of significant growth. Given that the Company will be filing its next rate case
5 at the latest in 2009, the use of a GDP growth rate that is heavily dependent upon high
6 growth rates from 1971 to 1984 is particularly inappropriate. There is no evidence that GDP
7 growth is the appropriate growth rate to use for utility dividends and this is especially true of
8 GDP growth from thirty years ago.

9 With regard to his risk premium models, Dr. Hadaway used a forecasted triple-B
10 utility bond rate. While GPE is currently rated triple-B, that rating is significantly impacted
11 by GPE's more risky, unregulated operations. Thus, it is more appropriate to utilize the long-
12 term government bond rate in the risk premium analysis, as I have done, along with the
13 appropriate risk premiums based on the geometric mean returns.

14 Finally, it should be noted that, in spite of all the flaws in Dr. Hadaway's analysis, his
15 recommended comparable group cost of equity recommendation is only 10.75%. An
16 additional 50 basis points have been added to the cost of equity recommendation. KCPL
17 claims that it deserves this cost of equity bonus in order to compensate the Company for its
18 "considerably higher construction risks." [5] However, any additional risk accruing to the
19 Company as a result of its construction program was addressed through the Regulatory Plan

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

1 approved by the KCC in 2004. Staff and the Company negotiated a Regulatory Plan in
2 order to minimize the risk associated with the long-term construction projects proposed by
3 KCPL. The parties worked for one year to develop a Regulatory Plan that was ultimately
4 approved by the KCC. That Regulatory Plan should have mitigated the need for a further
5 return on equity bonus associated with risk during project construction.

6 That plan included a CIAC regulatory mechanism to maintain the Company's cash
7 flow at investment grade levels during construction. One has to ask how many times the
8 Company plans to use its construction projects as an excuse to further bend the regulatory
9 process? Although CURB was not a signatory to the Stipulation that resulted in the
10 Regulatory Plan, the Company and Staff were parties to that Regulatory Plan. Pursuant to
11 the Regulatory Plan, any cash flow shortfalls resulting from the use of an appropriate return
12 on equity were supposed to be made up through the use of the CIAC mechanism. In fact,
13 KCPL has included an additional CIAC increase of $12.84 million in this case. Therefore,
14 the Company's request for a return on equity bonus associated with construction risk is
15 unnecessary and should be denied. Allowing the Company to charge ratepayers a return on
16 equity premium for construction risk while at the same time charging ratepayers a CIAC
17 surcharge to meet cash flow requirements would clearly constitute double-dipping.

18

19

20

21

1 **D. Overall Cost of Capital**

2 **Q. What is the overall cost of capital that you are recommending for KCPL?**

3 A. As shown on Schedule ACC-2, I am recommending an overall cost of capital for KCPL of

4 7.90 %.

5

6 **V. RATE BASE ISSUES**

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

8 **proceeding?**

9 A. The Company selected the test year ending December 31, 2006. In addition, the Company

10 made various post-test year adjustments through September 30, 2007.

11

12 **A. Utility Plant In Service**

13 **Q. Are you recommending any adjustment to the Company's claim for utility plant in**

14 **service?**

15 A. Yes, I am recommending one adjustment to the Company's claim. Specifically, I am

16 recommending an adjustment relating to the Company's claim for wind generation.

17

18 **Q. Please describe the Company's claim for wind generation.**

19 A. In the Company's last case, it included a post-test year adjustment of $166 million (excluding

20 AFUDC) related to the addition of a 100 MW wind generation facility. This project was

21 included in the Regulatory Plan at a projected cost of $130.8 million. In the last rate case,

CURB argued that the amount of wind generation included in rate base should be limited to the Company's capital costs approved in the Regulatory Plan, i.e., $130.8 million (excluding AFUDC). CURB's adjustment was based on the significant increase in capital costs relative to the approved Regulatory Plan and on the questionable capacity factor being used by the Company to support its decision to build wind generation. In that case, Staff also questioned the reasonableness of the capacity factor being used to support the Company's decision to build this wind generation plant. In the Stipulation in the last case, the parties agreed that "...Staff reserves the right to propose the same or similar performance mechanism in the next rate case as it did in this case." [6]

Q. Are you proposing any disallowance of capital costs associated with wind generation in this case?

A. Yes, I am. In this case, I am making the same recommendation that I made in the Company's last base rate case, i.e., I recommend that the KCC limit recovery of the capital costs associated with wind generation to the amount contained in the Regulatory Plan. As I noted in my testimony in last year's case, I am fully supportive of renewable energy initiatives. However, such initiatives should provide a balance between policies promoting renewable energy and the resulting financial burden placed on ratepayers. Moreover, the KCC approved the Company's proposal to build its own wind generation based on various cost assumptions as part of an overall Regulatory Plan. The Company should have some

[6] Settlement Agreement in Docket No. 06-KCPE-828-RTS, page 6.

1 obligation to ensure that the assumptions presented to the KCC were accurate, since it was
2 these assumptions that the KCC relied upon in deciding whether or not to approve the plan.
3 To the extent that certain assumptions on which the Regulatory Plan was based were not
4 accurate, KCPL's shareholders should bear at least a portion of that risk.

5 It is especially reasonable to require shareholders, rather than ratepayers, to bear at
6 least some of the risk because the Company did not fully explore its options with regard to
7 wind generation. KCPL failed to issue a Request for Proposal for a long-term purchased
8 power agreement associated with wind facilities, but rather decided that it was more efficient
9 to build wind generation itself. We now know that the decision to build wind generation was
10 based on flawed assumptions. Therefore, it is impossible to conclude that KCPL's decision
11 to build and own the wind generation was the best option for the Company and its ratepayers,
12 particularly given the other major construction projects being undertaken by KCPL. Thus, at
13 this point, the KCC has no way of knowing if less expensive options were available to
14 KCPL.
15

16 **Q. Hasn't the Company stated that in spite of the higher cost, the decision to build wind**
17 **generation still makes good economic sense?**

18 A. Yes, it has. In last year's case, KCPL stated it had increased its projected wind capacity
19 factor, resulting in a finding that building wind generation was an economic supply
20 alternative. However, the Company's actual wind generation capacity factor has consistently
21 been below the capacity factor projected by KCPL. This is not surprising. I pointed out in

1 last year's case that the new projected capacity factor was high relative to many other wind
2 projects.[7] Therefore, given the significant increase in capital costs and the actual capacity
3 factor, it is likely that the wind project will be much more expensive over its life than what
4 was projected by the Company in the Regulatory Plan.
5
6 **Q. Since the last case, are there other factors that have increased your concerns regarding**
7 **the wind generation?**
8 A. Yes, there are. The Regulatory Plan was essentially an integrated Company plan, in that it
9 set out to address supply issues in both Missouri and Kansas. It was on this basis that the
10 Regulatory Plan was "sold" to regulators. Capital projects included in the Regulatory Plan
11 totaled $1.23 billion. It should be noted that the Regulatory Plan was meant to be
12 incremental to the capital expenditures that would normally be made by KCPL. Thus, as
13 pointed out during the cross-examination of Mr. Giles in the last case, over the five-year life
14 of the plan, total capital expenditures were projected to be approximately $2 billion.[8]

15 Q. Just for clarity too, what we talk about in this plan is the resource plan, this is
16 about $1.2 billion of expenditures over a 5-, 6-year period roughly, correct?
17
18 A. Correct.
19
20 Q. But just to be clear, $1.2 billion is not all of KCPL's capital expenditures
21 over this period, correct?
22
23 A. That's true.
24

[7] The specific projected capacity factor is confidential but can be found on page 5 of Mr. Grimwade's testimony in Docket No. 06-KCPE-828-RTS.

[8] Docket No. 06-KCPE-828-RTS, June 17, 2005, pages 42-43.

Q. These are just -- these are the incremental, over and above what KCPL would normally spend?

A. That's right.

Q. So just what is over this 5-year period, if it's not the $1.2 billion that is going to get spent, what is the right number?

A. We -- our capital budget runs excluding nuclear fuel about 140 to 150 million per year.

Q. That would be another 7 to 800 million in capital expenditures over the period?

A. That's correct.

Q. So you're actually talking about $2 billion worth of capital expenditures over the term of this regulator (sic) plan is probably a more accurate description?

A. That's true.

According to the testimony of Mr. Cline in this case, total capital expenditures, including expenditures associated with the Regulatory Plan and normal, on-going capital expenditures, are now expected "to exceed $2.5 billion" over the 2007-2011 timeframe. This represents a substantial increase over the amounts included in the five-year Regulatory Plan. Additional costs will undoubtedly result from a recent Settlement Agreement entered into by KCPL, the Sierra Club, and Concerned Citizens of Platte County ("CCPC"). According to the Press Release announcing the Settlement Agreement,

> The most significant element of the agreement is the unprecedented commitment by KCP&L to pursue the offset of carbon emissions from its proposed Iatan 2 generating station, located near Weston, Missouri. The estimated 6,000,000 tons of annual carbon dioxide emissions are targeted to be offset by adding 400 megawatts (MW)

> of wind power; 300 MW of energy efficiency; and a yet to be determined combination of wind, efficiency, or the closing, altering, re-powering or efficiency improvements at any of its generating units.

The recent Missouri Settlement Agreement with the Sierra Club and CCPC will not only increase costs over what they would otherwise have been, but the Settlement also calls into question whether the 2004 Regulatory Plan was the most appropriate plan for KCPL, given the additional commitments that it has now made in the Missouri Settlement Agreement. According to KCPL, it "has not yet quantified the operating or capital costs potentially associated with the collaboration agreement."[9] Thus, the Settlement Agreement raises new issues that are not yet resolved by the Company, but which very may well impact on both future rates and the appropriateness of the Regulatory Plan already committed to by the Company and approved by the KCC. All of these uncertainties are magnified by the fact that the Company has an incentive to build its own facilities rather than acquiring generation through purchased power agreements.

Q. Why do utilities have an incentive to own their own facilities rather than acquiring generation through purchased power agreements?

A. There are only two ways that shareholders can increase their authorized operating income returns in a regulated environment. The first is to increase the return on equity awarded by a

[9] Response to CURB-114S.

1 regulatory agency. The second is to increase the rate base upon which that return is earned.
2 Therefore, utilities have a financial incentive to own their own facilities rather than
3 purchasing power through long-term agreements.
4
5 **Q. Given your concerns regarding the Company's Regulatory Plan and the wind**
6 **generation in particular, what do you recommend?**
7 A. Given the significant increase in capital costs, the excessive capacity factor used by the
8 Company to support its decision to build wind generation, the likelihood of continued cost
9 increases, and the uncertainty surrounding the Settlement Agreement with the Sierra Club
10 and CCPC, I continue to recommend that the KCC limit the Company's capital costs
11 associated with wind generation to the costs approved in the Regulatory Plan, i.e., $130.8
12 million (excluding AFUDC). It was the Company's decision not to evaluate the potential for
13 a purchased power agreement, which could have been less costly than building the wind
14 facility on its own. Therefore, Company's shareholders should absorb any additional costs
15 resulting from that decision. My adjustment is shown in Schedule ACC-10.
16
17 **B. Accumulated Depreciation**
18 **Q. How did the Company develop its claim for accumulated depreciation?**
19 A. The Company's claim for accumulated depreciation is based on its balance at December 31,
20 2006, adjusted to reflect additions to the depreciation reserve through September 30, 2007.
21 The Company developed its post-test year adjustment by including nine months of the

1 December 2006 provision for depreciation. In addition, the Company made a separate
2 adjustment to reflect post-test year depreciation reserve additions associated with the
3 LaCygne SCR.
4
5 **Q. Do you believe that the Company's methodology is reasonable?**
6 A. No, I do not. KCPL has included significant post-test year capital additions in its rate base
7 claim. While the Company has included depreciation expense associated with these
8 additions in its depreciation expense claim, its depreciation reserve adjustment does not
9 include any depreciation on these post-test year additions, except for the LaCygne SCR.
10 Therefore, the Company's claim for post-test year adjustments to its reserve for depreciation
11 is understated.
12
13 **Q. What do you recommend?**
14 A. I recommend an adjustment to reflect additions to the depreciation reserve that include
15 depreciation on all post-test year plant additions. In developing my adjustment, I assumed
16 that all post-test year plant additions, with the exception of the LaCygne SCR, will be added
17 proportionately throughout the nine-month period between January 1, 2007 and September
18 30, 2007. Assuming total additions over this period of $132.8 million, excluding the
19 LaCygne SCR, the average incremental plant would be ½ of this amount, of which
20 approximately $29.8 million would be the Kansas jurisdictional share. I then calculated nine
21 months of additional depreciation expense on this average plant balance, using a composite

depreciation rate. My adjustment is shown in Schedule ACC-11. I have not made any adjustments to the depreciation reserve adjustment included in the Company's filing relating to the LaCygne SCR.

C. Cash Working Capital

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

A. KCPL has included a cash working capital claim of ($16,662,634). 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. KCPL included cash working capital associated with its pension costs in its cash working capital claim, based on an expense lag of zero days. I am recommending that the Company's cash working capital claim associated with pension costs be eliminated.

Q. How are pension costs reflected in rates pursuant to the Regulatory Plans?

A. As noted in the response to KCC-167, the Regulatory Plan outlined the ratemaking treatment that would be used to account for the Company's pension expense during the construction

1 period covered by the Regulatory Plan. The KCC approved a ratemaking treatment for
2 pension costs that included the establishment of two regulatory assets, "Prior Net Prepaid
3 Pension Asset", which I will refer to as the Prepaid Pension Asset, and the Pension
4 Regulatory Asset. The Prepaid Pension Asset tracks the difference between the Company's
5 Financial Accounting Standard ("FAS") 87 pension expense and the amounts contributed to
6 the pension trust. The Pension Regulatory Asset tracks the difference between the FAS 87
7 pension expense as determined for ratemaking purposes and the amount of pension expense
8 collected from ratepayers. Both of these regulatory assets are included in rate base. Given
9 this prescribed regulatory treatment, I do not believe that an additional cash working capital
10 allowance associated with pension expense is either necessary or rational.
11
12 **Q. Does the Company's pension expense generate a cash working capital requirement?**
13 A. No, it does not. It is important to keep in mind that the purpose of a cash working capital
14 adjustment is to compensate a utility for the amount of cash that is required in order to cover
15 cash outflows between the time that expenses must be paid and the time that revenues are
16 received from customers. For example, if a utility pays its employees weekly but bills its
17 customers monthly, there will be a lag between when expenses must be paid and when the
18 corresponding revenue is received. This lag creates a cash working capital requirement that
19 must be funded by investors. Thus, only cash expenses should be included in a cash working
20 capital allowance.
21

1

2 **Q. Do companies always have a positive cash working capital requirement?**

3 A. No, they do not. There are some costs that are generally recovered from ratepayers in
4 advance of being paid out by the Company, such as interest expense. The need for cash
5 working capital will also depend on whether or not a company sells its receivables, as is the
6 case here. KCPL's claim in this case is a negative cash working capital claim, i.e., on
7 average, it receives revenues in advance of paying its bills. However, it has included a
8 positive cash working capital requirement for certain costs, including pension costs.

9

10 **Q. How did the Company determine its cash working capital claim associated with pension**
11 **costs?**

12 A. KCPL has used a net lag of 25.08 days for pension costs. This assumes that, on average,
13 revenues are received 25.08 days after the midpoint of the service period and that pension
14 costs are paid daily.

15

16 **Q. Do you agree with the Company's methodology?**

17 A. No, I do not. While pension costs may, at least theoretically, be accrued on a daily basis,
18 clearly the Company does not incur daily cash outlays relating to pension costs. The only
19 cash outlays incurred by KCPL are actual contributions to the pension fund, which do not
20 occur daily but rather occur very sporadically during the year. Thus, if the Company wanted
21 to determine a cash working capital allowance based on its pension expense, it should be

1 comparing the receipt of customer revenues against the very sporadic funding of the pension
2 trust. This would likely generate a negative cash working capital requirement. However, this
3 analysis is unnecessary since the KCC has already prescribed a special accounting treatment
4 for regulatory purposes.

5 In addition, the regulatory treatment that was adopted by the KCC in the Regulatory
6 Plan fully compensates the Company for amounts that are contributed to the pension plan,
7 since the Company is permitted to earn a return on the Prepaid Pension Asset. Thus,
8 including a cash working capital allowance on these costs results in a double-counting of
9 return to investors.

10

11 **Q. What do you recommend?**

12 A. I recommend that the KCC make an adjustment to eliminate the cash working capital
13 associated with pension costs included in the Company's claim. This allowance is
14 unnecessary, since the Company already earns a return on contributions made to the pension
15 fund in excess of its FAS 87 expenses. In addition, the Company's cash working capital
16 claim is based on an erroneous assumption about the cash outlays generated by pension
17 expense. My adjustment is shown in Schedule ACC-12.

18

19

20

21

1 **Q. Are you recommending any other adjustments to the Company's cash working capital**
2 **claim?**
3 A. Not at this time. However, it should be noted that the Company has included a cash
4 working capital requirement associated with fuel and purchased power costs. The
5 Company is seeking to establish an Energy Cost Adjustment ("ECA") clause in this case
6 to recover these costs on a dollar-for-dollar basis, with interest, from ratepayers. If the
7 Company's request for an ECA is accepted, then I recommend that the KCC eliminate
8 fuel and purchased power costs from the cash working capital calculation. The ECA is
9 typically based on two factors: estimated fuel and purchased power costs for a twelve-
10 month period, and an actual cost adjustment true-up factor. Therefore, in any given
11 month, there is likely to be either an under-recovery or over-recovery of fuel and
12 purchased power costs. Consequently, in any particular month, the revenue received by
13 KCPL may be reimbursing the Company for fuel and power purchased in the past, or it
14 may be providing funds for fuel and power that is still to be purchased in the future.
15 Because of the special nature of purchased fuel and purchased power adjustment
16 clauses, these costs are frequently excluded from the cash working capital calculation. This
17 is because it is very difficult at any point in time to determine if the Company is being
18 compensated for prior costs, current costs, or future costs. Since CURB is opposed to the
19 ECA, I am not recommending any cash working capital adjustment related to fuel and
20 purchased power costs. However, if an ECA is adopted by the KCC, then the Company's
21 cash working capital claim should be adjusted accordingly to eliminate fuel and purchased

1 power costs.

2

3 D. **Fossil Fuel Inventory**

4 **Q. How did the Company develop its claim for fossil fuel inventory?**

5 A. As described on page 39 of Mr. Blunk's testimony, inventory values for oil, lime and
6 limestone were calculated using the average inventory quantities for the 13-month period
7 ending December 2006, multiplied by the December 2006 per-unit value.[10] Coal inventory
8 was determined based on a Utility Fuel Inventory Model ("UFIM") that attempts to identify
9 the level of inventory resulting in the lowest expected overall cost.

10

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

12 A. Yes, I am. I am recommending an adjustment to the quantity of coal inventory. The
13 Company's quantity of coal in inventory is based on a theoretical model, not on actual results
14 during the test year. However, as discussed in the Company's testimony, coal supplies have
15 been impacted by rail disruptions, speculative traders, and clean air regulations. Therefore,
16 it is entirely possible that in any given year the Company may not meet its targeted coal
17 inventory projections. The targeted coal inventory levels being claimed in this case are
18 significantly above the actual inventory levels during the test year. Accordingly, the
19 Company's inventory claim for coal inventory, which is based on modeling rather than on

[10] Mr. Blunk's testimony actually states that September, rather than December, values were used. However, the workpapers to Adj. 51 indicate that the December amounts were used in the filing. I believe that Mr. Blunk's testimony contains a typographical error, and that the reference to September has been carried over from the last case.

1 actual results, appears to be overstated.

2

3 **Q. What do you recommend?**

4 A. I recommend basing the coal inventory level on the average balance for the thirteen months
5 ending December 2006. This methodology is consistent with the methodology used by
6 KCPL for other types of fuel inventory. This methodology is especially reasonable in this
7 case, since the Company will be filing another base rate case in two years, and perhaps even
8 sooner, and coal inventory levels can be updated at that time, if necessary. My adjustment is
9 shown in Schedule ACC-13.

10

11 **Q. Are you recommending any adjustment to the unit price for coal included in the**
12 **Company's inventory claim?**

13 A. No, I am not. According to page 17 of Mr. Grimwade's testimony, the Company has
14 contractual commitments for all of its expected coal requirements for 2007. Therefore, I
15 have not made any adjustment to the per unit cost included in the Company's claim.

16

17 **E. <u>FAS 87 Pension Assets</u>**

18 **Q. Are you recommending any adjustments to the Prepaid Pension Asset or Regulatory**
19 **Asset included by the Company in rate base?**

20 A. Yes, I am. In its filing, the Company included 100% of the projected deferrals in rate base.
21 However, when calculating the corresponding amortization expense, the Company

1 recognized that a portion of these costs, specifically 6.41%, would be allocated to the Joint
2 Partners. There is no reason why ratepayers should be paying a return on deferrals relating to
3 costs incurred on behalf of the Joint Partners.

4 In the response to CURB-117, the Company stated that "[t]he rationale for the joint
5 partner's portion was that the entire amount would be included in rate base until the
6 regulatory asset was amortized to help ensure that each party was kept whole over the course
7 of the rate process. It has since been agreed that the joint partner portion would be excluded
8 from rate base." Thus, at Schedule ACC-14, I have made adjustments to reduce the
9 Company's Prepaid Pension Asset and its Pension Regulatory Asset by the allocations to the
10 Joint Partners.

11

12 **F. FAS 88 Regulatory Asset**

13 **Q. Are you recommending any adjustments to the Company's claim for the FAS 88**
14 **Regulatory Asset?**

15 A. Yes, I am recommending two adjustments. First, similar to the above discussion with regard
16 to the Period Prepaid Pension Asset and Pension Regulatory Asset, the Company has
17 included 100% of its FAS 88 deferral in rate base. Therefore, I am recommending an
18 adjustment to reduce the deferral by the amount allocated to the Joint Partners. This
19 adjustment is shown in Schedule ACC-15.

20 In addition, the deferral included in the Company's claim contained estimated costs
21 of $2,585,000 related to Wolf Creek. In response to CURB-95, the Company indicated that

1 the actual Wolf Creek cost was only $1,486,140. Therefore, at Schedule ACC-15, I have
2 also made an adjustment to update the Company's FAS 88 regulatory asset to reflect the
3 actual Wolf Creek costs.
4
5 **Q. Do you have any additional comments regarding the various regulatory assets included**
6 **in rate base relating to the Prepaid Pension Asset, the Pension Regulatory Asset, and**
7 **the FAS 88 Regulatory Asset?**
8 A. Yes, I do. In my testimony in Docket No. 06-KCPE-828-RTS at pages 35-38, which I
9 incorporate herein by reference, I expressed my theoretical objection to including any
10 pension assets in rate base. However, as also stated in that testimony, I have attempted to
11 comply with the provisions of the Regulatory Plan to the greatest extent possible, in spite of
12 the fact that CURB was not a party to the Stipulation that resulted in the Regulatory Plan.
13 Therefore, I have utilized the pension methodology outlined in the Regulatory Plan in
14 developing my revenue requirement recommendations in this case, just as I did in last year's
15 case. Moreover, I do recognize that the Company is in a significant construction period and
16 that the KCC has agreed to abandon many of the traditional regulatory principles in setting
17 rates for KCPL during this period. Therefore, I have included both the Period Prepaid
18 Pension Asset and the Pension Regulatory Asset in my rate base calculation. It should be
19 noted, however, that the Regulatory Plan permits the parties to propose a different
20 methodology for pension costs in the first KCPL rate case proceeding after 2010. Therefore,
21 I view the pension methodology outlined in the Regulatory Plan as a temporary measure to

1 provide the Company with further cash flow during the construction cycle. My use of this
2 methodology should not be interpreted as agreement with this methodology, but only the
3 temporary acceptance of a poor regulatory practice during extraordinary times.[11]
4
5 **G. Demand Side Management ("DSM") Regulatory Asset**

6 **Q. Please explain the Company's claim associated with the DSM Regulatory Asset.**

7 A. The Regulatory Plan addressed a number of Demand Response, Efficiency and Affordability
8 programs to be undertaken by the Company over the next several years. Pursuant to the
9 Regulatory Plan, "KCPL will accumulate costs for these programs in regulatory asset
10 accounts as the costs are incurred through the next base rate case. The amortization of these
11 costs and return will be determined in the next rate case."
12
13 **Q. Did the Regulatory Plan provide for rate base treatment of the unamortized DSM**
14 **costs?**

15 A. No, the Regulatory Plan did not state that the unamortized balance would be included in rate
16 base. Rather it stated that the "amortization...and return" would be addressed in a
17 subsequent case. In this filing, the Company has included a DSM Regulatory Asset of
18 $4,717,535. It proposed to amortize this asset over a period of ten years.
19
20

[11] My concerns about reimbursement ratemaking also extend to other aspects of the Company's claim, such as

1 **Q. Are you recommending an adjustment to the Company's claim for the DSM Regulatory**
2 **Asset?**
3 A. Yes, I am recommending that the unamortized balance be excluded from rate base. Rate
4 base treatment for these costs was not specifically permitted pursuant to the Regulatory Plan.
5 In addition, the Stipulation in the Company's last case does not address these costs. The
6 Company is already being granted special ratemaking treatment for these costs by being
7 permitted to defer them and to eventually recover them on a dollar-for-dollar basis, with no
8 risk of under-recovery to shareholders. Accordingly, I recommend that rate base treatment
9 for these costs be denied. My adjustment is shown in Schedule ACC-16.
10
11 **H. Summary of Rate Base Issues**
12 **Q. What is the impact of all of your rate base adjustments?**
13 A. My recommended adjustments reduce the Company's rate base claim from $1,107,821,373,
14 as reflected in its filing, to $1,079,691,945, as summarized on Schedule ACC-9.
15
16 **VII. OPERATING INCOME ISSUES**
17 **A. Pro Forma Revenues**
18 **Q. Are you recommending any adjustments to the Company's pro forma revenue claim?**
19 A. Yes, I am recommending an adjustment to the Company's pro forma revenue claim relating
20 to off-system sales.

DSM costs, but I will not repeat my argument in other areas of my testimony.

1 **Q. Was the treatment of off-system sales margins addressed in the Regulatory Plan?**

2 A. Yes, it was. Appendix C, Section C of the Regulatory Plan states as follows:

> 3 The parties also agree that profits from off-system sales should
> 4 continue to be included above-the-line in the regulatory process
> 5 during the term of the Five-Year Regulatory Plan. KCPL specifically
> 6 agrees not to propose any adjustment or modification that would
> 7 remove any portion of its off-system sales costs and revenues
> 8 from being passed through the ECA mechanism. The specific
> 9 details of the ECA mechanism will be determined in
> 10 the 2006 rate proceeding.

11

12 KCPL did not propose an ECA mechanism in the filing it made in last year's case.
13 Instead, in that case, the Company proposed that fuel and purchased power costs, as well as
14 off-system sales revenues, be included in base rates. In the Stipulation in that case, the
15 parties agreed that,

> 16 Staff agrees to abandon its ECA recommendations in this case,
> 17 and KCPL agrees it shall propose an ECA mechanism, including
> 18 a proposed ECA tariff, in its next rate filing that will be filed no
> 19 later than March 1, 2007. Prior to March 1, 2007, the signatory
> 20 parties agree that they shall meet and discuss the specifics
> 21 of the ECA mechanism in order to attempt to reach a compromise
> 22 on the issue. Nothing in this section shall be interpreted to mean
> 23 that the signatory parties must accept without objection any ECA
> 24 mechanism proposed in KCPL's next rate filing or preclude any
> 25 party from presenting alternative mechanisms.

26

27 In this case, KCPL has proposed an ECA, which is discussed in greater detail in Section IX
28 of this testimony. While the requested revenue requirement increase of $34.22 million is
29 based on a traditional revenue requirement analysis that includes both fuel and purchased
30 power costs as well as projected off-system sales revenues, the Company's rate design
31 proposes to transfer these revenue and cost components into an ECA.

1 **Q. How did the Company determine the amount of off-system sales margins to include in**
2 **its revenue requirement claim and ultimately, as an offset to the ECA?**
3 A. In order to determine the most probable amount of off-system sales revenue that would be
4 received by the Company, KCPL engaged Northbridge Group, Inc. ("Northbridge") to
5 conduct a detailed risk analysis of the off-system sales market. This analysis considered
6 factors such as market price, volumetric risk associated with generation, variable cost,
7 generation unit outages, coal supply availability, weather, and uncertainty of retail sales
8 growth. Northridge developed a most-probable level of off-system sales margin, the details
9 of which are confidential.
10 In preparing the revenue requirement in this case, KCPL included off-system sales
11 margins at the 25th percentile. Based on the model, there is a 75% chance that actual off-
12 system sales margins will exceed this amount, and a 25% chance that actual off-system sales
13 margins will fall short of this amount. This is also the amount that was transferred in the rate
14 design process to the ECA.
15
16 **Q. Are you recommending an adjustment to the Company's claim?**
17 A. Yes, I am recommending that the Company's claim be adjusted to include the amount of off-
18 system sales revenues that is <u>most probable</u> to occur. As discussed later in this testimony,
19 CURB is opposing the Company's proposal to implement an ECA. Therefore, it is important
20 that base rates reflect realistic projections of fuel and purchased power expense, as well as
21 off-system sales. This would equate to the best estimate, or most-probable amount of off-

system sales, based on the detailed analysis conducted by Northbridge.

Regulatory commissions establish utility rates based on pro forma financial information, which includes normalized sales based on expected operating conditions. The same is true of expenses to the extent that regulatory commissions permit pro forma expense adjustments, i.e., regulatory commissions include pro forma adjustments that represent the most-probable or expected scenario. Regulatory commissions do not set revenues artificially low or expenses artificially high in order to guarantee that a utility will earn its authorized return, but only provide for a reasonable opportunity for the utility to earn its authorized return.

In this case, KCPL has a 75% chance of earning off-system sales margins that are higher than those reflected in utility rates. Accordingly, shareholders have a 75% chance of benefiting from these additional margins. This lopsided proposal should be rejected by the KCC in favor of a more balanced approach that reflects the most-probable outcome for off-system sales margins.

The Company's proposal is not balanced, in that there is a 75% chance that off-system sales margins will provide additional earnings to shareholders, and a 25% chance that shareholders will need to absorb additional costs. However, the Company's proposal also means that there is a 75% chance that ratepayers will not receive all of the benefits due to them pursuant to the Regulatory Plan, assuming that the ECA is rejected as recommended by CURB. Accordingly, I recommend that if the ECA is rejected, then off-system sales should be included in the revenue requirement calculation based on the 50th percentile, which

1 reflects the most-probable amount of off-system sales margins to be received by KCPL.

2

3 **B. Payroll Expense**

4 **Q. How did the Company develop its payroll claim in this case?**

5 A. KCPL's claim is based on the number of budgeted employees for KCPL and GPE[12] in 2007.
6 In developing its claim, the Company annualized payroll increases expected to occur by
7 September 30, 2007. In addition to payroll costs, the Company also made adjustments to
8 include overtime costs, severance costs, and incentive payments in its claim.

9

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

11 A. Yes, I am recommending one adjustment relating to employee vacancies. The Company's
12 claim assumes a full complement of budgeted employees. However, as shown in the
13 Company's Manpower Reports, KCPL/GPE have consistently had a large number of vacant
14 positions. According to the reports provided in response to CURB-21, the Company has
15 consistently had vacancies at any given time over the past three years, as one would expect in
16 a company of this size.

17 It is normal and customary for companies to have unfilled positions at any given time
18 as a result of terminations, transfers, and retirements. If utility rates are set based on a full
19 complement of employees, and if these employee positions remain vacant, then ratepayers
20 will have paid rates that are higher than necessary, to the benefit of shareholders. Therefore,

[12] Approximately 68% of GPE's costs are allocated to KCPL.

1 when setting rates, I recommend that the KCC consider the fact that, at any given time,
2 positions are likely to be vacant.
3
4 **Q. How did you quantify your adjustment?**
5 A. My adjustment is based on the average percentage of vacant positions for each month during
6 2006, the test year in this case. Based on the reports provided in response to CURB-21, I
7 calculated that, on average, 2.14% of the Company's positions were vacant during 2006.
8 Therefore, I reduced the Company's pro forma payroll expense claim by 2.14% to eliminate
9 payroll costs associated with vacant positions. The actual level of vacancies in the test year,
10 2.14%, is generally consistent with the three-year average of 2.08% vacancies experienced by
11 KCPL from 2004 to 2006.
12 I then reduced my recommended adjustment to eliminate the portion of payroll costs
13 that is billed to the Joint Partners, as well as the portion of payroll costs that is capitalized.
14 Finally, I applied the Kansas-jurisdictional allocator to determine the amount of the
15 adjustment allocated to Kansas. My adjustment is shown in Schedule ACC-19.
16
17 **Q. Have you also made an adjustment to the Company's payroll tax expense claim?**
18 A. Yes, I have made an adjustment to eliminate the payroll taxes associated with my payroll
19 adjustment relating to vacant positions. To quantify this adjustment, I utilized the statutory
20 Social Security and Medicare tax rate of 7.65%. This payroll tax adjustment is shown in
21 Schedule ACC-20.

1 **C. Talent Assessment Costs**

2 **Q. What are talent assessment costs?**

3 A. Talent assessment costs are severance and outplacement costs incurred by KCPL relating to a
4 major employee termination program undertaken by KCPL. The Company has included a
5 five-year amortization of total costs of $9,347,021incurred during 2006 in its claim. These
6 costs consist of $8,038,555 in severance costs, $658,179 in outplacement costs, and
7 $650,287 in payroll taxes.

8

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

10 A. Yes, I am recommending that the Company's claim for recovery of these costs be denied.
11 These costs are clearly non-recurring costs, as acknowledged by the Company. As stated on
12 page 27 of Mr. Weisensee's Testimony, "...the severance payments for employees not
13 retained...., and related outplacement costs, are not representative of a 'normal' severance
14 cost level." Moreover, it appears that KCPL has already expensed these costs on its books
15 and records of account, and should not now be allowed to receive retroactive recovery of
16 these costs. KCPL is also requesting a significant increase in employee positions in this case
17 relative to test year levels. While I made an adjustment to eliminate a pro forma level of
18 vacant positions from the Company's revenue requirement, I did not make any adjustment to
19 its claim for new 2007 positions. Thus, ratepayers should not be asked to fund additional
20 new positions at the same time they are being asked to fund severance costs for positions that
21 the Company did not need in the past and will not need in the future. For all these reasons, I

1 recommend that the Company's claim for talent assessment costs be denied. My adjustment
2 is shown in Schedule ACC-21.
3
4 **Q. Didn't the KCC permit the recovery of some talent assessment costs in the last case?**
5 A. Yes, it did. The Stipulation in the last case stated that KCPL was authorized "to establish a
6 regulatory asset for the Talent Assessment expenses in the amount of $516,316 (Kansas
7 jurisdictional $216,771). KCPL is authorized to amortize this regulatory asset over ten (10)
8 years commencing January 1, 2007. The deferred expenses will not receive any rate base
9 treatment in future cases." The Stipulation does not state that the Company may continue to
10 defer these costs, and in fact it appears from the Company's workpapers that 2006 costs were
11 not deferred but instead were expensed by the Company. Moreover, the Company's claim
12 for a five-year amortization for 2006 costs is inconsistent with the terms of the Stipulation
13 that provided for a ten-year deferral for 2005 costs. It should be noted that I have not made
14 any adjustment to the Company's claim for the amortization expense associated with the
15 2005 costs that was approved as part of the Stipulation in the last case. However, the
16 Stipulation did not approve a continued deferral for these costs. Moreover, they were
17 apparently not deferred during the test year. Finally, they represent non-recurring costs and
18 should be eliminated from the Company's prospective revenue requirement.
19
20
21

1 **D. Medical Benefits Expense**

2 **Q. How did the Company determine its medical benefits expense claim in this case?**

3 A. KCPL included a 2007 projected cost of $17,376,990 in its claim. This claim reflects an
4 increase of almost 20% over the actual test year costs of $14,547,805. The Company is self-
5 insured for a large portion of its medical claim liability. Therefore, to a large extent, actual
6 costs will depend upon the level of services required in any given year and the unit cost of
7 those services. The fact that the Company is self-insured makes it more difficult to
8 accurately predict the amount of medical benefits expense to be incurred in any given period.
9

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

11 A. Yes, I am. Since the Company is largely self-insured, the projected costs included by KCPL
12 in its claim are speculative and do not represent known and measurable changes to the test
13 year. Therefore, I recommend that the KCC utilize the most recent twelve months of actual
14 costs in order to determine pro forma medical costs in this case. In the response to KCC-312,
15 the Company indicated that the actual medical costs for the twelve months ending May 31,
16 2007 were $15,794,691. Therefore, at Schedule ACC-22, I have made an adjustment to
17 include these actual medical costs in the Company's claim.
18
19
20
21

1 **E. Employee Benefits - 401 K Expense**

2 **Q. Are you recommending any adjustment to the Company's claim for costs associated**
3 **with its 401K contributions?**

4 A. Yes, I am. In its filing, KCPL included 401K costs, based on annualized payroll costs at
5 KCPL and GPE. The Company used a contribution rate of 2.167% for KCPL payroll and of
6 1.814% for GPE payroll. This equates to a composite contribution rate of approximately
7 2.15%.

8 Since I am recommending adjustments to the Company's payroll cost claim, it is
9 necessary to make corresponding adjustments to its claim for related 401K costs. Therefore,
10 I have reduced the Company's 401K cost claim to eliminate contributions related to the
11 payroll costs that I have disallowed. To quantify my adjustment, I applied the composite
12 401K contribution rate of 2.15% to my recommended adjustment related to vacant positions.
13 My adjustment is shown in Schedule ACC-23.

14

15 **F. Amortization of FAS 88 Costs**

16 **Q. How were FAS 88 costs addressed in the Stipulation in last year's case?**

17 A. In that Stipulation, the parties agreed that,

18 KCPL shall establish a regulatory asset or liability, with rate base
19 recognition, for the amount of pension costs, before amounts
20 capitalized and applicable to joint owners, determined pursuant to
21 FAS 88 and the level of FAS 88 pension cost built into rates
22 (currently $0), effective January 1, 2006. This regulatory asset
23 or liability will be amortized over five (5) years beginning
24 with the effective date of rates approved in KCPL's next rate case.
25

1
2 In this case, KCPL reflected a five-year amortization for deferred FAS 88, consistent with the
3 Stipulation.[13] The deferred costs that were the subject of the amortization included actual
4 costs for KCPL, including the GPE allocation, and a projected allocation from Wolf Creek.
5
6 **Q. Are you recommending an adjustment to the Company's claim?**
7 A. Yes, as discussed in the Rate Base Section of this testimony, KCPL has now updated its FAS
8 88 allocation from Wolf Creek. Therefore, at Schedule ACC-24, I have made an adjustment
9 to reflect a five-year amortization of the updated FAS 88 deferred costs, including the revised
10 allocation from Wolf Creek.
11
12 **G. <u>Amortization of DSM Costs</u>**
13 **Q. Please describe the Company's claim relating to the amortization of deferred DSM**
14 **costs.**
15 A. As discussed in the Rate Base section of this testimony, the Company has included in its rate
16 base claim estimated deferred costs relating to a number of Demand Response, Efficiency
17 and Affordability programs. KCPL is proposing to amortize these costs over a period of 10
18 years.
19 The Company's claim is based on projected deferred costs of $4,717,535 over ten
20 years, or $471,753 annually. Deferred costs include $2,292,746 in costs that were deferred

[13] In addition, as previously addressed, KCPL has agreed to exclude the Joint Partners allocation from rate base.

1 (on a Kansas jurisdictional basis) at December 31, 2006, and additional costs of $2,424,789
2 projected to be deferred during the first nine months of 2007.
3
4 **Q. Are you recommending an adjustment to the Company's claim?**
5 A. Yes, in addition to the rate base adjustment discussed earlier in this testimony, I am also
6 recommending that the Company's amortization expense adjustment be reduced to reflect
7 only an amortization for actual costs incurred through December 31, 2006, the end of the test
8 year. Pursuant to the Regulatory Plan, the Company is prohibited from implementing any
9 program prior to obtaining KCC approval for the specific program. Therefore, in order to
10 ensure that only approved DSM programs are included in rates, and in order to provide the
11 parties with adequate time for review, I recommend that recovery in this case be limited to
12 amounts deferred through the end of the test year. Additional deferrals can be reviewed in
13 the Company's next base rate case. My adjustment, which limits recovery to the
14 amortization of deferrals through December 31, 2006, is shown in Schedule ACC-25.
15
16 **Q. Have you made any other adjustment to the Company's claim?**
17 A. Yes. In addition to limiting the amortization to costs that were deferred as of December 31,
18 2006, I have also made an adjustment to eliminate internal labor costs that have been booked
19 to the deferral. The Company's operating expense claim already includes a full complement
20 of employees, based on the number of projected employees at September 30, 2007.
21 Permitting the Company to recover internal costs relating to DSM, as well as employee

payroll costs, would result in a double recovery of these costs. Unless the Company can demonstrate that there are incremental employees who will be solely dedicated to the DSM function, or that its pro forma payroll claim does not include these DSM-related labor costs, then internal labor costs should be excluded from the amortization. At Schedule ACC-25, I have made an adjustment to reduce the deferred balance at December 31, 2006 by the amount of internal labor costs booked to the deferral through the end of the test year.

H. Legal Costs - Surface Transportation Board ("STB") Complaint

Q. Please describe the Company's claim for costs related to the complaint filed by KCPL with the Surface Transportation Board.

A. As discussed on page 27 of Mr. Blunk's testimony, KCPL "filed a rate complaint case on October 12, 2005, with the Surface Transportation Board ("STB"). In that complaint, KCPL charged that Union Pacific Railroad's ("UP") rates for the movement of coal from origins in the Powder River Basin of Wyoming to KCPL's Montrose Generating Station were unreasonably high."

The Stipulation resolving last year's case stated that,

> The Commission authorizes KCPL to establish a regulatory asset for actual Surface Transportation Board expenses incurred through December 31, 2006. KCPL will amortize this regulatory asset over a five-year period beginning January 1, 2007. The Commission authorizes KCPL to establish a regulatory asset for actual Surface Transportation Board expenses incurred after December 31, 2006 to be amortized over a five-year period in a future rate case. The deferred expenses will not receive any rate base treatment in future rate cases.

In this case, KCPL has included a substantial increase in deferred costs for the period

1 January 1, 2007 through September 30, 2007. Its revenue requirement claim includes an
2 adjustment to amortize the projected September 30, 2007 balance over a five-year period.
3 The specific details of the Company's request are confidential.
4
5 **Q. Are you recommending an adjustment to the Company's claim?**
6 A. Yes, I am. I am recommending that the amortization be limited to actual costs incurred
7 through December 31, 2006, the end of the test year. In the response to KCC-96, the
8 Company provided an update of actual costs spent in 2007. While this information only
9 provided costs through March 31, 2007, this is the last update that I believe has been
10 provided in discovery. According to this response, the Company has spent very little on this
11 litigation in 2007 to date, and nowhere near the level projected in its filing. Given the
12 uncertainty with regard to the actual 2007 costs, and the fact that few costs were incurred in
13 2007 to date, I recommend that the Company's amortization be limited to the actual costs
14 incurred through December 31, 2006. The Company's claim simply does not meet the test
15 for a known and measurable change to the test year. My adjustment is shown in Schedule
16 ACC-26. Given the Stipulation in the last case, I would expect KCPL to continue to defer
17 any post-test year costs incurred with regard to this litigation and to seek recovery of those
18 costs in its next base rate case filing.
19
20
21

1 **I. Missouri Litigation Costs**

2 **Q. Please describe the Company's claim for legal fees associated with litigation in**
3 **Missouri.**

4 A. The Company's filing includes certain costs incurred in defense of a suit filed in Missouri
5 by the Sierra Club and others. This litigation involved an appeal of the decision by the
6 Missouri Department of Natural Resources ("MDNR"), which issued a permit to KCPL
7 related to Iatan 2. The parties eventually reached a settlement of this litigation.

8 There is no reason to require Kansas ratepayers to bear any of these Missouri-related
9 litigation costs. Moreover, the Settlement Agreement reached among the parties may have
10 negative consequences for Kansas ratepayers. This Settlement Agreement requires the
11 Company "to pursue the offset of carbon emissions from its proposed Iatan 2 generating
12 station, located near Weston, Missouri. The estimated 6,000,000 tons of annual carbon
13 dioxide emissions are targeted to be offset by adding 400 megawatts (MW) of wind power;
14 300 MW of energy efficiency; and a yet to be determined combination of wind, efficiency, or
15 the closing, altering, re-powering or efficiency improvements at any of its generating units."[14]
16 The Company has not quantified the costs of compliance with the Settlement Agreement.
17 Nor has the Company demonstrated that compliance with the provisions of the Settlement
18 Agreement is in the best interests of Kansas ratepayers, or is consistent with the Regulatory
19 Plan previously approved by the KCC. For all these reasons, the KCC should deny the
20 Company's request to recover these litigation costs from Kansas ratepayers. My adjustment

[14] Sierra Club Press Release, March 20, 2007.

1 to eliminate these costs is shown in Schedule ACC-27.

2

3 **J. Merger-Related Costs**

4 **Q. Does the Company's claim include any merger-related costs?**

5 A. Yes, it does. KCPL's claim includes $7,789 of merger-related costs. In response to a
6 discovery request in the Missouri case, KCPL acknowledged that "[i]n 2006, KCPL
7 incremental merger-related costs of $7,789.05 were not transferred to GPE and therefore
8 were inadvertently included in KCPL's test year cost of service."[15] These costs do not relate
9 to the provision of safe and adequate utility service in Kansas. Moreover, KCPL has
10 acknowledged that these costs should not have been included in its regulated revenue
11 requirement. Accordingly, the KCC should reduce the Company's claim to remove these
12 merger-related costs. At Schedule ACC-28, I have made an adjustment to eliminate these
13 costs from the Company's claim.

14

15 **K. Credit Card Costs**

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

17 A. In last year's filing, the Company included various adjustments relating to a credit card
18 program whereby customers would be able to pay their utility bills by credit card. In that
19 filing, the Company included both set-up charges and on-going transaction fees associated
20 with this program. The Company began implementing the program on February 1, 2007.

[15] Per the response to KCC-138.

1 Thus, the test year in this case does not include any recurring costs associated with credit
2 card payments.

3 With regard to transaction costs, the specific costs are based on the type of credit card
4 used. For VISA and Mastercard payments, KCPL is charged both a fixed cost per transaction
5 as well as a variable cost per transaction. The variable cost per transaction is based on the
6 average amount of the payment. These incremental costs will be offset by certain cost
7 savings to the Company, such as savings in lockbox payment fees and check clearing fees.
8 The Company has utilized a 10% usage rate in its calculation, i.e., KCPL assumes that 10%
9 of payments will be made by credit / debit cards.

10

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

12 A. Yes, I am recommending two adjustments in the assumptions used by KCPL. First, based on
13 the Company's experience to date, the average bill that is paid by credit card is significantly
14 less than the $150 assumed by KCPL in its filing. Based on information provided in the
15 response to KCC-314, the current average bill that is paid by credit card is approximately
16 $127.00. The average bill increases to approximately $140.00 in the unlikely event that the
17 entire amount of the Company's rate increase request is granted. Thus, the use of an average
18 bill of $150 overstates the variable costs of the credit/ debit card program.

19 At Schedule ACC-29, I have made an adjustment to calculate the pro forma credit/
20 debit card transactional costs, assuming an average bill of $140.00. My adjustment is very
21 conservative, since I am recommending a significantly lower rate increase than the increase

proposed by the Company. Therefore, the Company's variable costs may be well below the amount that I have included in my revenue requirement calculation.

Q. What is your second recommended adjustment?

A. My second adjustment reduces the customer usage rate from 10% to 5%. In response to KCC-314, the Company provided actual credit card payments and fees to date, showing total credit card payments of 5,532 through April. The Company's claim in this case assumes total credit card payments of 540,000, which I believe is unreasonable given that the program is new and given the actual experience to date. Accordingly, I am recommending that a customer usage rate of 5% be used to determine the Company's pro forma costs. This usage rate can be reevaluated, based on actual results, when the Company files its next base rate case. My adjustment is shown in Schedule ACC-29.

L. Southwest Power Pool ("SPP") Fees

Q. Please describe the Company's expense adjustments relating to SPP fees.

A. KCPL has included an adjustment of $1,230,000 relating to regional transmission organization ("RTO") charges from SPP. Specifically, this adjustment includes $1,000,000 in increased costs relating to transmission expansion projects of SPP members and $230,000 in NERC/SPP fees. I am not recommending any adjustment to the $230,000 in NERC/SPP fees. However, I am recommending that the $1,000,000 in expansion project costs be eliminated.

1 **Q. What is the basis for your adjustment?**

2 A. My adjustment is based on the fact that this is not a timely test year adjustment. While the
3 Company's claim is based on projects that have been approved by SPP, in many cases the
4 projects have not yet been completed and/or the utility undertaking the project has not yet
5 filed for new rates at FERC.

6 According to the response to KCC-321S, "both the Base Plan Region-wide and Base
7 Plan Zonal revenue requirements are set at $0 for KCPL until amended through a rate filing
8 by any transmission owner in SPP." Moreover, that response goes on to state that "KCPL
9 has not made any FERC filings to date related to amending these revenue requirements to
10 facilitate cost recovery." While the Company went on to state that AEP did make a FERC
11 filing in June 2007, it is my understanding that the AEP filing has not yet resulted in any
12 charges to KCPL. If charges do result from that filing, they will not be effective until "the
13 latter half of 2007."

14 Based on the information provided to date, I believe that these costs do not represent
15 known and measurable changes to KCPL's test year results. In addition, if and when such
16 charges are actually imposed, it will be too far beyond the end of the December 31, 2006 test
17 year to include such costs in this case. In any event, it appears that only one utility has even
18 filed with FERC for recovery of any of these costs at this time. Moreover, the Company is
19 required to file another base rate case in two years, and has the option to file another case
20 next year. Therefore, if these charges are actually imposed in the interim, KCPL will have
21 ample opportunity to seek recovery. For all these reasons, I recommend that the Company's

1 claim for recovery of these expansion project costs be denied. My adjustment is shown in
2 Schedule ACC-30.
3
4 **M. Maintenance Costs**

5 **Q. Please describe the Company's expense adjustments relating to maintenance costs.**
6 A. KCPL has included several maintenance adjustments in its filing. These include adjustments
7 relating to generation in the amount of $6,784,745, transmission in the amount of
8 $1,990,000, distribution in the amount of ($462,002), and information technology in the
9 amount of $1,118,982.
10
11 **Q. Are you recommending any adjustments to the Company's claims for maintenance?**
12 A. Yes, I am recommending adjustments to the Company's claims for transmission, distribution,
13 and information technology. I am not recommending any adjustment to its claim relating to
14 generation maintenance.
15
16 **Q. Please describe your adjustment to the Company's transmission maintenance expense**
17 **claim.**
18 A. KCPL included incremental transmission maintenance costs of $1,990,000 in its filing. This
19 claim represents an increase of approximately 100% over the actual test year transmission
20 maintenance costs. The Company provided a breakdown of its incremental costs in its
21 workpapers. The Company's claim includes some new personnel, additional software and

1 hardware to support transmission activities, $500,000 to support additional Electric Power
2 Research Institute ("EPRI") programs, vegetative management programs, increased pole
3 inspections, and other projects.

4 While, in general, I am not objecting to the specific programs included in the
5 Company's filing, I do believe that the Company's claim is based on aggressive budgets that
6 do not reflect known and measurable changes to the test year. KCPL has not yet incurred any
7 costs for several of the software and hardware programs included in the filing. Nor has it
8 incurred any costs for many of the other programs, such as the Substation Circuit Switcher
9 pole replacement project, control house roof repairs, wood pole inspections, and others. In
10 some cases, the Company has also indicated that its cost projection includes costs that will be
11 incurred over more than one year, and/or costs that are non-recurring. In addition, the actual
12 vegetative management control costs related to transmission service do not appear to be any
13 greater than the actual costs incurred in the test year. Finally, to the extent that the
14 Company's projected expenditures include costs for internal labor, the Company has not
15 demonstrated that such labor is incremental to the labor costs already included in its payroll
16 cost adjustment.

17 Given the speculative nature of many of the transmission related expenditures
18 claimed by KCPL, I am recommending an adjustment to reduce their claim for incremental
19 transmission maintenance costs by 50%. I am recommending an adjustment to the overall
20 expense claim, rather than to specific projects, in order to provide maximum flexibility for
21 the Company in meeting specific maintenance needs as they arise. My adjustment, which is

1 shown in Schedule ACC-31, still represents an increase of over 50% of the transmission
2 maintenance costs incurred by the Company in the test year.
3
4 **Q. Please describe the Company's claim for distribution maintenance costs.**
5 A. KCPL has included an increase of $4,100,000 million in distribution maintenance costs,
6 offset by a decrease of $4,562,000 relating to the amortization of 2006 storm damage costs,
7 for a net decrease of $462,000. However, the $4.1 million increase being proposed by KCPL
8 represents an increase of 21.6% over the actual test year distribution maintenance costs.
9 Distribution projects included by KCPL in its claim include corrective maintenance
10 repairs resulting from a condition assessment program undertaken by the Company, wood
11 pole inspections and treatment, infrared thermal-scan inspections, manhole inspections,
12 vegetative maintenance, and other projects.
13
14 **Q. Are you recommending an adjustment to the Company's claim?**
15 A. Yes, I am. The claim for distribution maintenance costs, like the claim for transmission
16 maintenance costs, appears to be based on an aggressive budget. In general, budgeted
17 expenses should not be used for setting rates, as budgets are generally too speculative to be
18 used for determining regulated rates. This certainly appears to be the case here with regard to
19 distribution maintenance costs.
20 There have been no expenditures to date with regard to the corrective maintenance
21 repairs included by the Company in its filing. In addition, 60% of the corrective repairs

1 budget is for internal labor costs. Unless these costs relate to new employees whose
2 positions are not included in the Company's pro forma labor adjustment, then this labor
3 should already be reflected in the Company's payroll expense claim.
4 The Company's actual expenditures for other components of its incremental
5 distribution maintenance program appear to be under budget as well. Similar to the
6 Company's experience with the corrective maintenance program, KCPL has not expended
7 any funds associated with pole inspections, infrared thermal-scan inspections, or manhole
8 inspections. The Company has not separately tracked predictive maintenance and other
9 project costs, so it was not able to provide actual amounts spent to date for these projects.
10 With regard to vegetative maintenance, it does not appear that actual costs to date have been
11 significantly above test year levels and the Company acknowledged that the program is
12 "slightly behind schedule". Clearly, the Company's actual expenditures are far short of the
13 amounts being claimed. Overall, while I am not opposed to an increase in the Company's
14 distribution costs, the amounts included in the Company's claim are speculative and
15 unsupported, based on the documentation provided to date.
16
17 **Q. What do you recommend?**
18 A. As shown in the response to CURB-73, the actual test year distribution expense was low
19 relative to actual expenses in the prior year. However, the test year costs were generally
20 consistent with the costs incurred in 2003 and 2004. Based on historic data, I am
21 recommending that the Company's pro forma distribution maintenance costs be based on a

1 three-year average of these costs, increased by 10% to reflect a greater emphasis on
2 distribution maintenance activities in the future. While the Company has identified some
3 worthwhile incremental distribution projects, it has not justified the significant increase it has
4 requested. Many of these projects have had no expenditures to date. The distribution
5 budgets being used as the basis for the Company's claim are just too speculative to be used
6 for ratemaking purposes. Accordingly, while I recommend that the KCC make some
7 allowance for an increased emphasis on distribution maintenance, I believe that an increase
8 of 10% over the three-year average is a more reasonable proxy than the 21.6% increase over
9 the test year included in the Company's claim. My adjustment is shown in Schedule
10 ACC-32.
11
12 **Q. Why did you utilize a different approach for distribution maintenance costs, whereby**
13 **you included a 10% increase over the three-year average, as opposed to your approach**
14 **for transmission maintenance costs, where you included half of the Company's claimed**
15 **increase?**
16 A. Given that actual distribution maintenance costs appear low in the test year, I felt it was
17 important to first develop a normalized level of such costs. Moreover, one would expect
18 distribution maintenance costs to be somewhat more constant from year-to-year, except for
19 large storm-related costs that are usually tracked, and sometimes recovered, separately.
20 Therefore, the use of a three-year average base for these costs is appropriate. It should be
21 noted, however, that although I used different methodologies to develop my two adjustments,

1 the end results are not significantly different. I am recommending a pro forma distribution
2 maintenance cost of $22,143,656, as shown in Schedule ACC-32. If I adjusted distribution
3 maintenance costs using the same methodology that I did for transmission maintenance, my
4 pro forma distribution expenses would be $21,035,841.
5
6 **Q. Please describe the Company's adjustment relating to Information Technology**
7 **maintenance costs.**
8 A. The Company's adjustment generally annualizes test year costs for software support
9 maintenance expenditures. In addition, KCPL included an incremental adjustment of
10 $188,000 relating to data center equipment hardware maintenance and of $350,400 relating
11 to Integraph, Mobile software support.
12
13 **Q. What adjustment are you recommending to the Company's claim for Information**
14 **Technology maintenance costs?**
15 A. I am recommending that the incremental costs for the data center equipment hardware
16 maintenance and the Integraph, Mobile software support be eliminated from the Company's
17 claim. While most of KCPL's other Information Technology adjustments relate to
18 annualizing test year costs, these two adjustments relate to new expenditures. It appears that
19 at least one of these projects was included in the 2006 budget, although no costs were
20 actually incurred.
21 I am recommending that these amounts be excluded from the Company's claim

1 because KCPL has not provided a complete description of these expenditures or any
2 supporting documentation. In fact, I am unable to locate any discussion of these costs in the
3 Company's testimony in this case. Accordingly, at Schedule ACC-33, I have made an
4 adjustment to eliminate these costs from my recommended revenue requirement. If adequate
5 supporting documentation is provided during the rebuttal stage of this case, I will revise my
6 recommendation, if appropriate.
7

8 **N. Corporate Image Advertising**

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

10 A. Yes, I am recommending that institutional and strategic advertising costs of $337,670 be
11 disallowed. This corporate image advertising should not be included in a regulated utility's
12 revenue requirement. The purpose of such advertising is to promote the institution, in this
13 case KCPL and GPE, and its shareholders. Such advertising is designed to favorably
14 influence customer opinion. These ads constitute "soft-lobbying" of ratepayers on behalf of
15 the Company. This advertising may also used to enhance the attractiveness of offerings
16 made by unregulated affiliates of the utility. Such advertising is not necessary for the
17 provision of regulated utility service and should not be paid for by ratepayers. At Schedule
18 ACC-34, I have made an adjustment to eliminate institutional and strategic image advertising
19 costs from rates.
20
21

1 **Q. How did you identify the amount of corporate image advertising included in the**
2 **Company's claim?**
3 A. To quantify the amount of corporate image advertising costs included in the Company's
4 claim, I relied upon KCPL's response to KCC-43. This response quantified the Company's
5 advertising categories based on the advertising undertaken by KCPL during the year.
6
7 **O. Lobbying Expenses**
8 **Q. Are you recommending any adjustment to the Company's claim for lobbying expenses?**
9 A. Yes, I am recommending that lobbying costs be disallowed. According to the Company's
10 response to CURB-51, KCPL's filing includes lobbying costs of $154,674. I am
11 recommending that these costs be eliminated from the Company's claim. My adjustment is
12 shown in Schedule ACC-35.
13
14 **Q. Are lobbying costs an appropriate expense to include in a regulated utility's cost of**
15 **service?**
16 A. No, they are not. Lobbying costs are not necessary for the provision of safe and adequate
17 utility service. Moreover, the lobbying activities of a regulated utility may be focused on
18 policies and positions that enhance shareholders but may not benefit, and may even harm,
19 ratepayers. Regulatory agencies generally disallow costs involved with lobbying, since most
20 of these efforts are directed toward promoting the interests of the utilities' shareholders rather
21 than its ratepayers. Ratepayers have the ability to lobby on their own through the legislative

1 process. Moreover, lobbying activities have no functional relationship to the
2 provision of safe and adequate electric service. If the Company were to immediately cease
3 contributing to these types of efforts, utility service would in no way be disrupted. Clearly,
4 these costs should not be borne by ratepayers. For all these reasons, I recommend that
5 lobbying activities be disallowed as shown in Schedule ACC-35.
6
7 **Q. In addition to the lobbying costs identified above, are you recommending another**
8 **adjustment relating to lobbying?**
9 A. Yes, I am. In response to KCC-143, the Company identified $5,000 in costs for Five Star
10 Speakers that it indicated should be excluded from its claim. These costs relate to a guest
11 speaker hired for the annual Political Action Committee dinner. According to that data
12 request response, "[t]his amount ($5,000) will be removed from cost of service and
13 appropriately categorized as a lobbying expense." Therefore, at Schedule ACC-36, I have
14 made an adjustment to eliminate these costs from the Company's revenue requirement.
15
16 **P. Other Miscellaneous Expense Adjustments**
17 **Q. Are there other costs included in the Company's revenue requirement claim that**
18 **should not be borne by ratepayers?**
19 A. Yes, there are two additional expense adjustments, relating to spa and resort costs and
20 sporting events. According to the response to KCC-36, the Company included $36,524 in
21 its claim relating to the Elm Resort and Spa. KCC indicated that this was an appropriate

1 ratemaking expense, since it "related to employee training classes." [16] I am recommending
2 that these costs be disallowed. KCPL has not demonstrated that these costs were necessary
3 to the provision of safe and adequate service. It is reasonable to assume that such leadership
4 training could have been conducted on-site for lower cost. Given the significant financial
5 burdens that ratepayers are being asked to bear over the next five years, the Company should
6 be vigilant in eliminating unnecessary spa and resort meetings. My adjustment to eliminate
7 these costs from the Company's revenue requirement claim is shown in Schedule ACC-37. [17]

8 In addition, according to the response to KCC-63, KCPL has included $85,131 of
9 costs associated with the Kansas City Royals and other sporting events in its claim. These
10 costs do not directly relate to the provision of safe and adequate regulated utility service and
11 they should not be borne by regulated ratepayers. Moreover, ratepayers do not receive any
12 benefit from these expenditures, except for the lucky few that get the opportunity to attend
13 sporting events along with Company personnel. It is unreasonable to expect all utility
14 customers to subsidize tickets for sporting events. Accordingly, at Schedule ACC-38, I have
15 made an adjustment to eliminate these costs from my recommended revenue requirement.
16

17 **Q. <u>Property Tax Expense</u>**

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

19 A. The Company's claim was based on its 2007 budgeted property tax costs, adjusted to reflect

[16] Per the response to KCC-221.

[17] I note that in its last case, the Company included in its claim $75,363 related to two Directors and Officers retreats attended by various officers and their spouses. In response to discovery in that case, the Company quantified these costs and agreed to remove them from its regulated cost of service.

1 an additional 2007 property tax levy of 1.67% and further adjusted to reflect utility plant
2 balances at September 30, 2007. This resulted in a total property tax claim of $9,519,172.
3 The Company then made an additional adjustment to reflect estimated payments in lieu of
4 taxes ("PILOT") of $330,000 relating to the new wind generation facility.
5
6 **Q. Are you recommending any adjustments to the Company's property tax claim?**
7 A. Yes, I am recommending that the additional 2007 property tax levy of 1.67% be disallowed.
8 KCPL indicated it its workpapers that this amount was based on the three-year average of
9 system-wide increases. However, the 2007 budgeted property tax expense, used as the basis
10 for the Company's claim, already contains an increase over the actual 2006 composite
11 property tax rate. Therefore, no further adjustment should be necessary. My adjustment is
12 shown in Schedule ACC-39.
13
14 **R. <u>Depreciation Expense</u>**
15 **Q. Are you recommending an adjustment to the Company's depreciation expense claim?**
16 A. Yes, I am recommending one adjustment. As discussed previously, I am recommending
17 certain adjustments relating to the wind generation that the Company included in its rate base
18 claim. Therefore, at Schedule ACC-40 I have made an adjustment to exclude annual
19 depreciation expense associated with my recommended plant disallowance. To quantify my
20 adjustment, I used the 5% depreciation rate for wind generation facilities included in the
21 Company's filing.

S. 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-41. It is consistent (synchronized) with my recommended rate base, capital structure, and cost of capital recommendations. I am recommending a lower rate base, a higher debt ratio, and a higher cost of debt than the rate base, debt ratio, and cost of debt included in the Company's original filing. My recommendations result in 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-42, I have used a composite income tax factor of 39.78%, which includes a state income tax rate of 7.35% 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-43, reflects these same income tax rates. In addition, the revenue multiplier includes uncollectible costs at a rate of 0.31%, which was the actual test year rate according to the response to KCC-134.

1 **VIII. REVENUE REQUIREMENT SUMMARY**

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

3 A. My adjustments show that KCPL has a revenue surplus at present rates of $3,053,110, as
4 summarized on Schedule ACC-1. My recommendations result in revenue requirement
5 adjustments of $37,273,110 to the Company's requested revenue requirement increase of
6 $34,220,000.

7

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

10 A. Yes, at Schedule ACC-44, I have quantified the revenue requirement impact of the rate of
11 return, rate base, revenue and expense recommendations contained in this testimony.

12

13 **Q. Have you developed a pro forma income statement?**

14 A. Yes, Schedule ACC-45 contains a pro forma income statement, showing utility operating
15 income under several scenarios, including the Company's claimed operating income at
16 present rates, my recommended operating income at present rates, and operating income
17 under my proposed rate decrease. My recommendations will result in an overall return on
18 rate base of 7.90%.

19

20

21

1 **IX. ENERGY COST ADJUSTMENT ("ECA")**

2 **Q. Please discuss the Company's request for an ECA.**

3 A. The Company's proposed ECA is outlined on pages 10-17 of the testimony of Mr. Giles.
4 Essentially, the Company is proposing to implement an ECA based on estimated fuel and
5 purchased power costs, offset by projected off-system sales margins. These margins have
6 been estimated based on the 25th percentile, i.e, there is only a 25% probability that actual
7 margins would be less than those included in the ECA. The ECA proposed by the
8 Company would be subject to true-up based on actual fuel and purchased power costs, as
9 well as actual off-system sales margins.

10 CURB is opposed to the establishment of an ECA. KCPL depends primarily upon
11 nuclear and coal units for the vast majority of its generation. The Company is not highly
12 dependent upon fuels with greater price volatility such as gas and oil. In addition, when gas
13 and oil prices are high, KCPL can generally benefit through increased off-system sales. To
14 the extent that actual off-system sales exceed the margins included in base rates, the
15 Company and its shareholders have the potential to benefit.

16 In addition, pursuant to the Regulatory Plan, KCPL is required to file another base
17 rate case in two years, and is permitted to file another case next year. Therefore, if fuel and
18 purchased power costs differ significantly from amounts approved by the KCC in this case,
19 the Company will have the ability to file for rate relief in the near term.

20 It should be noted that KCPL had the ability to file for an ECA in last year's case and
21 choose not to include an ECA in its filing. Apparently, the Company felt that an ECA was

1 not in its best interest at that time. The current requirement for the Company to propose an
2 ECA in this case, as discussed in last year's Stipulation, was promulgated by Staff, and not
3 by KCPL.
4
5 **Q. In addition to the reasons expressed above that are specific to KCPL, i.e., the**
6 **Company's relatively stable fuel costs and the fact that it will be filing for another case**
7 **within two years, are there other problems inherent in ECA mechanisms?**
8 A. Yes, there are several. First, an ECA mechanism results in single-issue ratemaking. It
9 provides for dollar-for-dollar true-up and recovery of costs associated with one component of
10 the Company's overall revenue requirement. With an ECA, a utility can seek to increase
11 rates even if it is earning well above its authorized rate of return.
12 Second, an ECA mechanism results in reimbursement ratemaking. Rather than
13 providing the opportunity for a utility to earn its authorized rate of return, the ECA
14 mechanism assures the utility that its overall return will not be impacted by its fuel and
15 purchased power procurement practices.
16 Third, an ECA mechanism provides a disincentive to the utility to engage in hedging
17 activities or to adopt good management practices in order to control costs. With an ECA, the
18 utility has no incentive to minimize its fuel procurement and purchased power costs, since
19 the utility knows that such costs will be fully recovered from ratepayers. While I understand
20 that the Company does engage in some hedging, it is likely to take a much more aggressive
21 approach to minimizing its fuel costs if shareholders are at risk for a portion of these costs.

Fourth, an ECA mechanism results in rate uncertainty for ratepayers. This is especially true of ECA mechanisms that provide for monthly adjustments to customers' rates. These constant rate changes make it difficult for customers to anticipate their electric charges or to assess the accuracy of their monthly bills. Rate stability can be especially important to residential and small commercial customers.

Fifth, given limited resources, it is very difficult for the KCC Staff and/or CURB to undertake a thorough and comprehensive review of the purchasing decisions made by KCPL as part of each ECA review. Any review is further complicated by the complexity of the fuel purchasing contracts and of the purchasing decisions that must be made, sometimes on an hour-by-hour basis. It is virtually unheard of for any state regulatory commission to successfully pursue an ECA disallowance based on issues regarding the prudence of the purchasing decisions. Any review that Staff or CURB conducts will be largely to verify the arithmetic in the Company's ECA claims, rather than to determine whether or not appropriate purchasing decisions were made.

Sixth, the KCC has not examined the impact of the ECA on the Company's overall return requirements. Any mechanism that provides for a dollar-for-dollar pass-through of actual fuel and purchased power costs will significantly reduce the Company's risk, a factor that must be considered by the KCC.

Finally, adoption of an ECA 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

1 which should be thoroughly explored prior to implementing the adjustment mechanism
2 proposed by KCPL. While I do not expect significant variations in fuel and purchased
3 power costs over the next two years, given the Company's heavy reliance on nuclear and coal
4 generation, the fact remains that the KCC loses control over a significant part of the
5 ratesetting process when it permits a utility to establish an ECA.
6
7 **Q. Given the problems you just identified with ECA mechanisms, what do you**
8 **recommend?**
9 A. I recommend that the KCC reject the Company's proposal. ECA mechanisms provide a
10 disincentive for effective utility management and they result in rate instability that is harmful
11 to customers. They reflect poor regulatory policy because such mechanisms result in
12 reimbursement ratemaking on a single issue. Moreover, in this case, the ECA is particularly
13 unnecessary given the Company's relatively stable fuel costs and the fact that it is required to
14 file another base rate case shortly.
15
16 **Q. Does your recommendation regarding the ECA provide the proper incentives to utility**
17 **management?**
18 A. Yes, it does. My recommendation provides utility management with incentives both to
19 reduce energy costs and to maximize off-system sales. To the extent that off-system sales
20 are higher than the pro forma sales included in my revenue requirement recommendation,
21 shareholders would benefit. If, however, the KCC adopts an ECA mechanism, then 100%

of off-system sales should be flowed through that mechanism in order to provide ratepayers, who are paying 100% of the fuel and purchased power costs, with 100% of the benefit from such sales.

Moreover, my recommendation also provides the Company with an incentive to reduce fuel and purchased power costs. To the extent that fuel and purchased power costs are lower than those included in the Company's filing, shareholders would receive the benefit of these reduced costs between rate filings. In return, ratepayers receive rate stability and rate certainty.

X. CASH FLOW CONSIDERATIONS AND REGULATORY PLAN COMMENTS

Q. Will your recommended rate decrease require additional cash flow in order for the Company to meet the coverage ratios outlined in the Regulatory Plan?

A. If the KCC strictly adheres to the provisions of the Regulatory Plan, then an additional increase relating to cash flow may be required if my recommendations are accepted by the KCC. There were two coverage ratios included in the Regulatory Plan that can be addressed through the CIAC mechanism, funds from operations as a percentage of interest coverage and funds from operations as a percentage of total debt. (The third ratio, total debt to total capital, is being addressed by KCPL through its issuance of securities.)

I have attempted to examine the resulting coverage ratios based on the information available to me from the Company's filing. This calculation is shown in Schedule ACC-46. The calculation of funds from operations utilizes the operating income and depreciation and

1 amortization reflected in my revenue requirement calculation. Deferred income taxes are
2 based on the amount included in the Company's filing. I have calculated long-term debt
3 based on the Kansas-jurisdictional share of total debt reflected in my capital structure. I have
4 calculated pro forma interest expense on this debt, based on the composite debt cost used in
5 my cost of capital calculation.

6 For the remaining variables, capitalized lease obligations, off-balance sheet
7 adjustments, interest on short-term debt, and off-balance sheet interest expense, I have
8 reflected the amounts provided in the Attachment to Schedule MWC-4. However, I have not
9 made an independent review of these amounts, to determine if they should be included in the
10 coverage ratio calculation. I simply present them on Schedule ACC-46, to provide the KCC
11 with a preliminary indication of whether a CIAC adjustment is necessary.

12

13 **Q. What are the coverage ratios resulting from your calculation?**

14 A. As shown on ACC-46, I calculated a funds from operations / interest coverage ratio of 4.89.
15 This is well above the target ratio of 3.8 referenced in the Regulatory Plan. Clearly, no CIAC
16 is required in order for the Company to meet this ratio.

17 With regard to funds from operations / total debt, my preliminary calculation shows a
18 ratio of 23.27%, slightly below the 25% target specified in the Regulatory Plan. However,
19 the 23.27% is still in the range for BBB debt, as shown in Appendix E to the Regulatory
20 Plan. Moreover, the denominator of this ratio contains $75.4 million in off-balance sheet
21 adjustments and capitalized lease obligations, which may not be appropriate to include in the

1 calculation or may have been overstated by KCPL. In fact, the Regulatory Plan
2 acknowledged that it may be improper to include these obligations, stating that, "[t]he
3 prudence of the 'Capitalized Lease Obligations' and 'Off-Balance Sheet Obligations' will be
4 determined in the first general rate case that affords the Commission the opportunity to
5 review the matter." This issue was not addressed in the Stipulation in last year's case.
6 Therefore, at this time, I do not have sufficient information to definitively conclude whether
7 or not a CIAC adjustment is needed to meet this second ratio and maintain an investment
8 grade rating for KCPL.
9
10 **Q. If the KCC decides to require a funds from operation / total debt ratio of 25.0%, how**
11 **much additional revenue would be required?**
12 A. As shown on Schedule ACC-47, increasing the ratio from 23.25% to 25.00% would increase
13 the Company's revenue requirement by $16,436,781, assuming that the KCC accepts the
14 Company's claims for Capitalized Lease Obligations, Off-Balance Sheet Adjustments, and
15 the associated interest. If the KCC approves recovery of this additional amount, then the
16 $16,436,781 should be deducted from rate base beginning with the rate case filed in 2009, as
17 required under the Regulatory Plan. In addition, the $4 million of additional revenues
18 collected pursuant to the Stipulation in last year's case should also be reflected as a rate base
19 deduction. Any amounts raised from ratepayers due to cash flow requirements should be
20 deducted from rate base on a pre-tax basis so that ratepayers receive full value for the funds
21 that they have contributed.

1 **Q. If the KCC does not accept all of your recommended revenue requirement adjustments,**
2 **what impact would there be on the cash flow calculation?**
3 A. If the KCC finds that under a traditional revenue requirement analysis, the Company has the
4 need for a smaller reduction than the reduction of $3,053,110 that I recommend, or if the
5 KCC finds that the Company has a need for a rate increase, then the cash flow adjustment
6 discussed above should be adjusted accordingly. For example, if the KCC awarded a return
7 on equity that was higher than the return I recommend, the Company would have more
8 operating income that the operating income reflected in my testimony. In that case, a smaller
9 cash flow adjustment would be necessary. Therefore, in the event that some of my revenue
10 requirement adjustments are rejected, then any additional cash flow allowance would need to
11 be recalculated based on the revised financial parameters established by the KCC.
12
13 **Q. Do you question the need for ratepayers to provide any additional revenues for cash**
14 **flow purposes at this time?**
15 A. Yes, I do. KCPL is in the process of acquiring Aquila's electric operations in Kansas and
16 Missouri, as well as certain merchant services operations. This transaction has a total
17 indicated value of $1.7 billion. In addition, KCPL will assume approximately $1 billion of
18 net debt and other liabilities.
19 Aquila also recently entered into a Settlement Agreement with the Sierra Club and
20 CCPC in Missouri that contains significant new capital commitments on the part of the
21 Company. When the Regulatory Plan was approved, neither of these developments was

1 known. Instead, the Regulatory Plan was designed to assist KCPL in a long-term
2 construction program that was supposed to be necessary in order to continue to provide safe
3 and reliable electric service to Kansas ratepayers. It was envisioned at that time that all
4 parties would focus on the specific cash flow needs of programs outlined in the Regulatory
5 Plan. However, by entering into an acquisition agreement for the Aquila assets and by
6 committing to significant new capital projects in Missouri, the Company has introduced new
7 considerations that impact any evaluation of the need to obtain additional cash flow from
8 regulated Kansas ratepayers. If the Company believes that cash flow is sufficient to acquire
9 certain Aquila systems in a transaction with an indicated value of $1.7 billion, to acquire an
10 additional $1.0 billion of Aquila debt, and to make extensive long-term capital commitments
11 to the Sierra Club and CCPC, the KCC should seriously question whether the cash flow
12 methodology outlined in the Regulatory Plan is still necessary.

13 In addition, the amount of CIAC required to meet cash flow requirements pales in
14 comparison to the magnitude of the construction program being undertaken by KCPL. The
15 Company currently projects expenditures of $2.5 billion over the next five years and that
16 estimate does not include additional costs resulting from the litigation settlement in Missouri.
17 In the last case, the parties agreed to provide in rates $4 million of additional revenue related
18 to cash flow considerations. In this case, it appears that no more than $16.4 million would be
19 required and perhaps considerably less. Therefore, the KCC should consider whether it
20 makes sense to abandon well-established ratemaking principles, given the fact that the
21 eventual rate base deduction will be a very small percentage of the overall capital additions.

1 In addition, providing this cash flow allowance permits credit rating agencies, rather than the
2 KCC, to effectively set rates for KCPL.

3 It should be noted that in addition to these financial concerns, I have been informed
4 by counsel that CURB has reservations about the legality of the CIAC mechanism outlined in
5 the Regulatory Plan. Thus, there may be legal, as well as financial reasons, for determining
6 that no CIAC adjustment is necessary in this case.

7

8 **Q. Given the changes that have occurred since the Regulatory Plan was approved, should**
9 **the KCC reexamine the provisions of the Regulatory Plan?**

10 A. Yes, it should. KCPL presented the Regulatory Plan as a framework that was necessary in
11 order for the Company to build new generation, and to meet other commitments necessary to
12 serve Kansas customers. The generation resources envisioned under the plan were justified
13 by the Company based on assumptions with regard to cost, customer growth, environmental
14 concerns, and other factors that may no longer apply. Moreover, we now know that both the
15 cost estimates and the capacity forecasts used to support the Regulatory Plan were not
16 achieved.

17 KCPL has also entered into significant new capacity commitments since the
18 Regulatory Plan was approved. These commitments include new wind resources and other
19 supply commitments that may or may not be appropriate given the Regulatory Plan. Perhaps
20 more troubling is the fact that the Company has not quantified the financial impact of these
21 additional commitments or otherwise determined their impact on Kansas customers.

1 Moreover, these additional commitments will further strain the ability of the Company to
2 meet the financial requirements of the credit rating agencies.
3 KCPL has also agreed to acquire significant portions of Aquila in a transaction that
4 will require additional financial capital and may further strain the Company's ability to meet
5 credit rating agency guidelines.
6 By approving the CIAC mechanism outlined in the Regulatory Plan, the KCC
7 effectively ceded a portion of its ratemaking authority to credit rating agencies. It is well
8 established that these rating agencies evaluate a company based on the totality of its
9 operations and risk profile. As the Company moves further away from the entity that was
10 envisioned in the Regulatory Plan, and as the capital program is expanded as a result of both
11 cost overruns and commitments to new capital projects, the KCC should reevaluate both the
12 generation resources outlined in the Regulatory Plan and the concept of CIAC to meet cash
13 flow requirements required by outside rating agencies. Accordingly, CURB recommends
14 that the KCC reopen the Regulatory Plan to determine if its provisions are still applicable,
15 given these new developments.
16
17 **Q. Does this conclude your testimony?**
18 A. Yes, it does.

VERIFICATION

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 1 5th day of AUGUST, 2007.

Notary Public Marjorie M. Lenix

My Commission Expires: DECEMBER 31, 2008