BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENT OF ELECTRIC)
RATES OF KENTUCKY POWER COMPANY) CASE NO. 2005 -00341

KENTUCKY POWER COMPANY RESPONSES TO COMMISSION STAFF'S SECOND SET DATA REQUEST

VOLUME 2 OF 2

November 29, 2005

KENTUCKY POWER COMPANY
American Electric Power
SECOND DATA REQUESTS OF COMMISSION STAFF
Case No. 2005-00341

Item No. 51

Refer to the Moul Testimony, page 34. Explain why it is appropriate to use AEP in the DCF analysis since Kentucky Power has already performed an analysis on a proxy group.

Response

Mr. Moul has provided the DCF return for his Electric Group on page 34 of his testimony, and has not provided those results for AEP. AEP was excluded from the Electric Group because it fails to meet the selection criteria.

Witness: Paul R. Moul

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Item No. 52

Refer to the Moul Testimony, page 34. Kentucky Power's DCF Return on Equity ("ROE") recommendation is based upon a DCF calculation using a proxy group of electric companies (50 percent weight) and upon a DCF calculation using AEP (50 percent weight). If Kentucky Power is to rely so heavily upon a single calculation of its own ROE, explain why it is necessary to use a proxy group at all and explain the basis for giving the proxy group's estimate ROE a 50 percent weight.

Response

The DCF return shown on line 23 of page 34 is an average of two forms of the DCF (see line 20 of page 31 and line 13 of page 34), both computed with data for the Electric Group. AEP data was not employed here because it failed to qualify for the Electric Group.

Witness: Paul R. Moul

KENTUCKY POWER COMPANY
American Electric Power
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Item No. 53

Refer to the Moul Testimony, page 35 and Appendix H of the Moul Testimony, page H-2.

a. Provide citations from well known and accepted public sources that recommend using corporate bond yields rather than the yields on long-term treasury bonds, as the starting point for the risk premium analysis.

b. Explain why it is valid to add the risk premium to corporate bond yields rather than to the yields on long-term government bonds.

c. Kentucky Power has filed a rate case for an adjustment to its electric rates. Explain why it is valid to use data that does not solely reflect the electric industry, as a proxy for Kentucky Power.

d. Explain why the yield on 20-year treasury bonds, as opposed to the yield on 30-year treasury bonds, is the most appropriate risk free rate to use.

Response

a. The Principles of Public Utility Rates by James Bonbright discusses the use of public utility bond yields in the risk premium approach. A copy of an excerpt from that text is attached.

b. Corporate bonds yields provide a direct alternative to the return available to owners of corporate equity, when adjusted for variance in risks. The yields on long-term government bonds provide a representation of the risk-free rate of return that is used in the CAPM, which is a variation of the risk premium approach.

c. Please refer to Mr. Moul's testimony at page 40. The 4.75% common equity risk premium used by Mr. Moul was determined after first establishing that a 4.95% common equity risk premium was appropriate for the S&P Public Utilities. The 4.95% common equity risk premium for the S&P Public Utilities was calculated based upon the holding period returns for both the utility equity index and the returns on public utility bonds published by Lehman Brothers. As previously determined, the required common equity risk premium for the Electric Group is less than that required for the S&P Public Utilities due to differences in the composition of the companies in each group. Due to differences in risk

Witness: Paul R. Moul

fundamentals represented by an analysis that considered size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas, it was determined that 4.75% would be a reasonable common equity risk premium. It is Mr. Moul's opinion that a reasonable differentiation of the risk between the groups has been employed.

d. Ideally, it would be preferable to employ the longest maturity available as the yield on Treasury bonds as the measure of the risk-free rate of return in the CAPM. The source of these yields is taken from the Statistical Release H.15 issued by the Federal Reserve Board. Those yields are described as follows:

> "Yields on Treasury nominal securities at 'constant maturity' are interpolated by the U.S. Treasury from the daily yield curve for non-inflation-indexed Treasury securities. This curve, which relates the yield on a security to its time to maturity, is based on the closing market bid yields on actively traded Treasury securities in the over-the-counter market. These market yields are calculated from composites of quotations obtained by the Federal Reserve Bank of New York. The constant maturity yield values are read from the yield curve at fixed maturities, currently 1, 3 and 6 months and 1, 2, 3, 5, 7, 10 and 20 years. This method provides a yield for a 10-year maturity, for example, even if no outstanding security has exactly 10 years remaining to maturity. ..."

With the release dated February 25, 2002, the H.15 no longer reports a yield on 30-year constant maturity Treasury securities. This followed the Treasury's announcement on January 30, 2002 that effective February 18, 2002, a new long-term index would replace the yield on the 30-year bond. With that release, the H.15 began reporting a yield on an index of Treasury securities with 25 years or more remaining to maturity. The Treasury subsequently announced on May 5, 2004, that it would cease publication of the yield on the long-term index effective June 1, 2004. As such, the yield on the 20-year Treasury bond is presently the longest dated Treasury security that is reported in the Federal Reserve Statistical Release, H.15.

Witness: Paul R. Moul

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Principles of Public Utility Rates

Second Edition

by
JAMES C. BONBRIGHT
ALBERT L. DANIELSEN
DAVID R. KAMERSCHEN

with assistance of
JOHN B. LEGLER

To Martha E. Bonbright

Public Utilities Reports, Inc.
Arlington, Virginia

dimension of the dividend payments. A final consideration is the assumption of dividend reinvestment. This assumption is common to all the discounted cash flow models. It might be a very good assumption in the case of direct dividend reinvestment programs. Is it possible that the dividends may be spent, not reinvested, or perhaps put in a money market account at a lower return? The counterargument is that this does not matter. If investors choose to spend the dividend, they are foregoing the opportunity to reinvest, and the relevant consideration is the opportunity cost of the the dividend reinvestment. This is not a fully resolved issue, and perhaps both arguments have some merit.

Another variation of the basic DCF model is one which relaxes the assumption that the growth rate be constant. It may be assumed that the growth in dividends will be at one rate for a few years, and then, at another rate in perpetuity. This model is more complicated than the simple model, and the expected return is estimated through an iterative procedure. In reality, this more complicated version of the model is likely to produce results close to those produced by the simple annual model using a growth rate based on an average of the growth rates for the two time periods.

Risk Premium Approach

The risk premium approach is probably the second most popular approach to estimating the cost of equity. There are a number of specific techniques which fall under this general category. Basically, the theory suggests that the required rate of return is higher for riskier securities than less risky securities. Accordingly, the equity of a company has a higher required or expected return than its debt. The differential between the cost of equity and debt is the required premium for enticing investors to accept the greater risk associated with equity. With information on current debt rates and the magnitude of the risk premium, the cost of equity can be estimated using this method. The model may be defined as:

$$k = k_d + RP$$

where k is the required return on equity, k_d is the long-term cost of debt and RP is the risk premium.

Conceptual and Measurement Problems. The risk premium method sounds simple and quite appealing. But there are conceptual as well as measurement problems in implementing the technique. First,

circumstances may exist such that a negative risk premium or one well below average risk premiums may be calculated. This even happens to Company witnesses who generally argue that equity is always more risky than debt. The conventional wisdom states that equity is more risky than debt because the equityholder stands last in line as a claimant on the earnings of a corporation. However, there have been years when bond returns have exceeded stock returns. Occasionally, even risk premium studies performed on a prospective basis find negative premiums for some years usually when interest rates are rising rapidly. Risk premiums do change over time and premiums developed on the basis of historical averages fail to take into account any changing relationship in the riskiness of debt versus equity. Frequently, studies based on historical data implicitly assume that the risk premium is constant. However, in testimony, Morin (1987) has demonstrated that the risk premium fluctuates inversely with interest rates. While this demonstration confirms that the risk premium is not constant, basically it implies that the cost of equity is more stable than the cost of debt. While investors can expect the cost of debt and equity to move in the same direction, the two do not move in lock step.

The current cost of debt is sometimes calculated as an average of long-term debt yields of a broad-based group of comparable risk firms. Frequently, the current average yield on Moody's Public Utility Bonds of the same rating class as the company is used. Alternatively, it may be calculated based on the company's own current cost of long-term debt. Frequently, the risk premium added to the bond yield is derived from the historical differential between equity and debt. One often cited study of this type is by Ibbotson and Sinquefield (1984, p.5). This study initially calculated the annual differentials from 1926 through the mid-1970s and has been updated annually. For instance, between 1926 and 1983, the (arithmetic) means in percentage terms were as follows: common stock 11.8; long-term corporate bonds 4.4; long-term government bonds 3.7; United States Treasury bills 3.2; and inflation 3.1. The (arithmetic) mean differential between common stocks and United States government bonds is approximately 8.1 percent over the very long term. The differentials measured over shorter, more recent time periods, are lower. Analysts sometimes defend the use of the longer term differential on the basis of a lower standard error of the estimate (a statistical measure) and regard the 8.1 percent as the "best estimate". Therefore, if the company's current cost of debt, however measured, is say 9 percent, the cost of equity capital would be 17.1 percent (9.0 percent + 8.1 percent).

Historical premiums are challenged on the basis that they represent

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Item No. 54

Refer to the Moul Testimony, Appendices H and I, and Exhibit No. PRM-1, Schedule 11, page 2 of 2. Provide an explanation of why Kentucky Power argues that the arithmetic mean is the correct measure to use for estimating the risk premium, yet incorporates the geometric mean and other measures into its calculation.

Response

The arithmetic mean must be used exclusively in the CAPM because it is required by the specification of the model (i.e., it is a single period model). However, for the risk premium approach there is no similar restriction on the measurement of the return differentials. Here, a comprehensive approach was employed that used the return differentials measured with the arithmetic mean, the geometric mean, and the medians in order to gauge the appropriate risk premium.

WITNESS: Paul R Moul

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Item No. 55

Refer to the Moul Testimony, page 42. Kentucky Power unleverages, and then re-leverage, the betas in *Value Line*. Provide any sources that also advocate this technique for using *Value Line* betas.

Response

Please refer to the excerpt from Regulatory Finance: Utilities' Cost of Capital by Roger Morin for the formulas for adjusting betas for leverage difference.

Witness: Paul R. Moul

REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

Roger A. Morin, PhD

in collaboration with

Lisa Todd Hillman

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On the practical side, the approach is arbitrary and judgmental. A consensus on relative divisional risks may be difficult to reach. For example, the analysis may not distinguish those risk factors in each division that are diversifiable and those that are not. Even if arbitrary and qualitative risk differentials can be identified, there exists no financial model to translate those risk differences into rate of return differentials.

14.2 Pure-Play Companies

A second approach is to identify publicly-traded companies that are most similar to the division and then apply the traditional techniques of DCF and CAPM to the proxy firms. The average cost of equity for these companies can be used as an estimate of equity cost for the division. For example, the average beta of a group of gas distribution utilities can be used as a proxy for a similar non-traded gas distribution utility's unobservable beta and used in the CAPM to infer that utility's cost of capital.

One difficulty with the pure-play approach is that although the reference companies may have the same business risk, they may have different capital structures. Observed betas reflect both business risk and financial risk. The fundamental idea is contained in the following relationship:

OBSERVED BETA = BUSINESS RISK BETA + FINANCIAL RISK PREMIUM

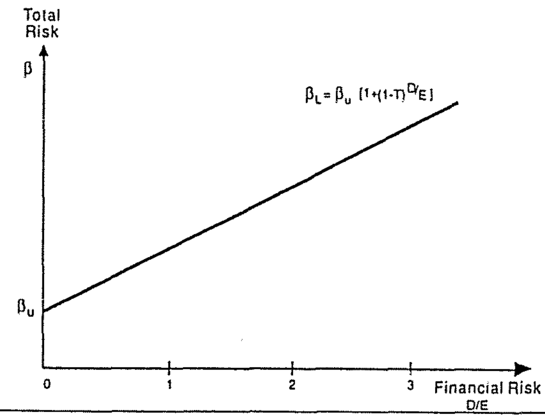
Hence, when a group of companies are considered comparable in every way except for financial structure, their betas are not directly comparable. Fortunately, there is a technique for adjusting betas for capital structure differences, based on CAPM theory. The following equation expresses the decomposition of observed beta between a business risk-related component, or unlevered beta, and a financial risk component related to the use of debt financing:

$$\beta_L = \beta_U \, [1 + (1-T) \, D/E] \qquad (14\text{-}1)$$

where β_L is the observed levered beta of a company, β_U is the unlevered beta of the same company with no debt in its capital structure, D/E is the ratio of debt to equity, and T the corporate income tax rate. Intuitively, one can think of the above equation as expressing the total risk of a company, β_L, as the sum of business risk, β_U, and a financial risk premium that depends on the magnitude of the company's debt ratio, D/E.

The relationship between beta and financial risk is depicted in Figure 14-2.

FIGURE 14-2
RELATIONSHIP BETWEEN BETA AND FINANCIAL RISK



The vertical axis represents the beta, or total risk, of the company. The horizontal axis denotes the degree of financial risk measured by the debt-equity ratio. For an all-equity financed company with no financial risk, the levered beta coincides with the unlevered beta. In other words, the company's total risk equals its business risk, as the financial risk is nil. As the financial risk increases, the total risk of the company increases steadily.

The important issue here is that beta is a measure of the systematic risk of the levered equity of the proxy firms, and these proxy companies will often employ leverage different from that used by the division for which the cost of equity is being measured. If we assume that the proxy companies are considered comparable in every way except for capital structure, their betas are not directly comparable. To circumvent this difficulty, the observed "levered" betas of the proxy firms must be "unlevered" in order to isolate their pure business risk component, then "relevered" using the division's own target capital structure. The unlevering of the company betas removes the effect of financial risk to focus on the pure business risk component of the pure-play companies. The relevering of the pure business risk betas accounts for the division's own financial leverage.

The following example demonstrates a two-step procedure for estimating the impact of a change in capital structure on beta. First, the "unlevered" beta of each company in the reference group is estimated and averaged so that the resulting group beta is purged of financial risk and is reflective of business risk only. Second, the business risk beta is relevered, or "recapitalized" to reflect the utility's own capital structure.

EXAMPLE 14-1

The levered beta of a pure-play company is 0.80 and its debt-equity ratio is 35%/65%. The division's target debt-equity ratio is 45%/55%. A corporate tax rate of 40% is applicable to both the pure-play company and the division, and book values are assumed equal to market values. The first step of the methodology is to purge the pure-play company's beta from the effects of financial leverage and obtain the unlevered beta using Equation 14-1:

$$\beta_L = \beta_U[1 + (1-T)\ D/E]$$

$$0.80 = \beta_U[1 + (1-.40)35/65]$$

Solving the above equation, $\beta_U = 0.60$. The second step is to estimate the levered beta of the division using the same equation in reverse, only this time using the division's own financial leverage:

$$\beta_L = \beta_U[1 + (1-T)D/E = 0.60\,[1 + (1 - 0.40)\ 45/55] = 0.90$$

The estimated beta for the division of 0.90 is then used in the CAPM or in an extended form of the model such as the ECAPM to estimate the cost of equity capital consistent with the division's own debt ratio.

EXAMPLE 14-2

The General Gas Company, a regulated distributor of natural gas, is a subsidiary of a holding company engaged in several business ventures, both regulated and unregulated. The utility's capital structure consists of 45% debt and 55% equity. The companies presented in Table 14-3 below are considered comparable in terms of business risk. The second and third columns of the table show the published beta and capital structure for each company, obtained from Value Line. The fourth column computes the unlevered beta for each company, by solving Equation 14-1 for β_U using each company's D/E. A 50% tax rate is assumed, and book values are assumed to be equal to market values. The average unlevered beta for the industry is 0.60, and reflects the business risk of the gas distribution industry and hence of General Gas Company. To estimate the levered beta associated with General Gas Company's own capital structure, Equation 14-1 is solved for β_L using the unlevered

beta for the industry and the new D/E as follows:

$$\beta L = \beta_U[1 + (1-T)\ D/E]$$

$$= 0.60 + (1-.50)\ .45/.55$$

$$= 1.01$$

The estimated beta for the new debt ratio is then used in the CAPM or in an extended form of the model such as the ECAPM to estimate the cost of equity capital consistent with General Gas Company's own debt ratio.

TABLE 14-3
THE COMPUTATION OF UNLEVERED BETAS
GENERAL GAS COMPANY: MARKET DATA

Company	Beta	Estimated Debt Ratio	Unlevered Beta
Diversified Energy Inc.	0.45	36.5%	0.35
Piedmont Natural Gas Co.	0.50	44.3%	0.36
Laclede Gas	0.65	40.1%	0.49
Consolidated Natural Gas	0.85	37.7%	0.65
Nicor Inc.	0.90	44.5%	0.64
KN Energy Inc.	0.95	46.1%	0.67
Columbia Gas	0.95	49.6%	0.64
Mountain Fuel	1.05	45.5%	0.74
Entex Inc.	1.20	50.1%	0.80
Northwest Energy Co.	1.30	64.1%	0.69
Average	0.88	45.9%	0.60

Source: Value Line

The pure-play methodology assumes that the pure-play companies have the same business risk as the division, and that, indeed, such pure-play companies can be identified to begin with. One difficulty with the approach is to identify undiversified "single line of business" proxy companies. The pool of pure-play companies is shrinking as utilities become more diversified over time. In fact, most companies, including utilities, are not perfectly homogeneous in risk and have multiple lines of business. Moreover, to the extent that the universe of pure-play companies is dwindling, the influence of abnormal observations, or outliers, on the proxy cost of capital estimate increases. Finally, the choice of screening parameters and cutoff points in defining a sample of pure-plays is arbitrary and judgmental. The analyst possesses a fair amount of latitude in defining screening criteria, such as degree of diversification, company size, and non-utility business.

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Item No. 56

Refer to the Moul Testimony, page 43. Explain why the market premium is developed by averaging historical and forecasted market performance.

Response

The market premium component of the CAPM, as with all inputs in the models of the cost of equity, is an expectational concept. When forming expectations concerning their returns on the market, knowledgeable investors would first apprise themselves of historical performance. The wide availability of historical data, such as that contained in the Ibbotson Yearbook, and frequent reference to this source in the financial press strongly suggests that investors consider these historical data in their investment decisions. For example, since 1996, the Ibbotson Associates was cited in The Wall Street Journal and Barron's on 348 occasions. The articles that appeared during 2004 and 2005 are listed below.

11/06/05 WSJ Brokers and Indexing: A Love Story

10/12/05 WSJ How to Prepare Your Portfolio

10/11/05 Barron's Small Cap Value May No Longer Be a Value

09/12/05 Barron's Mailbag

07/03/05 WSJ Fight Back Against Lower Returns

05/11/05 WSJ Taking Out a Mortgage to Buy Stocks

04/18/05 Barron's Q&A Table

05/01/05 WSJ The Fed Model: Fix It Before You Use It

04/18/05 Barron's The Art Of Investing

04/13/05 WSJ Why Bond Yields May Not Rise

04/05/05 WSJ Bribes Create Trouble for Monsanto

01/31/05 Barron's Roundtable -- Part III, Page 2

Witness: Paul R. Moul

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12/15/04 WSJ Concerns Grow About Hedge Funds' Prospects

11/23/04 WSJ Pensions Outperformed 401(k) Plans

12/01/04 WSJ Many Workers Mismanage Their 401(k)s

11/21/04 WSJ Seven Ways to Stop Saying 'Oops!'

11/07/04 WSJ Relax, You've Got Plenty of Time

11/03/04 WSJ Wealthy Clients Add Options to Portfolios

10/27/04 WSJ A Columnist Looks Back

10/25/04 Barron's Pad It!

10/18/04 WSJ As Economists Debate Markets, the Tide Shifts

10/14/04 WSJ Is This Bear Market Built to Last?

10/01/04 WSJ Bonds Tortoise Outruns Stocks Hare

08/22/04 WSJ A Normal Market? There's No Such Thing.

07/01/04 WSJ What a Healthy and Long Life Can Cost

07/01/04 WSJ Where Number Crunching Can Go Wrong

05/23/04 WSJ How to Play the Hot Commodities Market

05/31/04 Barron's All In The Family

05/20/04 WSJ Biotech's Dismal Bottom Line

05/19/04 WSJ Two Days Investors Won't Forget

03/28/04 WSJ Making a Nest Egg Last

03/16/04 Barron's Some Banks Are Rich With Dividends

04/05/04 Barron's The REIT Stuff

01/26/04 Barron's Cosmopolitan Guys

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Having advised themselves of historical performance, investors would then develop expected returns based upon widely available sources, such as Value Line and Standard & Poors. To accommodate both forecasts and historical information, Mr. Moul gave weight to both measures of market performance.

WITNESS: Paul R Moul

Kentucky Power Company

REQUEST

Refer to the Direct Testimony of Everett G. Phillips ("Phillips Testimony"), page 2. Provide copies of the referenced "Focused Management Audit" report ("Audit Report").

RESPONSE

A copy of the "Focused Management Audit" report by Schumaker & Company can be found on the Kentucky Public Service Commission website at:

http://psc.ky.gov/agencies/psc/hot_list/m_audit/aep/rpt_032403.pdf

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony, page 5. Provide copies of all proposed revisions to North America Electric Reliability Council transmission and distribution vegetation management standards.

RESPONSE

All revisions of the North America Electric Reliability Council (NERC) proposed standards on the Transmission Vegetation Management Program, including comments and responses to these comments on all the revisions, are publicly available and can be obtained from NERC's Transmission Vegetation Management site at http://www.nerc.com/~filez/standards/Vegetation-Management.html. This standard, when approved, will apply to 200 kV or higher voltage transmission lines (and lower voltage transmission lines determined to be critical to reliability by the Regional Reliability Councils) over which NERC has oversight. Currently Draft 3 is posted for ballot through November 16, 2005. We are not aware of any NERC standards that pertain to distribution vegetation management.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony, pages 6 and 7. Has Kentucky Power conducted an inventory of trees, tree growth, and tree mortality rates since the Audit Report was filed in March 2003? If so, provide copies of the inventory report.

RESPONSE

An inventory of trees, tree growth, and tree mortality rates has not been conducted. Establishing the inventory is part of the plan for vegetation management discussed in the Phillips Testimony, page 8.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Describe Kentucky Power's current procedures for distribution Right-of-Way ("ROW") maintenance and clearance and how that differs from a cycle-based approach.

RESPONSE

The Phillips Testimony, pages 4 and 5, describes the current procedure for distribution Right-of-Way maintenance:

"KPCo's Distribution "Performance Based" Vegetation Management Program is a comprehensive, integrated vegetation management program designed to ensure that the vegetation along KPCo's distribution circuits is trimmed at the proper time to protect our lines in an environmentally sound and cost-effective manner. KPCo uses a variety of vegetation management practices to control vegetation along its distribution rights-of-way, such as aerial sawing, mechanized trimming, manual trimming (roping, hand climbing), and herbicide applications."

"Each fall, vegetation work plans are developed for the following calendar year. One input into these work plans comes from our visual inspections, which are performed on approximately 50 percent of KPCo's distribution circuits per year as part of our Distribution Asset Programs. Other inputs into the work plan include historical reliability data, line inspections, customer density, customer complaints and time elapsed since vegetation management was last performed. The plan is kept dynamic and flexible to respond to local needs that may arise during the course of the year."

Performance Based vegetation management relies upon reliability data, line inspections and customer complaints as primary inputs into the work plan. A cyclic approach relies primarily on time elapsed since previously maintained, with lesser regard for reliability trends and the other primary inputs of a performance based program.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony, page 8. If Kentucky Power were to receive the necessary financial resources as requested in its application, is it committing to adopting a cycle-based approach to vegetation management for its distribution and transmission line ROW throughout its Kentucky service territory? Explain the response.

RESPONSE

Distribution:
Given the necessary funding Kentucky Power Company will establish a cycle-based approach to vegetation management on its distribution system. As described in Phillips Testimony, pages 9 and 10, it will take approximately four years to fully implement a system wide cycle based program. During this period end-to-end tree trimming, tree removals and widening of ROW where possible for all of KPCo's T&D circuits will take place.

Transmission:
Given the necessary funding Kentucky Power Company plans to establish a cycle-based approach to vegetation management on its transmission system. The timeframe for establishing this approach is four years; however this timetable may be affected by standards for vegetation management under development by the North America Electric Reliability Council (NERC) at the behest of the Federal Energy Regulatory Commission (FERC) (Phillips Testimony pages 5 and 6). The standards focus on transmission circuits operating at 200 kV and above along with critical transmission lines of lower voltage as determined by the applicable Regional Reliability Council (East Central Area Reliability Council - ECAR). It is anticipated that more vegetation inspections and more vigorous vegetation management on these specific transmission circuits will be required to comply with the developing standards. This will increase KPCo's transmission vegetation expenses related to these lines, thereby extending the time necessary to achieving a cycle based approach on the transmission and sub-transmission facilities not covered by the NERC standard.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony, page 10.

a. Explain this statement on line 11, "Capital dollars are used to widen the clear zone of existing rights-of-way."

b. Refer to Table 2. Provide a detailed description of the investments identified as capital expenditures incurred in conjunction with the proposed vegetation management program.

c. Refer to Table 2. Provide a detailed explanation of the O&M expenses anticipated to be incurred in conjunction with the proposed vegetation management program.

RESPONSE

a. Capital dollars are used in right-of-way clearing under several circumstances. Most notably, the clearing of new rights-of-way, clearing portions of existing rights-of-way not previously cleared (widening) and performing additional tree trimming on portions of trees not previously trimmed (including removal of previously trimmed trees).

b. During the Test Year approximately 20% of the vegetation program dollars spent on Outside Services and Material were expended for widening and tree removal, both capitalizable expenses (see 62a, above). Given the financial resources requested in its application, KPCo will place increased focus on widening and tree removal as steps toward improving the number of outages caused by trees falling into the line. Removal of trees also eliminates the need to perform repetitive trimming on those trees, and so results in lowered maintenance costs over the long term. The Company estimates that during implementation of a cycle based program, Capital expenditures will comprise approximately 30% of the total program expense for Outside Services and Material.

The funding necessary to implementing a cycle-based approach is based on performing end-to-end work on all of KPCo's Distribution and Transmission circuits and is further explained in Phillips Testimony, page 10: "The estimates (of both O&M and Capital) were based on actual line mile tree-trimming clearing expenses, which include base tree trimming work, herbicide application, and incremental tree trimming crews to perform end-to-end clearance, administrative oversight, and follow-up trimming for fast growing vegetation between cycles".

c. O&M expenses occur when previously cleared rights-of-way are recleared or otherwise maintained. This type of work comprises the majority of the efforts necessary to implement a cycle-based approach. The Company estimates that during implementation of a cycle based program, approximately 70% of the total program expense for Outside Services and Material will be incurred through O&M based work.

The funding necessary to implementing a cycle-based approach is based on performing end-to-end work on all of KPCo's Distribution and Transmission circuits and is further explained in Phillips Testimony, page 10: "The estimates (of both O&M and Capital) were based on actual line mile tree-trimming clearing expenses, which include base tree trimming work, herbicide application, and incremental tree trimming crews to perform end-to-end clearance, administrative oversight, and follow-up trimming for fast growing vegetation between cycles".

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony, page 17.

a. Explain in detail why Kentucky Power only measures the results of its current vegetation management programs through the use of quarterly customer satisfaction tracking studies.

b. Provide copies of the quarterly customer satisfaction tracking studies for calendar years 2002, 2003, 2004, and the available quarterly studies for 2005.

RESPONSE

a. KPCo uses the quarterly studies referred to on Phillips Testimony page 17 to gauge customer satisfaction with overall reliability; however Mr. Phillips testimony was not meant to imply that customer satisfaction surveys were the sole measurement of Kentucky Power's vegetation management program results. KPCo also monitors reliability and customer complaints. The SAIFI, CAIDI and SAIDI reliability indices are calculated for vegetation related outages to aid in work planning and monitoring effectiveness of the program. Customer complaints concerning service reliability, where vegetation caused outages are the primary driver, are used in a similar fashion.

To gauge the quality of the work performed by crews maintaining distribution rights-of-way, KPCo currently uses a field audit process monitoring completed work. The audits focus on obtaining proper clearance and adherence to industry standards for proper arboricultural trimming technique.

b. Please see the attached.

WITNESS: Everett G Phillips

KENTUCKY POWER - RESIDENTIAL CUSTOMER SATISFACTION DATA	Winter 2002	Spring 2002	Summer 2002	Fall 2002	Winter 2003	Spring 2003	Summer 2003	Fall 2003	Winter 2004	Spring 2004	Summer 2004	Fall 2004	Winter 2005	Spring 2005	Summer 2005
Reliability of electricity (Q15)	86	92	80	84	92	82	88	88	88	82	86	88	78	88	92
Service restoration (Q19)	88	88	86	88	92	88	90	86	88	84	88	88	82	90	90
Power quality (Q20)	86	86	88	90	90	90	86	84	92	88	88	92	88	90	78
(Completed Surveys)	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**50**	**51**	**50**	**50**	**50**	**50**	**50**	**50**

KENTUCKY POWER - COMMERCIAL CUSTOMER SATISFACTION DATA	Winter 2002	Spring 2002	Summer 2002	Fall 2002	Winter 2003	Spring 2003	Summer 2003	Fall 2003	Winter 2004	Spring 2004	Summer 2004	Fall 2004	Winter 2005	Spring 2005	Summer 2005
Reliability of electricity (Q15)	92	96	82	94	94	92	90	90	83	80	88	86	90	94	80
Service restoration (Q19)	90	94	88	84	92	90	94	84	92	84	86	82	92	90	86
Power quality (Q20)	92	94	88	92	96	90	84	90	89	86	92	80	86	90	74
(Completed Surveys)	**50**	**50**	**49**	**50**	**50**	**49**	**50**	**50**	**47**	**50**	**50**	**50**	**50**	**50**	**50**

Reliability of electricity (Q15) "How would you rate AEP's overall ability to provide you electricity without interruption? Please rate them using a ZERO to TEN scale, where ZERO means they are doing an EXTREMELY POOR JOB, TEN means they are doing an EXTREMELY GOOD JOB, and FIVE means NEITHER A GOOD NOR POOR JOB. Again, how would you rate AEP's performance being able to provide you with electricity without interruption?"

Service restoration (Q19) "I'd again like you to use the same ZERO to TEN scale that you used earlier, where ZERO means they are doing an EXTREMELY POOR JOB, TEN means they are doing an EXTREMELY GOOD JOB, and FIVE means NEITHER A GOOD NOR POOR JOB. Based on what you have experienced or know about AEP's performance, how would you rate their general ability to restore electric service when power outages occur?"

Power quality (Q20) "Now I'd like you to think about power quality. By power quality I mean the condition of the electricity that enters your (residence/business/organization). Power quality problems might occur when the lights flicker, or when voltage fluctuations cause computers or other sensitive equipment to malfunction, but the power is still on. This is different than momentary outages when all electrical equipment stops operating for a few seconds. Again using the same ZERO to TEN scale, how would you rate AEP's performance regarding power quality?"

Kentucky Power Company

REQUEST

Refer to the Phillips Testimony, page 19. Mr. Phillips makes the statement that, "It is important for KPCo and our customers that the Commission approve recovery of the expenditures associated with KPCo's proposal to place its T&D system on a cycle-based vegetation management program to enable us to continue our work to maintain and improve transmission and distribution system reliability." Explain in detail why Mr. Phillips believes it is reasonable to require ratepayers to pay for the projected O&M expenses and a return on the projected capital expenditures associated with this proposed program prior to Kentucky Power expending any funds for the program.

RESPONSE

Kentucky Power intends to initiate the programs upon receipt of a favorable Commission Order. As stated in Mr. Phillips' testimony on page 19, reliability of service to our Kentucky customers is very important to Kentucky Power (KPCo) and its customers. Customer expectations and demand for reliable electric service have grown and will continue to grow. Implementing the Focused Management Audit's recommended cycle-based approach for vegetation management is a critical part of KPCO's efforts in meeting customer demand for improved reliability. However, the cost to implement such a plan is significantly above the levels in KPCo's historical expenditures and current test year period. Therefore, KPCo believes it is appropriate to recover costs for enhancing reliability performance during the time the costs are incurred and the work is accomplished. This line of thought is consistent with the Commission's matching principle concept, in which, during the same period, revenues are matched with expenses incurred.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Attachment C of the Stipulation and Settlement Agreement approved in Case No. 1999-00149 addresses AEP's and Kentucky Power's service quality commitments.

a. Is Mr. Phillips familiar with the commitments made by Kentucky Power in Case No. 1999-00149? Explain the response.

b. Explain why Kentucky Power does not measure the results of its current vegetation management programs using the System Average Interruption Frequency Index ("SAIFI") and the Customer Average Interruption Duration Index ("CAIDI").

c. Provide Kentucky Power's annual SAIFI and CAIDI values, including all storms, for years 1999 through 2005.

d. Using the SAIFI and CAIDI values provided in part (c), prepare an analysis for each interruption index that shows the percentage change between each year. For any annual change that is greater than a positive or negative 15 percent, explain the reason(s) for the change.

RESPONSE

a. Yes, Mr. Phillips is familiar with those commitments. Attachment C contains a list of items that illustrate Kentucky Power's efforts to maintain service quality after the AEP – CSW merger.

b. As shown in the response to Question 63, Part a of this set of interrogatories, Mr. Phillips testimony was not meant to imply that customer satisfaction surveys were the sole measurement of Kentucky Power's vegetation management program results. The reliability indices SAIFI, CAIDI, and SAIDI are also used at circuit and company levels. These indices are calculated for all causes in general and for vegetation inside and outside of the right-of-ways in particular.

c.

KyPCo's overall indices including and excluding major events are:

	Including Major Events		Excluding Major Events	
Year	SAIFI	CAIDI	SAIFI	CAIDI
1999	1.71	4.01	1.62	2.79
2000	1.435	3.77	1.26	3.17
2001	2.16	4.51	1.67	3.29
2002	2.69	4.10	2.08	3.13
2003	2.88	7.10	1.95	2.88
2004	3.27	6.52	2.42	3.28
12M – Oct '05	2.74	2.98	2.74	2.98

KyPCo's vegetation <u>inside</u> right-of-way indices including and excluding major events are:

	Including Major Events		Excluding Major Events	
Year	SAIFI	CAIDI	SAIFI	CAIDI
1999	0.12	3.50	0.12	2.60
2000	0.11	4.73	0.09	3.34
2001	0.54	5.92	0.36	4.18
2002	0.70	5.11	0.49	3.64
2003	0.85	6.44	0.46	3.26
2004	0.94	9.29	0.57	3.38
12M – Oct '05	0.50	3.29	0.50	3.29

KyPCo's vegetation <u>outside</u> right-of-way indices including and excluding major events are:

	Including Major Events		Excluding Major Events	
Year	SAIFI	CAIDI	SAIFI	CAIDI
1999	0.34	6.20	0.30	4.31
2000	0.37	5.22	0.31	4.30
2001	0.26	6.46	0.15	5.02
2002	0.42	5.48	0.29	4.73
2003	0.48	8.27	0.29	4.07
2004	0.62	10.0	10.39	5.14
12M – Oct '05	0.51	4.63	0.51	4.63

d. Using the SAIFI and CAIDI values provided in part (c), prepare an analysis for each interruption index that shows the percentage change between each year. For any annual change that is greater than a positive or negative 15 percent, explain the reason(s) for the change.

<u>% Change in Overall Reliability Indices – No Exclusions</u>

Year	SAIFI	CAIDI	Dominant Event
2000	-15.8%	-6.0%	
2001	50.0%	19.6%	Smaller summer storms
2002	24.5%	-9.1%	Smaller summer & winter storms
2003	7.1%	73.2%	February ice storm
2004	13.5%	-8.2%	May severe t-storms
12M – Oct '05	-16.2%	-54.3%	No major events

Reliability indices are highly volatile. This is true even when excluding major events, when the indices are influenced by localized weather challenges that are not considered major events, but it is especially true when including major events. The effects of major events (usually ice, extreme wind, or severe thunderstorms) tend to dominate the reliability indices and the indices become more of a measure of how bad the events were or how many there were in a year. The Kentucky Power indices are also influenced by the improvements to the outage management system. The increased accuracy in outage recording after these improvements has resulted in increases in <u>recorded</u> reliability indices, although customers' <u>actual</u> outage experiences might not have changed.

It is very difficult to compare major event intensity. The number of customers interrupted and the customer-minutes of interruption during the event are calculated, but these are more of measures of the storms effects. The effects of major storms depend on what percentage of the service area are challenged by the weather, the customer density in those areas, and the speed at which the storm moves through the area in addition to the storm type and intensity.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to the Roush Testimony, pages 4 and 5, and the Application, Section V, Workpaper S-4, page 24 of 41.

a. Provide the supporting workpapers, including all assumptions and calculations, along with a narrative explanation, showing the derivation of the electric revenues of $195,124 shown on the workpaper.

b. Provide the supporting workpapers, including all assumptions and calculations, along with a narrative explanation, showing the derivation of the 72.85 percent ratio of operating and maintenance expenses to revenues for the test year.

RESPONSE

(a) and (b) Please see the Company's Application filing, Volume 3, Direct Testimony of David M. Roush, pages 4 and 5; Exhibit DMR-1, pages 1 and 2; Section III, pages 8 through 32; Section V, Schedule 4, page 1; Section V, Workpaper S-4, pages 2, 9, 10, 25 and 27; and the attached page 2 to this response for the detailed development of the Customer Annualization Adjustment.

WITNESS: David M Roush

KENTUCKY POWER COMPANY
Adjusted O&M Labor Expense
TWELVE MONTHS ENDED JUNE 30, 2005

	TOTAL ELECTRIC UTILITY			KENTUCKY P.S.C. JURISDICTION			Labor Adjustment		
	Total O&M Labor	A&G Excluding Regulatory	Total A&G (on OML)	Retail Allocation Factor	Total O&M Labor	Total A&G	Wages	Benefits	Savings Plan
Production									
Operation									
Account 500	$ 3,486,474		$ 4,507,572	0.986000	$ 3,437,663	$ 4,444,466			
Account 501	$ 219,723		$ 284,074	0.987000	$ 216,867	$ 280,381			
Account 502	$ 425,499		$ 550,117	0.986000	$ 419,542	$ 542,965 1/			
Account 505	$ 12,683		$ 16,398	0.986000	$ 12,505	$ 16,185 1/			
Account 506	$ 1,406,742		$ 1,818,740	0.986000	$ 1,387,048	$ 1,793,278			
Account 507	$ -		$ -		$ -	$ -			
Total Operation	$ 5,551,121		$ 7,176,901		$ 5,473,625	$ 7,077,275	$ 271,196	$ 96,626	$ 11,971
Maintenance									
Account 510	$ 625,188		$ 808,289	0.986000	$ 616,435	$ 796,973			
Account 511	$ 155,667		$ 201,258	0.986000	$ 153,488	$ 198,440			
Account 512 - Dem Related	$ 733,204		$ 947,941	0.986000	$ 722,939	$ 934,670			
Account 512 - Ener Related	$ 1,423,279		$ 1,840,121	0.987000	$ 1,404,776	$ 1,816,199			
Account 512 - Total	$ 2,156,483		$ 2,788,062			$ -			
Account 513	$ 545,326		$ 705,038	0.986000	$ 537,691	$ 695,167			
Account 514	$ 148,369		$ 191,822	0.986000	$ 146,292	$ 189,136			
Account 515	$ -		$ -		$ -	$ -			
Account 555	$ -		$ -		$ -	$ -			
Account 556	$ -		$ -		$ -	$ -			
Account 557	$ -		$ -		$ -	$ -			
Total Maintenance	$ 3,631,033		$ 4,694,469		$ 3,581,621	$ 4,630,587	$ 177,455	$ 63,226	$ 7,833
Total Production	$ 9,182,154		$ 11,871,370		$ 9,055,246	$ 11,707,862	$ 448,651	$ 159,852	$ 19,804
Demand-Related	$ 7,539,152		$ 9,747,175		$ 7,433,603	$ 9,052,131	$ 368,306	$ 131,225	$ 16,257
Energy-Related	$ 1,643,002		$ 2,124,195		$ 1,621,643	$ 2,655,731	$ 80,346	$ 28,627	$ 3,547
Transmission									
Operation	$ 434,957		$ 562,345			$ -			
Maintenance	$ 900,784		$ 1,164,600			$ -			
Total Transmission	$ 1,335,741		$ 1,726,945	0.986000	$ 1,317,041	$ 1,702,768	$ 65,254	$ 23,250	$ 2,880
Distribution									
Operation	$ 806,237		$ 1,042,363						
Maintenance	$ 4,843,525		$ 6,262,069						
Total Distribution	$ 5,649,762		$ 7,304,432	0.998000	$ 5,638,462	$ 7,289,823	$ 279,363	$ 99,536	$ 12,331
Total Customer Accounts	$ 1,735,702		$ 2,244,044	0.999983	$ 1,735,672	$ 2,244,006	$ 85,996	$ 30,640	$ 3,796
Total Customer Service & Informational	$ 497,208		$ 642,827	0.999983	$ 497,200	$ 642,816	$ 24,634	$ 8,777	$ 1,087
SUBTOTAL Excl A&G	$ 18,400,567			0.991471	$ 18,243,621		$ 903,899	$ 322,054	$ 39,899
Administrative & General									
Operation	$ 1,019,232								
Maintenance	$ 718,064								
Total Other Administrative & General	$ 1,737,296	$ 23,789,619	$ 23,789,618	0.991471	$ 1,722,479	$ 23,587,274			
Regulatory A&G	$ -		$ 30,211	1.000000	$ -	$ 30,211			
Total A&G Incl Regulatory	$ 1,737,296		$ 23,819,829		$ 1,722,479	$ 23,617,485			
Total Labor Payroll	$ 20,137,863				$ 19,966,100		$ 903,899	$ 322,054	$ 39,899

1/ A&G in Accounts 502 and 505 is energy-related

Kentucky Power Company

REQUEST

Refer to the Roush Testimony, pages 6 through 8, and the Application, Section III, page 34 of 373. Nearly all of the regulated electric utilities in Kentucky have rate designs that include flat, or level, energy rates for their residential customer class. Kentucky Power is proposing to maintain its current declining block rate structure.

a. Explain whether a declining block residential rate structure encourages or discourages energy consumption, particularly during times of system peak usage.

b. Does Kentucky Power have any study or analysis that supports its continued use of declining block residential rates?

c. Describe Kentucky Power's consideration of converting its residential rate schedule to flat, or level, energy rates.

RESPONSE

(a) A declining block residential rate structure could be one of many factors that lead to a customer decision which results in increased energy usage. However, a declining block residential rate structure does not necessarily result in increased usage at the time of the peak.

(b) The basis of the Company's proposed difference between the first block and second block residential energy charges is the residual customer charge. The residual customer charge is the difference between the full cost customer charge of $8.69 and the proposed charge of $5.50. Given the fixed nature of the residual customer costs, it is proper to recover such costs over the first kWh used by the customer and doing so helps to reduce subsidies within the residential class.

(c) If the residential customer charge were set at the full cost level of $8.69 /month, the Company's proposal would be a flat, or level energy charge.

WITNESS: David M Roush