COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY D/B/A DUKE ENERGY KENTUCKY TO INCREASE ITS ELECTRIC RATES	)))	CASE NO. 2006-00172

NOTICE OF FILING AND CERTIFICATION OF SERVICE

I hereby give notice that I have filed the original and nine true copies of the Attorney General's Direct Testimony with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 this the 13th day of September, 2006, and certify that this same day I have served the parties by mailing a true copy, postage prepaid, to the following:

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In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES OF	)	
THE UNION LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY

AND EXHIBITS

OF

ROBERT J. HENKES

ON BEHALF OF THE OFFICE OF RATE INTERVENTION
OF THE ATTORNEY GENERAL FOR
THE COMMONWEALTH OF KENTUCKY

September 13, 2006

Duke Energy Kentucky
Case No. 2006-00172
Direct Testimony and Exhibits of Robert J. Henkes

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I. STATEMENT OF QUALIFICATIONS

Q. WOULD YOU STATE YOUR NAME AND ADDRESS?

A. My name is Robert J. Henkes, and my business address is 7 Sunset Road, Old Greenwich, Connecticut, 06870.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am Principal and founder of Henkes Consulting, a financial consulting firm that specializes in utility regulation.

Q. WHAT IS YOUR REGULATORY EXPERIENCE?

A. I have prepared and presented numerous testimonies in rate proceedings involving electric, gas, telephone, water and wastewater companies in jurisdictions nationwide including Arkansas, Delaware, District of Columbia, Georgia, Kentucky, Maryland, New Jersey, New Mexico, Pennsylvania, Vermont, the U.S. Virgin Islands, and before the Federal Energy Regulatory Commission. A complete listing of jurisdictions and rate proceedings in which I have been involved is provided in Appendix I attached to this testimony.

Q. WHAT OTHER PROFESSIONAL EXPERIENCE HAVE YOU HAD?

A. Prior to founding Henkes Consulting in 1999, I was a Principal of The Georgetown Consulting Group, Inc. for over 20 years. At Georgetown Consulting, I performed the same type of consulting services that I am currently rendering through Henkes Consulting. Prior to my association with Georgetown Consulting, I was employed by the American Can Company as Manager of Financial Controls. Before joining the American Can Company, I was employed by the management consulting division of Touche Ross & Company (now Deloitte & Touche) for over six years. At Touche Ross, my experience, in addition to regulatory work, included numerous projects in a wide variety of industries and financial disciplines such as cash flow projections, bonding feasibility, capital and profit forecasting, and the design and implementation of accounting and budgetary reporting and control systems.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?

A. I hold a Bachelor degree in Management Science received from the Netherlands School of Business, The Netherlands in 1966; a Bachelor of Arts degree received from the University of Puget Sound, Tacoma, Washington in 1971; and an MBA degree in Finance received from Michigan State University, East Lansing, Michigan in 1973. I have also completed the CPA program of the New York University Graduate School of Business.

II. SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE SCOPE AND PURPOSE OF YOUR TESTIMONY?

A. I was engaged by the Office of Rate Intervention of the Attorney General of Kentucky ("AG") to conduct a review and analysis and present testimony regarding the petition of Duke Energy Kentucky ("DEK" or the "Company") for an increase in its base rates for electric service.

The purpose of this testimony is to present to the Kentucky Public Service Commission ("KPSC" or "the Commission") the appropriate overall rate of return, capitalization, rate base and pro forma operating income, as well as the appropriate revenue requirement for the Company in this proceeding.

In the determination of the recommended revenue requirement for DEK in this proceeding, I have relied on and incorporated the recommendations of the following other AG witnesses:

- Dr. J. Randall Woolridge, concerning the appropriate capital structure, cost rates for long- and short-term debt, return on equity rate and overall rate of return for the Company in this proceeding; and
- Mr. Michael J. Majoros, Jr., concerning the appropriate depreciation expenses to be reflected for ratemaking purposes in this proceeding.

Q. WHAT INFORMATION HAVE YOU RELIED UPON IN THE DEVELOPMENT

OF YOUR TESTIMONY?

A. In developing this testimony, I have reviewed and analyzed the Company's petition; testimonies, exhibits, workpapers and filing requirements; responses to AG and PSC initial and supplemental interrogatories and other relevant financial documents and data.

III. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE

A. The findings and conclusions reached by me in this case are as follows:

1. Based on previously established KPSC ratemaking policy, the appropriate capitalization to be used for rate making purposes in DEK's base rate proceedings should be determined by the application of the appropriate electric jurisdictional rate base ratio to DEK's total capitalization exclusive of non-jurisdictional capital.

   In accordance with this calculation method, the Company's appropriate electric jurisdictional capitalization, exclusive of the capital associated with the Advanced Metering Initiative and including the unamortized electric Investment Tax Credit balance, amounts to $550,695,662. This is $6,385,040 lower than the Company's proposed electric jurisdictional capitalization of $557,080,702. (Schedule RJH-1, line 1 and Schedule RJH-4)

2. The appropriate pro forma electric jurisdictional rate base amounts to $590,334,363 which is $802,864 lower than the Company's proposed pro forma electric jurisdictional rate base of $591,137,227. The corresponding ratio of electric jurisdictional rate base to total company jurisdictional rate base is

74.413%. (Schedule RJH-5)

3. The AG's expert rate of return witness, Dr. J. Randall Woolridge, has recommended an overall rate of return of 7.507%, including a return on equity of 9.25%, for DEK in this proceeding. This is equivalent to a rate of return of 7.003%[1] as measured based on the Company's gas jurisdictional rate base.

By comparison, the Company has proposed an overall rate of return of 8.761%, which is equivalent to a rate of return of 8.256%[2] as measured based on the Company's proposed gas jurisdictional rate base. (Schedule RJH-3)

4. The appropriate pro forma net after-tax electric jurisdictional operating income amounts to $40,704,765, which is $20,179,388 higher than DEK's proposed net after-tax electric jurisdictional operating income of $20,525,377. (Schedule RJH-1, line 4 and Schedule RJH-7)

5. The appropriate gross revenue conversion factor to be used for rate making purposes in this case is 1.6408112 (Schedule RJH-1, Line 6). This recommended conversion factor is lower than DEK's proposed conversion factor of 1.6449687. (Schedule RJH-1, line 6 and Schedule RJH-2)

6. The application of the recommended overall rate of return of 7.507% to the

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[1] Sch. RJH-1, line 3: $41,339,397 divided by rate base of $590,334,363 (Sch. RJH-5) = 7.003%

[2] Sch. RJH-1, line 3: $48,805,840 divided by rate base of $591,137,227 (Sch. RJH-5) = 8.256%

recommended electric jurisdictional capital structure of $550,695,662, combined with the recommended pro forma test period operating income of $40,704,765 and the revenue conversion factor of 1.6408112 indicates that the Company has an annual rate deficiency of $1,041,311. This is $45,478,499 lower than the Company's proposed annual rate deficiency of $46,519,810. These annual rate deficiency numbers exclude consideration of the increase in the Company's fuel revenue requirement. (Schedule RJH-1, lines 1-7)

7. The Company's proposed and AG's recommended annual increase in fuel revenue requirement amounts to $20,040,364. (Schedule RJH-1, line 8)

8. Including the annual increase in fuel revenue requirement, the AG's recommended total annual rate increase for DEK in this case amounts to $21,081,675. This recommended rate increase is $45,478,499 lower than the Company's proposed total annual rate increase of $66,560,174. (Schedule RJH-1, line 9)

IV. REVENUE REQUIREMENT ISSUES

A. GROSS REVENUE CONVERSION FACTOR

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN YOUR RECOMMENDED AND THE COMPANY'S PROPOSED GROSS REVENUE CONVERSION FACTORS.

A. As shown on Schedule RJH-2, line 2, the difference is caused by the inclusion of different uncollectible expense and KPSC maintenance tax ratios in the derivation of the Gross Revenue Conversion Factors. While the Company has reflected a KPSC maintenance tax ratio of .1670%, I have reflected the most recent actual ratio of .1643%; and while the Company has reflected an uncollectible expense ratio of .5493%, I have reflected the more appropriate uncollectible expense ratio of .3004%. These two recommended adjustments have reduced the Company's proposed Gross Revenue Conversion Factor of 1.6449687 to the recommended Gross Revenue Conversion Factor of 1.6408112.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDED UNCOLLECTIBLE EXPENSE RATIO OF .3004%?

A. As shown in the responses to AG-1-48 and AG-2-11, the net uncollectible expense (net of the time value of money component) reflected in the Forecasted Period amounts to $867,292. Taken as a ratio of the associated total billings of $288,693,617,[3] this results

[3] See WPD-2.31a, line 5 and response to AG-2-11.

in the appropriate uncollectible expense ratio of .3004% that should be used for ratemaking purposes in this case.

B. OVERALL RATE OF RETURN

Q. PLEASE DESCRIBE THE AG'S RECOMMENDED OVERALL RATE OF RETURN.

A. As shown on Schedule RJH-3, the AG's expert rate of return witness, Dr. J. Randall Woolridge, has recommended the following capital structure ratios: common equity ratio of 46.940% and long term- and short-term debt ratios of 46.070% and 6.990%. With regard to capital cost rates, Dr. Woolridge has recommended a return on equity rate of 9.25% and the same long term- and short-term debt cost rates of 6.090% and 5.138% as proposed by DEK. As shown on Schedule RJH-3, the resulting recommended overall rate of return is 7.507%.

C. ELECTRIC JURISDICTIONAL CAPITALIZATION

Q. PLEASE DESCRIBE THE METHODOLOGY USED BY THE COMPANY TO DETERMINE ITS PROPOSED ELECTRIC JURISDICTIONAL CAPITALIZATION IN THIS CASE.

A. As shown in the first column of Schedule RJH-4, line 1, the starting point of the Company's proposed electric jurisdictional capitalization is its projected 13-month average total company long-term and short-term debt and common equity balances for the Forecasted Period ended December 31, 2007. The Company then removed the capital associated with non-jurisdictional investment in order to arrive at the total company jurisdictional capitalization. Next, the Company applied its proposed electric jurisdictional rate base allocation factor to the total company jurisdictional capitalization in order to arrive at the electric jurisdictional capitalization. Next, the Company added the electric jurisdictional unamortized Investment Tax Credit ("ITC"). Finally, the Company added its proposed electric-allocated capital investment of $6.195 million associated with the Advanced Metering Initiative ("AMI") to arrive at its proposed 13-month average Forecasted Period adjusted electric jurisdictional capitalization of approximately $557,080,702.

Q. DO YOU AGREE WITH THIS PROPOSED METHODOLOGY TO DETERMINE THE APPROPRIATE ADJUSTED ELECTRIC JURISDICTIONAL CAPITALIZATION BALANCE FOR RATEMAKING PURPOSES IN THIS CASE?

A. Yes, I do. The previously described calculation methodology is in accordance with the method prescribed by the KPSC in the Company's most recent gas rate case, Case No. 2005-00042.

Q. COULD YOU NOW DESCRIBE YOUR RECOMMENDED ELECTRIC JURISDICTIONAL CAPITALIZATION BALANCE IN THIS CASE?

A. Yes. My recommended electric jurisdictional capitalization for the Forecasted Period is shown in the third column of Schedule RJH-4. It has been calculated in a manner consistent with the previously described methodology proposed by DEK, however, with two adjustments. The first adjustment is the fact that my recommended electric jurisdictional rate base allocation factor is 74.413% as compared to DEK's proposed electric jurisdictional rate base allocation factor of 74.439%. The second adjustment is the removal of DEK's proposed AMI capital addition in accordance with my recommendation to exclude any impact of the AMI project for ratemaking purposes in this case. My recommended electric jurisdictional rate base allocation factor and my recommendation to exclude ratemaking consideration of the Company's AMI project are explained in subsequent sections of this testimony.

In summary, as shown on Schedule RJH-4 line 8, the AG's recommended adjusted electric jurisdictional capitalization balance amounts to $550,695,662, which is $6,385,040 lower than the Company's proposed electric jurisdictional capitalization balance of $557,080,702.

D. ELECTRIC JURISDICTIONAL RATE BASE

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND YOUR RECOMMENDED ELECTRIC JURISDICTIONAL RATE BASE LEVELS FOR THE FORECASTED PERIOD IN THIS CASE.

A. The Company's proposed electric jurisdictional rate base of $591,137,227 is summarized by specific electric jurisdictional rate base component in column A of Schedule RJH-5. As shown in column B of Schedule RJH-5, I have recommended one rate base adjustment concerning the cash working capital rate base component. This recommended rate base adjustment reduces the Company's proposed electric jurisdictional rate base by $802,864 to a recommended electric jurisdictional rate base level of $590,334,363.

Q. PLEASE EXPLAIN YOUR RECOMMENDED CASH WORKING CAPITAL ADJUSTMENT.

A. The Company has proposed to calculate the cash working capital in this case based on the so-called "1/8th formula" method. This method assumes that 1/8th of the pro forma Forecasted Period operation and maintenance expenses, net of fuel and purchased power costs, represents a reasonable cash working capital approximation. I believe that only a properly performed detailed lead/lag study would generate an accurate approximation of a utility's cash working capital. However, based on my review of the Company's prior base rate proceedings, it is my understanding that the Commission has consistently allowed this Company's cash working capital to be determined based on this modified 1/8th method. I have therefore chosen not to challenge this method in this case.

As summarized on Schedule RJH-5, line 9 and further detailed on schedule RJH-6, the appropriate cash working capital requirement based on this 1/8th method amounts to $13,159,927. This is $802,864 lower than the Company's proposed cash working capital. The derivation of my recommended Forecasted Period operation and maintenance expenses to which the 1/8 ratio was applied is shown in detail on Schedule RJH-19.

Q. WHAT IS THE RECOMMENDED RATIO OF ELECTRIC JURISDICTIONAL RATE BASE AS COMPARED TO THE TOTAL COMPANY JURISDICTIONAL RATE BASE?

A. The total company jurisdictional rate base for the Forecasted Period consists of the combined total of the gas jurisdictional rate base and the electric jurisdictional rate base. As I previously discussed, the recommended electric jurisdictional rate base amounts to $590,334,363. The appropriate gas jurisdictional rate base to be used in this ratio analysis amounts to $202,983,847 (Schedule RJH-5, column D) This gas jurisdictional rate base comes straight from the Company's filing schedule WPA-1d. Comparing the electric jurisdictional rate base of $590,334,363 to the sum of the gas and electric jurisdictional rate base amounts of $793,318,210 (Schedule RJH-5, column E) indicates an appropriate electric jurisdictional rate base ratio of 74.413%.

E. ELECTRIC JURISDICTIONAL OPERATING INCOME

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED AND YOUR RECOMMENDED FORECASTED PERIOD NET AFTER-TAX ELECTRIC JURISDICTIONAL OPERATING INCOME LEVELS.

A. The Company has proposed a net after-tax electric jurisdictional operating income level for the Forecasted Period of $20,525,377. On Schedule RJH-7, lines 2 through 13, I show that I have made 12 adjustments to the Company's proposed operating income. Each of these recommended operating income adjustments will be discussed in the following sections of this testimony.

Schedule RJH-7, line 15 shows that, after considering all of the recommended operating income adjustments, the AG's recommended net after-tax electric jurisdictional operating income for the Forecasted Period amounts to $40,704,765.

- **Emission Allowance Sales Proceeds**

Q. WHAT IS THE ISSUE REGARDING EMISSION ALLOWANCE SALES PROCEEDS IN THIS CASE?

A. As confirmed in its responses to AG-1-27 and AG-2-7, even though the Company is booking and collecting Emission Allowance ("EA") sales proceeds since the transfer of the three Plants in January 2006 and has reflected such sales proceeds in the actual portion of its proposed Base Period, it has not reflected any of such sales proceeds in the Forecasted Period because the "Sale of Emission Allowances is not budgeted."[4] In its response to AG-2-7, the Company further confirmed the following pertinent information relating to these EA sales proceeds:

1) As a result of the transfer of the Plants, DEK has been receiving, and will continue to receive, EA sales proceeds since 1/1/06.
2) For calendar year 2005, the EA sales proceeds booked and received by the Plants' previous owner, Duke Energy Ohio ("DEO"), amounted to $10,102,405.
3) For the most recent 12-month period ended July 31, 2006, the combined total EA sales proceeds booked and received by DEO (up until 12/31/05) and DEK (as of 1/1/06) amounted to $7,430,465.
4) The Company agrees that EA sales proceeds should be treated above-the-line for ratemaking purposes.

[4] See response to AG-1-27, Account 411.

I agree with the Company's statement in its response to AG-2-7, that EA sales proceeds should be recognized for ratemaking purposes in this case.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. I recommend that an appropriate annual level of EA sales proceeds be reflected in the Forecasted Period operating revenue Account 411 and be treated as an offset to the base rate revenue requirement in this case. This is particularly appropriate since the Company is also requesting that its base rates include the revenue requirement associated with the Forecasted Period EA inventory of $5.9 million.[5]

As shown in footnote (1) of Schedule RJH-8, I believe that the average of the actual EA sales proceeds for 2005 and the 12-month period ended July 31, 2006 would serve as an appropriate annual sales proceed level for the Forecasted Period. This recommended annual EA sales proceeds level amounts to $8,766,435. After considering the associated uncollectible expenses, KPSC assessments, and income taxes, my recommendation increases the Company's proposed net after-tax operating income for the Forecasted Period by $5,342,745.

- **<u>MISO Make-Whole Revenues</u>**

Q. WHAT IS THE ISSUE REGARDING THE MISO MAKE-WHOLE REVENUES IN THIS CASE?

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[5] See WPA-1d, line 17.

A. As confirmed in its responses to AG-1-27 and AG-2-8, even though the Company is booking and collecting MISO Make-Whole revenues since the transfer of the three Plants in January 2006 and has reflected such revenues in the actual portion of its proposed Base Period, it has not reflected any of such revenues in the Forecasted Period because "This type of transaction is not budgeted."[6] In its response to AG-2-8, the Company further confirmed the following pertinent information relating to these revenues:

1) As a result of the transfer of the Plants, DEK has been receiving, and will continue to receive, MISO Make-Whole revenues since 1/1/06.
2) MISO Make-Whole payments started April 1, 2005, with the MISO Day 2 market. For the most recent 12-month period since April 1, 2005, i.e., for the 12-month period ended July 31, 2006, the combined total MISO Make-Whole revenues booked and received by Duke Energy Ohio (up until 12/31/05) and Duke Energy Kentucky (as of 1/1/06) amounted to $3,817,325.
3) While the Company agrees that MISO Make-Whole revenues should be treated above-the-line for ratemaking purposes, it believes these revenues should be included as a credit in the fuel clause.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. I recommend that an appropriate annual level of MISO Make-Whole revenues be reflected in the Forecasted Period operating revenue Account 456025 and be treated as an offset to the base rate revenue requirement in this case. This is particularly appropriate since the Company is also proposing that its base rates include the revenue requirement associated with all of the Forecasted Period's MISO costs. As shown on line 1 and footnote (1) of Schedule RJH-9, I have used the MISO Make-Whole revenues for the most recent 12-month period for which actual data are available at this time as the appropriate revenue level for the Forecasted Period. This annual period is the 12-

[6] See response to AG-1-27, Account 456025.

month period ended July 31, 2006 with actual MISO Make-Whole revenues of $3,817,325. After considering the associated uncollectible expenses, KPSC assessments, and income taxes, my recommendation increases the Company's proposed net after-tax operating income for the Forecasted Period by $2,326,486.

- **<u>Fuel Management Revenues</u>**

Q. IS THERE AN ISSUE WITH THE COMPANY'S FUEL MANAGEMENT REVENUES IN THIS CASE?

A. There may be an issue. As confirmed in its responses to AG-1-27 and AG-2-9e, even though the Company is booking and collecting fuel management revenues since the transfer of the three Plants in January 2006 and has reflected such revenues in the actual portion of its proposed Base Period, it has not reflected any of such revenues in the Forecasted Period. In its response to AG-2-9e, the Company further confirmed the following pertinent information relating to these fuel management revenues:

> The Company started receiving fuel management revenues in January 2006 beginning with the transfer of the generating stations. See below for the monthly [revenue] amounts beginning in January 2006.
>
> | Month | Amount |
> |---|---|
> | January | $113,319 |
> | February | $ 22,163 |
> | March | $ 24,686 |
> | April | $ 37,056 |
> | May | $ 22,500 |
> | June | $ 21,733 |
> | July | $ 22,840 |
>
> The Company is currently booking these revenues and expects to continue booking them until December 31, 2006. The revenues are related to a

synthetic fuel project that, based on current market conditions, is likely to end at the end of 2006.

As can be calculated from the above table, if one were to annualize the actual fuel management revenues for the first 7 months of 2006, such an annualized revenue level would be approximately $453,000. Based on the Company's claimed uncertainty regarding the continuation of these revenues in the Forecasted Period, I have chosen not to reflect these annualized fuel management revenues as an offset to the Forecasted Period base rate revenue requirement. However, in case the Company will continue to receive such fuel management revenues after 12/31/06, I recommend that all such revenues booked and collected by the Company from 1/1/07 forward be treated as a credit in the Company's fuel clause.

- **<u>Rent Revenue from Common Facility Unit 7</u>**

Q. WHAT IS THE ISSUE WITH THE RENT REVENUES FROM COMMON FACILITY UNIT 7 IN THIS CASE?

A. As confirmed in its responses to AG-1-27 and AG-2-9d, even though the Company is booking and collecting these rent revenues since the transfer of the three Plants in January 2006 and has reflected such revenues in the actual portion of its proposed Base Period, it has not reflected any of such rent revenues in the Forecasted Period. In its response to AG-2-9d, the Company further confirmed the following pertinent information relating to these rent revenues:

The Company started receiving these rent revenues in January 2006 beginning with the transfer of the generating stations. See below for the monthly [rent revenue] amounts beginning in January 2006.

Month	Amount
January	$55,616
February	$55,616
March	$55,616
April	$55,616
May	$55,616
June	$55,616
July	$55,616

These rentals are related to common facilities at Miami Fort Station and the agreement with Duke Energy Ohio for use of these common facilities is currently in effect and is expected to be in place during the Forecasted Period.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. The aforementioned information indicates that the Company is currently receiving annualized rent revenues of $666,192 ($55,616 x 12 months) and will continue to receive such rent revenues in the Forecasted Period. I therefore recommend that an annual level of $666,192 for such rent revenues be reflected in the Forecasted Period operating revenue Account 454710 and be treated as an offset to the base rate revenue requirement in this case. As shown on Schedule RJH-10, after considering the associated uncollectible expenses, KPSC assessments, and income taxes, my recommendation increases the Company's proposed net after-tax operating income for the Forecasted Period by $406,014.

- **<u>Other Operating Revenues</u>**

Q. ARE THERE ADDITIONAL "OTHER OPERATING REVENUES" WHICH ARE CONSISTENTLY BOOKED AND COLLECTED BY THE COMPANY, BUT WHICH HAVE NOT BEEN REFLECTED BY THE COMPANY IN THE FORECASTED PERIOD?

A. Yes. The response to AG-1-26 shows the actual annual revenues received by the Company for each of its Other Operating Revenue accounts during the years 2003 through 2005 and the 12-month period ended 5/31/06. In the table below, I have listed the actual average revenues for the period 2003 through 5/31/06 for each of the Other Operating Revenue that have not already been addressed in the prior three sections of this testimony:

	Actual Average Annual Revenues For 2003 through May 31, 2006
Acct. 451 Miscellaneous Service Revenues	$ 32,314
Acct. 451020 Miscellaneous Connection Charge	59,128
Acct. 451040 Temporary Facilities*	95,578
Acct. 451050 Customer Diversion	5,414
Acct. 451060 Bad Check Charge	18,231
Acct. 454020 Rent Elec Other Equipment	27,570
Acct. 454100 Pole Contact Revenues	135,477
Acct. 456865 Transmission Rev RB Interco	218,408
Total Other Operating Revenues	$592,120

* Average excludes year 2003

As confirmed in the response to AG-1-27, the Company has not reflected any of these Other Operating Revenues in the Forecasted Period.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. Since the Company is consistently booking and collection these Other Operating Revenues, I recommend that the annual revenues in the above table, totaling $592,120, be reflected in the corresponding Forecasted Period Other Operating Revenue accounts and be treated as an offset to the base rate revenue requirement in this case.

Q. IS THERE ANOTHER OTHER OPERATING REVENUE ISSUE?

A. Yes. As discussed on page 34 of the direct testimony of Company witness Bailey, the Company in this case is proposing new reconnection charges. As confirmed in its response to AG-1-24, the Company has not reflected the annualized incremental revenues associated with these newly proposed reconnection charges in the Forecasted Period. In its response to AG-2-6, the Company agrees that it would be appropriate to reflect such annualized incremental revenues for ratemaking purposes in this case and has quantified[7] that such additional revenues amount to $140,217. Thus, I recommend that such additional revenues also be treated as an offset to the Forecasted Period base rate revenue requirement.

Q. WHAT IS THE IMPACT OF YOUR OTHER OPERATING REVENUE RECOMMENDATIONS ON THE COMPANY'S PROPOSED FORECASTED PERIOD NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-11, after considering the associated uncollectible expenses, KPSC assessments, and income taxes, my recommendation increases the Company's

[7] By way of its response to KPSC-3-44.

proposed net after-tax operating income for the Forecasted Period by $446,326.

- **Weather Normalization**

Q. DID THE COMPANY USE WEATHER NORMALS IN ITS SALES FORECAST FOR THE FORECASTED PERIOD?

A. Yes. As described on page 14 of Company witness Stevie, the Company used 5,018 Heating Degree Days ("HDD") and 1,048 Cooling Degree Days ("CDD") as the basis of normal weather in developing its Forecasted Period sales forecast. These weather normals are based on weather data for the 10-year period ended 2004.

Q. IS THIS PROPOSED 10-YEAR WEATHER NORMALIZATION APPROACH CONSISTENT WITH THE WEATHER NORMALIZATION APPROACH USED BY THE COMMISSION IN THE COMPANY'S RECENTLY CONCLUDED GAS BASE RATE CASE, CASE NO. 2005-00042?

A. No. In its Order dated December 22, 2005 in Case No. 2005-00042, the Commission ordered that the weather normalization in the Company's most recent gas rate case be based on the most recent 25-year period for which actual weather data were available at that time. Case No. 2005-00042 also was the second consecutive ULH&P gas rate case where the Commission rejected the Company's proposed 10-year weather normalization approach.

Q. WHAT WEATHER NORMALIZATION APPROACH DO YOU RECOMMEND

BE USED IN THE DETERMINATION OF THE FORECASTED PERIOD SALES FORECAST IN THIS CASE?

A. I recommend that the Forecasted Period's sales forecast in this case be weather normalized in a manner consistent with the weather normalization approach ordered by the Commission as recently as December 22, 2005 in the Company's gas rate case, Case No. 2005-00042. Specifically, I recommend that the sales forecast for the Forecasted Period be based on weather data for the most recent available 25-year period from 1981 through 2005.

Q. DID THE COMPANY CALCULATE THE IMPACT ON ITS PROPOSED FORECASTED PERIOD NET REVENUES OF USING THIS RECOMMENDED 25-YEAR WEATHER NORMALIZATION APPROACH?

A. Yes. In its response to KPSC-2-37c, the Company calculated that the use of a 25-year weather normalization approach (1981-2005) rather than the Company's proposed 10-year weather normalization approach (1985-2004) would increase the Forecasted Period net revenues[8] by $866,797.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED FORECASTED PERIOD NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-12, after considering the associated uncollectible expenses, KPSC assessments, and income taxes, my recommendation increases the Company's

[8] Revenues net of associated fuel costs.

proposed net after-tax operating income for the Forecasted Period by $528,273.

- **AMI Investment and Operating Income Impact**

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSAL TO REFLECT THE INVESTMENT AND OPERATING INCOME IMPACT OF THE ADVANCED METERING INITIATIVE ("AMI") PROGRAM IN THE ELECTRIC RATES TO BE ESTABLISHED IN THIS CASE?

A. No, I do not. I believe that the AMI revenue requirement reflected by the Company in this case cannot be considered adequately known and measurable as it is based on too many speculative assumptions and relies on cost and cost savings estimates from as far out as the year 2011. Specifically, the Company has not spent any costs on this program and is not assumed to do so until December 2006 at the earliest. The Company then made the assumption that 45% of the meters will be replaced during the 2007 Forecasted Period. Next, the Company assumed that by the year 2011, the program will have reached a "steady state" such that all of the net savings will have leveled out. Based on these assumptions, the Company estimated the program costs and savings for each of the years 2006 through 2011 and then relied on the estimated costs and savings from the year 2011 in its determination of the 2007 Forecasted Period AMI revenue requirement.

In addition, the Company has not applied for a Certificate of Public Convenience and Necessity ("CPCN") for the AMI program in its May 31, 2006 Application and, at this time, the Commission has not granted a CPCN for this program.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED RATE RECOVERY FOR THIS PROGRAM?

A. Based on the aforementioned information, I recommend that the Commission reject the Company's requested rate recovery for this AMI program in this case. Company witness Stanley indicates on page 20 of his direct testimony that the implementation of the AMI program is projected to generate substantial cost savings to the extent of $34 million through the year 2020. These AMI related savings are not included in the Forecasted Period financial results. Thus, if the Company goes ahead with this program once it has received a CPCN from the Commission, it may well be that the incremental revenue requirement associated with the AMI program implementation will be completely or mostly offset by the savings generated by the program, thereby not requiring any increase in the base rates.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION ON THE COMPANY'S PROPOSED FORECASTED PERIOD CAPITALIZATION AND NET AFTER-TAX OPERATING INCOME?

A. As shown on Schedule RJH-4, line 7, my recommendation decreases the Company's electric-allocated capitalization by $6,195,185. In addition, as shown on Schedule RJH-7, line 7, my recommendation decreases the Company's proposed Forecasted Period net after-tax operating income by $159,187

- **Back-Up Power Sales Capacity Charges**

Q. WHAT RECOMMENDED POSITION REGARDING THE CAPACITY CHARGES IN THE COMPANY'S BACK-UP POWER SALES AGREEMENT ("PSA") IS REFLECTED IN THIS TESTIMONY?

A. The Forecasted Period Back-Up PSA capacity charges that have been reflected by me in this testimony are the capacity charges that have been calculated in accordance with the terms of the Back-Up PSA that was approved by the Commission in Case No. 2003-00252. As shown in the response to AG-1-61c, these capacity charges amount to $5,059,000, which is $5,372,923 lower than the Company's proposed Forecasted Period Back-Up capacity charges of $10,431,923 based on the "refreshed pricing" of the Back-Up PSA capacity charges that were approved by the Commission in Case No. 2003-00252. As shown on Schedule RJH-13, this recommended position increases the Company's proposed Forecasted Period net after-tax operating income by $3,289,841. If the Commission were to approve a Back-Up PSA capacity charge amount different from the $5,059,000 amount that reflects the terms of the Back-Up PSA approved by the Commission in Case No. 2003-00252, my testimony on this issue and the information on Schedule RJH-13 should be changed to be consistent with this Commission ruling.

- **<u>Amortization of Deferred Expenses</u>**

Q. IS THE COMPANY PROPOSING TO AMORTIZE CERTAIN DEFERRED COSTS IN THIS CASE?

A. Yes. The Company is proposing to amortize two regulatory assets for rate recovery in this case. These regulatory assets and the Company's proposed rate treatment for these regulatory assets are shown on WPD-2.15a and described on pages 15 and 16 of Company witness Wathen.

Q. PLEASE EXPLAIN THE COMPANY'S RATEMAKING PROPOSAL WITH REGARD TO THE FIRST REGULATORY ASSET.

A. The first regulatory asset concerns the deferred costs associated with a work force reduction program offered by the Company in 1992, almost 15 years ago. When the Company implemented this severance program in 1992, it incurred $1,530,917 of electric-allocated implementation costs. The Company deferred this cost and has not amortized this deferred cost balance up to this point. Mr. Wathen presents the following proposal with regard to this issue on pages 15 and 16 of his direct testimony:

> The gas portion of the severance program costs and savings were reflected in gas rates by the Commission in its Order in Case No. 92-346. Since the Company has not filed an electric rate case since Case No. 91-370, it has not had an opportunity to recover these costs from [its electric] ratepayers.... Since it has been over ten years since the severance program was offered, the Company believes that a three-year amortization period in this proceeding is appropriate.

Thus, in this case, the Company is proposing to charge its electric ratepayers with an annual amortization amount of $510,306.[9]

Q. DO YOU AGREE WITH THIS PROPOSED DEFERRED COST AMORTIZATION?

A. No. There are many reasons why this proposal is inappropriate. First, it should be

[9] $1,530,917 amortized over three years.

understood that the Commission only allowed the Company to include in its gas rates an amortization of the gas-allocated deferred severance program implementation cost in Case No. 92-346 because the gas rates in that case also included the annual expense savings from this severance program. In this regard, page 25 of the Commission's Order in Case No. 92-346 indicates that the annual labor and other expense savings from the severance program that were included in the Case No. 92-346 gas rates amounted to $968,736 as compared to the one-time gas-allocated program implementation cost of $1,009,887. In order to match the costs with the expense savings associated with this severance program, the Commission allowed an appropriate amortization of the severance program cost in the Case No. 92-346 gas rates.

The situation with regard to the electric-allocated expense savings and costs associated with this 1992 severance program is completely different. The annual electric labor and other expense savings have never been reflected in the Company's electric rates and, therefore, have never been received by the Company's electric ratepayers. While the Company concedes in its response to AG-1-42c that it experienced cost savings from the implementation of the 1992 work force reduction program during the period 1992 – 2006, it has indicated that it cannot specifically quantify these savings because "the Company is unable to locate the information that would be required to estimate the electric portion of the workforce reduction costs and savings."[10] However, as previously discussed, we know from the Case No. 92-346 Order that the estimated gas

[10] See the responses to AG-1-42d, KPSC-2-83a and KPSC-3-40b.

portion of the annual labor and other cost savings associated with the severance program amounts to $968,736. Assuming that the electric annual cost savings portion would similarly be around $968,736,[11] this would indicate a total cumulative electric cost savings amount of $14.5 million for the 15-year period from 1992 through 2006. This total cumulative expense savings amount is almost 10 times higher than the deferred cost balance of $1.53 million the Company is proposing to charge to its electric ratepayers on a going forward basis starting in 2007. In summary, the Company's stockholders have been reimbursed many times over by the ratepayers for their $1.53 million cost outlay back in 1992 and it would be very inappropriate and inequitable to charge these costs to the ratepayers again.

A second reason why the Company's proposed rate recovery of this deferred cost should be disallowed is that the Company never sought approval from the Commission to establish a regulatory asset for this electric portion of the 1992 workforce reduction program. This was confirmed by the Company in its response to KPSC-3-40.

A third reason why the Company's proposal regarding this deferred cost should be disallowed is that the Company should have started amortizing this cost balance in 1992 to match the electric cost savings from the workforce reduction program, and had it properly done so, the deferred cost balance of $1.53 million would no longer be on its books at this time.

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[11] This is a conservative assumption since the Company's electric workforce reduction was larger in scale than the Company's gas workforce reduction.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. Based on the aforementioned findings and conclusions regarding this issue, I recommend that the Company's proposal to amortize over 3 years this regulatory asset balance of $1,530,917 be rejected by the Commission. My recommendation is reflected on Schedule RJH-14, lines 4-6.

Q. PLEASE EXPLAIN THE COMPANY'S RATEMAKING PROPOSAL WITH REGARD TO THE SECOND REGULATORY ASSET.

A. The second regulatory asset concerns the actual/projected deferred cost of $1,478,571 associated with the transfer of the Plants. In accordance with the December 5, 2003 Commission Order in Case No. 2003-00252, the Company is proposing to amortize this deferred cost balance over 5 years, resulting in a proposed annual amortization expense amount of $295,714 in this case.

Q. WHAT FINDINGS DID THE COMMISSION MAKE IN ITS DECEMBER 5, 2003 ORDER IN CASE NO. 2003-000252 REGARDING THIS COST DEFERRAL?

A. On pages 12 – 14 of its Order, the Commission presented the following findings:

> <u>Transaction Costs</u>
> In its amended application, ULH&P requests that it be permitted to defer no more than $2.45 million of transaction costs incurred in conjunction with the proposed acquisition. ULH&P also proposes that the deferred costs be amortized over 5 years, without carrying charges, beginning on the effective date of the Commission's Order in the next general rate case. ULH&P has estimated that the total transaction costs would be $4.9 million, and would include transaction costs associated with filing preparation, financing, and taxes….

> ...The Commission finds that ULH&P's proposal is reasonable and should be approved. Limiting the deferral provides for a sharing of the transaction costs between ULH&P's shareholders and ratepayers.... [emphasis supplied]

Thus, in Case No. 2003-00252, the Company essentially committed that it would share its deferred transfer cost on a 50/50 basis between its ratepayers and shareholders. Another way of looking at this is that, since the Company estimated that the total transfer costs would be $4.9 million, it essentially declared in Case No. 2003-00252 that it was willing to have its shareholders absorb a maximum deferred transfer cost amount of $2.45 million. In further support of this, footnote 21 on page 13 of the Commission's Case No. 2003-00252 states that ULH&P explained that:

> ...The proposal to defer roughly half of the estimated transaction costs was one of the areas in which ULH&P felt comfortable in shifting the "balance more in customers' favor." See T.E., Volume I, October 29, 2003, at 16.

Q. BASED ON THE AFOREMENTIONED INFORMATION, DO YOU AGREE WITH THE COMPANY'S PROPOSAL IN THIS CASE TO CHARGE 100% OF ITS TOTAL TRANSFER COSTS OF $1,478,571 TO THE RATEPAYERS?

A. No, I do not. The Company made a commitment in Case No. 2003-00252 to share its transfer cost on a 50/50 basis between ratepayers and shareholders and, in fact, implied that it was willing to have its shareholders absorb a maximum transfer cost amount of $2.45 million. The Commission's Case No. 2003-00252 ruling to allow the Company to defer and amortize in future rates up to $2.45 million worth of these transaction costs was based on the expectation that the

Company's total cost estimate of $4.9 million would be accurate and that there would be a 50/50 ratepayer/shareholder sharing of this total cost amount. The fact that the total transfer costs is now estimated to be $1,478,571, i.e., less than half of the Company's estimate of $4.9 million in Case No. 2003-00252, should not mean that, therefore, the ratepayers should pay for the entire transfer cost. This would be inconsistent with the original intent of both the Company and the Commission in Case No. 2003-00252 and with the Company's position expressed in Case No. 2003-00252 that "it felt comfortable in shifting the balance more in customers' favor."

In summary, the Company should honor the commitments it made in Case No. 2003-00252 with regard to this issue. There are two approaches one could take in fulfilling these commitments. The first approach would disallow rate treatment for the entire transfer cost of $1,478,571 in view of the facts that the Company was willing to have its shareholders absorb a maximum transfer cost amount of $2.45 million and that the actual total transfer cost of $1,478,571 is below this maximum cost absorption limit. The second approach would be to maintain the status quo of the ratepayer/shareholder 50/50 sharing of the total transfer cost that was established in Case No. 2003-00252. Under this approach, half of the total transfer cost amount of $1,478,571 would be disallowed for ratemaking purposes in this case.

Q. WHAT IS YOUR RECOMMENDATION WITH REGARD TO THIS ISSUE?

A. To be conservative, I recommend that the Commission implement the aforementioned second ratemaking approach which allows 50%, or $739,286, of the total transfer cost of $1,478,571 for rate recovery. Using a 5-year amortization for this allowed deferred cost amount results in a recommended annual amortization expense of $147,857. My recommendation is reflected on Schedule RJH-14, lines 1-3. Lines 4-6 address the workforce reduction issue

Q. WHAT IS THE IMPACT OF YOUR DEFERRED COST RECOMMENDATIONS ON THE COMPANY'S PROPOSED FORECASTED PERIOD OPERATING INCOME?

A. As shown on Schedule RJH-14, my recommended deferred cost adjustments have the effect of increasing the Company's proposed Forecasted Period net after-tax operating income by $402,993.

- <u>**Miscellaneous Expense Adjustments**</u>

Q. PLEASE EXPLAIN THE MISCELLANEOUS EXPENSE ADJUSTMENTS YOU SHOW ON SCHEDULE RJH-15.

A. The first adjustment item concerns the recommended removal of governmental affairs expenses that are included in the Company's proposed above-the-line Forecasted Period operating expenses. In its response to AG-1-59a, the Company states that the nature and purpose of these expenses ..." is to monitor legislative and executive public policy as it pertains to the utility industry and specifically to Duke Energy Kentucky's business..."

I recommend that these expenses be removed for ratemaking purposes in this case, since I do not believe that they are required to provide safe, adequate and reliable electric service. It should be noted that the Company agreed to remove similar governmental affairs expenses in its recent gas base rate case, Case No. 2005-00042.[12] As shown in footnote (1) of Schedule RJH-15, the total Forecasted Period governmental affairs expenses amount to $120,970. However, of this total expense, an amount of $81,921 was already excluded from the Forecasted Period as part of the Company's proposed Miscellaneous Expense adjustment detailed on WPD-2.22a. I recommend that the remaining Forecasted Period governmental expense amount of $39,049 also be excluded for ratemaking purposes in this case.

The second recommended expense adjustment concerns the Company's proposed Forecasted Period association dues. As shown in the response to AG-1-57, the Forecasted Period includes $181,260 for association dues. This same response also shows that the corresponding actual association dues for 2005 and the 12-month period ended May 31, 2006 were $105,817 and $130,633, respectively. In AG-2-16, DEK was requested to provide a detailed component breakout of the Forecasted Period association dues amount of $181,260. The Company's response was that such an expense component breakout is not available. In this same data response, the Company did provide a detailed component breakout of the actual association dues of $130,633 for the 12-month period ended 5/31/06. Since the Company cannot provide an adequate basis for its proposed Forecasted Period association dues amount of $181,260, I recommend

[12] See Appendix D to the Commission Order in Case No. 2005-00042.

that the actual association dues amount of $130,633 for the 12-month period ended 5/31/06 be used as the starting point for the appropriate Forecasted Period association dues determination. As shown in footnote (2) of Schedule RJH-15, I then removed various association dues components in order to arrive at the recommended net association dues amount of $55,607. This recommendation reduces the Company's proposed Forecasted Period association dues amount of $181,260 by $125,653.

Q. PLEASE DESCRIBE THE ASSOCIATION DUES COMPONENTS THAT YOU HAVE REMOVED FOR RATEMAKING PURPOSES IN THIS CASE, AS SHOWN IN FOOTNOTE (2) OF SCHEDULE RJH-15.

A. The first excluded association dues component concerns the Company's Edison Electric Institute ("EEI") dues of $68,692. EEI is an organization whose primary purpose is lobbying on behalf of the electric industry. On page 48 of its Order of the Company's most recent electric rate case, Case No. 91-370, the Commission made the following statements in support of its decision to disallow EEI dues for ratemaking purposes in that case:

> ULH&P indicated that it has not performed any cost/benefit analysis for the EEI dues. Further, ULH&P could not identify any specific benefits it or its ratepayers received from membership. The Commission is familiar with EEI and aware of the nature of its activities. We have excluded EEI membership dues in other rate proceedings when ratepayer benefit could not be demonstrated. Given the nature of EEI and ULH&P's lack of demonstrating ratepayer benefit of membership, the Commission has removed from operating expenses the allocated membership dues of $50,993.

In its response to AG-1-52 in the current case, where the Company was requested to provide the most recent study conducted to quantify the ratepayer benefits of the

Company's EEI membership, the Company stated that:

> Duke Energy Kentucky has not performed any formal studies to quantify the benefits of the Company's EEI membership.

Based on the aforementioned findings, I have recommended the removal of EEI dues for ratemaking purposes in this case.

The second excluded association dues component concerns American Gas Association ("AGA") dues of $4,456. I do not believe it appropriate that DEK's electric ratepayers be charged with these gas operations related dues.

The third and fourth excluded association dues components concern Democratic Leadership Council dues of $1,578 and American Legislative Exchange dues of $300. In my opinion, such dues should not be charged to the Company's ratepayers.

Q. PLEASE EXPLAIN THE FINAL MISCELLANEOUS EXPENSE ADJUSTMENT SHOWN ON SCHEDULE RJH-15, LINE 3.

A. This expense adjustment concerns various professional service fees that I have removed from the Forecasted Period based on my review of the Company's workpaper WPF-5b and its responses to Commission data requests KPSC-2-33 and KPSC-3-22. As shown on Schedule RJH-15, line 3 and footnote (3), the recommended expense adjustment totals $227,124.

Q. WHAT IS THE IMPACT OF YOUR MISCELLANEOUS EXPENSE

ADJUSTMENTS ON THE COMPANY'S PROPOSED FORECASTED PERIOD OPERATING INCOME?

A. As shown on Schedule RJH-15, line 6, my recommended miscellaneous expense adjustments have the effect of increasing the Company's proposed Forecasted Period net after-tax operating income by $239,915.

- **<u>Property Tax Adjustments</u>**

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED PROPERTY TAXES FOR THE FORECASTED PERIOD.

A. As shown on Schedules RJH-10, the Company's proposed property taxes for the Forecasted Period amount to $5,625,540. This proposed Forecasted Period property tax amount has not been adjusted downwards to reflect the fact that the Company in prior years has consistently been successful in negotiating assessment values lower than net book value with the Kentucky Department of Revenues ("KDR"). On page 10 of his direct testimony, Company witness Keith Butler states with regard to the Company's proposed property taxes:

> We calculated the property tax expense based on the assessed value of Duke Energy Kentucky's property located in Kentucky and Ohio with adjustments for anticipated property tax rate increases, additions including the power plant transfers, retirements and additional depreciation. As in prior years, Duke Energy Kentucky will attempt to negotiate proper assessment values with the KDR [Kentucky Department of Revenues]. The Company will notify the Commission of the result of its negotiations with the KDR for the 2006 tax year so the Commission can determine whether to adjust Duke Energy Kentucky's property tax expense for the forecasted test period....

Q. HOW SUCCESSFUL HAS THE COMPANY BEEN IN PRIOR YEARS IN ITS NEGOTIATIONS WITH THE KDR TO OBTAIN ASSESSMENT VALUES LOWER THAN NET BOOK VALUE?

A. As confirmed in the response to AG-1-20, during the 4-year period 2002 – 2005, the Company was able to negotiate the following final assessment values in comparison to net book value:

	Tentative Assessment (% of Net Book Value)	Final Negotiated Assessment (% of Net Book Value)
2002	112%	**85%**
2003	91%	**76%**
2004	106%	**79%**
2005	141%	**82%**
Average	113%	**81%**

Thus, while the KDR-established tentative assessments for DEK's properties averaged 113% of net book value for the most recent 4-year period 2002 - 2005, DEK was able to negotiate final assessment values that averaged 81% of net book value during this same period.

Q. HAS THE COMPANY RE-CALCULATED ITS FORECASTED PERIOD PROPERTY TAXES BASED ON THE ASSUMPTION THAT THE COMPANY, IN ITS CURRENT NEGOTIATIONS WITH THE KDR, WILL BE EQUALLY SUCCESSFUL IN REDUCING ITS PROPERTY ASSESSMENT VALUE AS IT WAS IN THE MOST RECENT 2005 TAX YEAR?

A. Yes. In its responses to AG-1-20b and AG-2-4, the Company has calculated the reduced Forecasted Period property taxes that would result if the Company would be successful in obtaining an assessment value of 82.27% (equal to the 2005 final assessment) of the

2006 net book value. As shown on Schedule RJH-16, lines 1 and 2, these reduced property taxes add to a total amount of $4,627,771, which is $997,769 lower than the Company's proposed Forecasted Period property taxes of $5,625,540.

Q. ARE THERE ADDITIONAL ISSUES WITH REGARD TO THE COMPANY'S PROPOSED FORECASTED PERIOD PROPERTY TAXES?

A. Yes. As confirmed in the Company's response to AG-2-5, the proposed Forecasted Period property taxes include $282,301 worth of property taxes associated with the non-jurisdictional plant for the Florence service building, which amount should be removed for ratemaking purposes in this case. This same response also indicates that property taxes of $24,807 associated with the Cox Road facility were not, but should be, included in the Forecasted Test Period. I have reflected these required property tax corrections on Schedule RJH-16, lines 3 and 4.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH REGARD TO THE APPROPRIATE FORECASTED PERIOD PROPERTY TAXES TO BE REFLECTED FOR RATEMAKING PURPOSES IN THIS CASE?

A. As shown on Schedule RJH-16, line 5, at this time I recommend that the appropriate Forecasted Period property taxes should amount to $4,370,277. This recommendation increases the Company's proposed Forecasted Period operating income by $768,598. I also recommend that if the actual assessment results of the Company's current negotiations with the KDR for the 2006 tax year become available before the close of record in this proceeding, the Company should re-calculate its Forecasted Period property taxes based on these latest negotiated assessment results, and these re-calculated property taxes should replace the currently recommended property tax levels on Schedule RJH-16, lines 1 and 2.

- **Interest Synchronization Adjustment**

Q. ON SCHEDULE RJH-17 YOU SHOW THE COMPANY'S PROPOSED AND YOUR RECOMMENDED INTEREST SYNCHRONIZATION ADJUSTMENTS. ARE THERE ANY ISSUES ASSOCIATED WITH THE INTEREST SYNCHRONIZATION ADJUSTMENT IN THIS CASE?

A. No, there are no issues per se. I agree with the approach and calculation components of the Company's proposed interest synchronization adjustment, and the only reason for the difference between the two adjustments is that the Company's proposed and my recommended electric capitalization balances and weighted cost of debt percentages are different.

As shown on Schedule RJH-17, the difference between my recommended and the Company's proposed interest synchronization adjustments increases the Company's proposed Forecasted Period net after-tax operating income by $466,834.

- **Depreciation Expense Adjustment**

Q. PLEASE EXPLAIN THE OPERATING INCOME ADJUSTMENT WITH

REGARD TO DEPRECIATION EXPENSES SHOWN ON SCHEDULE RJH-18.

A. This Forecasted Period operating income adjustment reflects my adoption of the depreciation expense recommendations contained in the testimony of Michael Majoros, the AG's expert depreciation witness. As shown on Schedule RJH-18, Mr. Majoros' depreciation recommendations reduce the Company's proposed Forecasted Period depreciation expenses by $9,996,000 which, in turn, increases DEK's proposed Forecasted Period net after-tax income by $6,120,551.

- **Transmission Cost Recovery Mechanism**

Q. IN THIS CASE THE COMPANY IS PROPOSING TO IMPLEMENT A TRACKER COST RECOVERY MECHANISM ("RIDER TCRM") TO PASS THROUGH TO CUSTOMERS INCREMENTAL CHANGES IN CERTAIN MISO TRANSMISSION COSTS AS COMPARED TO THE CORRESPONDING MISO TRANSMISSION COSTS INCLUDED IN BASE RATES. DO YOU AGREE WITH THIS PROPOSAL?

A. No. While counsel will address the legal issues relating to the establishment of a tracker, I will address the accounting impact of trackers and why this tracker should not be allowed.

Traditional ratemaking involves the establishment of a base rate that allows the utility an *opportunity* to recover its cost of service and to earn a fair rate of return but does not guarantee either because some expenses and revenues will rise and others will fall while the base rate remains the same. Both the risk and reward of the efficient operation of the company are on the utility when the cost of service is recovered through base rates. Trackers are formula rates that set up the elements of expense or revenue to be collected/credited under the rate. The tracker may result in a credit or charge based on how the included expenses and revenues actually materialize. The purpose of a tracker is to guarantee cost recovery.

From an accounting perspective, the impact of a tracker established in the context of general rate case, where the base rates are set on traditional principles of ratemaking, is to declare that the general rates established in the case cannot in and of themselves be fair, just and reasonable because the expenses and revenues covered by the tracker cannot be accommodated within the traditional ratemaking expectation that some expenses and revenues will rise and others will fall, but the *opportunity* to earn will continue to be present until new rates are sought. Outside of (i) trackers agreed to by all parties to allow the parties to give and/or receive the benefits of settlements, and (ii) trackers allowed or required by the state's regulatory scheme, my experience has been that trackers are generally utilized only when the covered costs or revenues represent a very significant portion of the utility's total operating costs or operating revenues – i.e., are "material" - and exhibit extreme volatility and unpredictability. These are the properties that underlie the most commonly utilized trackers, fuel adjustment clauses and gas recovery clauses. Rate recovery through a tracking mechanism should continue to be allowed only when very specific requirements of materiality and volatility can be met.

As shown and source-referenced on Schedule RJH-20, while the Company's Forecasted Period total MISO costs amount to $21,876,213, the only component of these total MISO transmission costs that the Company has claimed is potentially volatile is the MISO Day 2 market cost of $12,047,693. I believe that this MISO cost component fails to meet the "materiality" requirement. The MISO Day 2 market cost of $12,047,693 represents only 5.3% of the total Forecasted Period O&M expenses.[13] By comparison, the Company's Forecasted Period fuel and purchased power expense of $113,892,375 (for which the Company has a fuel adjustment clause) represents 50.3%[14] of the total Forecasted Period O&M expenses. It should also be noted that the annual MISO Day 2 market cost of $12,047,693 will be included in the Company's base rates and only the potential annual *change* from this base rate cost represents a cost volatility. From this perspective, the materiality of the cost subject to volatility would probably be close to negligible.

In summary, I don't believe that the MISO costs that are subject to potential volatility can be considered material enough to justify the implementation of the proposed tracking mechanism. I also note that if the Commission were to allow the Company's tracking mechanism proposal, this would represent a novelty in that it would, for the first time, introduce a tracker in an area (transmission) where previously no trackers have been allowed.

[13] $12,047,693 divided by total Forecasted Period O&M expenses of $226,948,657 is 5.30%.

[14] $113,892,375 divided by total Forecasted Period O&M expenses of $226,948,657 is 50.2%.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING THIS ISSUE?

A. Yes. In its testimonies and in the proposed Rider TCRM tariff sheet on Schedule L-2.2, page 71 of 88, the Company seems to indicate that the only MISO costs that would be eligible for inclusion in Rider TCRM would be the MISO Day 2 market costs. For the Forecasted Period this MISO cost amounts to $12,047,693. For example, Mr. Wathen states on page 35 of his direct testimony:

> The Company proposes traditional base rate recovery of its projected transmission costs for the forecasted test year. In addition, because of the volatility and magnitude of <u>transmission costs associated with participation in the Midwest ISO Day 2 market,</u> we propose to establish a tracker cost recovery mechanism ("Rider TCRM") to pass through to customers incremental changes in costs compared to the amounts included in base rates. (emphasis supplied)

In addition, the proposed Rider TCRM tariff sheet on Schedule L-2.2, page 71 shows that the future eligible TCRM costs will be compared to the corresponding TCRM costs in the "base year" (the Forecasted Period in this proceeding) and the eligible TCRM costs in the base year are shown to be the Forecasted Period MISO Day 2 market costs of $12,047,693.

However, in its response to AG-2-23, the Company now indicates that it proposes that the Rider TCRM eligible costs would include *all* MISO costs of $21,876,213,[15] including the $9,828,520 MISO cost components that are to be considered stable, not volatile. This is inconsistent with the Company's testimony and tariff sheet regarding Rider TCRM and requires clarification on the part of the Company in its rebuttal

[15] See Schedule RJH-20 for a breakout of this total cost amount.

testimony.

Q. MR. HENKES, DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES OF	)	
THE UNION LIGHT, HEAT AND POWER COMPANY	)	**CASE NO. 2006-00172**
D/B/A DUKE ENERGY KENTUCKY, INC.	)	

AFFIDAVIT

I, Robert J. Henkes, hereby swear and affirm that the foregoing testimony and all supporting appendices and schedules were prepared by me or under my direct supervision and are, to the best of my information and belief, true and accurate.

____

COMMONWEALTH/STATE OF CT
COUNTY OF Fairfield

Subscribed and sworn to before me by Robert J. Henkes this the 7th day of September, 2006.

My Commission Expires: 2/28/10

LISA A LATTANZIO
Notary Public
State of Connecticut
My Commission Expires 02/28/2010

____
Notary Public, State at Large

APPENDIX I

PRIOR REGULATORY EXPERIENCE OF ROBERT J. HENKES

* = Testimonies prepared and submitted

ARKANSAS

Southwestern Bell Telephone Company Divestiture Base Rate Proceeding*	Docket 83-045-U	09/1983

DELAWARE

Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 41-79	04/1980
Delmarva Power and Light Company Electric Fuel Clause Proceeding	Docket 80-39	02/1981
Delmarva Power and Light Company Sale of Power Station Generation	Complaint Docket 279-80	04/1981
Delmarva Power and Light Company Electric Base Rate Proceeding	Docket 81-12	06/1981
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 81-13	08/1981
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 82-45	04/1983
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 83-26	04/1984
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 84-30	04/1985
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 85-26	03/1986
Delmarva Power and Light Company Report of DP&L Operating Earnings*	Docket 86-24	07/1986
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 86-24	12/1986 01/1987
Delmarva Power and Light Company	Docket 85-26	10/1986

Report Re. PROMOD and Its Use in Fuel Clause Proceedings*		
Diamond State Telephone Company Base Rate Proceeding*	Docket 86-20	04/1987
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 87-33	06/1988
Delmarva Power and Light Company Electric Fuel Clause Proceeding*	Docket 90-35F	05/1991
Delmarva Power and Light Company Electric Base Rate Proceeding*	Docket 91-20	10/1991
Delmarva Power and Light Company Gas Base Rate Proceeding*	Docket 91-24	04/1992
Artesian Water Company Water Base Rate Proceeding*	Docket 97-66	07/1997
Artesian Water Company Water Base Rate Proceeding*	Docket 97-340	02/1998
United Water Delaware Water Base Rate Proceeding*	Docket 98-98	08/1998
Delmarva Power and Light Company Revenue Requirement and Stranded Cost Reviews	Not Docketed	12/1998
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Direct Test.)	09/1999
Artesian Water Company Water Base Rate Proceeding*	Docket 99-197 (Supplement. Test)	10/1999
Tidewater Utilities/ Public Water Co. Water Base Rate Proceedings*	Docket No. 99-466	03/2000
Delmarva Power & Light Company Competitive Services Margin Sharing Proceeding*	Docket No. 00-314	03/2001
Artesian Water Company Water Base Rate Proceeding*	Docket No. 00-649	04/2001

Chesapeake Gas Company Gas Base Rate Proceeding*	Docket No. 01-307	12/2001
Tidewater Utilities Water Base Rate Proceeding*	Docket No. 02-28	07/2002
Artesian Water Company Water Base Rate Proceeding*	Docket No. 02-109	09/2002
Delmarva Power & Light Company Electric Cost of Service Proceeding	Docket No. 02-231	03/2003
Delmarva Power & Light Company Gas Base Rate Proceeding*	Docket No. 03-127	08/2003
Artesian Water Company Water Base Rate Proceeding*	Docket No. 04-42	08/2004

DISTRICT OF COLUMBIA

District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 870	05/1988
District of Columbia Natural Gas Co. Gas Base Rate Proceeding*	Formal Case 890	02/1990
District of Columbia Natural Gas Co. Waiver of Certain GS Provisions	Formal Case 898	08/1990
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 850	07/1991
Chesapeake and Potomac Telephone Co. Base Rate Proceeding*	Formal Case 926	10/1993
Bell Atlantic - District of Columbia SPF Surcharge Proceeding	Formal Case 926	06/19/94
Bell Atlantic - District of Columbia Price Cap Plan and Earnings Review	Formal Case 814 IV	07/1995

GEORGIA

Southern Bell Telephone Company	Docket 3465-U	08/1984

Base Rate Proceeding		
Southern Bell Telephone Company Base Rate Proceeding	Docket 3518-U	08/1985
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3673-U	08/1987
Georgia Power Company Electric Base Rate and Nuclear Power Plant Phase-In Proceeding*	Docket 3840-U	08/1989
Southern Bell Telephone Company Base Rate Proceeding	Docket 3905-U	08/1990
Southern Bell Telephone Company Implementation, Administration and Mechanics of Universal Service Fund*	Docket 3921-U	10/1990
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket 4177-U	08/1992
Southern Bell Telephone Company Report on Cash Working Capital*	Docket 3905-U	03/1993
Atlanta Gas Light Company Gas Base Rate Proceeding*	Docket No. 4451-U	08/1993
Atlanta Gas Light Company Gas Base Rate Proceeding	Docket No. 5116-U	08/1994
Georgia Independent Telephone Companies Earnings Review and Show Cause Proceedings	Various Dockets	1994
Georgia Power Company Earnings Review - Report to GPSC*	Non-Docketed	09/1995
Georgia Alltel Telecommunication Companies Earnings and Rate Reviews	Docket No. 6746-U	07/1996
Frontier Communications of Georgia Earnings and Rate Review	Docket No. 4997-U	07/1996
Georgia Power Company Electric Base Rate / Accounting Order Proceeding	Docket No. 9355-U	12/1998

Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 14618-U	03/2002
Georgia Power Company Electric Base Rate / Alternative Rate Plan Proceeding*	Docket No. 18300-U	12/2004
Savannah Electric Power Company Electric Base Rate Case/Alternative Rate Plan*	Docket No. 19758-U	03/2005

<u>FERC</u>

Philadelphia Electric/Conowingo Power Electric Base Rate Proceeding*	Docket ER 80-557/558	07/1981

<u>KENTUCKY</u>

Kentucky Power Company Electric Base Rate Proceeding*	Case 8429	04/1982
Kentucky Power Company Electric Base Rate Proceeding*	Case 8734	06/1983
Kentucky Power Company Electric Base Rate Proceeding*	Case 9061	09/1984
South Central Bell Telephone Company Base Rate Proceeding*	Case 9160	01/1985
Kentucky-American Water Company Base Rate Proceeding*	Case 97-034	06/1997
Delta Natural Gas Company Base Rate Proceeding*	Case 97-066	07/1997
Kentucky Utilities and LG&E Company Environmental Surcharge Proceeding	97-SC-1091-DG	01/1999
Delta Natural Gas Company Experimental Alternative Regulation Plan*	Case No. 99-046	07/1999
Delta Natural Gas Company Base Rate Proceeding*	Case No. 99-176	09/1999

Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2000-080	06/2000
Kentucky-American Water Company Base Rate Proceeding*	Case No. 2000-120	07/2000
Jackson Energy Cooperative Corporation Electric Base Rate Proceeding*	Case No. 2000-373	02/2001
Kentucky-American Water Company Base Rate Rehearing*	Case No. 2000-120	02/2001
Kentucky-American Water Company Rehearing Opposition Testimony*	Case No. 2000-120	03/2001
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2001-092	09/2001
Louisville Gas & Electric Company and Kentucky Utilities Company Deferred Debits Accounting Order	Case No. 2001-169	10/2001
Fleming-Mason Energy Cooperative Electric Base Rate Proceeding	Case No. 2001-244	05/2002
Northern Kentucky Water District Water District Base Rate Proceeding	Case No. 2003-0224	02/2004
Louisville Gas & Electric Company Electric Base Rate Proceeding*	Case No. 2003-0433	03/2004
Louisville Gas & Electric Company Gas Base Rate Proceeding*	Case No. 2003-0433	03/2004
Delta Natural Gas Company Base Rate Proceeding*	Case No. 2004-00067	07/2004
Union Light Heat and Power Company Gas Base Rate Proceeding*	Case No. 2005-00042	06/2005
Big Sandy Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00125	08/2005
Louisville Gas & Electric Company Value Delivery Surcredit Mechanism*	Case No. 2005-00352	12/2005

Kentucky Utilities Company Value Delivery Surcredit Mechanism*	Case No. 2005-00351	12/2005
Kentucky Power Company Electric Base Rate Proceeding*	Case No. 2005-00341	01/2006
Cumberland Valley Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00187	05/2006
South Kentucky Rural Electric Cooperative Electric Base Rate Proceeding	Case No. 2005-00450	07/2006

MAINE

Continental Telephone Company of Maine Base Rate Proceeding	Docket 90-040	12/1990
Central Maine Power Company Electric Base Rate Proceeding	Docket 90-076	03/1991
New England Telephone Corporation - Maine Chapter 120 Earnings Review	Docket 94-254	12/1994

MARYLAND

Potomac Electric Power Company Electric Base Rate Proceeding*	Case 7384	01/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7427	08/1980
Chesapeake and Potomac Telephone Company Western Electric and License Contract	Case 7467	10/1980
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7467	10/1980
Washington Gas Light Company Gas Base Rate Proceeding	Case 7466	11/1980
Delmarva Power and Light Company Electric Base Rate Proceeding*	Case 7570	10/1981
Chesapeake and Potomac Telephone Company	Case 7591	12/1981

Base Rate Proceeding*		
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7661	11/1982
Chesapeake and Potomac Telephone Company Computer Inquiry II*	Case 7661	12/1982
Chesapeake and Potomac Telephone Company Divestiture Base Rate Proceeding*	Case 7735	10/1983
AT&T Communications of Maryland Base Rate Proceeding	Case 7788	1984
Chesapeake and Potomac Telephone Company Base Rate Proceeding*	Case 7851	03/1985
Potomac Electric Power Company Electric Base Rate Proceeding	Case 7878	1985
Delmarva Power and Light Company Electric Base Rate Proceeding	Case 7829	1985

NEW HAMPSHIRE

Granite State Electric Company Electric Base Rate Proceeding	Docket DR 77-63	1977

NEW JERSEY

Elizabethtown Water Company Water Base Rate Proceeding	Docket 757-769	07/1975
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 759-899	09/1975
Middlesex Water Company Water Base Rate Proceeding	Docket 761-37	01/1976
Jersey Central Power and Light Company Electric Base Rate Proceeding	Docket 769-965	09/1976
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings	Docket 761-8	10/1976

Atlantic City Electric Company Electric Base Rate Proceeding*	Docket 772-113	04/1977
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 7711-1107	05/1978
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 794-310	04/1979
Rockland Electric Company Electric Base Rate Proceeding*	Docket 795-413	09/1979
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 802-135	02/1980
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8011-836	02/1981
Rockland Electric Company Electric Base Rate Proceeding*	Docket 811-6	05/1981
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 8110-883	02/1982
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket 812-76	08/1982
Public Service Electric and Gas Company Raw Materials Adjustment Clause	Docket 812-76	08/1982
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8211-1030	11/1982
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 829-777	12/1982
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket 837-620	10/1983
New Jersey Bell Telephone Company Base Rate Proceeding	Docket 8311-954	11/1983
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1035	02/1984

Rockland Electric Company Electric Fuel Clause Proceeding*	Docket 849-1014	11/1984
AT&T Communications of New Jersey Base Rate Proceeding*	Docket 8311-1064	05/1985
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER8512-1163	05/1986
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	07/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8609-973	12/1986
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER8710-1189	01/1988
Public Service Electric and Gas Company Electric Fuel Clause Proceeding*	Docket ER8512-1163	02/1988
United Telephone of New Jersey Base Rate Proceeding	Docket TR8810-1187	08/1989
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket ER9009-10695	09/1990
United Telephone of New Jersey Base Rate Proceeding	Docket TR9007-0726J	02/1991
Elizabethtown Gas Company Gas Base Rate Proceeding*	Docket GR9012-1391J	05/1991
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER9109145J	11/1991
Jersey Central Power and Light Company Electric Fuel Clause Proceeding	Docket ER91121765J	03/1992
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR9108-1393J	03/1992
Public Service Electric and Gas Company Electric and Gas Base Rate Proceedings*	Docket ER91111698J	07/1992
Rockland Electric Company	Docket ER92090900J	12/1992

Electric Fuel Clause Proceeding		
Middlesex Water Company Water Base Rate Proceeding*	Docket WR92090885J	01/1993
Elizabethtown Water Company Water Base Rate Proceeding*	Docket WR92070774J	02/1993
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER91111698J	03/1993
New Jersey Natural Gas Company Gas Base Rate Proceeding*	Docket GR93040114	08/1993
Atlantic City Electric Company Electric Fuel Clause Proceeding	Docket ER94020033	07/1994
Borough of Butler Electric Utility Various Electric Fuel Clause Proceedings	Docket ER94020025	1994
Elizabethtown Water Company Water Base Rate Proceeding	Non-Docketed	11/1994
Public Service Electric and Gas Company Electric Fuel Clause Proceeding	Docket ER 94070293	11/1994
Rockland Electric Company Electric Fuel Clause Proceeding and Purchased Power Contract By-Out	Docket Nos. 940200045 and ER 9409036	12/1994
Jersey Central Power & Light Company Electric Fuel Clause Proceeding	Docket ER94120577	05/1995
Elizabethtown Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR95010010	05/1995
Middlesex Water Company Purchased Water Adjustment Clause Proceeding	Docket WR94020067	05/1995
New Jersey American Water Company* Base Rate Proceeding	Docket WR95040165	01/1996
Rockland Electric Company Electric Fuel Clause Proceeding	Docket ER95090425	01/1996
United Water of New Jersey	Docket WR95070303	01/1996

Base Rate Proceeding*		
Elizabethtown Water Company Base Rate Proceeding*	Docket WR95110557	03/1996
New Jersey Water and Sewer Adjustment Clauses Rulemaking Proceeding*	Non-Docketed	03/1996
United Water Vernon Sewage Company Base Rate Proceeding*	Docket WR96030204	07/1996
United Water Great Gorge Company Base Rate Proceeding*	Docket WR96030205	07/1996
South Jersey Gas Company Base Rate Proceeding	Docket GR960100932	08/1996
Middlesex Water Company Purchased Water Adjustment Clause Proceeding*	Docket WR96040307	08/1996
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER96030257	08/1996
Public Service Electric & Gas Company and Atlantic City Electric Company Investigation into the continuing outage of the Salem Nuclear Generating Station*	Docket Nos. ES96039158 & ES96030159	10/1996
Rockland Electric Company Electric Fuel Clause Proceeding*	Docket No.EC96110784	01/1997
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No.WR96100768	03/1997
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER97020105	08/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	11/1997
Atlantic City Electric Company Limited Issue Rate Proceeding*	Docket No.ER97080562	12/1997
Rockland Electric Company Limited Issue Rate Proceeding	Docket No.ER97080567	12/1997

South Jersey Gas Company Limited Issue Rate Proceeding	Docket No.GR97050349	12/1997
New Jersey American Water Company Limited Issue Rate Proceeding	Docket No.WR97070538	12/1997
Elizabethtown Water Company and Mount Holly Water Company Limited Issue Rate Proceedings	Docket Nos. WR97040288, WR97040289	12/1997
United Water of New Jersey, United Water Toms River and United Water Lambertville Limited Issue Rate Proceedings	Docket Nos.WR9700540, WR97070541, WR97070539	12/1997
Public Service Electric & Gas Company Electric Restructuring Proceedings*	Docket Nos. EX912058Y, EO97070461, EO97070462, EO97070463	01/1998
Consumers New Jersey Water Company Base Rate Proceeding*	Docket No. WR97080615	01/1998
New Jersey-American Water Company Base Rate Proceeding*	Docket No.WR98010015	07/1998
Consumers New Jersey Water Company Merger Proceeding	Docket No.WM98080706	12/1998
Atlantic City Electric Company Fuel Adjustment Clause Proceeding*	Docket No.ER98090789	02/1999
Middlesex Water Company Base Rate Proceeding*	Docket No.WR98090795	03/1999
Mount Holly Water Company Base Rate Proceeding - Phase I*	Docket No. WR99010032	07/1999
Mount Holly Water Company Base Rate Proceeding - Phase II*	Docket No. WR99010032	09/1999
New Jersey American Water Company Acquisitions of Water Systems	Docket Nos. WM9910018 WM9910019	09/1999 09/1999
Mount Holly Water Company Merger with Homestead Water Utility	Docket No. WM99020091	10/1999

Applied Wastewater Management, Inc. Merger with Homestead Treatment Utility	Docket No.WM99020090	10/1999
Environmental Disposal Corporation (Sewer) Base Rate Proceeding*	Docket No.WR99040249	02/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No.GR99070509	03/2000
DSM Adjustment Clause Proceeding	Docket No. GR99070510	03/2000
New Jersey American Water Company Gain on Sale of Land	Docket No. WM99090677	04/2000
Jersey Central Power & Light Company NUG Contract Buydown	Docket No. EM99120958	04/2000
Shore Water Company Base Rate Proceeding	Docket No. WR99090678	05/2000
Shorelands Water Company Water Diversion Rights Acquisition	Docket No. WO00030183	05/2000
Mount Holly and Elizabethtown Water Companies Computer and Billing Services Contracts	Docket Nos. WO99040259 WO9904260	06/2000 06/2000
United Water Resources, Inc. Merger with Suez-Lyonnaise	Docket No. WM99110853	06/2000
E'Town Corporation Merger with Thames, Ltd.	Docket No. WM99120923	08/2000
Consumers Water Company Water Base Rate Proceeding*	Docket No. WR00030174	09/2000
Atlantic City Electric Company Buydown of Purchased Power Contract	Docket No. EE00060388	09/2000
Applied Wastewater Management, Inc. Authorization for Accounting Changes	Docket No. WR00010055	10/2000
Elizabethtown Gas Company		
Gas Cost Adjustment Clause Proceeding	Docket No. GR00070470	10/2000
DSM Adjustment Clause Proceeding	Docket No. GR00070471	10/2000
Trenton Water Works Water Base Rate Proceeding*	Docket No. WR00020096	10/2000

Middlesex Water Company Water Base Rate Proceeding*	Docket No. WR00060362	11/2000
New Jersey American Water Company Land Sale - Ocean City	Docket No. WM00060389	11/2000
Pineland Water Company Water Base Rate Proceeding*	Docket No. WR00070454	12/2000
Pineland Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR00070455	12/2000
Elizabethtown Gas Company Regulatory Treatment of Gain on Sale of Property*	Docket No. GR00070470	02/2001
Wildwood Water Utility Water Base Rate Proceeding*	Docket No. WR00100717	04/2001
Roxbury Water Company Water Base Rate Proceeding	Docket No. WR01010006	06/2001
SB Water Company Water Base Rate Proceeding	Docket No. WR01040232	06/2001
Pennsgrove Water Company Water Base Rate Proceeding*	Docket No. WR00120939	07/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Direct Testimony	Docket No. GR01050328	08/2001
Public Service Electric & Gas Company Gas Base Rate Proceeding* Surrebuttal Testimony	Docket No. GR01050328	09/2001
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR01040205	10/2001
Middlesex Water Company Financing Proceeding	Docket No. WF01090574	12/2001
New Jersey American Water Company Financing Proceeding	Docket No. WF01050337	12/2001

Consumers New Jersey Water Company Stock Transfer/Change in Control Proceeding	Docket No. WF01080523	01/2002
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding*	Docket No. WM01120833	07/2002
Borough of Haledon – Water Department Water Base Rate Proceeding*	Docket No. WR01080532	07/2002
New Jersey American Water Company Change of Control (Merger) Proceeding	Docket No. WM02020072	09/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02050303	10/2002
United Water Lambertville Land Sale Proceeding	Docket No. WM02080520	11/2002
United Water Vernon Hills & Hampton Management Service Agreement	Docket No. WE02080528	11/2002
United Water New Jersey Metering Contract With Affiliate	Docket No. WO02080536	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Surrebuttal and Supplemental Surrebuttal Testimonies*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Minimum Pension Liability Proceeding	Docket No. EO02110853	12/2002
Public Service Electric & Gas Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02050303	12/2002
Public Service Electric & Gas Company Electric Deferred Balance Proceeding Direct Testimony*	Docket No. ER02050303	01/2003
Rockland Electric Company Electric Base Rate Proceeding Direct Testimony*	Docket No. ER02100724	01/2003

Public Service Electric & Gas Company Supplemental Direct Testimony*	Docket No. ER02050303	02/2003
Rockland Electric Company Electric Base Rate Proceeding Supplemental Direct Testimony*	Docket No. ER02100724	02/2003
Consumers New Jersey Water Company Acquisition of Maxim Sewerage Company	Docket No. WM02110808	05/2003
Rockland Electric Company Audit of Competitive Services	Docket No. EA02020098	06/2003
New Jersey Natural Gas Company Audit of Competitive Services	Docket No. GA02020100	06/2003
Public Service Electric & Gas Company Audit of Competitive Services	Docket No. EA02020097	06/2003
Mount Holly Water Company Water Base Rate Proceeding*	Docket No. WR03070509	12/2003
Elizabethtown Water Company Water Base Rate Proceeding*	Docket No. WR03070510	12/2003
New Jersey-American Water Company Water and Sewer Base Rate Proceeding*	Docket No. WR03070511	12/2003
Applied Wastewater Management, Inc. Water and Sewer Base Rate Proceeding*	Docket No. WR03030222	01/2004
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR03110900	04/2004
Consumers New Jersey Water Company Water Base Rate Proceeding	Docket No. WR02030133	07/2004
Roxiticus Water Company Purchased Water Adjustment Clause	Docket No. WR04060454	08/2004
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET04040235	08/2004
Wildwood Water Utility Water Base Rate Proceeding - Interim Rates	Docket No. WR04070620	08/2004

United Water Toms River Litigation Cost Accounting Proceeding	Docket No. WF04070603	11/2004
Lake Valley Water Company Water Base Rate Proceeding	Docket No. WR04070722	12/2004
Public Service Electric & Gas Company Customer Account System Proceeding	Docket No. EE04070718	02/2005
Jersey Central Power and Light Company Various Land Sales Proceedings	Docket No. EM04101107 Docket No. EM04101073 Docket No. EM04111473	02/2005 02/2005 03/2005
Environmental Disposal Corporation Water Base Rate Proceeding	Docket No. WR040080760	05/2005
Universal Service Fund Compliance Filing For 7 New Jersey Electric and Gas Utilities	Docket No. EX00020091	05/2005
Rockland Electric Company Societal Benefit Charge Proceeding	Docket No. ET05040313	08/2005
Public Service Electric & Gas Company Buried Underground Distribution Tariff Proceeding	Docket No. ET05010053	08/2005
Aqua New Jersey Acquisition of Berkeley Water Co. Water Merger Proceeding	Docket No. WM04121767	08/2005
Middlesex Water Company Water Base Rate Proceeding	Docket No. WR05050451	10/2005
Public Service Electric & Gas Company Land Sale Proceeding	Docket No. EM05070650	10/2005
Public Service Electric & Gas Company Merger of PSEG and Exelon Corporation Direct Testimony	Docket No. EM05020106	11/2005
Public Service Electric & Gas Company* Merger of PSEG and Exelon Corporation Surrebuttal Testimony	Docket No. EM05020106	12/2005
Public Service Electric & Gas Company* Financial Review of Electric Operations	Docket No. ER02050303	12/2005

Rockland Electric Company Competitive Services Audit	Docket No. EA02020098	12/2005
Public Service Electric & Gas Company Customer Accounting System Cost Recovery	Docket No. EE04070718	01/2006
Roxiticus Water Company Stock Sale and Change of Ownership and Control	Docket No. WM05080755	01/2006
Public Service Electric & Gas Company Competitive Services Audit	Docket No. EA02020097	02/2006
Wildwood Water Company Water Base Rate Proceeding	Docket No. WR05070613	03/2006
Pinelands Water Company Water Base Rate Proceeding*	Docket No. WR05080681	03/2006
Pinelands Wastewater Company Wastewater Base Rate Proceeding*	Docket No. WR05080680	03/2006
Aqua New Jersey Water Company Water Base Rate Proceeding*	Docket No. WR05121022	06/2006
Public Service Electric & Gas Company Gas Base Rate Proceeding*	Docket No. GR05100845	07/2006

NEW MEXICO

Southwestern Public Service Company Electric Base Rate Proceeding*	Case 1957	11/1985
El Paso Electric Company Rate Moderation Plan	Case 2009	1986
El Paso Electric Company Electric Base Rate Proceeding	Case 2092	06/1987
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2147	03/1988
El Paso Electric Company Electric Base Rate Proceeding*	Case 2162	06/1988
Public Service Company of New Mexico	Case 2146/Phase II	10/1988

Phase-In Plan*		
El Paso Electric Company Electric Base Rate Proceeding*	Case 2279	11/1989
Gas Company of New Mexico Gas Base Rate Proceeding*	Case 2307	04/1990
El Paso Electric Company Rate Moderation Plan*	Case 2222	04/1990
Generic Electric Fuel Clause - New Mexico Amendments to NMPSC Rule 550	Case 2360	02/1991
Southwestern Public Service Company Rate Reduction Proceeding	Case 2573	03/1994
El Paso Electric Company Base Rate Proceeding	Case 2722	02/1998

OHIO

Dayton Power and Light Company Electric Base Rate Proceeding	Case 76-823	1976

PENNSYLVANIA

Duquesne Light Company Electric Base Rate Proceeding*	R.I.D. No. R-821945	09/1982
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	04/1984
AT&T Communications of Pennsylvania Base Rate Proceeding*	Docket P-830452	11/1984
National Fuel Gas Distribution Company Gas Base Rate Proceeding*	Docket R-870719	12/1987

RHODE ISLAND

Blackstone Valley Electric Company Electric Base Rate Proceeding	Docket No. 1289	

Newport Electric Company
Report on Emergency Relief

VERMONT

Continental Telephone Company of Vermont Base Rate Proceeding	Docket No. 3986	
Green Mountain Power Corporation Electric Base Rate Proceeding	Docket No. 5695	01/1994
Central Vermont Public Service Corp. Rate Investigation	Docket No. 5701	04/1994
Central Vermont Public Service Corp. Electric Base Rate Proceeding*	Docket No. 5724	05/1994
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5780	01/1995
Green Mountain Power Corporation Electric Base Rate Proceeding*	Docket No. 5857	01/1996

VIRGIN ISLANDS

Virgin Islands Telephone Corporation Base Rate Proceeding*	Docket 126	

DUKE ENERGY KENTUCKY

CASE NO. 2006-000172

<u>SCHEDULES RJH-1 THROUGH RJH-20</u>

Foreasted Period Ended 12/31/07 Sch. RJH-3
Case No. 2006-00172

DUKE ENERGY KENTUCKY
RATE OF RETURN

DEK PROPOSED RATE OF RETURN	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)
Common Equity	50.882%	11.500%	5.851%
Long-Term Debt	40.626%	6.090%	2.474%
Short-Term Debt	8.492%	5.138%	0.436%
Total	100.000%		8.761%

AG's RECOMMENDED RATE OF RETURN	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)
Common Equity	50.882%	9.500% (2)	4.834%
Long-Term Debt	40.626%	6.090%	2.474%
Short-Term Debt	8.492%	5.138%	0.436%
Total	100.000%		7.744%

(1) Filing Schedule J-1, page 2.
(2) Testimony of Dr. J. Randall Woolridge

Forecasted Period Ended 12/31/07
Case No. 2006-00172

DUKE ENERGY KENTUCKY
REVENUE DEFICIENCY

		DEK (1)	Adjustment	AG	
1.	Capitalization Allocated to Electric	$ 557,080,702	$ (6,385,040)	$ 550,695,662	Sch. RJH-4
2.	Rate of Return	8.761%		7.507%	Sch. RJH-3
3.	Operating Income Requirement	48,805,840		41,339,397	
4.	Pro Forma Operating Income	20,525,377	20,179,388	40,704,765	Sch. RJH-7
5.	Operating Income Deficiency	28,280,463		634,632	
6.	Gross Revenue Conversion Factor	1.6449687		1.6408112	Sch. RJH-2
7.	Revenue Deficiency Excluding Fuel	46,519,810	(45,478,499)	1,041,311	
8.	Increase in Fuel Revenue Req.	20,040,364		20,040,364	
9.	Requested Revenue Increase Including Fuel	$ 66,560,174	$ (45,478,499)	$ 21,081,675	

(1) Filing Schedule A

Forecasted Period Ended 12/31/07
Case No. 2006-00172

DUKE ENERGY KENTUCKY
REVENUE CONVERSION FACTOR

	DEK (1)	Adjustment	AG	
1. Operating Revenues	100.00%		100.00%	
2. Less: a. Uncollectible Expense	0.5493%		0.3004%	(2)
b. KPSC Maintenance Tax	0.1670%		0.1643%	(3)
c. Total	0.7163%		0.4647%	
3. Income Before SIT and FIT	99.2837%		99.5353%	
4. State Income Tax @ 5.80%	5.7585%		5.7730%	
5. Income Before FIT	93.5252%		93.7623%	
6. Federal Income Tax @ 35%	32.7338%		32.8168%	
7. After-Tax Income	60.7914%		60.9455%	
8. Revenue Conversion Factor [L1 / L7]	1.6449687	(0.0041575)	1.6408112	

(1) Schedule H, page 2

(2) Per response to AG-2-11:

- Adjusted net charge-off per filing	$ 867,292
- Total billings subject to charge-off	$ 288,693,617
- Percent net charge offs to total billings	0.3004%

(3) Response to AG-1-45c

DUKE ENERGY KENTUCKY
RATE OF RETURN

DEK PROPOSED RATE OF RETURN	Ratios	Cost Rates	Weighted Cost Rates
	(1)	(1)	(1)
Common Equity	50.882%	11.500%	5.851%
Long-Term Debt	40.626%	6.090%	2.474%
Short-Term Debt	8.492%	5.138%	0.436%
Total	100.000%		8.761%

AG's RECOMMENDED RATE OF RETURN	Ratios	Cost Rates	Weighted Cost Rates
	(2)	(2)	(2)
Common Equity	46.940%	9.250%	4.342%
Long-Term Debt	46.070%	6.090%	2.806%
Short-Term Debt	6.990%	5.138%	0.359%
Total	100.000%		7.507%

(1) Filing Schedule J-1, page 2.
(2) Testimony of Dr. J. Randall Woolridge, Schedule JRW-1

DUKE ENERGY KENTUCKY
ELECTRIC-ALLOCATED CAPITALIZATION

	DEK (1)	Adjustment	AG	
1. Total Capitalization	$ 678,813,216		$ 678,813,216	
2. Less: Non-Jurisdictional Plant	60,297,309		60,297,309	
3. Jurisdictional Capitalization	739,110,525		739,110,525	
4. Electric Jurisdictional Rate Base Allocator	74.439%		74.413%	Sch. RJH-5
5. Electric Jurisdictional Capitalization	550,186,484	(189,855)	549,996,629	
6. Plus: Jurisdictional Electric ITC	699,033		699,033	
7. Cap. Increase from AMI Project	6,195,185	(6,195,185)	-	(2)
8. Total Electric-Allocated Capitalization	$ 557,080,702	$ (6,385,040)	$ 550,695,662	

(1) WPA-1c
(2) Testimony of Robert J. Henkes

Forec...ed Period Ended 12/31/07
Case No. 2006-00172

DUKE ENERGY KENTUCKY
ELECTRIC-ALLOCATED JURISDICTIONAL RATE BASE

	A	B	C		D	E
	Electric Jurisdictional Rate Base				Gas Jursidictional Rate Base	Total Co. Jursidictional Rate Base
	DEK	Adjustment	AG			
	(1)		[A+B]		(1)	[C+D]
1. Utility Plant in Service	$ 1,122,822,000		$ 1,122,822,000		$ 314,376,588	$ 1,437,198,588
2. CWIP	4,263,000		4,263,000		10,530,272	14,793,272
3. Fuel Inventory	8,873,933		8,873,933		-	8,873,933
4. Propane Inventory	-		-		647,500	647,500
5. Other Materials and Supplies	8,467,889		8,467,889		172,385	8,640,274
6. Gas Stored Underground	-		-		6,557,000	6,557,000
7. Prepayments	6,699,569		6,699,569		-	6,699,569
8. Emission Allowances	5,919,968		5,919,968		-	5,919,968
9. Cash Working Capital	13,962,791	(802,864)	13,159,927	(2)	2,388,409	15,548,336
10. Depreciation Reserve	(539,866,000)		(539,866,000)		(103,799,241)	(643,665,241)
11. Accumulated Deferred Income Taxes	(40,005,923)		(40,005,923)		(25,395,313)	(65,401,236)
12. Customer Advances for Construction	-		-		(2,468,711)	(2,468,711)
13. Investment Tax Credit - 3%	-		-		(25,042)	(25,042)
14. Total	$ 591,137,227	$ (802,864)	$ 590,334,363		$ 202,983,847	$ 793,318,210
15. Ratio of Electric Jurisdictional to Total Company Jurisdictional [C/E]:			74.413%			

(1) WPA-1d
(2) Sch. RJH-6, L3

DUKE ENERGY KENTUCKY
CASH WORKING CAPITAL

	DEK (1)	Adjustment	AG	
1. Total Pro Forma O&M Expense Exclusive of Fuel & Purchased Power Expense	$ 111,702,325	$ (6,422,912)	$ 105,279,413	Sch. RJH-19, L5
2. CWC Ratio	0.125	0.125	0.125	
3. Cash Working Capital	$ 13,962,791	$ (802,864)	$ 13,159,927	

(1) WPB-5.1a

DUKE ENERGY KENTUCKY
PRO FORMA OPERATING INCOME

1. Pro Forma Operating Income Proposed by DEK	$ 20,525,377	(1)
AG-Recommended Operating Income Adjustments:		
2. Emission Allowances Sales Proceeds	5,342,745	Sch. RJH-8
3. MISO Make-Whole Revenues	2,326,486	Sch. RJH-9
4. Rent Revenue from Common Facility Unit 7	406,014	Sch. RJH-10
5. Other Operating Revenues	446,326	Sch. RJH-11
6. Weather Normalization Adjustment	528,273	Sch. RJH-12
7. Reversal of AMI Operating Income Adjustment	(159,187)	(2)
8. Back-Up Power Sales Capacity Charges	3,289,841	Sch. RJH-13
9. Amortization of Deferred Expenses	402,993	Sch. RJH-14
10. Miscellaneous Expense Adjustments	239,915	Sch. RJH-15
11. Property Tax Adjustment	768,598	Sch. RJH-16
12. Interest Synchronization Adjustment	466,834	Sch. RJH-17
13. Depreciation Expense Adjustment	6,120,551	Sch. RJH-18
14. AG-Recommended Income Adjustments	20,179,388	
15. AG-Recommended Pro Forma Operating Income	$ 40,704,765	

(1) Filing Schedule C-1
(2) Schedule D-1, page 8

Forecasted Period Ended 12/31/07 | Sch. RJH-8
Case No. 2006-00172

DUKE ENERGY KENTUCKY
REVENUES FROM SALES OF EMISSION ALLOWANCES

1. Estimate of Acct. 411 - Emission Allowance Sale Proceeds in Forecasted Period	$	8,766,435	(1)
2. Impact on Uncollectibles @ .3004% of Line 1		26,334	
3. Impact on KPSC Assessments @ .1643% of Line 1		14,403	
4. Impact on Pre-Tax Operating Income [L1 - L2 - L3]		8,725,697	
5. Composite After-Tax Income Rate		61.23%	(2)
6. Impact on Operating Income	$	5,342,745	

(1) Per response to AG-2-7b:

- Actual 2005 Emission Allowance proceeds	$	10,102,405
- Actual 12-months ended 7/31/06 Emission Allowance proceeds		7,430,465
- Average Emission Allowance proceeds	$	8,766,435

(2) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

DUKE ENERGY KENTUCKY
MISO MAKE-WHOLE REVENUES

1. Estimate of Acct. 456025 - MISO Make-Whole Revenues in Forecasted Period	$	3,817,325	(1)
2. Impact on Uncollectibles @ .3004% of Line 1		11,467	
3. Impact on KPSC Assessments @ .1643% of Line 1		6,272	
4. Impact on Pre-Tax Operating Income [L1 - L2 - L3]		3,799,586	
5. Composite After-Tax Income Rate		61.23%	(2)
6. Impact on Operating Income	$	2,326,486	

(1) Per response to AG-2-8b:

		Actual Revenues for 12-Months Ended 7/31/06
- Woodsdale Unit 1	$	22,549
- Woodsdale Unit 2		22,784
- Woodsdale Unit 3		1,429,318
- Woodsdale Unit 4		22,246
- Woodsdale Unit 5		1,422,593
- Woodsdale Unit 6		852,664
- Miami Fort 6		45,171
- Total	$	3,817,325

(2) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

Forecasted Period Ended 12/31/07
Case No. 2006-00172

Sch. RJH-10

DUKE ENERGY KENTUCKY
ACCOUNT 454710 - RENT REVENUE FROM COMMON FACILITY UNIT 7

1. Acct. 454710 - Rent Revenue from Common Facility Unit 7 in Forecasted Period	$	666,192	(1)
2. Impact on Uncollectibles @ .3004% of Line 1		2,001	
3. Impact on KPSC Assessments @ .1643% of Line 1		1,095	
4. Impact on Pre-Tax Operating Income [L1 - L2 - L3]		663,096	
5. Composite After-Tax Income Rate		61.23%	(2)
6. Impact on Operating Income	$	406,014	

(1) Per response to AG-2-9d:

- Current monthly rent revenues	$	55,616
- Annualization factor		12
- Annualized rent revenues for forecasted period	$	667,392

(2) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

Forecasted Period Ended 12/31/07 Sch. RJH-11
Case No. 2006-00172

DUKE ENERGY KENTUCKY
OTHER OPERATING REVENUES

1. Other Operating Revenues in Accts. 451, 454 and 456 Not Reflected by DEK in Forecasted Period	$	592,120	(1)
2. Incremental Revenues from DEK's Proposed New Miscellaneous Charge Revenues		140,217	(2)
3. Total Recommended Other Operating Revenues Adjustment		732,337	
4. Impact on Uncollectibles @ .3004% of Line 3		2,200	
5. Impact on KPSC Assessments @ .1643% of Line 3		1,203	
6. Impact on Pre-Tax Operating Income [L3 - L4 - L5]		728,934	
7. Composite After-Tax Income Rate		61.23%	(3)
8. Impact on Operating Income	$	446,326	

(1) Per responses to AG-1-26 and AG-1-27:

		Actual Average Annual Revenues for 2003 through 5/31/06		Forecasted Period
Acct. 451	Miscellaneous Service Revenues	$ 32,314		$ -
Acct. 451020	Misc Reconnection Charge	59,128		-
Acct. 451040	Temporarty Facilities	95,578	*	-
Acct. 451050	Customer Diversion	5,414		-
Acct. 451060	Bad Check Charge	18,231		-
Acct. 454020	Rent Elec Other Equipment	27,570		-
Acct. 454100	Pole Contact Revenues	135,477		-
Acct. 456865	Transmission Rev RB Interco	218,408		-
Total		$ 592,120		$ -

* Average excludes year 2003

(2) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

Forecasted Period Ended 12/31/07 | Sch. RJH-12
Case No. 2006-00172

DUKE ENERGY KENTUCKY
WEATHER NORMALIZATION ADJUSTMENT

1. Impact on Net Revenues from Using 25-Year Weather Normalization Period 1981 - 2005 versus DEK's Proposed 10-Year Weather Normalization Period	$	866,797	(1)
2. Impact on Uncollectibles @ .3004% of Line 1		2,604	
3. Impact on KPSC Assessments @ .1643% of Line 1		1,424	
4. Impact on Pre-Tax Operating Income [L1 - L2 - L3]		862,769	
5. Composite After-Tax Income Rate		61.23%	(2)
6. Impact on Operating Income	$	528,273	

(1) Response to PSC-2-37
(2) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

Forecasted Period Ended 12/31/0
Case No. 2006-000172

Sch. RJH-13

DUKE ENERGY KENTUCKY
BACK-UP POWER SALES CAPACITY CHARGE ADJUSTMENT

1. Back-Up Power Sales Capacity Charges as per DEK's Proposed "Refreshed Pricing"	$	10,431,923	(1)
2. Back-Up Power Sales Capacity Charges as per Contract Approved by Commission in Case No. 2003-00252		5,059,000	(2)
3. Difference in Capacity Charges		5,372,923	
4. Composite After-Tax Income Rate		61.23%	(3)
5. Impact on Operating Income	$	3,289,841	

(1) Schedule D-2.25
(2) Response to AG-1-61c
(3) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

DUKE ENERGY KENTUCKY
AMORTIZATION OF DEFERRED EXPENSES

	DEK (1)	Adjustment	AG (2)
1. Deferred Costs Associated with Transfer of Plants:			
a. Actual Through 2/28/06	$ 1,291,571	$ (645,786)	$ 645,786
b. Projected for Consultants	87,000	(43,500)	43,500
c. Projected for Outside Counsel	100,000	(50,000)	50,000
d. Total	1,478,571	(739,286)	739,286
2. Amortization Period (Yrs)	5	5	5
3. Annual Amortization Expense	295,714	(147,857)	147,857
4. Deferred Costs - Electric Workforce Reduction	1,530,917	(1,530,917)	-
5. Amortization Period (Yrs)	3	3	3
6. Annual Amortization Expense	510,306	(510,306)	-
7. Total Annual Amortization Expense [L3 + L6}	$ 806,020	$ (658,163)	$ 147,857
8. Composite After-Tax Income Rate		61.23%	(3)
9. Impact on Operating Income		$ 402,993	

(1) WPD-2.15a
(2) Testimony of Robert J. Henkes
(3) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

DUKE ENERGY KENTUCKY
MISCELLANEOUS EXPENSE ADJUSTMENTS

1.	Remove Governmental Affairs Expenses	$	(39,049)	(1)
2.	Adjust Association Dues		(125,653)	(2)
3.	Remove Certain Professional Services Fees		(227,124)	(3)
4.	Total Miscellaneous Expense Adjustments		(391,826)	
5.	Composite After-Tax Income Rate		61.23%	(4)
6.	Impact on Operating Income	$	239,915	

(1)	- Total governmental affairs expenses in forecasted period:	$	120,970	AG-1-59(b)
	- Govt. affairs expenses already removed from forecasted period		(81,921)	WPD-2-22a
	- Additional governmental affairs expenses to be removed	$	39,049	
(2)	Per Response to AG-2-16:			
	- Actual dues for 12-month period ended 5/31/06	$	130,633	
	- Less: EEI dues		(68,692)	
	- Less: AGA dues		(4,456)	
	- Less Democratic Leadership Council dues		(1,578)	
	- Less: American Legislative Exhange dues		(300)	
	- Recommended dues for forecasted period		55,607	
	- DEK-proposed dues for forecasted period		181,260	
	- Recommended expense adjustment	$	(125,653)	
(3)	Removal of following forecasted period professional fees:			
	- Annual Report Design	$	9,072	WPF-5b
	- Annual Report Print		15,564	WPF-5b
	- Sarbanes Oxley		111,516	WPF-5b
	- Shareholder meeting		2,592	WPF-5b
	- Stock surveillance		3,888	WPF-5b
	- Stock transfer agent		31,116	WPF-5b
	- Sarbanes Oxley (Pricewaterhouse Coopers)		53,376	PSC-2-33c
	- Total professional fees removal	$	227,124	

(4) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

Forecasted Period Ended 12/31/07
Case No. 2006-00172

Sch. RJH-16

DUKE ENERGY KENTUCKY
PROPERTY TAX ADJUSTMENT

	DEK (1)	Adjustment	AG	
1. Property Taxes in Accts 408020, 408025, and 408056	$ 4,875,540	$ (861,769)	$ 4,013,771	(2)
2. Property Taxes in Acct 408065 (East Bend)	750,000	(136,000)	614,000	(3)
3. Remove Non-Jurisdictional Property Taxes re. Florence Service Building	-	(282,301)	(282,301)	(4)
4. Add Cox Road Property Taxes	-	24,807	24,807	(4)
5. Total Property Taxes	$ 5,625,540	(1,255,263)	$ 4,370,277	
4. Composite After-Tax Income Rate		61.23% (5)		
5. Impact on Operating Income		$ 768,598		

(1) Sch. C-2.1, page 13 of 14
(2) Response to AG-1-20
(3) Response to AG-2-4
(4) Response to AG-2-5
(5) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

Forecasted Period Ended 12/31/07
Case No. 2006-0017

Sch. RJH-17

DUKE ENERGY KENTUCKY
INTEREST SYNCHRONIZATION ADJUSTMENT

	DEK (1)	Adjustment	AG	
1. Electric-Allocated Capitalization	$ 557,080,702	$ (6,385,040)	$ 550,695,662	Sch. RJH-4
2. Less: CWIP Subject to AFUDC	(4,263,000)		(4,263,000)	
3. Net Capitalization	552,817,702	(6,385,040)	546,432,662	
4. Weighted Debt Cost Rates:				
a. Long Term Debt	2.474%		2.806%	Sch. RJH-3
b. Short Term Debt	0.436%		0.359%	Sch. RJH-3
c. Total Weighted Debt Cost	2.910%		3.165%	
5. Pro Forma Interest [L3 x L4c]	16,089,440	1,204,111	17,293,551	
6. Forecasted Period Per Books Interest	12,998,412		12,998,412	
7. Tax-Deductible Interest Adjustment	$ 3,091,028	1,204,111	$ 4,295,139	
8. Composite Income Tax Rate		38.77%	(2)	
9. Impact on Operating Income		$ 466,834		

(1) WPD-2.18a
(2) Composite of SIT of 5.8% and FIT of 35% = 38.77%.

DUKE ENERGY KENTUCKY
DEPRECIATION EXPENSE ADJUSTMENT

	DEK (1)	Adjustment	AG (2)
1. Forecasted Period Depreciation Expenses Excluding AMI Depreciation	$ 32,810,000	$ (9,996,000)	$ 22,814,000
2. Composite After-Tax Income Rate		61.23%	(3)
3. Impact on Operating Income		$ 6,120,551	

(1) Schedule B-3.2, pages 1-6
(2) Testimony of Michael Majoros
(3) Composite of SIT of 5.8% and FIT of 35% = 38.77%. 1 minus 38.77% = 61.23%

DUKE ENERGY KENTUCKY
RECOMMENDED ADJUSTED OPERATION AND MAINTENANCE EXPENSES

1. Pro Forma O&M Expenses Proposed by DEK	$111,702,325	(1)
AG-Recommended O&M Expense Adjustments:		
2. Back-Up Power Sales Capacity Charges	(5,372,923)	Sch. RJH-13, L3
3. Amortization of Deferred Expenses	(658,163)	Sch. RJH-14, L7
4. Miscellaneous Expense Adjustments	(391,826)	Sch. RJH-15, L4
5. Pro Forma O&M Expenses Recommended by AG	$105,279,413	

(1) Schedule C-1

DUKE ENERGY KENTUCKY
MISO TRANSMISSION COSTS

	Source: AG-2-23	Source: AG-1-70e
Components of Account 561		
1. Schedule 10-FERC	$ 212,304	Stable
2. Schedule 10	824,732	Stable
3. Schedule 16	174,939	Stable
4. Schedule 17	320,107	Stable
5. Total Account 561	1,532,082	
Components of Account 565		
6. Schedule 9 - NITS (Adjusted)	8,296,438	Stable
Components of Account 565 - MISO Day 2 Costs		
7. Congestion, Losses, RSG, *etc.*	12,047,693	Potentially Volatile
8. Grand Total	$ 21,876,213	

Commonwealth of Kentucky

BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
	)	
THE APPLICATION OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	**CASE NO. 2006-00172**
D/B/A DUKE ENERGY KENTUCKY TO	)	
INCREASE ITS ELECTRIC RATES	)	

DIRECT TESTIMONY

OF

DR. J. RANDALL WOOLRIDGE

September, 2006

Duke Energy Kentucky

Direct Testimony of
J. Randall Woolridge

TABLE OF CONTENTS

LIST OF EXHIBITS

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is J. Randall Woolridge and my business address is 120 Haymaker Circle, State College, PA 16801. I am a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed University Fellow in Business Administration at the University Park Campus of the Pennsylvania State University. I am also the Director of the Smeal College Trading Room and President of the Nittany Lion Fund, LLC. A summary of my educational background, research, and related business experience is provided in Appendix A.

I. SUBJECT OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked by the Kentucky Office of the Attorney General to provide an opinion as to the overall fair rate of return or cost of capital for the electric utility operations of Union Light, Heat, and Power Company d/b/a Duke Energy Kentucky ("DEK" or "Company") and to evaluate DEK's rate of return testimony in this proceeding.

Q. PLEASE REVIEW YOUR COST OF CAPITAL RETURN FINDINGS.

A. I have arrived at a cost of capital for the electric utility services of DEK. I have established an equity cost rate of 9.25% for DEK by applying the Discounted Cash Flow ("DCF") and a Capital Asset Pricing Model ("CAPM") approaches to two groups of electric utility companies. Utilizing my equity cost rate, capital structure ratios, and senior capital cost rates, I am recommending an overall fair rate of return of 7.51% for DEK. This recommendation is summarized in

Exhibit_(JRW-1).

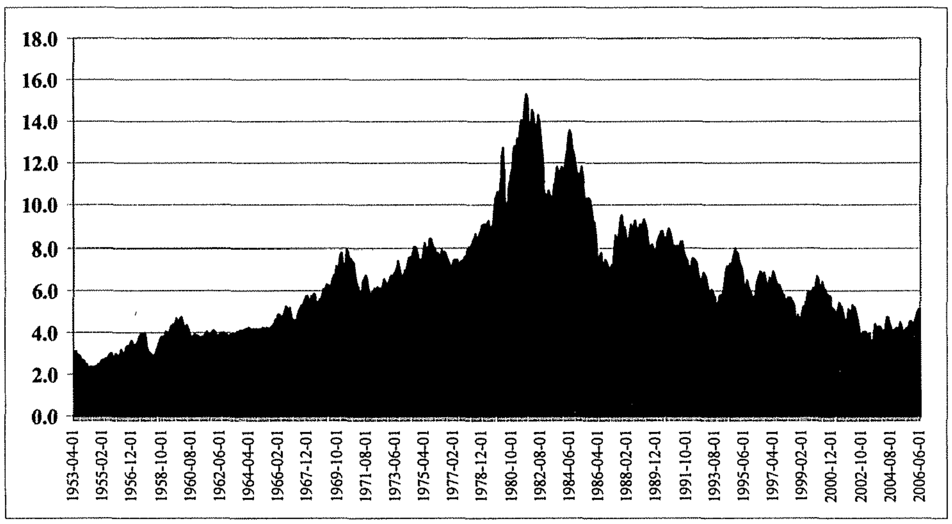
II. AN OVERVIEW OF CAPITAL COSTS IN TODAY'S MARKETS

Q. PLEASE DISCUSS CAPITAL COSTS IN TODAY'S MARKETS.

A. Long-term capital cost rates for U.S. corporations are currently at their lowest levels in more than four decades. Long-term corporate capital cost rates are determined by the level of interest rates and the risk premium demanded by investors to buy the debt and equity capital of corporate issuers. The base level of interest rates in the US economy is indicated by the rates on ten-year U.S. Treasury bonds. The rates are provided in the graph below from 1953 to the present. As indicated, prior to the decline in rates that began in the year 2000, the 10-year Treasury had not been in the 4-5 percent range since the 1960s.

Yields on Ten-Year Treasury Bonds

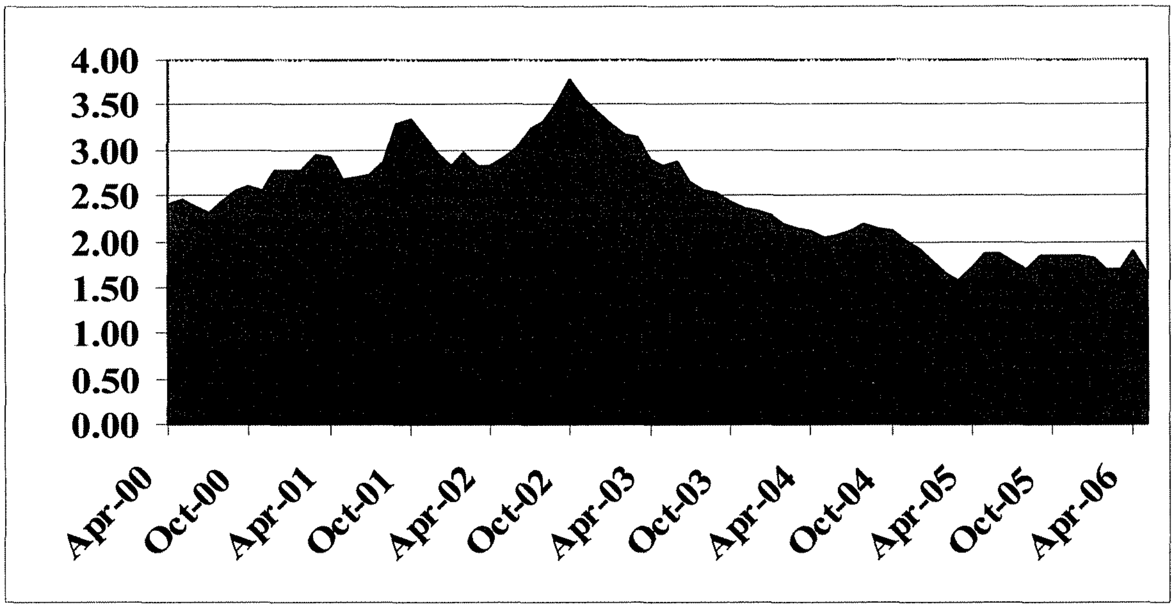
1953-Present



Source: http://research.stlouisfed.org/fred2/data/GS10.txt

The second base component of the corporate capital cost rates is the risk premium. The risk premium is the return premium required by investors to purchase riskier securities. Risk premiums for bonds are the yield differentials between different bond classes as rated by agencies such as Moody's, and Standard and Poor's. The graph below provides the yield differential between Baa-rate corporate bonds and 10-year Treasuries. This yield differential peaked at 350 basis points (BPs) in 2002 and has declined significantly since that time. This is an indication that the market price of risk has declined and therefore the risk premium has declined in recent years.

Corporate Bond Yield Spreads
Baa-Rated Corporate Bond Yield Minus Ten-Year Treasury Bond Yield



Source: http://www.treas.gov/offices/domestic-finance/debt-management/interest-rate/index.html

The equity risk premium is the return premium required to purchase stocks as opposed to bonds. Since the equity risk premium is not readily observable in the markets (as are bond risk premiums), and there are alternative approaches to estimating the equity premium, it is the subject of much debate. One way to estimate the equity risk premium is to compare the mean returns on bonds and stocks over long historical periods. Measured in this manner, the equity risk premium has been in the 5-7 percent range. But recent studies by leading academics indicate the forward-looking equity risk premium is in the 3-4 percent range. These authors indicate that historical equity risk premiums are upwardly biased measures of expected equity risk premiums. Jeremy Siegel, a Wharton finance professor and author of the book *Stocks for the Long Term*, published a study entitled "The Shrinking Equity Risk Premium."[1] He concludes:

> The degree of the equity risk premium calculated from data estimated from 1926 is unlikely to persist in the future. The real return on fixed-income assets is likely to be significantly higher than estimated on earlier data. This is confirmed by the yields available on Treasury index-linked securities, which currently exceed 4%. Furthermore, despite the acceleration in earnings growth, the return on equities is likely to fall from its historical level due to the very high level of equity prices relative to fundamentals.

Even Alan Greenspan, the former Chairman of the Federal Reserve Board, indicated in an October 14, 1999, speech on financial risk that the fact that equity risk premiums have declined during the past decade is "not in dispute." His assessment focused on the relationship between information availability and equity risk premiums.

> There can be little doubt that the dramatic improvements in information technology in recent years have altered our approach to risk. Some analysts perceive that information technology has permanently lowered equity premiums and, hence, permanently raised the prices of the collateral that underlies all financial assets.
>
> The reason, of course, is that information is critical to the evaluation of risk. The less that is known about the current state of a market or a venture, the less the ability to project future outcomes

[1] Jeremy J. Siegel, "The Shrinking Equity Risk Premium," *The Journal of Portfolio Management* (Fall, 1999), p.15.

> and, hence, the more those potential outcomes will be discounted.
>
> The rise in the availability of real-time information has reduced the uncertainties and thereby lowered the variances that we employ to guide portfolio decisions. At least part of the observed fall in equity premiums in our economy and others over the past five years does not appear to be the result of ephemeral changes in perceptions. It is presumably the result of a permanent technology-driven increase in information availability, which by definition reduces uncertainty and therefore risk premiums. This decline is most evident in equity risk premiums. It is less clear in the corporate bond market, where relative supplies of corporate and Treasury bonds and other factors we cannot easily identify have outweighed the effects of more readily available information about borrowers.[2]

In sum, the relatively low interest rates in today's markets as well as the lower risk premiums required by investors indicate that capital costs for U.S. companies are the lowest in decades. In addition, the *Jobs and Growth Tax Relief Reconciliation Act of 2003* further lowered capital cost rates for companies.

Q. HOW DID THE *JOBS AND GROWTH TAX RELIEF RECONCILIATION ACT of 2003* REDUCE THE COST OF CAPITAL FOR COMPANIES?

A. On May 28th of 2003, President Bush signed the *Jobs and Growth Tax Relief Reconciliation Act of 2003.* The primary purpose of this legislation was to reduce taxes to enhance economic growth. A primary component of the new tax law was a significant reduction in the taxation of corporate dividends for individuals. Dividends have been described as "double-taxed." First, corporations pay taxes on the income they earn before they pay dividends to investors, then

[2] Alan Greenspan, "Measuring Financial Risk in the Twenty-First Century," Office of the Comptroller of the Currency Conference, October 14, 1999.

investors pay taxes on the dividends that they receive from corporations. One of the implications of the double taxation of dividends is that, all else equal, it results in a higher cost of raising capital for corporations. The tax legislation reduced the effect of double taxation of dividends by lowering the tax rate on dividends from the 30 percent range (the average tax bracket for individuals) to 15 percent.

Overall, the 2003 tax law reduced the pre-tax return requirements of investors, thereby reducing corporations' cost of equity capital. This is because the reduction in the taxation of dividends for individuals enhances their after-tax returns and thereby reduces their pre-tax required returns. This reduction in pre-tax required returns (due to the lower tax on dividends) effectively reduces the cost of equity capital for companies. The 2003 tax law also reduced the tax rate on long-term capital gains from 20% to 15%. My assessment indicates that the magnitude of the reduction in corporate equity cost rates could be as large as 100 basis points (See Exhibit_(JRW-2)).

III. COMPARISON GROUP SELECTION

Q. PLEASE DESCRIBE YOUR APPROACH TO DEVELOPING A FAIR RATE OF RETURN RECOMMENDATION FOR DEK.

A. To develop a fair rate of return recommendation for DEK, I evaluated the return requirements of investors on the common stock of two groups of publicly-held electric utility companies.

Q. PLEASE DESCRIBE YOUR GROUPS OF ELECTRIC SERVICE COMPANIES.

A. My primary proxy group consists of the companies in Moody's Electric Utilities. I require that (1) they receive at least 50% of revenues from regulated electric utility operations and (2) they are not currently in the process of being acquired. As a result, this primary group, which I call Group A, includes thirteen electric utility companies. Summary financial statistics for the companies in Group A are provided on page 1 of Exhibit_(JRW-3). On average, the operating revenues and net plant for the proxy group are $7,872M and $12,135M, respectively. The group has an average common equity ratio of 43.6%, and a current average earned return on common equity of 11.5%.

My second group, which I call Group B, is the group of vertically integrated electric utility companies identified by Dr. Morin. As above, these companies receive at least 50% of revenues from regulated electric utility operations and are not currently in the process of being acquired. As a result I end up with twenty-six companies in Group B. The average operating revenues and net plant for the proxy group are $6,081M and $9,410M, respectively. The group has an average common equity ratio of 45.6%, and a current average earned return on common equity of 9.6%.

IV. CAPITAL STRUCTURE RATIOS AND DEBT COST RATES

Q. WHAT CAPITAL STRUCTURE RATIOS AND SENIOR CAPITAL COST RATES ARE YOU USING TO ESTIMATE AN OVERALL RATE OF RETURN FOR DEK?

A. Exhibit_(JRW-4) provides an evaluation of DEK's proposed capital structure and the average capital structures of the companies in the proxy group. The Company has proposed a capital structure consisting of 8.49% short-term debt, 40.63% long-term debt, and 50.88% common equity. The Company has employed a short-term debt cost rate of 5.14% and a long-term debt cost rate of 6.09%.

Also shown in Exhibit_(JRW-4) is the average capitalization of the companies in my primary proxy group, Group A. On average, these companies employ 5.48% short-term debt, 51.52% long-term debt, and 43.00% shareholders' equity. Hence, it is clear that DEK is proposing a capital structure that contains much more common equity than the companies in Group A which represents Moody's Electric Utilities.

To develop a capital structure in this proceeding, I am proposing to use the average of (1) DEK's proposed capital structure, and (2) the average for Group A. I will adopt the Company's proposed senior capital cost rates. The resulting common equity ratio – 46.94% -- is entirely consistent with the common equity ratio of my proxy Group B. This is summarized below.

DEK, Inc.
Proposed Capital Structure and Senior Capital Cost Rates

Source of Capital	Capitalization Ratio	Cost Rate
Short-Term Debt	**6.99%**	**5.14%**
Long-Term Debt	**46.07%**	**6.09%**
Common Equity	**46.94%**	

V. THE COST OF COMMON EQUITY CAPITAL

A. OVERVIEW

Q. WHY MUST AN OVERALL COST OF CAPITAL OR FAIR RATE OF RETURN

BE ESTABLISHED FOR A PUBLIC UTILITY?

A. In a competitive industry, the return on a firm's common equity capital is determined through the competitive market for its goods and services. Due to the capital requirements needed to provide utility services, however, and to the economic benefit to society from avoiding duplication of these services, some public utilities are monopolies. It is not appropriate to permit monopoly utilities to set their own prices because of the lack of competition and the essential nature of the services they provide. Thus, regulation seeks to establish prices which are fair to consumers and at the same time are sufficient to meet the operating and capital costs of the utility, i.e., provide an adequate return on capital to attract investors.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COST OF CAPITAL IN THE CONTEXT OF THE THEORY OF THE FIRM.

A. The total cost of operating a business includes the cost of capital. The cost of common equity capital is the expected return on a firm's common stock that the marginal investor would deem sufficient to compensate for risk and the time value of money. In equilibrium, the expected and required rates of return on a company's common stock are equal.

Normative economic models of the firm, developed under very restrictive assumptions, provide insight into the relationship between firm performance or profitability, capital costs, and the value of the firm. Under the economist's ideal model of perfect competition, where entry and exit is costless, products are undifferentiated, and there are increasing marginal costs of production, firms produce up to the point where price equals marginal cost. Over time, a long-run equilibrium is established where price equals average cost, including the firm's capital costs. In equilibrium, total revenues equal total costs, and because capital costs represent investors' required return on the firm's capital, actual returns equal required returns and the market value and the book value of the firm's securities must be equal.

In the real world, firms can achieve competitive advantage due to product market imperfections. Most notably, companies can gain competitive advantage through product differentiation (adding real or perceived value to products) and by achieving economies of scale (decreasing marginal costs of production). Competitive advantage allows firms to price products above average cost and thereby earn accounting profits greater than those required to cover capital costs. When these profits are in excess of that required by investors, or when a firm earns a return on equity in excess of its cost of equity, investors respond by valuing the firm's equity in excess of its book value.

James M. McTaggart, founder of the international management consulting firm Marakon Associates, has described this essential relationship between the return on equity, the cost of equity, and the market-to-book ratio in the following manner:[3]

> Fundamentally, the value of a company is determined by the cash flow it generates over time for its owners, and the minimum acceptable rate of return required by capital investors. This "cost of equity capital" is used to discount the expected equity cash flow, converting it to a present value. The cash flow is, in turn, produced by the interaction of a company's return on equity and the annual rate of equity growth. High return on equity (ROE) companies in low-growth markets, such as Kellogg, are prodigious generators of cash flow, while low ROE companies in high-growth markets, such as Texas Instruments, barely generate enough cash flow to finance growth.
>
> A company's ROE over time, relative to its cost of equity, also determines whether it is worth more or less than its book value. If its ROE is consistently greater than the cost of equity capital (the investor's minimum acceptable return), the

[3] James M. McTaggart, "The Ultimate Poison Pill: Closing the Value Gap," *Commentary* (Spring 1988), p. 2.

> business is economically profitable and its market value will exceed book value. If, however, the business earns an ROE consistently less than its cost of equity, it is economically unprofitable and its market value will be less than book value.

As such, the relationship between a firm's return on equity, cost of equity, and market-to-book ratio is relatively straightforward. A firm which earns a return on equity above its cost of equity will see its common stock sell at a price above its book value. Conversely, a firm which earns a return on equity below its cost of equity will see its common stock sell at a price below its book value.

Q. PLEASE PROVIDE ADDITIONAL INSIGHTS INTO THE RELATIONSHIP BETWEEN RETURN ON EQUITY AND MARKET-TO-BOOK RATIOS?

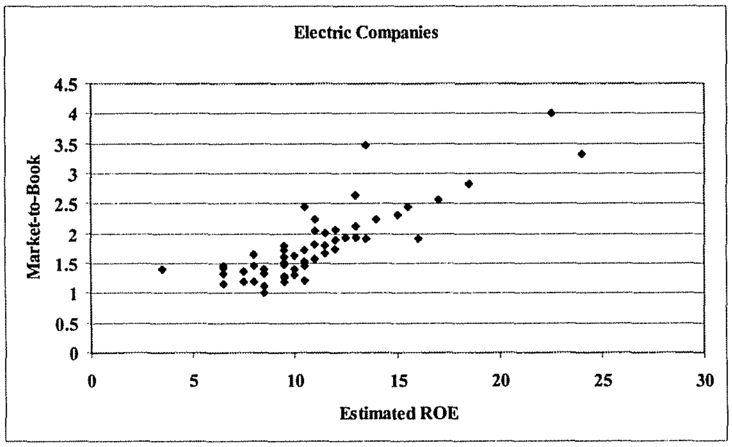
A. This relationship is discussed in a classic Harvard Business School case study entitled "A Note on Value Drivers." On page 2 of that case study, the author describes the relationship very succinctly:[4]

> *For a given industry, more profitable firms – those able to generate higher returns per dollar of equity – should have higher market-to-book ratios. Conversely, firms which are unable to generate returns in excess of their cost of equity should sell for less than book value.*

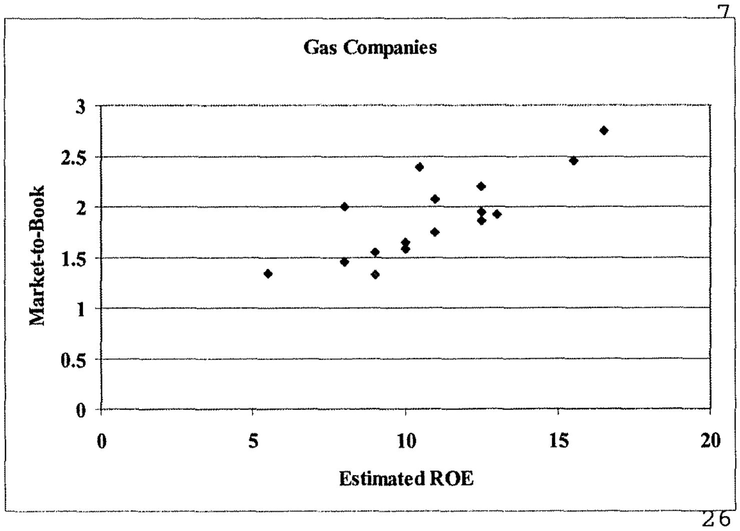
Profitability	*Value*
If ROE > K	*then Market/Book > 1*
If ROE = K	*then Market/Book =1*
If ROE < K	*then Market/Book < 1*

To assess the relationship by industry, as suggested above, I have performed a regression study between estimated return on equity and market-to-book ratios using natural gas distribution, electric utility and water utility companies. I used all companies in these three industries which are covered by *Value Line* and who have estimated return on equity and market-to-book ratio data. The results are presented below.

The Relationship Between Estimated ROE and Market-to-Book Ratios
Value Line Electrics Companies, Gas Distribution Companies, and Water Utilities

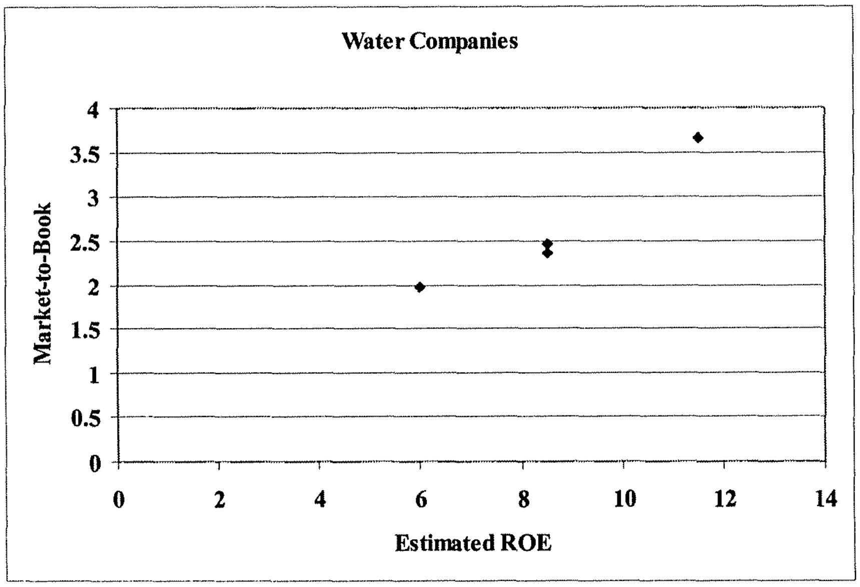


R-Square = .70
N=58



R-Square = .64
N=16

[4] Benjamin Esty, "A Note on Value Drivers," Harvard Business School Case No. 9-297-082, April 7, 1997.



R-Square = .93
N=4

The average R-squares for the electric, gas, and water companies are 0.70, 0.64, and 0.93. This demonstrates the strong and statistically significant relationship between ROEs and market-to-book ratios.

Q. WHAT ECONOMIC FACTORS HAVE AFFECTED THE COST OF EQUITY CAPITAL FOR PUBLIC UTILITIES?

A. Exhibit_(JRW-5) provides indicators of public utility equity cost rates over the past decade. Page 1 shows the yields on 10-year, 'A' rated public utility bonds. These yields peaked in the 1990s at 10%, and have generally declined since that time. They hovered in the 4.5 to 5.0 percent between 2003 and 2005, and have since increased to the 5.5%. Page 2 provides the dividend yields for the fifteen utilities in the Dow Jones Utilities Average over the past decade. These yields peaked in 1994 at 7.2%. Since that time they have declined and were below 4.0% as of 2005.

Average earned returns on common equity and market-to-book ratios are given on page 3 of

Exhibit_(JRW-5). Over the past decade, earned returns on common equity have consistently been in the 10.0 - 13.0 percent range. The high point was 13.45 % in 2001, and they have decreased since that time. As of 2005, the average was 11.75%. Over the past decade, market-to-book ratios for this group have increased gradually, but with several ups and downs. The market-to-book average was 1.75 as of 2001, declined to 1.45 in 2003, and increased to 1.95 as of 2005.

The indicators in Exhibit_(JRW-5), coupled with the overall decrease in interest rates, suggest that capital costs for the Dow Jones Utilities have decreased over the past decade. Specifically for the equity cost rate, the increase in the market-to-book ratios, coupled with a slightly lower average return on equity, suggests a decline in the overall equity cost rate.

Q. WHAT FACTORS DETERMINE INVESTORS' EXPECTED OR REQUIRED RATE OF RETURN ON EQUITY?

A. The expected or required rate of return on common stock is a function of market-wide, as well as company-specific, factors. The most important market factor is the time value of money as indicated by the level of interest rates in the economy. Common stock investor requirements generally increase and decrease with like changes in interest rates. The perceived risk of a firm is the predominant factor that influences investor return requirements on a company-specific basis. A firm's investment risk is often separated into business and financial risk. Business risk encompasses all factors that affect a firm's operating revenues and expenses. Financial risk results from incurring fixed obligations in the form of debt in financing its assets.

Q. HOW DOES THE INVESTMENT RISK OF ELECTRIC UTILITY COMPANIES COMPARE WITH THAT OF OTHER INDUSTRIES?

A. Due to the essential nature of their service as well as their regulated status, public utilities are exposed to a lesser degree of business risk than other, non-regulated businesses. This relatively low level of business risk allows public utilities to meet much of their capital requirements through borrowing in the financial markets, thereby incurring greater than average financial risk. Nonetheless, the overall investment risk of public utilities is below most other industries. Exhibit_(JRW-6) provides an assessment of investment risk for 100 industries as measured by beta, which according to modern capital market theory is the only relevant measure of investment risk that need be of concern for investors. These betas come from the *Value Line Investment Survey* and are compiled by Aswath Damodoran of New York University. They may be found on the Internet at http://www.stern.nyu.edu/~adamodar/. The study shows that the investment risk of public utilities is relatively low. The average beta for electric utilities is in the bottom third of the 100 industries in terms of beta. As such, the cost of equity for the electric utility industry is among the lowest of all industries in the U.S.

Q. HOW CAN THE EXPECTED OR REQUIRED RATE OF RETURN ON COMMON EQUITY CAPITAL BE DETERMINED?

A. The costs of debt and preferred stock are normally based on historical or book values and can be determined with a great degree of accuracy. The cost of common equity capital, however, cannot be determined precisely and must instead be estimated from market data and informed judgment. This return to the stockholder should be commensurate with returns on investments in other enterprises having comparable risks.

According to valuation principles, the present value of an asset equals the discounted value of its expected future cash flows. Investors discount these expected cash flows at their required rate of return that, as noted above, reflects the time value of money and the perceived riskiness of the expected future cash flows. As such, the cost of common equity is the rate at which investors discount expected cash flows associated with common stock ownership.

Models have been developed to ascertain the cost of common equity capital for a firm. Each model, however, has been developed using restrictive economic assumptions. Consequently, judgment is required in selecting appropriate financial valuation models to estimate a firm's cost of common equity capital, in determining the data inputs for these models, and in interpreting the models' results. All of these decisions must take into consideration the firm involved as well as conditions in the economy and the financial markets.

Q. HOW DO YOU PLAN TO ESTIMATE THE COST OF EQUITY CAPITAL FOR THE COMPANY?

A. I rely primarily on the Discounted Cash Flow ("DCF") model to estimate the cost of equity capital. Given the investment valuation process and the nature of the utility business, I believe that the DCF model provides a good measure of equity cost rates for public utilities. I have also estimate an equity cost rate for the Company using the Capital Asset Pricing Model (CAPM) study.

B. DISCOUNTED CASH FLOW ANALYSIS

Q. BRIEFLY DESCRIBE THE THEORY BEHIND THE TRADITIONAL DCF MODEL.

A. According to the discounted cash flow model, the current stock price is equal to the discounted value of all future dividends that investors expect to receive from investment in the firm. As such, stockholders' returns ultimately result from current as well as future dividends. As owners of a corporation, common stockholders are entitled to a pro-rata share of the firm's earnings. The DCF model presumes that earnings that are not paid out in the form of dividends are reinvested in the firm so as to provide for future growth in earnings and dividends. The rate at which investors discount future dividends, which reflects the timing and riskiness of the expected cash flows, is interpreted as the market's expected or required return on the common stock. Therefore this discount rate represents the cost of common equity. Algebraically, the DCF model can be expressed as:

$$P = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots \frac{Dn}{(1+k)^n}$$

where P is the current stock price, D_n is the dividend in year n, and k is the cost of common equity.

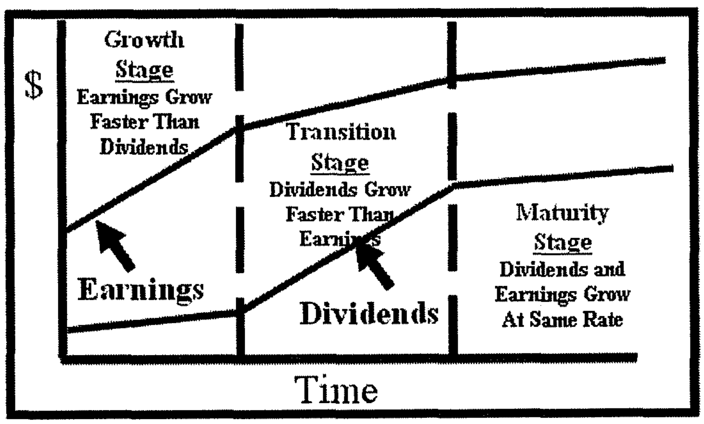
Q. IS THE DCF MODEL CONSISTENT WITH VALUATION TECHNIQUES EMPLOYED BY INVESTMENT FIRMS?

A. Yes. Virtually all investment firms use some form of the DCF model as a valuation technique. One common application for investment firms is called the three-stage DCF or dividend discount model (DDM). This model presumes that a company's dividend payout progresses initially through a growth stage, then proceeds through a transition stage, and finally assumes a steady-state stage. The dividend-payment stage of a firm depends on the profitability of its internal investments, which, in turn, is largely a function of the life cycle of the product or service. These stages are depicted in the graphic below labeled the Three-Stage DCF Model.[5]

> 1. **Growth stage**: Characterized by rapidly expanding sales, high profit margins, and abnormally high growth in earnings per share. Because of highly profitable expected investment opportunities, the payout ratio is low. Competitors are attracted by the unusually high earnings, leading to a decline in the growth rate.
>
> 2. **Transition stage**: In later years, increased competition reduces profit margins and earnings growth slows. With fewer new investment opportunities, the company begins to pay out a larger percentage of earnings.
>
> 3. **Maturity (steady-state) stage**: Eventually the company reaches a position where its new investment opportunities offer, on average, only slightly attractive returns on equity. At that time its earnings growth rate, payout ratio, and return on equity stabilize for the remainder of its life. The constant-growth DCF model is appropriate when a firm is in the maturity stage of the life cycle.

In using this model to estimate a firm's cost of equity capital, dividends are projected into the future using the different growth rates in the alternative stages, and then the equity cost rate is the discount rate that equates the present value of the future dividends to the current stock price.

Three-Stage DCF Model



[5] This description comes from William F. Sharp, Gordon J. Alexander, and Jeffrey V. Bailey, *Investments* (Prentice-Hall, 1995), pp. 590-91.

Q. HOW DO YOU ESTIMATE STOCKHOLDERS' EXPECTED OR REQUIRED RATE OF RETURN USING THE DCF MODEL?

A. Under certain assumptions, including a constant and infinite expected growth rate, and constant dividend/earnings and price/earnings ratios, the DCF model can be simplified to the following:

$$P = \frac{D_1}{k - g}$$

where D_1 represents the expected dividend over the coming year and g is the expected growth rate of dividends. This is known as the constant-growth version of the DCF model. To use the constant-growth DCF model to estimate a firm's cost of equity, one solves for k in the above expression to obtain the following:

$$k = \frac{D_1}{P} + g$$

The economics of the public utility business indicate that the industry is in the steady-state or constant-growth stage of a three-stage DCF. The economics include the relative stability of the utility business, the maturity of the demand for public utility services, and the regulated status of public utilities (especially the fact that their returns on investment are effectively set through the ratemaking process). The DCF valuation procedure for companies in this stage is the constant-growth DCF. In the constant-growth version of the DCF model, the current dividend payment and stock price are directly observable. Therefore, the primary problem and controversy in applying the DCF model to estimate equity cost rates entails estimating investors' expected dividend growth rate.

Q. WHAT FACTORS SHOULD ONE CONSIDER WHEN APPLYING THE DCF METHODOLOGY?

A. One should be sensitive to several factors when using the DCF model to estimate a firm's cost of equity capital. In general, one must recognize the assumptions under which the DCF model was developed in estimating its components (the dividend yield and expected growth rate). The dividend yield can be measured precisely at any point in time, but tends to vary somewhat over time. Estimation of expected growth is considerably more difficult. One must consider recent firm performance, in conjunction with current economic developments and other information available to investors, to accurately estimate investors' expectations.

Q. PLEASE DISCUSS EXHIBIT_(JRW-7).

A. My DCF analysis is provided in Exhibit_(JRW-7). The DCF summary is on page 1 of this Exhibit and the supporting data and analysis for the dividend yield and expected growth rate are provided on the following pages.

Q. WHAT DIVIDEND YIELDS ARE YOU EMPLOYING IN YOUR DCF ANALYSIS FOR YOUR TWO GROUPS OF ELECTRIC UTILITY COMPANIES?

A. The dividend yields on the common stock for the companies in the two groups are provided on page 2 of Exhibit_(JRW-7) for the six -month period ending August, 2006. Over this period, the average monthly dividend yield for the companies in Groups A and B have been 4.40% and 4.20%, respectively. As of August, 2006, the mean dividend yield for the companies in the groups were 4.40% and 4.20%, respectively. For the DCF dividend yield, I use the average of the six month and August, 2006 dividend yields. Hence, the DCF dividends yield for Groups A and B are 4.40% and 4.20%, respectively.

Q. PLEASE DISCUSS THE APPROPRIATE ADJUSTMENT TO THE SPOT DIVIDEND YIELD.

A. According to the traditional DCF model, the dividend yield term relates to the dividend yield over the coming period. As indicated by Professor Myron Gordon, who is commonly associated with the development of the DCF model for popular use, this is obtained by (1) multiplying the expected dividend over the coming quarter by 4, and (2) dividing this dividend by the current stock price to determine the appropriate dividend yield for a firm, which pays dividends on a quarterly basis.[6]

In applying the DCF model, some analysts adjust the current dividend for growth over the coming year as opposed to the coming quarter. This can be complicated because firms tend to announce changes in dividends at different times during the year. As such, the dividend yield computed based on presumed growth over the coming quarter as opposed to the coming year can be quite different. Consequently, it is common for analysts to adjust the dividend yield by some fraction of the long-term expected growth rate.

The appropriate adjustment to the dividend yield is further complicated in the regulatory process when the overall cost of capital is applied to a projected or end-of-future-test-year rate base. The net effect of this application is an overstatement of the equity cost rate estimate derived from

[6] *Petition for Modification of Prescribed Rate of Return*, Federal Communications Commission, Docket No. 79-05, Direct Testimony of Myron J. Gordon and Lawrence I. Gould at 62 (April 1980).

the DCF model. In the context of the constant-growth DCF model, both the adjusted dividend yield and the growth component are overstated. The overstatement results from applying an equity cost rate computed using current market data to a future or test-year-end rate base which includes growth associated with the retention of earnings during the year. In other words, an equity cost rate times a future, yet to be achieved rate base, results in an inflated dividend yield and growth rate.

Q. GIVEN THIS DISCUSSION, WHAT ADJUSTMENT FACTOR WILL YOU USE FOR YOUR DIVIDEND YIELD?

A. I will adjust the dividend yield by 1/2 the expected growth so as to reflect growth over the coming year.

Q. PLEASE DISCUSS THE GROWTH RATE COMPONENT OF THE DCF MODEL.

A. There is much debate as to the proper methodology to employ in estimating the growth component of the DCF model. By definition, this component is investors' expectation of the long-term dividend growth rate. In developing growth expectations, investors have access to both historical and projected growth rates for earnings and dividends per share and for internal or book value growth.

Q. WHAT GROWTH DATA HAVE YOU REVIEWED FOR THE TWO GROUPS OF ELECTRIC COMPANIES?

A. I have analyzed a number of measures of growth for the electric utility companies. I have reviewed *Value Line's* historical and projected growth rate estimates for EPS, DPS, and BVPS. In addition, I have utilized the average EPS growth rate forecasts of Wall Street analysts as provided by Zacks, Reuters, and First Call. These services solicit 5-year earning growth rate projections for securities analysts and compile and publish the averages of these forecasts on the Internet. Finally, I have also assessed prospective growth as measured by prospective earnings retention rates and earned returns on common equity.

Q. PLEASE DISCUSS HISTORICAL GROWTH IN EARNINGS AND DIVIDENDS AS WELL AS INTERNAL GROWTH.

A. Historical growth rates for EPS, DPS, and BVPS are readily available to virtually all investors and presumably are an important ingredient in forming expectations concerning future growth. However, one must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles). However, one must appraise the context in which the growth rate is being employed. According to the conventional DCF model, the expected return on a security is equal to the sum of the dividend yield and the expected long-term growth in dividends. Therefore, to best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.

Internally generated growth is a function of the percentage of earnings retained within the firm (the earnings retention rate) and the rate of return earned on those earnings (the return on equity). The internal growth rate is computed as the retention rate times the return on equity. Internal growth is significant in determining long-run earnings and, therefore, dividends. Investors recognize the importance of internally generated growth and pay premiums for stocks of companies that retain earnings and earn high returns on internal investments.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF *VALUE LINE'S* HISTORICAL AND PROJECTED GROWTH RATES FOR THE PROXY GROUP OF ELECTRIC UTILITY COMPANIES.

A. Page 3 of Exhibit_(JRW-7) provides the historical growth rates for the companies in the two groups as provided in the *Value Line Investment Survey.* Due to the presence of outliers, both means and median measures of central tendency are shown. For Group A, historic growth has been relatively low and volatile. The range of the central tendency measures is from -1.3% to 2.5%, with an average of 0.8%. The historical growth rate pattern for Group B is very similar to that of Group A. The range of the central tendency measures for Group B is from -1.5% to 3.0%, with an average of 0.9%.

Page 4 of Exhibit_(JRW-7) provides a summary of projected growth rates for the companies in the two groups as provided in the *Value Line Investment Survey.* As above, due to outliers, both the means and medians are shown. For Group A, the mean/median projected growth rates for EPS, DPS, and BVPS are 6.0%/5.0%, 5.1%/4.5%, and 5.0%/5.0%. The average of the mean and median figures is 5.1%. Also shown on page 4 of Exhibit_(JRW-7) is the prospective internal growth as indicated by the prospective earnings retention rate and return on common equity. The average of the mean and median figures for internal growth is 4.4% for Group A.

Projected growth rate measures for Group B are again similar to those for Group A. The mean/median projected growth rates for Group B for EPS, DPS, and BVPS are 5.4%/5.5%, 4.0%/4.5%, and 4.5%/4.00%. The average of the mean and median figures is 4.7%. Prospective internal growth, also shown on page 4 of Exhibit_(JRW-7), is the product of the prospective earnings retention rate and return on common equity. The average of the mean and median figures for internal growth is 3.80% for Group B.

Q. PLEASE ASSESS GROWTH FOR THE GROUPS AS MEASURED BY ANALYSTS' FORECASTS OF EXPECTED 5-YEAR GROWTH IN EPS.

A. Zacks, First Call, and Reuters collect, summarize, and publish Wall Street analysts' projected five-year EPS growth rate forecasts for companies. These forecasts are provided for the companies in the electric utility proxy groups on page 5 of Exhibit_(JRW-7). The average of the mean and median analysts' projected growth forecasts is 4.9% for Group A and 5.5% for Group B.[7]

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE HISTORICAL AND PROSPECTIVE GROWTH OF THE ELECTRIC COMPANY PROXY GROUPS.

A. The table below shows the summary DCF growth rate indicators for the two groups of electric utility companies. For both groups, *Value Line*'s historical growth rate in EPS, DPS, and BVPS is quite low and with means of only 0.8% and 0.9%. The average of *Value Line*'s projected growth rates for EPS, DPS, and BVPS is 5.1% for Group A and 4.7% for Group B. Prospective internal growth is 4.4% for Group A and 3.80% for Group B using *Value Line*'s average projected earning retention rate and average return on common equity. The average of the mean and median projected EPS growth rate figures of Wall Street analysts are 4.90% for Group A and 5.50% for Group B.

[7] Since there is considerable overlap in analyst coverage between the three services, and not all of the companies have forecasts from the different services, I have averaged the expected 5-year EPS growth rates from the three services for

DCF Growth Rate Indicators

Growth Rate Indicator	Group A	Group B
Historic *Value Line* Growth in EPS, DPS, and BVPS	0. 8%	0.8%
Projected *Value Line* Growth in EPS, DPS, and BVPS	5.1%	4.7%
Internal Growth ROE * Retention rate	4.4%	3.8%
Projected EPS Growth from First Call, Reuters, and Zacks	4.9%	5.5%

Based on these growth rate indicators, and giving more weight to the projected figures, an expected growth rate for Group A would appear to be in the 4.50-5.00 percent range. I will use the midpoint of this range – 4.75% - as my expected DCF growth rate for Group A. For Group B, projected growth rate figures suggest a slightly higher expected growth rate. Hence, I will use an expected DCF growth rate of 5.0% for Group B.

Q. BASED ON THE ABOVE ANALYSIS, WHAT IS YOUR INDICATED COMMON EQUITY COST RATE FROM THE DCF MODEL FOR THE GROUPS?

A. My DCF-derived equity cost rate for the two groups are:

$$\text{DCF Equity Cost Rate (k)} = \frac{D}{P} + g$$

	Dividend Yield	½ Growth Adjustment	DCF Growth Rate	Equity Cost Rate
Group A	4.40%	1.02375	4.75%	9.25%
Group B	4.20%	1.02500	5.00%	9.31%

each company to arrive at an expected EPS growth rate by company.

These results are summarized on page 1 of Exhibit_(JRW-7).

C. CAPITAL ASSET PRICING MODEL RESULTS

Q. PLEASE DISCUSS THE CAPITAL ASSET PRICING MODEL (CAPM).

A. The CAPM is a risk premium approach to gauging a firm's cost of equity capital. According to the risk premium approach, the cost of equity is the sum of the interest rate on a risk-free bond (R_f) and a risk premium (RP), as in the following:

$$k = R_f + RP$$

The yield on long-term Treasury securities is normally used as R_f. Risk premiums are measured in different ways. The CAPM is a theory of the risk and expected returns of common stocks. In the CAPM, two types of risk are associated with a stock: firm-specific risk or unsystematic risk; and market or systematic risk, which is measured by a firm's beta. The only risk that investors receive a return for bearing is systematic risk.

According to the CAPM, the expected return on a company's stock, which is also the equity cost rate (K), is equal to:

$$K = (R_f) + \beta_{ibm} * [E(R_m) - (R_f)]$$

Where:

- K represents the estimated rate of return on the stock;
- $E(R_m)$ represents the expected return on the overall stock market. Frequently, the 'market' refers to the S&P 500;
- (R_f) represents the risk-free rate of interest;

- $[E(R_m) - (R_f)]$ represents the expected equity or market risk premium—the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks; and
- *Beta*—($ß_i$) is a measure of the systematic risk of an asset.

To estimate the required return or cost of equity using the CAPM requires three inputs: the risk-free rate of interest (R_f), the beta ($ß_i$), and the expected equity or market risk premium, $[E(R_m) - (R_f)]$. R_f is the easiest of the inputs to measure – it is the yield on long-term Treasury bonds. $ß_i$, the measure of systematic risk, is a little more difficult to measure because there are different opinions about what adjustments, if any, should be made to historical betas due to their tendency to regress to 1.0 over time. And finally, an even more difficult input to measure is the expected equity or market risk premium, $[E(R_m) - (R_f)]$. I will discuss each of these inputs, with most of the discussion focusing on the expected equity risk premium.

Q. PLEASE DISCUSS EXHIBIT_(JRW-8).

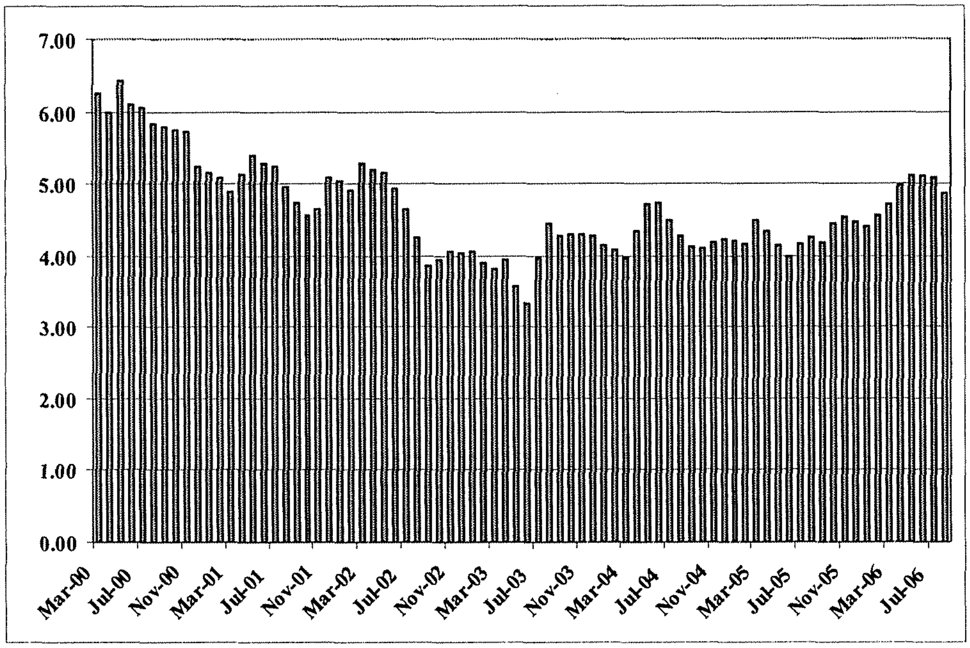
A. Exhibit_(JRW-8) provides the summary results for my CAPM study. Page 1 shows the results, and the pages following it, contain the supporting data.

Q. PLEASE DISCUSS THE RISK-FREE INTEREST RATE.

A. The yield on long-term Treasury bonds has usually been viewed as the risk-free rate of interest in the CAPM. The yield on long-term Treasury bonds, in turn, has been considered to be the yield on Treasury bonds with 30-year maturities. However, since the Treasury issuance of 30-Year Treasuries was interrupted for a period of time in recent years, the yield on 10-year Treasury bonds has replaced the yield on 30-year Treasury bonds as the benchmark long-term Treasury rate. The 10-year Treasury yields over the past five years are shown in the chart below.

These rates hit a 60-year low in the summer of 2003 at 3.33%. They increased with the rebounding economy and fluctuated in the 4.0-4.50 percent range over the past three years until advancing to 5.0% in recent months in response to a strong economy and increases in energy, commodity, and consumer prices.

Ten-Year U.S. Treasury Yields
January 2000-August 2006



Source: http://www.federalreserve.gov/releases/h15/current/h15.pdf

Q. WHAT RISK-FREE INTEREST RATE ARE YOU USING IN YOUR CAPM?

A. With the growing budget deficit, the U.S. Treasury has decided to again begin issuing a 30-year bond. As such, the market may again begin to focus on its yield as the benchmark for long-term capital costs in the U.S.

In recent months, the yields on the 10- and 30- year Treasuries have increased and have been in the 5.00%-5.25% range. As of September 11, 2006, as shown in the table below, the rates on 10- and 30- Treasuries were 4.77% and 4.92%, respectively. Given this recent range and recent movement, I will use 5.00% as the risk-free rate, or R_f, in my CAPM.

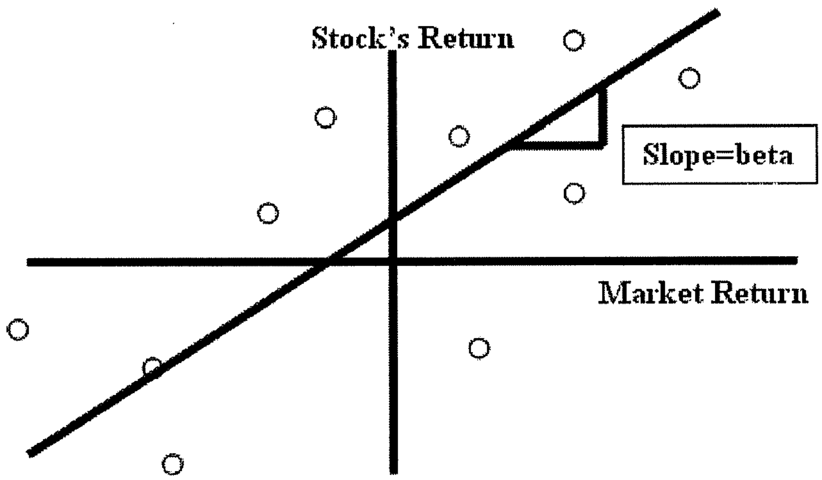
U.S. Treasury Yields
September 11, 2006

NOTES/BONDS	COUPON	MATURITY DATE	CURRENT PRICE/YIELD
2-YEAR	4.875	08/31/2008	100-04 / 4.81
3-YEAR	4.875	08/15/2009	100-12 / 4.73
5-YEAR	4.625	08/31/2011	99-20¼ / 4.71
10-YEAR	4.875	08/15/2016	100-25½ / 4.77
30-YEAR	4.500	02/15/2036	93-16+ / 4.92

Q. WHAT BETAS ARE YOU EMPLOYING IN YOUR CAPM?

A. Beta (ß) is a measure of the systematic risk of a stock. The market, usually taken to be the S&P 500, has a beta of 1.0. The beta of a stock with the same price movement as the market also has a beta of 1.0. A stock whose price movement is greater than that of the market, such as a technology stock, is riskier than the market and has a beta greater than 1.0. A stock with below average price movement, such as that of a regulated public utility, is less risky than the market and has a beta less than 1.0. Estimating a stock's beta involves running a linear regression of a stock's return on the market return as in the following:

Calculation of Beta



The slope of the regression line is the stock's ß. A steeper line indicates the stock is more sensitive to the return on the overall market. This means that the stock has a higher ß and greater than average market risk. A less steep line indicates a lower ß and less market risk.

Numerous online investment information services, such Yahoo and Reuters, provide estimates of stock betas. Usually these services report different betas for the same stock. The differences are usually due to (1) the time period over which the ß is measured and (2) any adjustments that are made to reflect the fact that betas tend to regress to 1.0 over time. In estimating an equity cost rate for the two groups of electric utility companies, I am using the average betas for the companies as provided in the *Value Line Investment Survey*. As shown on page 2 of Exhibit_(JRW-8), the median beta for the companies in both Groups A and B is 0.85.

Q. PLEASE DISCUSS ANY OPPOSING VIEWS REGARDING THE EQUITY RISK PREMIUM.

A. The equity or market risk premium—$[E(R_m) - R_f]$: is equal to the expected return on the stock market (e.g., the expected return on the S&P 500 ($E(R_m)$) minus the risk-free rate of interest (R_f). The equity premium is the difference in the expected total return between investing in equities and investing in "safe" fixed-income assets, such as long-term government bonds. However, while the equity risk premium is easy to define conceptually, it is difficult to measure because it requires an estimate of the expected return on the market.

Q. PLEASE DISCUSS THE ALTERNATIVE APPROACHES TO ESTIMATING THE EQUITY RISK PREMIUM.

A. The table below highlights the primary approaches to, and issues in, estimating the expected equity risk premium. The traditional way to measure the equity risk premium is to use the difference between historical average stock and bond returns. In this case, historical stock and bond returns, also called ex post returns, are used as the measures of the market's expected return (known as the ex ante or forward-looking expected return). This type of historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of using historical financial market returns as measures of expected returns. Most historical assessments of the equity risk premium suggest an equity risk premium of 5-7 percent above the rate on long-term Treasury bonds. However, this can be a problem because (1) ex post returns are not the same as ex ante expectations, (2) market risk premiums can change over time, increasing when investors become more risk-averse, and decreasing when investors become less risk-averse, and (3) market conditions can change such that ex post historical returns are poor estimates of ex ante expectations.

Risk Premium Approaches

	Historical Ex Post Excess Returns	Surveys	Ex Ante Models and Market Data
Means of Assessing the Equity-Bond Risk Premium	Historical average is a popular proxy for the ex ante premium – but likely to be misleading	Investor and expert surveys can provide direct estimates of prevailing expected returns/premiums	Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium
Problems/Debated Issues	Time variation in required returns and systematic selection and other biases have boosted valuations over time, and have exaggerated realized excess equity returns compared with ex ante expected premiums	Limited survey histories and questions of survey representativeness. Surveys may tell more about hoped-for expected returns than about objective required premiums due to irrational biases such as extrapolation.	Assumptions needed for DCF inputs, notably the trend earnings growth rate, make even these models' outputs subjective. The range of views on the growth rate, as well as the debate on the relevant stock and bond yields, leads to a range of premium estimates.

Source: Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003).

The use of historical returns as market expectations has been criticized in numerous academic studies.[8] The general theme of these studies is that the large equity risk premium discovered in historical stock and bond returns cannot be justified by the fundamental data. These studies, which fall under the category "Ex Ante Models and Market Data," compute ex ante expected returns using market data to arrive at an expected equity risk premium. These studies have also been called "Puzzle Research" after the famous study by Mehra and Prescott in which the authors first questioned the magnitude of historical equity risk premiums relative to fundamentals.[9]

Q. PLEASE BRIEFLY SUMMARIZE SOME OF THE ACADEMIC STUDIES THAT DEVELOP EX ANTE EQUITY RISK PREMIUMS.

[8] The problems with using ex post historical returns as measures of ex ante expectations will be discussed at length later in my testimony.

A. Two of the most prominent studies of ex ante expected equity risk premiums were by Eugene Fama and Ken French (2002) and James Claus and Jacob Thomas (2001). The primary debate in these studies revolves around two related issues: (1) the size of expected equity risk premium, which is the return equity investors require above the yield on bonds; and (2) the fact that estimates of the ex ante expected equity risk premium using fundamental firm data (earnings and dividends) are much lower than estimates using historical stock and bond return data. Fama and French (2002), two of the most preeminent scholars in finance, use dividend and earnings growth models to estimate expected stock returns and ex ante expected equity risk premiums.[10] They compare these results to actual stock returns over the period 1951-2000. Fama and French estimate that the expected equity risk premium from DCF models using dividend and earnings growth to be between 2.55% and 4.32%. These figures are much lower than the ex post historical equity risk premium produced from the average stock and bond return over the same period, which is 7.40%.

Fama and French conclude that the ex ante equity risk premium estimates using DCF models and fundamental data are superior to those using ex post historical stock returns for three reasons: (1) the estimates are more precise (a lower standard error); (2) the Sharpe ratio, which is measured as the [(expected stock return – risk-free rate)/standard deviation], is constant over time for the DCF models but varies considerably over time and more than doubles for the average stock-bond return model; and (3) valuation theory specifies relationships between the market-to-book ratio, return on investment, and cost of equity capital that favor estimates from fundamentals. They also conclude that the high average stock returns over the past 50 years

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[9] Rahnish Mehra and Edward Prescott, "The Equity Premium: A Puzzle," *Journal of Monetary Economics* (1985).
[10] Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, (April 2002).

were the result of low expected returns and that the average equity risk premium has been in the 3-4 percent range.

The study by Claus and Thomas of Columbia University provides direct support for the findings of Fama and French.[11] These authors compute ex ante expected equity risk premiums over the 1985-1998 period by (1) computing the discount rate that equates market values with the present value of expected future cash flows, and (2) then subtracting the risk-free interest rate. The expected cash flows are developed using analysts' earnings forecasts. The authors conclude that over this period the ex ante expected equity risk premium is in the range of 3.0%. Claus and Thomas note that, over this period, ex post historical stock returns overstate the ex ante expected equity risk premium because, as the expected equity risk premium has declined, stock prices have risen. In other words, from a valuation perspective, the present value of expected future returns increase when the required rate of return decreases. The higher stock prices have produced stock returns that have exceeded investors' expectations and therefore ex post historical equity risk premium estimates are biased upwards as measures of ex ante expected equity risk premiums.

Q. PLEASE PROVIDE A SUMMARY OF THE EX ANTE EQUITY RISK PREMIUM STUDIES.

A. Richard Derrig and Elisha Orr (2003) recently completed the most comprehensive paper to date which summarizes and assesses the many risk premium studies.[12] These authors reviewed the

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[11] James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).
[12] Richard Derrig and Elisha Orr, "Equity Risk Premium: Expectations Great and Small," Working Paper (version 3.0), Automobile Insurers Bureau of Massachusetts, August 28, 2003.

various approaches to estimating the equity risk premium, and the overall results. Page 3 of Exhibit_(JRW-8) provides a summary of the results of the primary risk premium studies reviewed by Derrig and Orr. In developing page 3 of Exhibit_(JRW-8), I have (1) updated the results of the studies that have been updated by the various authors, (2) included the results of several additional studies and surveys, and (3) included the results of the "Building Blocks" approach to estimating the equity risk premium, including a study I performed which is presented below.

On page 3, the risk premium studies listed under the 'Social Security' and 'Puzzle Research' sections are primarily ex ante expected equity risk premium studies (as discussed above). Most of these studies are performed by leading academic scholars in finance and economics. Also provided are the results of studies by Ibbotson and Chen and myself which use the Building Blocks approach.

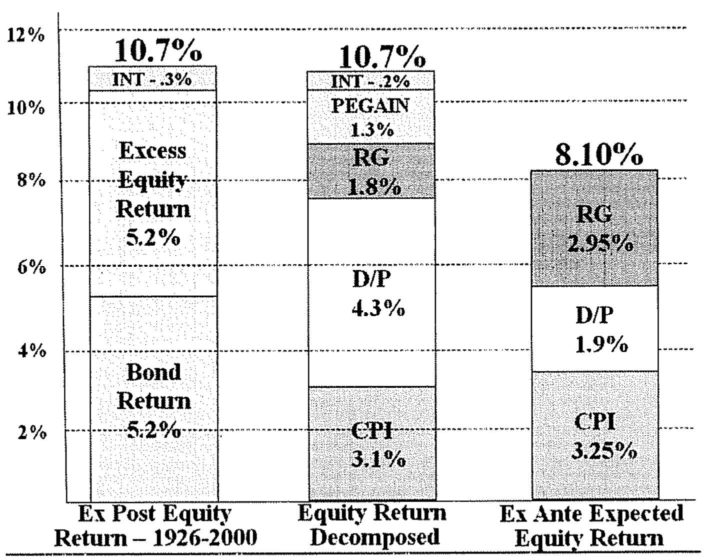
Q. PLEASE DISCUSS YOUR DEVELOPMENT OF AN EX ANTE EXPECTED EQUITY RISK PREMIUM COMPUTED USING THE BUILDING BLOCKS METHODOLOGY.

A. Ibbotson and Chen (2002) evaluate the ex post historical mean stock and bond returns in what is called the Building Blocks approach.[13] They use 75 years of data and relate the compounded historical returns to the different fundamental variables employed by different researchers in building ex ante expected equity risk premiums. Among the variables included were inflation, real EPS and DPS growth, ROE and book value growth, and P/E ratios. By relating the fundamental factors to the ex post historical returns, the methodology bridges the gap

[13] Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003.

between the ex post and ex ante equity risk premiums. Ilmanen (2003) illustrates this approach using the geometric returns and five fundamental variables – inflation (CPI), dividend yield (D/P), real earnings growth (RG), repricing gains (PEGAIN) and return interaction/reinvestment (INT).[14] This is shown in the graph below. The first column breaks the 1926-2000 geometric mean stock return of 10.7% into the different return components demanded by investors: the historical Treasury bond return (5.2%), the excess equity return (5.2%), and a small interaction term (0.3%). This 10.7% annual stock return over the 1926-2000 period can then be broken down into the following fundamental elements: inflation (3.1%), dividend yield (4.3%), real earnings growth (1.8%), repricing gains (1.3%) associated with higher P/E ratios, and a small interaction term (0.2%).

Decomposing Equity Market Returns
The Building Blocks Methodology



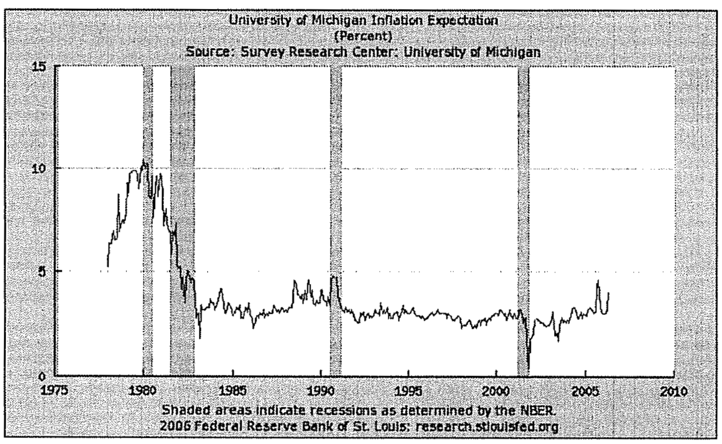
[14] Antti Ilmanen, Expected Returns on Stocks and Bonds," *Journal of Portfolio Management*, (Winter 2003), p. 11.

Q. HOW ARE YOU USING THIS METHODOLOGY TO DERIVE AN EX ANTE EXPECTED EQUITY RISK PREMIUM?

A. The third column in the graph above shows current inputs to estimate an ex ante expected market return. These inputs include the following:

CPI – To assess expected inflation, I have employed expectations of the short-term and long-term inflation rate. The graph below shows the expected annual inflation rate according to consumers, as measured by the CPI, over the coming year. This survey is published monthly by the University of Michigan Survey Research Center. This survey is published monthly by the University of Michigan Survey Research Center. In the most recent report, the expected one-year expected inflation rate was 4.0%.

Expected Inflation Rate
University of Michigan Consumer Research
(Data Source: http://research.stlouisfed.org/fred2/series/MICH/98)



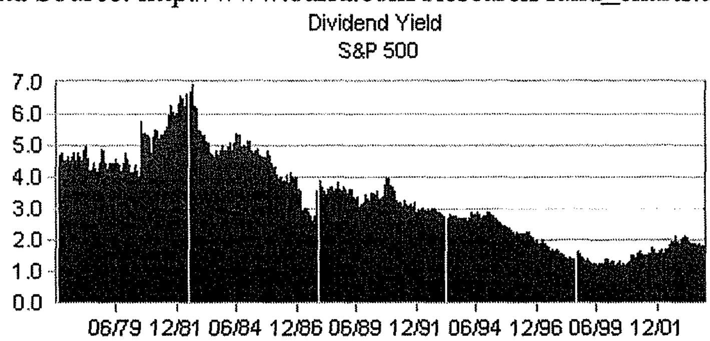
Longer term inflation forecasts are available in the Federal Reserve Bank of Philadelphia's publication entitled *Survey of Professional Forecasters.*[15] This survey of professional economists has been published for almost 50 years. While this survey is published quarterly, only the first quarter survey includes long-term forecasts of GDP growth, inflation, and market returns. In the first quarter, 2006 survey, published on February 13, 2006, the median long-term (10-term) expected inflation rate as measured by the CPI was 2.50% (see page 4 of Exhibit_(JRW-8)).

Given these results, I will use the average of the University of Michigan and Philadelphia Federal Reserve's surveys (4.0% and 2.50%), or 3.25%.

D/P – As shown in the graph below, the dividend yield on the S&P 500 has decreased gradually over the past decade. Today, it is far below its norm of 4.3% over the 1926-2000 time period. Whereas the S&P dividend yield bottomed out at less than 1.4% in 2000, it is currently at 1.9% which I use in the ex ante risk premium analysis.

S&P 500 Dividend Yield

(Data Source: http://www.barra.com/Research/fund_charts.asp)



[15]Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters,* February 14, 2005. The *Survey of Professional Forecasters* was formerly conducted by the American Statistical Association (ASA) and the National Bureau of Economic Research (NBER) and was known as the ASA/NBER survey. The survey, which began in 1968, is conducted each quarter. The Federal Reserve Bank of Philadelphia, in cooperation with the NBER, assumed responsibility for the survey in June 1990.

RG – To measure expected real growth in earnings, I use (1) the historical real earnings growth rate for the S&P 500, and (2) expected real GDP growth. The S&P 500 was created in 1960. It includes 500 companies which come from ten different sectors of the economy. Over the 1960-2005 period, nominal growth in EPS for the S&P 500 was 7.11%. On page 5 of Exhibit_(JRW-8), real EPS growth is computed using the CPI as a measure of inflation. As indicated by Ibbotson and Chen, real earnings growth over the 1926-2000 period was 1.8%. The real growth figure over 1960-2005 period for the S&P 500 is 2.7%.

The second input for expected real earnings growth is expected real GDP growth. The rationale is that over the long-term, corporate profits have averaged a relatively consistent 5.50% of US GDP.[16] Real GDP growth, according to McKinsey, has averaged 3.5% over the past 80 years. Expected GDP growth, according to the Federal Reserve Bank of Philadelphia's *Survey of Professional Forecasters,* is 3.2% (see page 4 of Exhibit_(JRW-8)).

Given these results, I will use the average of the historical S&P EPS real growth and the historical real GDP growth (and as supported by the Philadelphia Federal Reserve survey of expected GDP growth) (2.7% and 3.2%), or 2.95%, for real earnings growth.

PEGAIN – the repricing gains associated with increases in the P/E ratio accounted for 1.3% of the 10.7% annual stock return in the 1926-2000 period. In estimating an ex ante expected stock market return, one issue is whether investors expect P/E ratios to increase from their current levels. The graph below shows the P/E ratios for the S&P 500 over the past 25 years. The run-up and eventual peak in P/Es is most notable in the chart. The relatively low P/E ratios (in the range of 10)

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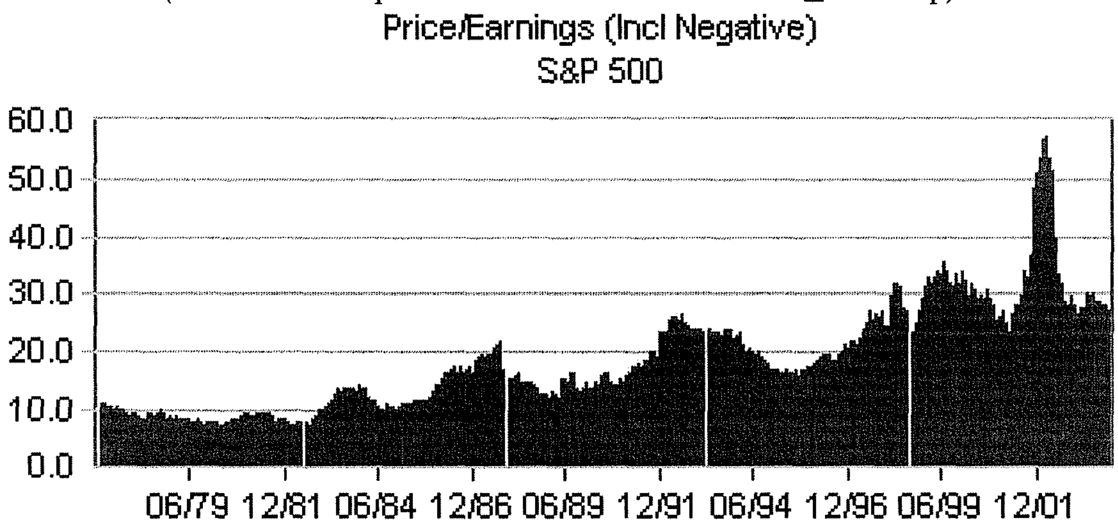
[16] Marc. H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

over two decades ago are also quite notable. As of September, 2006 the P/E for the S&P 500, using the trailing 12 months EPS, is 20.50 according to www.investor.reuters.com.

Given the current economic and capital markets environment, I do not believe that investors expect even higher P/E ratios. Therefore, a PEGAIN would not be appropriate in estimating an ex ante expected stock market return. There are two primary reasons for this. First, the average historical S&P 500 P/E ratio is 15 – thus the current P/E exceeds this figure by almost 50%. Second, as previously noted, interest rates are at a cyclical low not seen in almost 50 years. This is a primary reason for the high current P/Es. Given the current market environment with relatively high P/E ratios and low relative interest rate, investors are not likely to expect to get stock market gains from lower interest rates and higher P/E ratios.

S&P 500 P/E Ratios
(Data Source: http://www.barra.com/Research/fund_charts.asp)



Q. GIVEN THIS DISCUSSION, WHAT IS YOUR EX ANTE EXPECTED MARKET RETURN AND EQUITY RISK PREMIUM USING THE "BUILDING BLOCKS

METHODOLOGY"?

A. My expected market return is represented by the last column on the right in the graph entitled "Decomposing Equity Market Returns: The Building Blocks Methodology" found earlier in my testimony. As shown on page 37, my expected market return is 8.10% which is composed of 3.25% expected inflation, 1.90% dividend yield, and 2.95% real earnings growth rate.

Expected Inflation	Dividend Yield	Real Earnings Growth Rate	Expected Market Return
3.25%	1.90%	2.95%	8.10%

Q. GIVEN THAT THE HISTORICAL COMPOUNDED ANNUAL MARKET RETURN IS IN EXCESS OF 10%, WHY DO YOU BELIEVE THAT YOUR EXPECTED MARKET RETURN OF 8.10% IS REASONABLE?

A. As discussed above in the development of the expected market return, stock prices are relatively high at the present time in relation to earnings and dividends and interest rates are relatively low. Hence, it is unlikely that investors are going to experience high stock market returns due to higher P/E ratios and/or lower interest rates. In addition, as shown in the decomposition of equity market returns, whereas the dividend portion of the return was historically 4.3%, the current dividend yield is only 1.9%. Due to these reasons, lower market returns are expected for the future.

Q. IS YOUR EXPECTED MARKET RETURN OF 8.10% CONSISTENT WITH THE

FORECASTS OF MARKET PROFESSIONALS?

A. Yes. In the first quarter, 2006 survey, published on February 13, 2006, the median long-term expected return on the S&P 500 was 7.00 (see page 4 of Exhibit_(JRW-8)). This is clearly consistent with my expected market return of 8.10%.

Q. IS YOUR EXPECTED MARKET RETURN CONSISTENT WITH THE EXPECTED MARKET RETURNS OF CORPORATE CHIEF FINANCIAL OFFICERS (CFOs)?

A. Yes. John Graham and Campbell Harvey of Duke University conduct an annual survey of corporate CFOs. The survey is a joint project of Duke University and *CFO Magazine*. In the 2006 survey, the average expected return on the S&P 500 over the next ten years is 8.05%.[17]

Q. GIVEN THIS EXPECTED MARKET RETURN, WHAT IS YOUR EX ANTE EQUITY RISK PREMIUM USING THE BUILDING BLOCKS METHODOLOGY?

A. As shown above, the current 30-year treasury yield is 4.92%. My ex ante equity risk premium is simply the expected market return from the Building Blocks methodology minus this risk-free rate:

Ex Ante Equity Risk Premium = 8.10% - 4.92% = 3.18%

Q. GIVEN THIS DISCUSSION, HOW ARE YOU MEASURING AN EXPECTED EQUITY RISK PREMIUM IN THIS PROCEEDING?

A. As discussed above, page 3 of Exhibit_(JRW-8) provides a summary of the results of a

[17] The survey results are available at www.cfosurvey.org..

variety of the equity risk premium studies. These include the results of (1) the study of historical risk premiums as provided by Ibbotson, (2) ex ante equity risk premium studies (studies commissioned by the Social Security Administration as well as those labeled 'Puzzle Research'), (3) equity risk premium surveys of CFOs, Financial Forecasters, as well as academics, (4) Building Block approaches to the equity risk premium, and (5) other miscellaneous studies. The overall average equity risk premium of these studies is 4.13%, which I will use as the equity risk premium in my CAPM study.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS OF LEADING INVESTMENT FIRMS?

A. Yes. One of the first studies in this area was by Stephen Einhorn, one of Wall Street's leading investment strategists.[18] His study showed that the market or equity risk premium had declined to the 2.0 to 3.0 percent range by the early 1990s. Among the evidence he provided in support of a lower equity risk premium is the inverse relationship between real interest rates (observed interest rates minus inflation) and stock prices. He noted that the decline in the market risk premium has led to a significant change in the relationship between interest rates and stock prices. One implication of this development was that stock prices had increased higher than would be suggested by the historical relationship between valuation levels and interest rates.

The equity risk premiums of some of the other leading investment firms today support the result of the academic studies. An article in *The Economist* indicated that some other firms like J.P. Morgan are estimating an equity risk premium for an average risk stock in the 2.0 to 3.0 percent

[18] Steven G. Einhorn, "The Perplexing Issue of Valuation: Will the Real Value Please Stand Up?" *Financial*

range above the interest rate on U.S. Treasury Bonds.[19]

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY CORPORATE CHIEF FINANCIAL OFFICERS (CFOs)?

A. Yes. In the previous referenced 2006 CFO survey conducted by John Graham and Campbell Harvey, the average ex ante 10-year equity risk premium was 3.05%.[20]

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EX ANTE EQUITY RISK PREMIUMS OF PROFESSIONAL FORECASTERS?

A. Yes. The financial forecasters in the previously-referenced Federal Reserve Bank of Philadelphia survey project both stock and bond returns. As shown on page 4 of Exhibit_(JRW-8)), the median long-term expected stock and bond returns were 7.00% and 5.00%, respectively. This provides an ex ante equity risk premium of 2.00%.

Q. IS YOUR EX ANTE EQUITY RISK PREMIUM CONSISTENT WITH THE EQUITY RISK PREMIUMS USED BY THE LEADING CONSULTING FIRMS?

A. Yes. McKinsey & Co. is widely recognized as the leading management consulting firm in the world. They recently published a study entitled "The Real Cost of Equity" in which they developed an ex ante equity risk premium for the US. In reference to the decline in the equity risk premium, as well as what is the appropriate equity risk premium to employ for corporate valuation

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Analysts Journal (July-August 1990), pp. 11-16.

[19] For example, see "Welcome to Bull Country," *The Economist* (July 18, 1998), pp. 21-3, and "Choosing the Right Mixture," *The Economist* (February 27, 1999), pp. 71-2.

[20] The survey results are available at www.cfosurvey.org..

purposes, the McKinsey authors concluded the following:

> We attribute this decline not to equities becoming less risky (the inflation-adjusted cost of equity has not changed) but to investors demanding higher returns in real terms on government bonds after the inflation shocks of the late 1970s and early 1980s. We believe that using an equity risk premium of 3.5 to 4 percent in the current environment better reflects the true long-term opportunity cost of equity capital and hence will yield more accurate valuations for companies.[21]

Q. WHAT EQUITY COST RATE IS INDICATED BY YOUR CAPM ANALYSIS?

A. The results of my CAPM study for the two groups of electric utility companies as well as DEK are provided below:

$$K = (R_f) + \beta_{ibm} * [E(R_m) - (R_f)]$$

	Risk-Free Rate	Beta	Equity Risk Premium	Equity Cost Rate
Group A	5.00%	0.85	4.13%	8.50 %
Group B	5.00%	0.85	4.13%	8.50 %

D. EQUITY COST RATE SUMMARY

Q. PLEASE SUMMARIZE YOUR EQUITY COST RATE STUDY.

A. The results for my DCF and CAPM analyses for the proxy group of electric utility companies are indicated below:

	DCF	CAPM
Group A	9.25%	8.50%
Group B	9.31%	8.50%

[21] Marc H. Goedhart, et al, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.15. .

Q. GIVEN THESE RESULTS, WHAT IS YOUR ESTIMATED EQUITY COST RATE FOR THE GROUP OF ELECTRIC COMPANIES?

A. Giving these results, I conclude that the equity cost rate for the two proxy group of electric utilities is in the 8.5-9.31 percent range. Given primary weight to the DCF approach, I am recommending an equity cost rate of 9.25%. This presumes that the Commission adopts my capital structure. If the Commission were to adopt DEK's proposed capital structure, my recommended return on common equity would be 9.00%.

Q. ISN'T THIS RATE OF RETURN LOW BY HISTORICAL STANDARDS?

A. Yes it is, and appropriately so. My rate of return is low by historical standards for three reasons. First, as discussed above, current capital costs are very low by historical standards, with interest rates at a cyclical low not seen since the 1960s. Second, the 2003 tax law, which reduces the tax rates on dividend income and capital gains, lowers the pre-tax return required by investors. And third, as discussed below, the equity or market risk premium has declined.

Q. FINALLY, PLEASE DISCUSS YOUR RATE OF RETURN IN LIGHT OF RECENT YIELDS ON 'A' RATED PUBLIC UTILITY BONDS.

A. In recent months the yields on long-term public utility bonds have been in the 6.00 percent range. My rate of return may appear to be too low given these yields. However, as previously noted, my recommendation must be viewed in the context of the significant decline in the market or equity risk premium. As a result, the return premium that equity investors require over bond yields is much lower than today. This decline was previously reviewed in my discussion of capital costs in today's markets. In addition, it will be examined in more depth in my rebuttal testimony.

Q. HOW DO YOU TEST THE REASONABLENESS OF YOUR COST OF EQUITY AND OVERALL RATE OF RETURN RECOMMENDATION?

A. To test the reasonableness of my 9.25% equity cost rate recommendation, I examine the relationship between the return on common equity and the market-to-book ratios for the group of electric utility companies.

Q. WHAT DO THE RETURNS ON COMMON EQUITY AND MARKET-TO-BOOK RATIOS FOR THE GROUP OF ELECTRIC UTILITIES INDICATE ABOUT THE REASONABLENESS OF YOUR 9.25% RECOMMENDATION?

A. Exhibit_(JRW-3) provides financial performance and market valuation statistics for the group of electric utility companies. The current return on equity and market-to-book ratios for the group are summarized below:

	Current ROE	Market-to-Book Ratio
Group A	11.5 %	202.1
Group B	9.60%	157.4

Source: Exhibit_(JRW-3).

These results clearly indicate that, on average, these companies are earning returns on equity above their equity cost rates. As such, this observation provides evidence that my recommended equity cost rate of 9.25% is reasonable and fully consistent with the financial performance and market valuation of the proxy group of electric utility companies.

VI. CRITIQUE OF DEK'S RATE OF RETURN TESTIMONY

Q. PLEASE SUMMARIZE DEK'S OVERALL RATE OF RETURN RECOMMENDATION.

A. DEK's rate of return recommendation is provided by DEK witnesses Lynn J. Good and Dr. Roger A. Morin. The Company has proposed a capital structure consisting of 8.49% short-term debt, 40.63% long-term debt, and 50.88% common equity and a short-term debt cost rate of 5.14% and a long-term debt cost rate of 6.09%. Dr. Morin has recommended an equity cost rate in the range of 11.25%-11.50%.

Q. PLEASE EVALUATE THE COMPANY'S RATE OF RETURN POSITION.

A. The Company's proposed rate of return is excessive due an inappropriate capital structure and an overstated equity cost rate. Dr. Morin's estimated equity cost rate in the range 11.25-11.50% is unreasonably high primarily due to (1)) excessive risk premium estimates in his CAPM and risk premium approaches, (2) upwardly-biased growth rates in his DCF equity cost rate approach; and (3) an unnecessary flotation cost adjustment.

Q. WHAT ISSUES ARE YOU ADDRESSING IN YOUR REBUTTAL TESTIMONY?

A. I am addressing the following issues: (1) DEK's proposed capital structure; (2) the proxy group employed by Dr. Morin; and (3) Dr. Morin's equity cost rate approaches and results.

Capital Structure and DEK's Financial and Investment Risks

Q. PLEASE DISCUSS THE CAPITAL STRUCTURE ISSUE IN THIS PROCEEDING?

A. As shown in Exhibit_(JRW-3), the current common equity ratio for the predominantly electric utilities in Moody's Electrics (My Group A) is only 43.6%. The Company's proposed capitalization includes a significantly higher common equity ratio (50.88) than these companies.

Q. HAS DR. MORIN RECOGNIZED AND ADJUSTED FOR DEK'S LOWER DEGREE OF FINANCIAL RISK IN ARRIVING AT AN EQUITY RATE FOR THE COMPANY?

A. No.

Proxy Groups

Q. PLEASE DISCUSS THE PROXY GROUPS EMPLOYED BY DR. MORIN IN ESTIMATING DEK'S COST OF COMMON EQUITY.

A. In different stages of his analysis, Dr. Morin employs Moody's Electric Utilities, a group of 20 electric utility companies, as well as a group of 27 vertically-integrated electric utility companies. The biggest issue with his group of Moody's Electrics is that he includes companies that receive less than 50% of their revenues from regulated electric utility operations. In my Group A, I only use those companies in Moody's Electrics that receive at least 50% of revenues from regulated electric utility operations.

Equity Cost Rate Approaches and Results

Q. PLEASE REVIEW THE ERRORS IN DR. MORIN'S EQUITY COST RATE APPROACHES.

A. The primary errors in Dr. Morin's equity cost rate studies are (1) excessive risk premium estimates in his risk premium approaches, (2) upwardly-biased expected growth rates in his DCF equity cost rate; and (3) an unnecessary flotation cost adjustment applied to all equity cost rate estimates.

Dr. Morin estimates an equity cost rate for DEK in the range of 11.25%-11.50% by applying risk premium and DCF methodologies. His equity cost rate approaches and resulting estimates for DEK are summarized below:

Summary of Equity Cost Rate Approaches and Results

Approach	Group	Result
CAPM		
RF = 5.0%	Proxy Electrics	11.7%
ECAPM		
RF = 5.0%	Proxy Electrics	12.0%
Risk Premium		
RF = 5.0%	Proxy Electrics	10.9%
Allowed Risk Premium		
RF = 5.0%	U.S. Electrics	10.9%
DCF		
Value Line Growth	Integrated. Elec. Co.	10.1%
Zacks Growth	Integrated. Elec. Co	10.1%
	Duke Energy	12.1%
Value Line Growth	Moody's Electrics	10.4%
Zacks Growth	Moody's Electrics	10.6%

Q. PLEASE REVIEW DR. MORIN'S EQUITY COST RATE APPROACHES.

A. Dr. Morin employs several variants of the risk premium approach as well as a DCF approach. The various risk premium approaches include the CAPM, the empirical CAPM (ECAPM), a historical risk premium, and an allowed risk premium.

Q. PLEASE PROVIDE A SUMMARY OF DR. MORIN'S VARIOUS RISK PREMIUM APPROACHES, INCLUDING HIS CAPM.

A. The tables below provide the results of Dr. Morin's various risk premium approaches, including his CAPM.

CAPM Results
Moody's Electric Utilities

		Moody's Electrics
Risk-Free Rate		5.0%
Average Beta		.85
Historic Return Premium	7.1%	
VL DCF Risk Premium	7.9%	
Equity Risk Premium		7.50%
Equity Cost Rate		11.40%
Flotation Cost Adjustment		.30
CAPM Equity Cost Rate		**11.7%**

ECAPM Results
Moody's Electric Utilities

		Moody's Electrics
Risk-Free Rate		5.0%
Average Beta		.85
Historic Return Premium	7.1%	
VL DCF Risk Premium	7.9%	
Equity Risk Premium		7.50%
Equity Cost Rate		11.70%
Flotation Cost Adjustment		.30
CAPM Equity Cost Rate		**12.0%**

Historic Risk Premium Results
Moody's Electric Utilities

	Moody's Electrics
Risk-Free Rate	5.0%
Historic Return Premium	5.6%
Equity Cost Rate	10.6%
Flotation Cost Adjustment	.30
Hist. RP Equity Cost Rate	**10.9%**

Allowed Risk Premium Results
Electric Utility Companies

Risk-Free Rate	5.0%
Allowed Return Premium	5.9 %
Allowed RP Equity Cost Rate	**10.9%**

Q. HOW ARE YOU EVALUATING THESE APPROACHES?

A. There are certain common elements to these approaches that I am initially discussing. Then I provide additional commentary on the individual approaches. The common elements include flotation costs and computing an equity risk premium using historical returns.

Q. PLEASE ADDRESS THE FLOTATION COST ADJUSTMENT ISSUE. IS A FLOTATION COST ADJUSTMENT NECESSARY IN THIS PROCEEDING?

A. There has been no evidence presented in this proceeding that DEK has sold, or intends to sell, common stock to investors in the market. Therefore, since no flotation or equity issuance costs have been identified, there is no reason to provide DEK with additional revenues through a flotation cost adjustment to the allowed rate of return. A flotation cost adjustment in this case would simply provide additional revenues for an expense that the Company has not incurred in the recent past or does not expect to incur in the foreseeable future.

Q. PLEASE ADDRESS THE SECOND COMMON ISSUE INVOVLING THE USE OF

HISTORIC STOCK AND BOND RETURNS TO COMPUTE A FORWARD-LOOKING OR EX ANTE RISK PREMIUM.

A. In his CAPM and historic risk premium approaches, Dr. Morin has used historical stock and bond returns to compute an expected risk premium. His historical evaluation of stock and bond returns is often called the "Ibbotson approach" after Professor Roger Ibbotson who popularized this method of assessing historic financial market returns. Dr. Morin evaluates the historic stock-bond return relationship for the overall market and for electric utility stocks for different periods over the 1926-2005 period.

Using the historic relationship between stock and bond returns to measure an ex ante equity risk premium is erroneous and, especially in this case, overstates the true market equity risk premium. The equity risk premium is based on expectations of the future and when past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. At the present time, using historic returns to measure the ex ante equity risk premium ignores current market conditions and masks the dramatic change in the risk and return relationship between stocks and bonds. This change suggests that the equity risk premium has declined.

Q. PLEASE DISCUSS THE ERRORS IN USING HISTORICAL STOCK AND BOND RETURNS TO ESTIMATE AN EQUITY RISK PREMIUM.

A. There are a number of flaws in using historical returns over long time periods to estimate expected equity risk premiums. These issues include:

(A) Biased historic bond returns;

(B) The arithmetic versus the geometric mean return;

(C) Unattainable and biased historic stock returns;

(D) Survivorship bias;

(E) The "Peso Problem;"

(F) Market conditions today are significantly different than the past; and

(G) Changes in risk and return in the markets.

These issues will be addressed in order.

Biased Historical Bond Returns

Q. HOW ARE HISTORICAL BOND RETURNS BIASED?

A. An essential assumption of these studies is that over long periods of time investors' expectations are realized. However, the experienced returns of bondholders in the past violate this critical assumption. Historical bond returns are biased downward as a measure of expectancy because of capital losses suffered by bondholders in the past. As such, risk premiums derived from this data are biased upwards.

The Arithmetic versus the Geometric Mean Return

Q. PLEASE DISCUSS THE ISSUE RELATING TO THE USE OF THE ARITHMETIC VERSUS THE GEOMETRIC MEAN RETURNS IN THE IBBOTSON METHODOLOGY.

A. The measure of investment return has a significant effect on the interpretation of the risk premium results. When analyzing a single security price series over time (i.e., a time series), the best measure of investment performance is the geometric mean return. Using the arithmetic mean overstates the return experienced by investors. In a study entitled "Risk and Return on Equity: The Use and Misuse of Historical Estimates," Carleton and Lakonishok make the following observation: "The geometric mean measures the changes in wealth over more than one period on a buy and hold (with dividends invested) strategy."[22] Since Dr. Morin's study covers more than one period (and he assumes that dividends are reinvested), he should be employing the geometric mean and not the arithmetic mean.

Q. PLEASE PROVIDE AN EXAMPLE DEMONSTRATING THE PROBLEM WITH USING THE ARITHMETIC MEAN RETURN.

A. To demonstrate the upward bias of the arithmetic mean, consider the following example. Assume that you have a stock (that pays no dividend) that is selling for $100 today, increases to $200 in one year, and then falls back to $100 in two years. The table below shows the prices and returns.

Time Period	Stock Price	Annual Return
0	$100	
1	$200	100%
2	$100	-50%

The arithmetic mean return is simply (100% + (-50%))/2 = 25% per year. The geometric mean return is $((2 * .50)^{(1/2)}) - 1 = 0\%$ per year. Therefore, the arithmetic mean return suggests that your stock has appreciated at an annual rate of 25%, while the geometric mean return indicates an

[22] Willard T. Carleton and Josef Lakonishok, "Risk and Return on Equity: The Use and Misuse of Historical Estimates," *Financial Analysts Journal* (January-February, 1985), pp. 38-47.

annual return of 0%. Since after two years, your stock is still only worth $100, the geometric mean return is the appropriate return measure. For this reason, when stock returns and earnings growth rates are reported in the financial press, they are generally reported using the geometric mean. This is because of the upward bias of the arithmetic mean. Therefore, Dr. Morin's arithmetic mean return measures are biased and should be disregarded.

<u>Unattainable and Biased Historical Stock Returns</u>

Q. YOU NOTE THAT HISTORICAL STOCK RETURNS ARE BIASED USING THE IBBOTSON METHODOLOGY. PLEASE ELABORATE.

A. Returns developed using Ibbotson's methodology are computed on stock indexes and therefore (1) cannot be reflective of expectations because these returns are unattainable to investors, and (2) produce biased results. This methodology assumes (a) monthly portfolio rebalancing and (b) reinvestment of interest and dividends. Monthly portfolio rebalancing presumes that investors rebalance their portfolios at the end of each month in order to have an equal dollar amount invested in each security at the beginning of each month. The assumption would obviously generate extremely high transaction costs and, as such, these returns are unattainable to investors. In addition, an academic study demonstrates that the monthly portfolio rebalancing assumption produces biased estimates of stock returns.[23]

Transaction costs themselves provide another bias in historic versus expected returns. The observed stock returns of the past were not the realized returns of investors due to the much higher

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[23] See Richard Roll, "On Computing Mean Returns and the Small Firm Premium," *Journal of Financial Economics* (1983), pp. 371-86.

transaction costs of previous decades. These higher transaction costs are reflected through the higher commissions on stock trades, and the lack of low cost mutual funds like index funds.

<u>Survivorship Bias</u>

Q. HOW DOES SURVIVORSHIP BIAS AFFECT DR. MORIN'S HISTORIC EQUITY RISK PREMIUM?

A. Using historical data to estimate an equity risk premium suffers from survivorship bias. Survivorship bias results when using returns from indexes like the S&P 500. The S&P 500 includes only companies that have survived. The fact that returns of firms that did not perform so well were dropped from these indexes is not reflected. Therefore these stock returns are upwardly biased because they only reflect the returns from more successful companies.

<u>The "Peso Problem"</u>

Q. WHAT IS THE "PESO PROBLEM" AND HOW DOES IT AFFECT HISTORIC RETURNS AND EQUITY RISK PREMIUMS?

A. Dr. Morin's use of historical return data also suffers from the so-called "peso problem." The 'peso problem' issue was first highlighted by the Nobel laureate, Milton Friedman, and gets its name from conditions related to the Mexican peso market in the early 1970s. This issue involves the fact that past stock market returns were higher than were expected at the time because despite war, depression, and other social, political, and economic events, the US economy survived and did not suffer hyperinflation, invasion, and the calamities of other countries. As such, highly improbable events, which may or may not occur in the future, are factored into stock prices, leading to seemingly low valuations. Higher than expected stock returns are then earned when these events do not subsequently occur. Therefore, the 'peso problem' indicates that historic stock returns are overstated as measures of expected returns.

Market Conditions Today are Significantly Different than in the Past

Q. FROM AN EQUITY RISK PREMIUM PERSPECTIVE, PLEASE DISCUSS HOW MARKET CONDITIONS ARE DIFFERENT TODAY.

A. The equity risk premium is based on expectations of the future. When past market conditions vary significantly from the present, historic data does not provide a realistic or accurate barometer of expectations of the future. As noted previously, stock valuations (as measured by P/E) are relatively high and interest rates are relatively low, on a historic basis. Therefore, given the high stock prices and low interest rates, expected returns are likely to be lower on a going forward basis.

Changes in Risk and Return in the Markets

Q. PLEASE DISCUSS THE NOTION THAT HISTORICAL EQUITY RISK PREMIUM STUDIES DO NOT REFLECT THE CHANGE IN RISK AND RETURN IN TODAY'S FINANCIAL MARKETS.

A. The historical equity risk premium methodology is unrealistic in that it makes the explicit assumption that risk premiums do not change over time based on market conditions such as inflation, interest rates, and expected economic growth. Furthermore, using historic returns to measure the equity risk premium masks the dramatic change in the risk and return relationship between stocks and bonds. The nature of the change, as I will discuss below, is that bonds have increased in risk relative to stocks. This change suggests that the equity risk premium has declined in recent years.

Page 1 of Exhibit_(JRW-9) provides the yields on long-term U.S. Treasury bonds from 1926 to 2005. One very obvious observation from this graph is that interest rates increase dramatically from the mid-1960s until the early 1980s, and since have returned to their 1960 levels. The annual market risk premiums for the 1926 to 2005 period are provided on page 2 of Exhibit_(JRW-9). The annual market risk premium is defined as the return on common stock minus the return on long-term Treasury Bonds. There is considerable variability in this series and a clear decline in recent decades. The high was 54% in 1933 and the low was -38% in 1931. Evidence of a change in the relative riskiness of bonds and stocks is provided on page 3 of Exhibit_(JRW-9) which plots the standard deviation of monthly stock and bond returns since 1930. The plot shows that, whereas stock returns were much more volatile than bond returns from the 1930s to the 1970s, bond returns became more variable than stock returns during the 1980s. In recent years stocks and bonds have become much more similar in terms of volatility, but stocks are still a little more volatile. The decrease in the volatility of stocks relative to bonds over time has been attributed to several stock related factors: the impact of technology on productivity and the new economy; the role of information (see former Federal Reserve Chairman Greenspan's comments referred to earlier in this testimony) on the economy and markets; better cost and risk management by businesses; and several bond related factors; deregulation of the financial system; inflation fears and interest rates; and the increase in the use of debt financing. Further evidence of the greater relative riskiness of bonds is shown on page 4 of Exhibit_(JRW-9), which plots real interest rates (the nominal interest rate minus inflation) from 1926 to 2005. Real rates have been well above historic norms during the past 10-15 years. These high real interest rates reflect the fact that investors view bonds as riskier investments.

The net effect of the change in risk and return has been a significant decrease in the return premium that stock investors require over bond yields. In short, the equity or market risk premium has declined in recent years. This decline has been discovered in studies by leading academic scholars and investment firms, and has been acknowledged by government regulators. As such, using a historic equity risk premium analysis is simply outdated and not reflective of current Investor expectations and investment fundamentals.

Q. NOW TURN TO YOUR SPECIFIC COMMENTS ON DR. MORIN'S VARIOUS RISK PREMIUM APPROACHES. PLEASE INITIALLY ASSESS DR. MORIN'S USE OF THE CAPITAL ASSET PRICING MODEL.

A. On pages 21 to 34 of his testimony, and in Exhibit RAM-2, Dr. Morin applies the CAPM and a variant, the Empirical CAPM (ECAPM), to his proxy group of 20 electric utility companies. I have two concerns with Dr. Morin's CAPM/ECAPM analyses: (1) most significantly, his equity or market risk premium, and (2) the weights used in the so-called ECAPM.

Q. YOUR PRIMARY ISSUE WITH DR. MORIN'S CAPM/ECAPM INVOLVES THE EQUITY RISK PREMIUM. WHAT IS YOUR CONCERN ON THIS MATTER?

A. The primary problem with both Dr. Morin's CAPM and ECAPM is the magnitude of the equity risk premium. Dr. Morin has employed a 7.50% equity or market risk premium. He computes this equity or market risk premium as the average of the results of historic and projected equity risk studies. He computes a historic risk premium as the difference between the historic stock and bond returns over the 1926 and 2005 period. The problems and errors with this methodology were discussed above. He calculates the forecasted equity risk premium of 7.9% as the difference between a prospective DCF-derived overall market return of 12.9% (using dividend yield and growth rates from *Value Line*) and a risk-free rate of 5.0%.

Q. PLEASE SUMMARIZE DR. MORIN'S PROSPECTIVE MARKET RETURN OF 12.9%.

A. Dr. Morin computes an expected return of 12.9% on the stock market using a dividend yield of 1.2% and expected DPS growth rate of 11.3%. He adjusts the dividend yield for a full year's growth and to account for the quarterly payment of dividends. The growth rate data represent *Value Line's* 5-year growth rates for all stocks for which DPS growth rate projections are made

Q. PLEASE EVALUATE THIS EXPECTED MARKET RETURN.

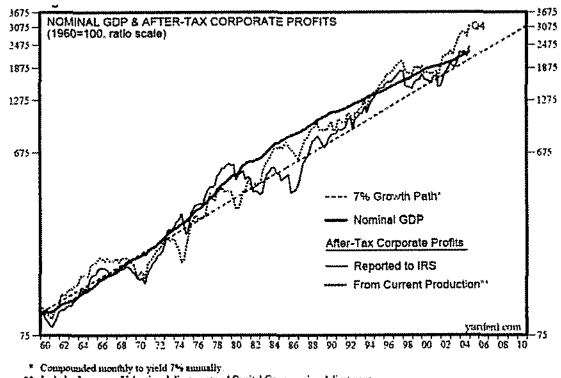
A. An expected market return of 12.9% is out of line with historic norms and is inconsistent with current market conditions. The primary reason is that the expected growth rate 11.3% is clearly excessive and inconsistent with economic, earnings, dividends growth in the U.S.

The average historic compounded return on large company stocks in the U.S. has been 10.4% according to the 2006 SBBI Yearbook. To suggest that investors are going to expect a return that is 200 basis points above this is not logical. This is especially so given current market conditions. As discussed above, at the present time stock prices (relative to earnings) are high and interest rates are low. Major stock market upswings which produce above average returns tend to occur when stock prices are low and interest rates are high. Thus, historic norms and current market conditions do not suggest above average stock returns. Consistent with this observation, the financial forecasters in the Federal Reserve Bank of Philadelphia survey expect a market return of 7.00% over the next ten years. In addition, as discussed above, CFO's expect a market return of 8.05% over the next ten years.

Q. WHAT EVIDENCE CAN YOU PROVIDE THAT INDICATES DR. MORIN'S GROWTH RATES ARE EXCESSIVE?

A. Dr. Morin's expected DPS growth rate of 11.3% is inconsistent with economic and earnings and dividend growth in the U.S. This is especially true when you consider that in a DCF framework, the growth rate is for a long period of time. The long-term economic and earnings growth rate in the U.S. has only been about 7%. Edward Yardeni, a well-known Wall Street economist, calls this the "7% Solution" to growth in the U.S. The graph below comes from his analysis of GNP and profit growth since 1960.

The 7% Solution
Nominal GNP and Profit Growth since 1960



Source: Edward Yardeni, Strategists Handbook, Oak Associates, April 2005

As further evidence of the long-term growth rate in the U.S., I have performed a study of the growth in nominal GNP, S&P 500 stock price appreciation, and S&P 500 EPS and DPS growth since 1960. The results are provided on page 1 of Exhibit_(JRW-10) and a summary is given in the table below.

GNP, S&P 500 Stock Price, EPS, and DPS Growth
1960-Present

Nominal GNP	7.22%
S&P 500 Stock Price Appreciation	7.05%
S&P 500 EPS	7.11%
S&P 500 DPS	5.54%
Average	6.73%

The results offer compelling evidence that a long-run growth rate in the range of 7% is appropriate for companies in the U.S. Long-run growth in DPS is below this figure at 5.54%. Dr. Morin's long-run DPS growth rate projections are totally unrealistic. His estimates suggest that companies in the U.S. would be expected to (1) nearly double their growth rates in DPS in the future, and (2) maintain that growth indefinitely in an economy that is expected to growth at about one half his projected growth rates. Such a scenario lacks rational economic reasoning.

Q. ON PAGE 30 OF HIS TESTIMONY DR. MORIN REFERS TO A STUDY BY HARRIS, MARSTON, MISHRA, AND O'BRIEN (HMMO) TO SUPPORT HIS OVERALL EQUITY RISK PREMIUM. PLEASE COMMENT.

A. The HMMO study develops an expected market return in a DCF framework using analysts' expected EPS forecasts as measures of expected growth. This methodology is fundamentally flawed since it is well known that analysts' EPS growth rate forecasts are upwardly biased and therefore using these estimates in a market DCF model produces inflated expected market returns and equity risk premiums. This issue is addressed later in my testimony.

Q. PLEASE ADDRESS YOUR SEOND SPECIFIC ISSUE WITH DR. MORIN'S CAPM AND ECAPM?

A. Dr. Morin has employed not only a traditional CAPM, but also the so-called ECAPM. In his testimony, Dr. Morin cites a chapter from his book, but does not provide support for his weights of 0.25 and 0.75 in his CAPM. On this issue, I agree that tests of the CAPM have indicated the Security Market Line (SML) is not as steep as predicted by the CAPM. However, none of these studies use adjusted betas (such as those used by Dr. Morin and myself) which address the empirical issues with the SML. Furthermore, a SML with a slope coefficient which is not as steep as predicted by the CAPM is also consistent with a declining equity risk premium. Needless to say, I have provided plenty of empirical evidence regarding the decline in the equity risk premium. Finally, to my knowledge, there are no studies published in refereed academic journals that support these weights and/or recommends their use in applying the CAPM.

Q. PLEASE REVIEW DR. MORIN'S HISTORIC RISK PREMIUM ANALYSIS.

A. On pages 34 to 35 of his testimony and in Exhibit RAM-3, Dr. Morin performs a historic risk premium analysis using Moody's Electric Utility Index. There are two problems with his analysis: (1) the historic risk premium methodology; and (2) the flotation cost adjustment. The flaws with respect to these issues have been addressed above.

Q. WHAT ISSUES DO YOU HAVE WITH DR. MORIN'S ALLOWED RISK PREMIUM?

A. Dr. Morin provides his evaluation of allowed risk premiums on pages 35-37 of his testimony. The major issue in this approach is Dr. Morin's conclusion regarding the appropriate risk premium from the study. Dr. Morin's approach involves circular reasoning since the results of other electric utility rate cases are employed to derive a risk premium in this proceeding. If such an approach is used in this and other jurisdictions, then no one will be testing to evaluate whether the ROE recommendation is above or below investors' required rate of return. Furthermore, Dr. Morin has not performed any analysis to examine whether the annual allowed ROEs are above, equal to, or below investors' required return. As discussed above, if a firm's return on equity is above (below) the return that investor's require, the market price of its stock will be above (below) the book value of the stock. Since Dr. Morin has not evaluated the market-to-book ratios for electric utilities involved in the annual rate cases, he cannot indicate whether these allowed ROEs are above or below investors' requirements. As a general notion, however, since the market-to-book ratios for electric utility companies have been in excess of 1.0 for some time, it would indicate that the allowed ROE's are above equity cost rates.

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF DR. MORIN'S RISK PREMIUM ANALYSES.

A. Dr. Morin's risk premium studies are flawed and exaggerate the required return and equity cost rate for DEK. In general, Dr. Morin's equity risk premium estimates are flawed and excessive. Hence, Dr. Morin's risk premium analyses are erroneous and should be disregarded in estimating DEK's equity cost rate.

Q. PLEASE SUMMARIZE DR. MORIN'S RISK PREMIUM STUDIES IN LIGHT OF THE EVIDENCE ON RISK PREMIUMS IN TODAY'S MARKETS.

A. The primary issue in both his risk premium and CAPM analyses is the magnitude of the equity or market risk premium. Dr. Morin's risk premium estimates should be ignored because they are totally out of line with the equity risk premium estimates (1) discovered in recent academic studies by leading finance scholars and (2) employed by leading investment banks, management consulting firms, financial forecasters and corporate CFOs. In both his risk premium and CAPM studies, a more realistic market risk premium is in the 2-4 percent range above Treasury yields.

Q. PLEASE SUMMARIZE DR. MORIN'S DCF ESTIMATES.

A. On pages 37 to 50 of his testimony and in Exhibits RAM-6, RAM-7, RAM-8, and RAM-9, Dr. Morin performs DCF analyses using Moody's Electrics, the group of vertically integrated electric utilities, and Duke Energy. His results are summarized below.

DCF Results
Vertically Integrated Electric Utilities

	VL EPS Growth Forecasts	Analysts' EPS Growth Forecasts
Dividend Yield	3.9%	4.0%
Growth Adjustment	0.2%	0.3%
Adjusted Dividend Yield	4.1%	4.1%
DCF Growth Rate	5.7%	5.8%
Equity Cost Rate	10.0%	10.1%
Flotation Cost Adjustment	.20	.20
DCF Equity Cost Rate	**10.2%**	**10.3%**

DCF Results
Duke Energy

	VL EPS Growth Forecasts	Analysts' EPS Growth Forecasts
Dividend Yield	4.3%	4.3%
Growth Adjustment	0.4%	0.2%
Adjusted Dividend Yield	4.7%	4.6%
DCF Growth Rate	8.5%	6.0%
Equity Cost Rate	13.2%	10.6%
Flotation Cost Adjustment	.20	.20
DCF Equity Cost Rate	**13.4%**	**10.8%**

DCF Results
Moody's Electric Utilities

	VL EPS Growth Forecasts	Analysts' EPS Growth Forecasts
Dividend Yield	4.2%	4.2%
Growth Adjustment	0.2%	0.2%
Adjusted Dividend Yield	4.4%	4.4%
DCF Growth Rate	5.9%	5.7%
Equity Cost Rate	10.4%	10.1%
Flotation Cost Adjustment	.20	.30
DCF Equity Cost Rate	**10.6%**	**10.4%**

The errors in his DCF analyses include: (1) adjusting the dividend for a full year of growth, (2) adjusting for flotation costs, and (3) relying solely on forecasts of EPS growth. The first two issues were addressed above. The primary issue with Dr. Morin's DCF analysis, however, is his sole reliance on EPS forecasts as measures of growth.

Q. PLEASE REVIEW DR. MORIN'S DCF GROWTH RATE.

A. Dr. Morin computes DCF equity cost rates using EPS growth rate forecasts of (1) *Value Line* and (2) securities analysts as provided by Zacks Investment research.

Q. WHAT ARE YOUR CONCERNS WITH DR. MORIN'S DCF GROWTH RATE?

A. Dr. Morin's DCF growth rate estimates are biased because he has employed only one indicator of expected growth - forecasts of EPS growth. He has ignored all other indicators of expected growth, especially historic growth. Furthermore, it seems highly unlikely that investors today would rely exclusively on the forecasts of securities firms and analysts, and ignore historic growth, in arriving at expected growth. In the academic world, the fact that the EPS forecasts of securities' analysts are overly optimistic and biased upwards has been known for years. In addition, as I show below, *Value Line*'s EPS forecasts are excessive and unrealistic.

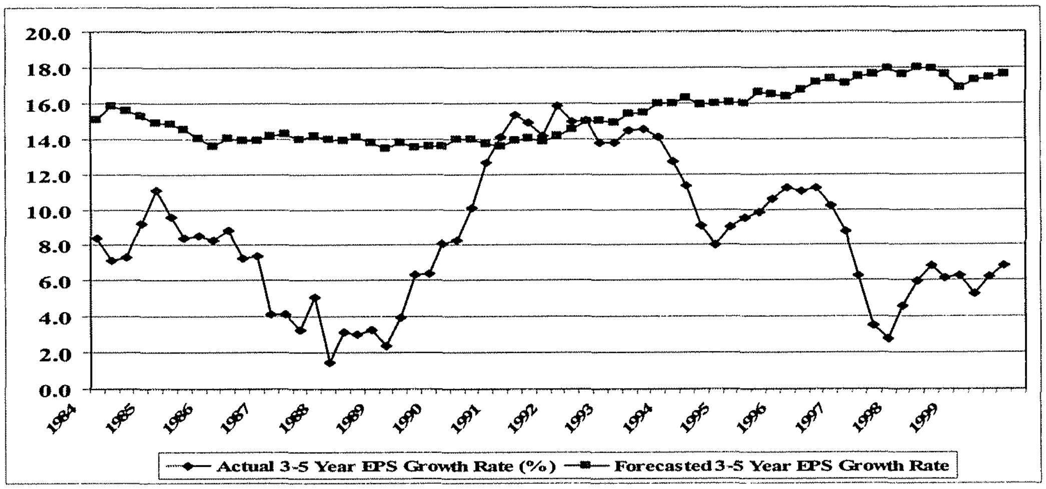
Q. PLEASE REVIEW THE BIAS IN ANALYSTS' GROWTH RATE FORECASTS.

A. Analysts' growth rate forecasts are collected and published by Zacks, First Call, I/B/E/S, and Reuters. These services retrieve and compile EPS forecasts from Wall Street Analysts. These analysts come from both the sell side (Merrill Lynch, Paine Webber) and the buy side (Prudential Insurance, Fidelity).

The problem with using these forecasts to estimate a DCF growth rate is that the objectivity of Wall Street research has been challenged, and many have argued that analysts' EPS forecasts are overly optimistic and biased upwards. To evaluate the accuracy of analysts' EPS forecasts, I have compared actual 3-5 year EPS growth rates with forecasted EPS growth rates on a quarterly basis over the past 20 years for all companies covered by the I/B/E/S data base. In the graph below, I show the average analysts' forecasted 3-5 year EPS growth rate with the average actual 3-5 year EPS growth rate. Because of the necessary 3-5 year follow-up period to measure actual growth, the analysis in this graph only (1) covers forecasted and actual EPS growth rates through 1999, and (2) includes only companies that have 3-5 years of actual EPS data following the forecast period.

The following example shows how the results can be interpreted. As of the first quarter of 1995, analysts were projecting an average 3-5-year annual EPS growth rate of 15.98%, but companies only generated an average annual EPS growth rate over the next 3-5 years of 8.14%. This 15.98% figure represented the average projected growth rate for 1,115 companies, with an average of 4.70 analysts' forecasts per company over the 20 year period covered by the study. The only periods when firms met or exceeded analysts' EPS growth rate expectations were for six consecutive quarters in 1991-92 following the one-year economic downturn at the turn of the decade.

Analysts' Forecasted 3-5-Year Forecasted Versus Actual EPS Growth Rates 1984-1999



Source: J. Randall Woolridge.

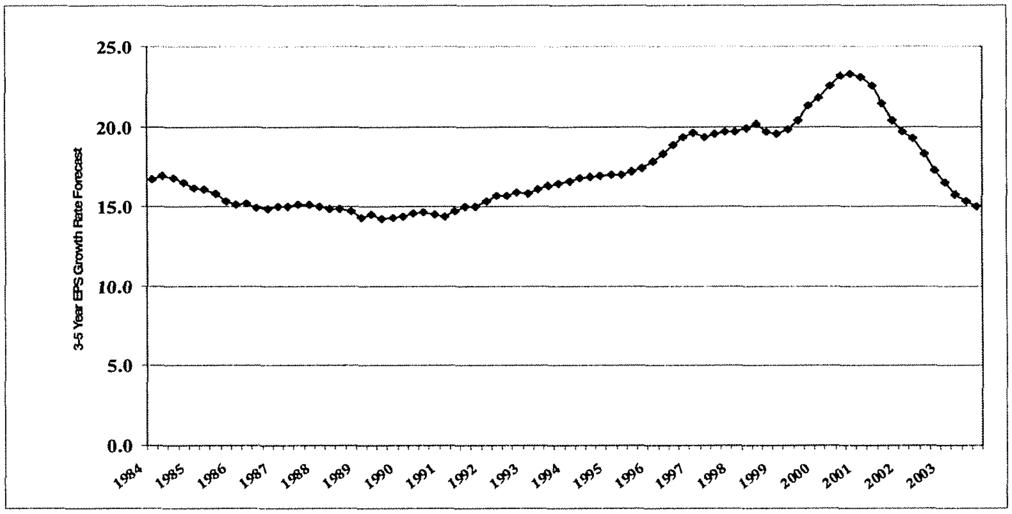
Over the entire time period, Wall Street analysts have continually forecasted 3-5-year EPS growth rates in the 14-18 percent range (mean = 15.32%), but these firms have only delivered an average EPS growth rate of 8.75%.

The post-1999 period has seen the boom and then the bust in the stock market, an economic recession, 9/11, and the Iraq war. Furthermore, and highly significant in the context of this study, we have also had the Elliott Spitzer investigation of Wall Street firms and the subsequent Global Securities Settlement in which nine major brokerage firms paid a fine of $1.5B for their biased investment research.

To evaluate the impact of these events on analysts' forecasts, the graph below provides the average 3-5-year EPS growth rate projections for all companies provided in the I/B/E/S database on a quarterly basis from 1985 to 2004. In this graph, no comparison to actual EPS growth rates is made and hence there is no follow-up period. Therefore, 3-5 year growth rate forecasts are shown until 2004 and, since companies are not lost due to a lack of follow-up EPS data, these results are for a larger sample of firms.[24] Analysts' forecasts for EPS growth were higher for this larger sample of firms, with a more pronounced run-up and then decline around the stock market peak in 2000. The average projected growth rate hovered in the 14.5%-17.5% range until 1995, and then increased dramatically over the next five years to 23.3% in the fourth quarter of the year 2000. Forecasted growth has since declined to the 15.0% range.

[24] The number of companies in the sample grows from 2,220 in 1984, peaks at 4,610 in 1998, and then declines to 3,351 in 2004. The number of analysts' forecasts per company averages between 3.75 to 5.10, with an overall mean of 4.37.

Mean Analysts' 3-5-Year Forecasted EPS Growth Rates
1985-2004



Source: J. Randall Woolridge.

While analysts' EPS growth rates forecasts have subsided since 2000, these results suggest that, despite the Elliot Spitzer investigation and the Global Securities Settlement, analysts' EPS forecasts are still upwardly biased. The actual 3-5 year EPS growth rate over time has been about one half the projected 3-5 year growth rate forecast of 15.0%. Furthermore, as discussed above, historic growth in GNP and corporate earnings has been in the 7% range. As such, an EPS growth rate forecast of 15% does not reflect economic reality. This observation is supported by a *Wall Street Journal* article entitled "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." The following quote provides insight into the continuing bias in analysts' forecasts:

> Hope springs eternal, says Mark Donovan, who manages Boston Partners Large Cap Value Fund. 'You would have thought that, given what happened in the last three years, people would have given up the ghost. But in large measure they have not.'
>
> These overly optimistic growth estimates also show that, even with all the regulatory focus on too-bullish analysts allegedly influenced

by their firms' investment-banking relationships, a lot of things haven't changed: Research remains rosy and many believe it always will.[25]

Q. ARE *VALUE LINE*'S GROWTH RATE FORECASTS SIMILARILY UPWARDLY BIASED?

A. Yes. *Value Line* has a decidedly positive bias to its earnings growth rate forecasts as well. To assess *Value Line*'s earnings growth rate forecasts, I used the *Value Line Investment Analyzer*. The results are summarized in the table below. I initially filtered the database and found that *Value Line* has 3-5 year EPS growth rate forecasts for 2,587 firms. The average projected EPS growth rate was 16.0%. This is incredibly high given that the average historical EPS growth rate in the US is about seven percent! Equally incredible is that *Value Line* only predicts negative EPS growth for sixteen companies. That is less than one percent of the companies covered by *Value Line*. Given the ups and downs of corporate earnings, this is unreasonable.

Value Line 3-5 year EPS Growth Rate Forecasts

	Average Projected EPS Growth rate	**Number of Negative EPS Growth Projections**	**Percent of Negative EPS Growth Projections**
2,587 Firms	**16.0%**	**16**	**0.62%**

To put this figure in perspective, I screened the 2,587 firms with 3-5 year growth rate forecasts to see what percent had experienced negative EPS growth rates over the past five years. *Value Line* reported a five-year historic growth rate for 1,626 of the 2,587 companies. It should be noted that the past five years have been a period of rapidly rising corporate earnings as the economy and

[25] Ken Brown, "Analysts Still Coming Up Rosy – Over-Optimism on Growth Rates is Rampant – and the Estimates Help to Buoy the Market's Valuation." *Wall Street Journal*, (January 27, 2003), p. C1.

businesses have rebounded from the recession of 2001. These results, shown in the table below, indicate that the average historic growth was 9.51% and *Value Line* reported negative historic growth for 380 firms which represents 23.4% of these companies.

Historic Five-Year EPS Growth Rates for Companies with Value Line 3-5 year EPS Growth Rate Forecasts

	Average Historic EPS Growth rate	Number with Negative Historic EPS Growth	Percent with Negative Historic EPS Growth
1,626 Firms	**9.51%**	**380**	**23.4%**

These results indicate that *Value Line*'s EPS forecasts are excessive and unrealistic. It appears that analysts at *Value Line* are similar to the analysts at Wall Street firms and view future earnings through 'rose-colored' glasses and provide overly-optimistic forecasts of future growth.

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF DR. MORIN'S DCF GROWTH RATE.

A. The growth rate estimates for the electric utility companies are upwardly biased because Dr. Morin has relied solely on forecasts of EPS growth to measure a DCF growth rate. He has ignored all other indicators of growth to measure investors' expectations. As demonstrated and discussed above, it is well known that analysts' EPS growth rate forecasts are upwardly biased measures of actual growth. Hence, it is highly unlikely that investors would simply look to these biased forecasts as the only measures of expected growth.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

Yes, it does.

APPENDIX A

EDUCATIONAL BACKGROUND, RESEARCH, AND RELATED BUSINESS EXPERIENCE

J. RANDALL WOOLRIDGE

J. Randall Woolridge is a Professor of Finance and the Goldman, Sachs & Co. and Frank P. Smeal Endowed Faculty Fellow in Business Administration in the College of Business Administration of the Pennsylvania State University in University Park, PA. In addition, Professor Woolridge is Director of the Smeal College Trading Room and President and CEO of the Nittany Lion Fund, LLC.

Professor Woolridge received a Bachelor of Arts degree in Economics from the University of North Carolina, a Master of Business Administration degree from the Pennsylvania State University, and a Doctor of Philosophy degree in Business Administration (major area-finance, minor area-statistics) from the University of Iowa. At Iowa he received a Graduate Fellowship and was awarded membership in Beta Gamma Sigma, a national business honorary society. He has taught Finance courses at the University of Iowa, Cornell College, and the University of Pittsburgh, as well as the Pennsylvania State University. These courses include corporation finance, commercial and investment banking, and investments at the undergraduate, graduate, and executive MBA levels.

Professor Woolridge's research has centered on the theoretical and empirical foundations of corporation finance and financial markets and institutions. He has published over 35 articles in the best academic and professional journals in the field, including the *Journal of Finance,* the *Journal of Financial Economics,* and the *Harvard Business Review.* His research has been cited extensively in the business press. His work has been featured in the *New York Times*, *Forbes, Fortune, The Economist*, *Financial World*, *Barron's*, *Wall Street Journal*, *Business Week*, *Washington Post, Investors' Business Daily*, *Worth Magazine*, *USA Today*, and other publications. In addition, Dr. Woolridge has appeared as a guest on CNN's *Money Line* and CNBC's *Morning Call* and *Business Today.*

The second edition of Professor Woolridge's popular stock valuation book, *The StreetSmart Guide to Valuing a Stock* (McGraw-Hill, 2003), was recently released. He has also co-authored *Spinoffs and Equity Carve-Outs: Achieving Faster Growth and Better Performance* (Financial Executives Research Foundation, 1999) as well as a new textbook entitled *Modern Corporate Finance, Capital Markets, and Valuation* (Kendall Hunt, 2003). Dr. Woolridge is a founder and a managing director of www.valuepro.net - a stock valuation website.

Professor Woolridge has also consulted with and prepared research reports for major corporations, financial institutions, and investment banking firms, and government agencies. In addition, he has directed and participated in over 500 university- and company- sponsored professional development programs for executives in 25 countries in North and South America, Europe, Asia, and Africa.

Dr. Woolridge has prepared testimony and/or provided consultation services in the following cases:

Pennsylvania: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Pennsylvania Public Utility Commission:
Bell Telephone Company (R-811819), Peoples Natural Gas Company (R-832315), Pennsylvania Power Company (R-832409), Western Pennsylvania Water Company (R-832381), Pennsylvania Power Company (R-842740), Pennsylvania Gas and Water Company (R-850178), Metropolitan Edison Company (R-860384), Pennsylvania Electric Company (R-860413), North Penn Gas Company (R-860535), Philadelphia Electric Company (R-870629), Western Pennsylvania Water Company (R-870825), York Water Company (R-870749), Pennsylvania-American Water Company (R-880916), Equitable Gas Company (R-880971), the Bloomsburg Water Co. (R-891494), Columbia Gas of

Pennsylvania, Inc. (R-891468), Pennsylvania-American Water Company (R-90562), Breezewood Telephone Company (R-901666), York Water Company (R-901813), Columbia Gas of Pennsylvania, Inc. (R-901873), National Fuel Electric utility Company (R-911912), Pennsylvania-American Water Company (R-911909), Borough of Media Water Fund (R-912150), UGI Utilities, Inc. - Electric Utility Division (R-922195), Dauphin Consolidated Water Supply Company - General Waterworks of Pennsylvania, Inc, (R-932604), National Fuel Electric utility Company (R-932548), Commonwealth Telephone Company (I-920020), Conestoga Telephone and Telegraph Company (I-920015), Peoples Natural Gas Company (R-932866), Blue Mountain Consolidated Water Company (R-932873), National Fuel Gas Company (R-942991), UGI - Gas Division (R-953297), UGI - Electric Division (R-953534), Pennsylvania-American Water Company (R-973944), Pennsylvania-American Water Company (R-994638), Philadelphia Suburban Water Company (R-994868;R-994877;R-994878; R-9948790), Philadelphia Suburban Water Company (R-994868), Wellsboro Electric Company (R-00016356), Philadelphia Suburban Water Company (R-00016750), National Fuel Electric utility Company (R-00038168), Pennsylvania-American Water Company (R-00038304), York Water Company (R-00049165), Valley Energy Company (R-00049345), Wellsboro Electric Company (R-00049313), and National Fuel Gas utility Corporation (R-00049656).

New Jersey: Dr. Woolridge prepared testimony for the New Jersey Department of the Public Advocate, Division of Rate Counsel: New Jersey-American Water Company (R-91081399J), New Jersey-American Water Company (R-92090908J), and Environmental Disposal Corp (R-94070319).

Hawaii: Dr. Woolridge prepared testimony for the Hawaii Office of the Consumer Advocate: East Honolulu Community Services, Inc. (Docket No. 7718).

Delaware: Dr. Woolridge prepared testimony for the Delaware Division of Public Advocate: Artesian Water Company (R-00-649).

Ohio: Dr. Woolridge prepared testimony for the Ohio Office of Consumers' Council: SBC Ohio (Case No. 02-1280-TP-UNC R-00-649), and Cincinnati Gas & Electric Company (Case No. 05-0059-EL-AIR).

New York: Dr. Woolridge prepared testimony for the County of Nassau in New York State: Long Island Lighting Company (PSC Case No. 942354).

Florida: Dr. Woolridge prepared testimony for the Office of Peoples Counsel in Florida: Florida Power & Light Co. (Docket No. 050045-EL).

Connecticut: Dr. Woolridge prepared testimony for the Office of Consumer Counsel in Connecticut: United Illuminating (Docket No. 96-03-29), Yankee Gas Company (Docket No. 04-06-01), Southern Connecticut Gas Company (Docket No. 03-03-17), the United Illuminating Company (Docket No. 05-06-04).

California: Dr. Woolridge prepared testimony for the Office of Ratepayer Advocate in California: San Gabriel Valley Water Company (Docket No. 05-08-021).

South Carolina: Dr. Woolridge prepared testimony for the Office of Regulatory Staff in South Carolina: Soouth Carolina Electric and Gas Company (Docket No. 2005-113-G).

Kentucky: Dr. Woolridge prepared testimony for the Office of Attorney General in Kentucky: Kentucky-American Water Company (Case No. 2004-00103), Union Heat, Light, and Power Company (Case No. 2004-00042), and Kentucky Power Company (Case No. 2005-00341).

Washington, D.C.: Dr. Woolridge prepared testimony for the Office of the People's Counsel in the District of

Columbia: Potomac Electric Power Company (Formal Case No. 939).

Washington: Dr. Woolridge consulted with trial staff of the Washington Utilities and Transportation Commission on the following cases: Puget Energy Corp. (Docket Nos. UE-011570 and UG-011571); and Avista Corporation (Docket No. UE-011514).

Kansas: Dr. Woolridge prepared testimony on behalf of the Kansas Citizens' Utility Ratepayer Board Utilities in the following cases: Western Resources Inc. (Docket No. 01-WSRE-949-GIE), UtiliCorp (Docket No. 02-UTCG701-CIG), and westar Energy, Inc. (Docket No. 05-WSEE-981-RTS).

FERC: Dr. Woolridge has prepared testimony on behalf of the Pennsylvania Office of Consumer Advocate in the following cases before the Federal Energy Regulatory Commission: National Fuel Gas Supply Corporation (RP-92-73-000) and Columbia Gulf Transmission Company (RP97-52-000).

Vermont: Dr. Woolridge prepared testimony for the Department of Public Service in the Central Vermont Public Service Case (Docket No. 6988).

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES OF	**)**	
THE UNION LIGHT, HEAT AND POWER COMPANY	**)**	**CASE NO. 2006-00172**
D/B/A DUKE ENERGY KENTUCKY, INC.	**)**	

AFFIDAVIT

I, J. Randall Woolridge, hereby swear and affirm that the foregoing testimony and all supporting appendices and schedules were prepared by me or under my direct supervision and are, to the best of my information and belief, true and accurate.

J Randall Woolridge

COMMONWEALTH PENNSYLVANIA

COUNTY OF CENTRE

Subscribed and sworn to before me by J. Randall Woolridge this the 12th day of September, 2006.

My Commission Expires:

NOTARIAL SEAL
Mary L. Hart, Notary Public
State College Boro., Centre County
~~My commission expires August 25, 2009~~

Mary L. Hart

Exhibit_(JRW-1)

Duke Energy Kentucky
Cost of Capital

As of September 30, 2006

Capital Source	Capitalization Ratio*	Cost Rate	Weighted Cost Rate
Short--Term Debt	6.99%	5.14%	0.36%
Long-Term Debt	46.07%	6.09%	2.81%
Common Equity	46.94%	9.25%	4.34%
Total	100.00%		7.51%

* See Exhibit_(JRW-4).

**The Impact of the 2003 Tax Legislation
On the Cost of Equity Capital**

On May 28, 2003, President Bush signed the *Jobs and Growth Tax Relief Reconciliation Act of 2003.* The primary purpose of this legislation was to reduce taxes to enhance economic growth. A primary component of the new tax law was a significant reduction in the taxation of corporate dividends for individuals. Dividends have been described as "double-taxed." First, corporations pay taxes on the income they earn before they pay dividends to investors, then investors pay taxes on the dividends that they receive from corporations. One of the implications of the double taxation of dividends is that, all else equal, it results in a high cost of raising capital for corporations.

The new tax legislation reduces the double taxation of dividends by lowering the tax rate on dividends from the 30 percent range (the average tax bracket for individuals) to 15 percent. This reduction in the taxation of dividends for individuals enhances their after-tax returns and thereby reduces their pre-tax required returns. This reduction in pre-tax required returns (due to the lower tax on dividends) effectively reduces the cost of equity capital for companies. The new tax law also reduced the tax rate on long-term capital gains from 20% to 15%.

To demonstrate the effect of the new legislation, assume that a utility has a 10% expected return – 5.0% in dividends and 5.0% in capital gains. The new tax law reduces the double-taxation by reducing the tax rate on dividends from the 30 percent range (the marginal tax bracket for the average individual taxpayer) to 15 percent. The table below illustrates the effect of the new tax law. Panel A shows that under the old tax law a 10.0% pre-tax return provided for a 7.5% after tax return. Panel B shows that under the new tax law, with tax rates of 15% on both dividends and capital gains, the 10% pre-tax return is worth 8.5% on an after-tax basis. In Panel C, I have held the after-tax return constant (at 7.5%) to illustrate the effect of the new tax law on required pre-tax returns. Assuming that the entire after-tax 1% return difference (7.5% to 8.5%) is attributed to the lower taxation of dividends, the 10.0% pre-tax return under the new law is now only 8.82%. In other words, to generate an after-tax return of 7.5%, the new tax law reduced the required pre-tax return from 10.0% to 8.82%.

The Impact of the New Tax Law on Pre- and After- Tax Returns

Panel A
Old Tax Law
10% Pre-Tax Return - 5% Dividend Yield & 5% Capital Gain
Tax Rates - Dividends 30% & Capital Gains 20%

	Pre-Tax Return	Tax Rate	After-Tax Return
Dividends	5.00%	30.00%	3.50%
Capital Gain	5.00%	20.00%	4.00%
Total	10.00%		7.50%

Panel B
New Tax Law
10% Pre-Tax Return - 5% Dividend Yield & 5% Capital Gain
Tax Rates - Dividends 15% & Capital Gains 15%

	Pre-Tax Return	Tax Rate	After-Tax Return
Dividends	5.00%	15.00%	4.25%
Capital Gain	5.00%	15.00%	4.25%
Total	10.00%		8.50%

Panel C
The Effect of the New Tax Law on Pre-Tax Returns
7.50% After-Tax Return - 3.25% Dividend Yield & 4.25% Capital Gain
Tax Rates - Dividends 15% & Capital Gains 15%

	Pre-Tax Return	Tax Rate	After-Tax Return
Dividends	3.82%	15.00%	3.25%
Capital Gain	5.00%	15.00%	4.25%
Total	8.82%		7.50%

Exhibit_(JRW-3)

Duke Energy Kentucky

Electric Utility Proxy Group A

Summary Financial Statistics

Company		S&P Bond Rating	Operating Revenue ($mil)	Percent Electric Revenue	Net Plant ($mil)	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Price/ Earnings Ratio	Market to Book Ratio
American Elec. Pwr.	AEP	BBB	12,236.0	95%	24808.0	3.5	TX, OH,WV	45.0%	12.1%	12.2	143
CH Energy Group	CHG	A	1,002.7	53%	785.7	5.7	NY	57.0%	8.2%	17.2	139
Con. Edison	ED	A	12,206.0	64%	16481.0	3.4	NY	47.0%	10.1%	14.7	147
DPL, Inc.	DPL	BBB-	1,318.9	100%	2633.1	3.3	MI	35.0%	14.1%	24.3	370
Duquesne Light Holdings	DQE	BBB+	927.4	79%	1577.9	2.6	PA	35.0%	14.4%	23.2	191
Energy East Corp.	EAS	BBB+	5,357.8	56%	5757.1	2.7	NY	42.0%	8.3%	14.7	121
Exelton	EXC	BBB+	15,657.0	88%	22295.0	5.3	PA, IL	39.0%	10.2%	45.7	406
FirstEnergy	FE	BBB	12,253.1	79%	14285.0	4.0	PA	45.0%	10.6%	18.1	184
IDACORP	IDA	AA-	533.0	60%	677.3	2.3	ID	55.0%	10.3%	16.9	172
PPL Corp.	PPL	A-	6,400.0	69%	11034.0	3.5	PA	40.0%	18.7%	14.3	253
Progress Energy	PGN	BBB	10,441.0	78%	14570.0	2.1	NC,SC,FL	42.0%	8.4%	16.0	134
Southern Co.	SO	A+	13,873.7	98%	27968.3	4.0	GA, FL,AL,MS	42.0%	14.4%	15.8	226
Xcel Energy Inc.	XEL	A-	10,123.5	75%	14882.8	2.5	MN,WI,MD,SD	43.0%	9.7%	15.2	141
Mean			**7,871.5**	**76.5%**	**12,135.0**	**3.5**		**43.6%**	**11.5%**	**19.1**	**202.1**
Median			**10,123.5**	**78.0%**	**14,285.0**	**3.4**		**42.0%**	**10.3%**	**16.0**	**172.0**

Data Source: AUS *Utility Reports*, September, 2006, *Value Line Investment Survey*, 2006.

Electric Utility Proxy Group B

Summary Financial Statistics

Company		S&P Bond Rating	Operating Revenue ($mil)	Percent Electric Revenue	Net Plant ($mil)	Pre-Tax Interest Coverage	Primary Service Area	Common Equity Ratio*	Return on Equity	Price/ Earnings Ratio	Market to Book Ratio
ALLETE	ALE	A	758.6	78%	862.3	5.2	MN, WI	61.00%	3.10%	66.2	205
Alliant Energy	LNT	A-	3,411.8	70%	4,466.5	4.2	WI, MN, IA, IL	54.0%	2.3%	68.2	158
Ameren Corp.	AEE	A-	6,959.0	79%	13,854.0	5.0	MO, IL	50.0%	9.5%	18.3	163
American Elec. Pwr.	AEP	BBB	12,236.0	95%	24808.0	3.5	TX, OH,WV, AZ	45.0%	12.1%	12.2	143
Cent. Vermont P.S.	CV	BBB	318.0	100%	300.5	1.6	VT	63.0%	4.5%	21.0	93
Cleco	CNL	BBB	967.8	95%	1,108.3	4.5	LA	52.0%	NM	6.1	166
Edison Intl	EIX	BBB	12,157.0	81%	14,747.0	3.2	CA	39.0%	16.9%	12.0	188
El Paso Electric	EE	BBB	12,157.0	81%	14747.0	2.5	TX, NM	39.0%	16.9%	22.5	162
Empire District	EDE	BBB+	394.6	93%	916.2	2.3	KS, MO, AR	46.0%	6.7%	20.9	141
Energy East Corp.	EAS	BBB+	5,357.8	56%	5757.1	2.7	NY	42.0%	8.3%	14.7	121
Entergy	ETR	BBB-	11,059.7	80%	19310.2	4.2	AR,LA, TX, MS	39.0%	10.2%	15.6	185
FirstEnergy	FE	BBB	12,253.1	79%	14285.0	4.0	PA	45.0%	10.6%	18.1	184
FPL Group	FPL	A	12,993.0	78%	23,285.0	3.9	FL	44.0%	11.7%	16.0	180
Green Mountain Power	GMP	BBB	248.6	100%	237.2	3.3	VT	56.0%	10.0%	12.7	124
Hawaaian Electric	HE	NR	2,317.9	82%	2,558.8	3.8	HI	37.0%	11.3%	16.1	179
IDACORP	IDA	A-	938.9	98%	2336.5	2.3	ID	49.0%	6.4%	21.3	136
MGE Energy	MGEE	AA-	533.0	60%	677.3	4.3	WI	55.0%	10.3%	16.9	172
Northeast Utilities	NU	BBB	7,280.0	70%	5,728.5	1.5	CT	43.0%	NM	NM	133
PG&E	PCG	BBB	12,183.0	71%	20,254.0	3.7	CA	42.0%	11.9%	16.5	183
Pinnacle West	PNW	BBB-	3,073.3	74%	7,645.3	2.5	AZ	48.0%	6.6%	18.6	121
PNM Resources	PNM	BBB	2,304.7	76%	2999.4	3.0	NM	39.0%	5.1%	28.1	137
Progress Energy	PGN	BBB	10,441.0	78%	14570.0	2.1	NC,SC,FL	42.0%	8.4%	16.0	134
Puget Energy	PSD	BBB	2,709.3	61%	4,667.9	2.3	WA	44.0%	7.8%	14.1	117
Southern Co.	SO	A+	13,873.7	98%	27968.3	3.8	GA, FL,AL,MS	42.0%	14.4%	15.8	226
TECO Energy	TE	BBB-	3,161.9	58%	4,584.3	2.2	FL	29.0%	13.9%	14.9	190
Wisconsin Energy	WEC	A-	3,972.3	61%	6,501.9	3.3	WI, MI	42.0%	12.0%	14.6	169
Xcel Energy Inc.	XEL	A-	10,123.5	75%	14882.8	2.5	MN, WI,ND,SD,MI	43.0%	9.7%	15.2	141
Mean			**6,080.9**	**78.8%**	**9,409.6**	**3.2**		**45.6%**	**9.6%**	**20.5**	**157.4**
Median			**3,972.3**	**78.0%**	**5,757.1**	**3.3**		**44.0%**	**10.0%**	**16.1**	**162.0**

Data Source: AUS *Utility Reports*, September, 2006, *Value Line Investment Survey*, 2006.

Exhibit_(JRW-4)

Duke Energy Kentucky

Capital Structure Ratios

Duke Energy Kentucky Proposed Capital Structure

Type of Capital	Ratios	Cost Rate
Short--Term Debt	8.49%	5.14%
Long-Term Debt	40.63%	6.09%
Common Equity	50.88%	
Total	100.00%	

Capital Structure - Electric Utility Proxy Group A

Average Of All Companies Ratios	2006 1st Quarter	2005 4th Quarter	2005 3rd Quarter	2005 2nd Quarter
Short-term debt	6.36%	6.41%	4.27%	4.85%
Current portion of long-term debt	3.85%	3.55%	2.62%	3.02%
Long-term debt	47.13%	47.52%	48.92%	49.48%
Preferred Equity	1.34%	1.39%	1.42%	1.44%
Common shareholder's equity	41.31%	41.13%	42.76%	41.22%
	100.00%	100.00%	100.00%	100.00%

Average Ratios - Last Four Quarters	
Short-term debt	5.48%
Current portion of long-term debt	3.26%
Long-term debt	48.26%
Preferred Equity	1.40%
Common shareholder's equity	41.60%
Total	100.00%

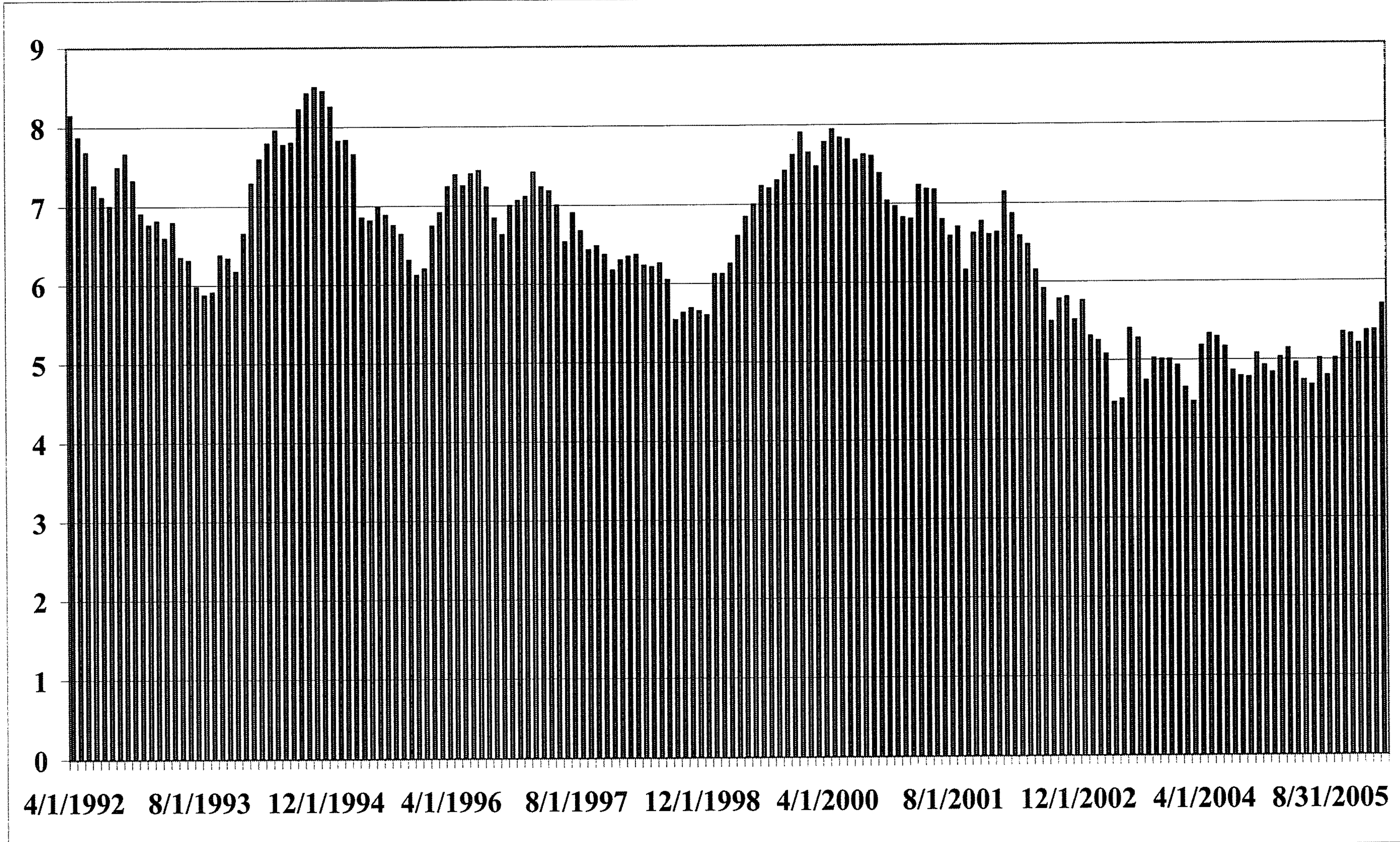
Capital Structure - Electric Utility Proxy Group A*	
Short-term debt	5.48%
Long-term debt	51.52%
Common shareholder's equity	43.00%

Duke Energy Kentucky Proposed Capital Stru

Short--Term Debt	8.49%
Long-Term Debt	40.63%
Common Equity	50.88%

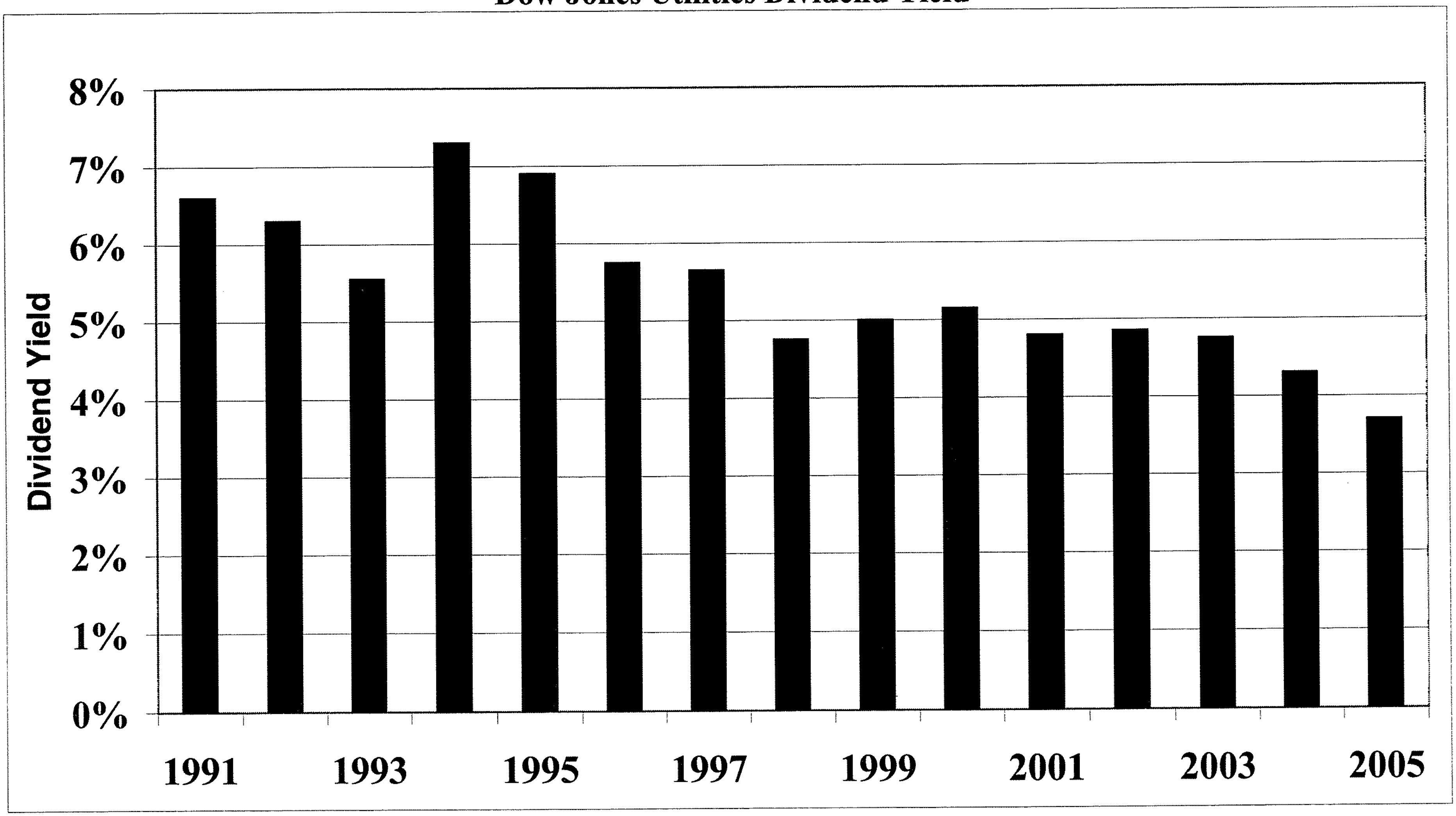
Exhibit_(JRW-5)

Long-Term 'A' Rated Public Utility Bonds



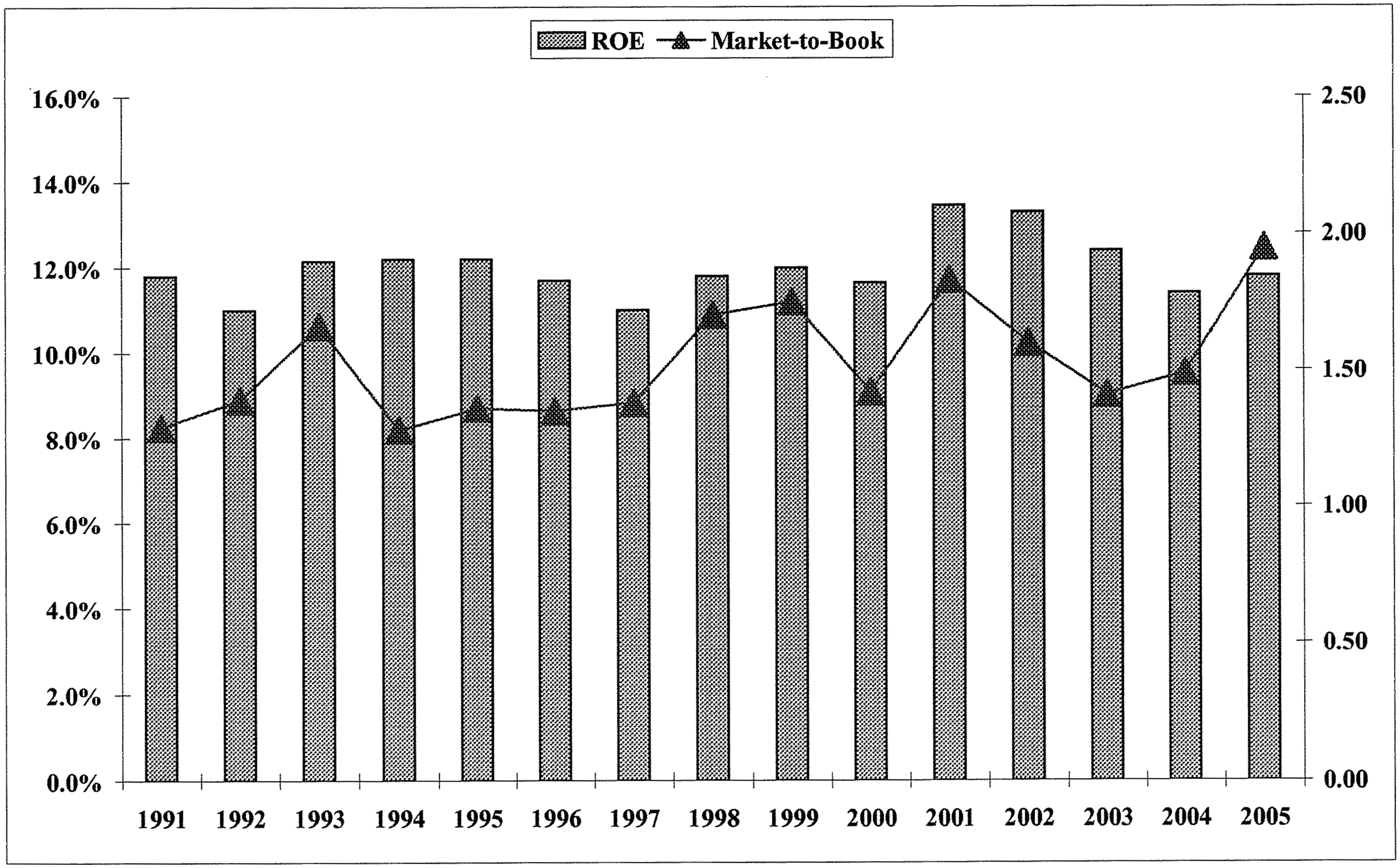
Data Source: Bloomberg (FMCI Function).

Exhibit_(JRW-5)
Dow Jones Utilities Dividend Yield



Data Source: *Value Line Investment Survey*

Exhibit_(JRW-5)
Dow Jones Utilities - Market to Book and ROE



Data Source: *Value Line Investment Survey*

Exhibit_(JRW-6)

Industry Average Betas

Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta	Industry Name	Number of Firms	Beta
E-Commerce	59	3.04	Manuf. Housing/RV	16	1.08	Paper/Forest Products	40	0.82
Semiconductor	121	2.97	Retail (Special Lines)	177	1.08	Hotel/Gaming	76	0.82
Semiconductor Equip	14	2.91	Medical Supplies	261	1.04	Diversified Co.	118	0.82
Internet	306	2.78	Foreign Electronics	11	1.03	Toiletries/Cosmetics	20	0.82
Telecom. Equipment	122	2.61	Metals & Mining (Div.)	77	1.03	Packaging & Container	37	0.82
Wireless Networking	66	2.60	Chemical (Basic)	18	1.03	Electric Util. (Central)	25	0.81
Entertainment Tech	32	2.47	Oilfield Svcs/Equip.	98	1.02	Pharmacy Services	15	0.81
Power	25	2.23	Shoe	22	1.02	Electric Utility (East)	29	0.80
Computers/Peripherals	138	2.23	Retail Store	46	0.99	Household Products	26	0.79
Computer Software/Svcs	395	2.06	Retail Automotive	14	0.98	Bank (Canadian)	7	0.76
Foreign Telecom.	20	1.88	Industrial Services	207	0.97	Environmental	91	0.76
Cable TV	22	1.82	Medical Services	184	0.96	Financial Svcs. (Div.)	244	0.75
Precision Instrument	104	1.81	Building Materials	45	0.96	Bank (Midwest)	39	0.75
Telecom. Services	146	1.69	Natural Gas (Div.)	36	0.96	Publishing	47	0.74
Electronics	175	1.65	Utility (Foreign)	5	0.95	Insurance (Life)	43	0.73
Biotechnology	87	1.63	Steel (General)	26	0.94	Investment Co.	21	0.73
Electrical Equipment	91	1.59	Homebuilding	34	0.92	Railroad	18	0.73
Drug	306	1.59	Coal	12	0.92	Maritime	39	0.72
Advertising	34	1.56	Furn/Home Furnishings	36	0.92	Canadian Energy	11	0.72
Bank (Foreign)	4	1.51	Electric Utility (West)	15	0.90	Cement & Aggregates	12	0.71
Entertainment	86	1.47	Chemical (Specialty)	92	0.90	Natural Gas (Distrib.)	29	0.70
Air Transport	45	1.40	Apparel	60	0.90	Insurance (Prop/Cas.)	84	0.70
Healthcare Information	35	1.38	Petroleum (Integrated)	30	0.90	Restaurant	82	0.68
Securities Brokerage	31	1.36	Retail Building Supply	10	0.89	R.E.I.T.	122	0.67
Human Resources	30	1.26	Metal Fabricating	41	0.88	Petroleum (Producing)	148	0.67
Investment Co.(Foreign)	15	1.26	Trucking	37	0.88	Precious Metals	62	0.67
Auto & Truck	29	1.23	Information Services	36	0.86	Tobacco	11	0.66
Auto Parts	58	1.22	Home Appliance	15	0.86	Water Utility	16	0.64
Tire & Rubber	13	1.19	Grocery	23	0.86	Food Processing	110	0.61
Steel (Integrated)	14	1.14	Newspaper	19	0.86	Beverage (Soft Drink)	19	0.61
Office Equip/Supplies	27	1.10	Aerospace/Defense	70	0.84	Food Wholesalers	21	0.60
Educational Services	38	1.09	Chemical (Diversified)	33	0.84	Beverage (Alcoholic)	22	0.56
Recreation	74	1.08	Machinery	134	0.83	Bank	487	0.55
						Thrift	221	0.49
						Market	**7113**	**1.15**

Data Source: http://pages.stern.nyu.edu/~adamodar/

Exhibit_(JRW-7)

Duke Energy Kentucky
Discounted Cash Flow Analysis

Electric Utility Proxy Group A

Dividend Yield*	4.40%
Adjustment Factor	1.02375
Adjusted Dividend Yield	4.50%
Growth Rate**	4.75%
Equity Cost Rate	9.25%

Electric Utility Proxy Group B

Dividend Yield*	4.20%
Adjustment Factor	1.025
Adjusted Dividend Yield	4.31%
Growth Rate**	5.00%
Equity Cost Rate	9.31%

* Page 2 of Exhibit_(JRW-7)

** Based on data provided on pages 3-5, Exhibit_(JRW-7)

Exhibit_(JRW-7)

Duke Energy Kentucky

Monthly Dividend Yields
March 2006 - August 2006

Electric Utility Proxy Group A

Company	Ticker	Mar	Apr	May	June	July	Aug	Mean
American Elec. Pwr.	AEP	4.1%	4.2%	4.5%	4.5%	4.4%	4.4%	4.4%
CH Energy Group	CHG	4.5%	4.6%	4.7%	4.7%	4.8%	4.8%	4.7%
Con. Edison	ED	5.0%	5.1%	5.5%	5.5%	5.2%	5.2%	5.3%
DPL, Inc.	DPL	3.7%	3.7%	3.7%	3.8%	3.8%	3.8%	3.8%
Duquesne Light Holdings	DQE	5.7%	6.0%	6.1%	6.1%	6.3%	6.3%	6.1%
Energy East Corp.	EAS	4.6%	4.7%	4.9%	5.1%	4.9%	4.9%	4.9%
Exelton	EXC	2.8%	2.9%	3.1%	2.9%	2.8%	2.8%	2.9%
FirstEnergy	FE	3.6%	3.6%	3.7%	3.4%	3.4%	3.4%	3.5%
IDACORP	IDA	3.7%	3.8%	3.7%	3.6%	3.6%	3.6%	3.7%
PPL Corp.	PPL	3.2%	3.3%	3.5%	3.4%	3.5%	3.5%	3.4%
Progress Energy	PGN	5.4%	5.4%	5.8%	5.9%	5.7%	5.7%	5.7%
Southern Co.	SO	4.4%	4.5%	4.7%	4.8%	4.8%	4.8%	4.7%
Xcel Energy Inc.	XEL	4.5%	4.7%	4.8%	4.7%	4.6%	4.6%	4.7%
Mean		4.2%	4.3%	4.5%	4.5%	4.4%	4.4%	4.4%

Data Source: AUS Utility Reports, monthly issues.

Electric Utility Proxy Group B

Company	Ticker	Mar	Apr	May	June	July	Aug	Mean
ALLETE	ALE	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%	3.2%
Alliant Energy	LNT	3.6%	3.5%	3.7%	3.5%	3.4%	3.4%	3.5%
Ameren Corp.	AEE	5.0%	5.1%	5.1%	5.2%	5.1%	5.1%	5.1%
American Elec. Pwr.	AEP	4.1%	4.2%	4.5%	4.5%	4.4%	4.4%	4.4%
Central Vermont	CV	4.3%	4.4%	4.7%	5.2%	5.5%	5.5%	4.9%
Cleco	CNL	4.2%	4.2%	4.2%	4.1%	4.1%	4.1%	4.2%
Edison Intl	EIX	2.5%	2.5%	2.8%	2.7%	2.7%	2.7%	2.7%
Empire District	EDE	5.7%	5.8%	5.8%	5.8%	6.2%	6.2%	5.9%
Energy East Corp.	EAS	4.6%	4.7%	4.9%	5.1%	4.9%	4.9%	4.9%
Entergy	ETR	3.0%	3.1%	3.2%	3.2%	3.1%	3.1%	3.1%
FirstEnergy	FE	3.6%	3.6%	3.7%	3.4%	3.4%	3.4%	3.5%
FPL Group	FPL	3.6%	3.7%	3.9%	3.9%	3.7%	3.7%	3.8%
Green Mountain Power	GMP	3.6%	4.0%	4.0%	4.0%	4.0%	4.0%	3.9%
Hawaiian Electric	HE	4.7%	4.6%	4.7%	4.8%	4.6%	4.6%	4.7%
IDACORP	IDA	3.7%	3.8%	3.7%	3.6%	3.6%	3.6%	3.7%
MGE Energy	MGEE	4.1%	4.3%	4.6%	4.6%	4.7%	4.7%	4.5%
Northeast Utilities	NU	3.5%	3.6%	3.6%	3.6%	3.7%	3.7%	3.6%
PG&E	PCG	3.5%	3.3%	3.4%	3.4%	3.4%	3.4%	3.4%
Pinnacle West	PNW	4.8%	5.0%	5.1%	5.1%	5.1%	5.1%	5.0%
PNM Resources	PNM	3.5%	5.0%	3.6%	3.6%	3.4%	3.4%	3.8%
Progress Energy	PGN	5.4%	5.4%	5.8%	5.9%	5.7%	5.7%	5.7%
Puget Energy	PSD	4.7%	4.7%	4.9%	4.9%	4.8%	4.8%	4.8%
Southern Co.	SO	4.4%	4.5%	4.7%	4.8%	4.8%	4.8%	4.7%
TECO Energy	TE	4.5%	4.7%	4.7%	5.1%	5.2%	5.2%	4.9%
Wisconsin Energy	WEC	2.3%	2.3%	2.4%	2.3%	2.3%	2.3%	2.3%
Xcel Energy Inc.	XEL	4.5%	4.7%	4.8%	4.7%	4.6%	4.6%	4.7%
Mean		4.0%	4.2%	4.2%	4.2%	4.2%	4.2%	4.2%

Data Source: AUS Utility Reports, monthly issues.
Note: El Paso Electric was eliminated from the DCF analysis since it does not pay a cash dividend.

Exhibit_(JRW-7)

Duke Energy Kentucky

DCF Equity Cost Growth Rate Measures

Value Line Historic Growth Rates

Electric Utility Proxy Group A

Company	Sym	*Value Line* Historic Growth					
		Past 10 Years			Past 5 Years		
		Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
American Elec. Pwr.	AEP	-0.50%	-4.50%	-0.50%	3.50%	-9.00%	-3.50%
CH Energy Group	CHG	-	0.50%	2.00%	-1.50%	-	2.00%
Con. Edison	ED	-0.50%	1.50%	2.50%	-2.00%	1.00%	2.50%
DPL, Inc.	DPL	2.50%	2.00%	1.00%	-1.00%	0.50%	-1.00%
Duquesne Light Holdings	DQE	-5.50%	-1.50%	-7.00%	-12.00%	-8.50%	-14.50%
Energy East Corp.	EAS	3.50%	1.50%	4.50%	-2.50%	5.00%	6.00%
Exelton	EXC	-	-	-	11.50%	-	4.00%
FirstEnergy	FE	2.00%	1.50%	5.50%	NA	2.50%	6.00%
IDACORP	IDA	-2.50%	-3.00%	2.50%	-11.00%	-6.00%	3.00%
PPL Corp.	PPL	7.00%	-	3.00%	8.50%	8.50%	12.00%
Progress Energy	PGN	3.50%	3.00%	6.50%	4.50%	3.00%	6.50%
Southern Co.	SO	2.5%	2.0%	1.0%	2.0%	1.0%	-1.0%
Xcel Energy Inc.	XEL	-3.5%	-5.0%	-1.0%	-5.5%	-11.0%	-4.5%
Mean		**0.8%**	**-0.2%**	**1.7%**	**-0.5%**	**-1.2%**	**1.3%**
Median		**2.0%**	**1.5%**	**2.3%**	**-1.3%**	**1.0%**	**2.5%**
		Average of Mean and Median Figures =			**0.8%**		

Electric Utility Proxy Group B

Company	Sym	*Value Line* Historic Growth					
		Past 10 Years			Past 5 Years		
		Earnings	Dividends	Book Value	Earnings	Dividends	Book Value
ALLETE	ALE	-	-	-	-	-	-
Alliant Energy	LNT	-1.50%	-6.00%	1.00%	-1.00%	-12.50%	-2.50%
Ameren Corp.	AEE	0.50%	0.50%	3.00%	0.50%	-	5.00%
American Elec. Pwr.	AEP	-0.50%	-4.50%	-0.50%	3.50%	-9.00%	-3.50%
Central Vermont	CV	-4.50%	-3.00%	2.00%	1.00%	0.50%	2.50%
Cleco	CNL	3.50%	2.00%	4.50%	1.00%	2.00%	4.00%
Edison Intl	EIX	3.00%	-6.50%	3.00%	-	-9.00%	8.50%
Empire District	EDE	-1.50%	-	2.00%	-5.00%	-	2.00%
Energy East Corp.	EAS	3.50%	1.50%	4.50%	-2.50%	5.00%	6.00%
Entergy	ETR	6.50%	0.50%	3.00%	10.00%	7.50%	4.50%
FirstEnergy	FE	2.00%	1.50%	5.50%	NA	2.50%	6.00%
FPL Group	FPL	5.00%	2.50%	6.00%	3.50%	4.50%	6.00%
Green Mountain Power	GMP	-1.00%	-8.50%	-	-	5.00%	3.00%
Hawaaian Electric	HE	1.50%	0.50%	2.00%	1.00%	NA	3.00%
IDACORP	IDA	-2.50%	-3.00%	2.50%	-11.00%	-6.00%	3.00%
MGE Energy	MGEE	1.50%	1.00%	2.50%	4.00%	1.00%	5.00%
Northeast Utilities	NU	-6.50%	-10.00%	-0.50%	-	30.50%	3.00%
PG&E	PCG	-2.00%	-	-2.00%	-	-	1.00%
Pinnacle West	PNW	2.00%	11.00%	5.00%	-4.50%	6.54%	4.00%
PNM Resources	PNM	4.00%	-	6.00%	-1.00%	5.00%	4.50%
Progress Energy	PGN	3.50%	3.00%	6.50%	4.50%	3.00%	6.50%
Puget Energy	PSD	-3.50%	-6.00%	-1.00%	-7.50%	-11.50%	0.50%
Southern Co.	SO	2.50%	2.00%	1.00%	2.00%	1.00%	-1.00%
TECO Energy	TE	-9.00%	-2.00%	-2.00%	-20.00%	-8.50%	-7.50%
Wisconsin Energy	WEC	1.50%	-5.00%	3.00%	7.50%	-11.00%	5.00%
Xcel Energy Inc.	XEL	-3.50%	-5.00%	-1.00%	-5.50%	-11.00%	-4.50%
Mean		**0.2%**	**-1.5%**	**2.3%**	**-1.0%**	**-0.2%**	**2.6%**
Median		**1.5%**	**-0.8%**	**2.5%**	**0.8%**	**1.0%**	**3.0%**
		Average of Mean and Median Figures =			**0.9%**		

Data Source: *Value Line Investment Survey, September, 2006.*

Exhibit_(JRW-7)

Duke Energy Kentucky

DCF Equity Cost Growth Rate Measures

***Value Line* Projected Growth Rates**

Electric Utility Proxy Group A

Company	Sym	*Value Line* Projected Growth Est'd. '03-'05 to '09-'11			*Value Line* Internal Growth		
		Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
American Elec. Pwr.	AEP	4.00%	4.00%	5.50%	11.00%	41.00%	4.51%
CH Energy Group	CHG	3.00%	0.50%	2.00%	9.00%	30.00%	2.70%
Con. Edison	ED	3.00%	1.00%	3.00%	9.00%	25.00%	2.25%
Constellation Energy	CEG	13.00%	11.50%	9.00%	14.50%	65.00%	9.43%
Duquesne Light Holdings	DQE	5.00%	Nil	5.50%	12.50%	31.00%	3.88%
Energy East Corp.	EAS	4.00%	4.50%	2.50%	9.50%	39.00%	3.71%
Exelton	EXC	7.00%	11.00%	7.50%	20.00%	44.00%	8.80%
FirstEnergy	FE	11.50%	5.00%	6.50%	11.00%	49.00%	5.39%
IDACORP	IDA	4.50%	-2.00%	3.00%	7.00%	40.00%	2.80%
PPL Corp.	PPL	11.00%	13.50%	9.00%	19.50%	49.00%	9.56%
Progress Energy	PGN	1.50%	2.00%	3.00%	9.00%	23.00%	2.07%
Southern Co.	SO	5.00%	4.50%	5.00%	14.50%	31.00%	4.50%
Xcel Energy Inc.	XEL	6.00%	5.50%	3.00%	10.50%	33.00%	3.47%
Mean		6.0%	5.1%	5.0%	12.1%	38.5%	4.8%
Median		5.0%	4.5%	5.0%	11.0%	39.0%	3.9%
Average of Mean and Median Figures =			5.1%	Average of Mean and Median Figures =			4.4%

Electric Utility Proxy Group B

Company	Sym	*Value Line* Projected Growth Est'd. '03-'05 to '09-'11			*Value Line* Internal Growth		
		Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth
ALLETE	ALE	7.00%	9.00%	6.00%	12.00%	40.00%	4.80%
Alliant Energy	LNT	4.50%	7.00%	3.50%	9.00%	35.00%	3.15%
Ameren Corp.	AEE	1.50%	0.00%	3.00%	9.50%	23.00%	2.19%
American Elec. Pwr.	AEP	4.00%	4.00%	5.50%	11.00%	41.00%	4.51%
Central Vermont	CV	9.50%	-1.00%	1.00%	8.00%	44.00%	3.52%
Cleco	CNL	4.50%	2.00%	8.00%	9.00%	40.00%	3.60%
Edison Intl	EIX	8.00%	NMF	9.00%	10.50%	58.00%	6.09%
Empire District	EDE	6.50%	Nil	2.00%	9.50%	21.00%	2.00%
Energy East Corp.	EAS	4.00%	4.50%	2.50%	9.50%	39.00%	3.71%
Entergy	ETR	5.00%	7.00%	5.00%	10.00%	46.00%	4.60%
FirstEnergy	FE	11.50%	5.00%	6.50%	11.00%	49.00%	5.39%
FPL Group	FPL	6.00%	5.50%	7.00%	11.50%	47.00%	5.41%
Green Mountain Power	GMP	3.50%	10.00%	3.50%	10.00%	39.00%	3.90%
Hawaaian Electric	HE	3.00%	Nil	2.50%	10.00%	28.00%	2.80%
IDACORP	IDA	4.50%	-2.00%	3.00%	7.00%	40.00%	2.80%
MGE Energy	MGEE	6.00%	0.50%	7.00%	12.00%	37.00%	4.44%
Northeast Utilities	NU	6.50%	6.50%	0.50%	8.00%	37.00%	2.96%
PG&E	PCG	5.50%	NMF	8.00%	11.00%	44.00%	4.84%
Pinnacle West	PNW	6.00%	5.00%	3.50%	9.00%	32.00%	2.88%
PNM Resources	PNM	5.50%	8.50%	4.00%	8.00%	42.00%	3.36%
Progress Energy	PGN	1.50%	2.00%	3.00%	9.00%	23.00%	2.07%
Puget Energy	PSD	5.00%	1.50%	4.00%	8.50%	40.00%	3.40%
Southern Co.	SO	5.00%	4.50%	5.00%	14.50%	31.00%	4.50%
TECO Energy	TE	NMF	-0.50%	4.50%	15.00%	47.00%	7.05%
Wisconsin Energy	WEC	6.00%	4.50%	6.00%	11.00%	66.00%	7.26%
Xcel Energy Inc.	XEL	6.00%	5.50%	3.00%	10.50%	33.00%	3.47%
Mean		5.4%	4.0%	4.5%	10.2%	39.3%	4.0%
Median		5.5%	4.5%	4.0%	10.0%	40.0%	3.7%
Average of Mean and Median Figures =			4.7%	Average of Mean and Median Figures =			3.8%

Data Source: *Value Line Investment Survey, September, 2006*

Exhibit_(JRW-7)

Duke Energy Kentucky
DCF Equity Cost Growth Rate Measures
Analysts Projected EPS Growth Rate Estimates

Electric Utility Proxy Group A

Company	Sym	Yahoo First Call	Reuters	Zack's	Average
American Elec. Pwr.	AEP	3.0%	3.7%	3.0%	3.2%
CH Energy Group	CHG	N/A	N/A	N/A	N/A
Con. Edison	ED	3.0%	3.7%	3.5%	3.4%
DPL, Inc.	DPL	5.0%	8.3%	7.0%	6.8%
Duquesne Light Holdings	DQE	5.5%	3.0%	N/A	4.3%
Energy East Corp.	EAS	4.0%	4.3%	4.5%	4.3%
Exelton	EXC	9.5%	9.3%	9.5%	9.4%
FirstEnergy	FE	5.0%	5.7%	4.9%	5.2%
IDACORP	IDA	5.0%	4.8%	4.7%	4.8%
PPL Corp.	PPL	10.5%	7.9%	8.7%	9.0%
Progress Energy	PGN	3.5%	3.9%	3.6%	3.7%
Southern Co.	SO	5.0%	4.5%	4.8%	4.8%
Xcel Energy Inc.	XEL	4.0%	4.2%	4.3%	4.2%
Mean		**5.3%**	**5.3%**	**5.3%**	**5.3%**
Median		**5.0%**	**4.4%**	**4.7%**	**4.5%**
Average of Mean and Median					**4.9%**

Data Sources: www.zacks.com, www.investor.reuters.com, http://quote.yahoo.com. Sept, 2006.

Electric Utility Proxy Group B

Company	Sym	Yahoo First Call	Reuters	Zack's	Average
ALLETE	ALE	8.5%	6.8%	7.3%	7.5%
Alliant Energy	LNT	4.5%	3.7%	4.0%	4.1%
Ameren Corp.	AEE	4.0%	6.0%	5.4%	5.1%
American Elec. Pwr.	AEP	3.0%	3.7%	3.0%	3.2%
Central Vermont	CV	N/A	N/A	N/A	N/A
Cleco	CNL	4.0%	8.0%	8.0%	6.7%
Edison Intl	EIX	8.0%	8.0%	7.7%	7.9%
Empire District	EDE	2.0%	4.5%	0.0%	2.2%
Energy East Corp.	EAS	4.0%	4.3%	4.5%	4.3%
Entergy	ETR	7.5%	7.5%	7.5%	7.5%
FirstEnergy	FE	5.0%	5.7%	4.9%	5.2%
FPL Group	FPL	9.5%	7.0%	6.8%	7.8%
Green Mountain Power	GMP	N/A	N/A	N/A	N/A
Hawaiian Electric	HE	3.0%	4.3%	5.2%	4.2%
IDACORP	IDA	5.0%	4.8%	4.7%	4.8%
MGE Energy	MGEE	N/A	N/A	N/A	N/A
Northeast Utilities	NU	7.0%	7.5%	8.7%	7.7%
PG&E	PCG	8.0%	6.8%	7.7%	7.5%
Pinnacle West	PNW	6.0%	6.4%	6.8%	6.4%
PNM Resources	PNM	12.0%	11.5%	8.3%	10.6%
Progress Energy	PGN	3.5%	3.9%	3.6%	3.7%
Puget Energy	PSD	4.0%	4.8%	7.0%	5.3%
Southern Co.	SO	5.0%	4.5%	4.7%	4.7%
TECO Energy	TE	3.0%	6.5%	5.4%	5.0%
Wisconsin Energy	WEC	8.0%	7.0%	7.0%	7.3%

Xcel Energy Inc.	**XEL**	4.0%	4.2%	4.3%	4.2%
Mean		**5.6%**	**6.0%**	**5.8%**	**5.8%**
Median		**5.0%**	**6.0%**	**5.4%**	**5.2%**
Average of Mean and Median					**5.5%**

Data Sources: www.zacks.com, www.investor.reuters.com, http://quote.yahoo.com. Sept, 2006.

Exhibit_(JRW-8)

Duke Energy Kentucky
Capital Asset Pricing Model

Electric Utility Proxy Group A

Risk-Free Interest Rate	5.00%
Beta*	0.85
Ex Ante Equity Risk Premium**	4.13%
CAPM Cost of Equity	8.5%

Electric Utility Proxy Group B

Risk-Free Interest Rate	5.00%
Beta*	0.85
Ex Ante Equity Risk Premium**	4.13%
CAPM Cost of Equity	8.5%

* See page 2 of Exhibit_(JRW-8)
** See page 3 of Exhibit_(JRW-8)

Exhibit_(JRW-8)

Duke Energy Kentucky
Beta

Electric Utility Proxy Group A

Company		Beta
American Elec. Pwr.	AEP	1.25
CH Energy Group	CHG	0.85
Con. Edison	ED	0.70
DPL, Inc.	DPL	1.00
Duquesne Light Holdings	DQE	0.90
Energy East Corp.	EAS	0.90
Exelton	EXC	0.80
FirstEnergy	FE	0.80
IDACORP	IDA	1.00
PPL Corp.	PPL	1.00
Progress Energy	PGN	0.85
Southern Co.	SO	0.65
Xcel Energy Inc.	XEL	0.85
Mean		0.89
Median		0.85

Electric Utility Proxy Group B

Company		Beta
ALLETE	ALE	NMF
Alliant Energy Co.	LNT	0.90
Ameren Corp.	AEE	0.75
American Elec. Pwr.	AEP	1.25
Central Vermont	CV	0.7
Cleco	CNL	1.25
Edison Intl	EIX	1.10
El Paso Electric	EE	0.7
Empire District	EDE	0.8
Energy East Corp.	EAS	0.90
Entergy	ETR	0.85
FirstEnergy	FE	0.80
FPL Group	FPL	0.85
Green Mountain Power	GMP	0.6
Hawaaian Electric	HE	0.70
IDACORP	IDA	1.00
MGE Energy	MGEE	0.7
Northeast Utilities	NU	0.85
PG&E	PCG	1.15
Pinnacle West	PNW	1.00
PNM Resources	PNM	1.00
Progress Energy	PGN	0.85
Puget Energy	PSD	0.80
Southern Co.	SO	0.65
TECO Energy	TE	1.05
Wisconsin Energy	WEC	0.80
Xcel Energy Inc.	XEL	0.90
Mean		0.88
Median		0.85

Data Source: *Value Line Investment Survey, July, 2006.*

Duke Energy Kentucky
Capital Asset Pricing Model
Equity Risk Premium

Category	Study Authors		Range Low	Range High	Mean of Range	Mean	Category Average
Historic							
	Ibbotson	Arithmetic			6.50%	5.70%	
		Geometric			4.90%		
	AVERAGE						5.70%
Puzzle Research							
	Claus Thomas					3.00%	
	Arnott and Bernstein					2.40%	
	Constantinides					6.90%	
	Cornell		3.50%	7.00%	5.25%		
	Dimson, Marsh, and Staunton	Arithmetic	3.50%	5.25%	3.25%	4.17%	
		Geometric	2.50%	4.00%			
	Fama French		2.55%	4.32%		3.44%	
	Harris & Marston					7.14%	
	Siegel	Geometric				2.50%	
	AVERAGE						4.22%
Surveys							
	Survey of Financial Forecasters					2.00%	
	Graham and Harvey - CFOs					3.05%	
	Welch - Academics		5.00%	5.50%		5.25%	
	AVERAGE						3.43%
Social Security							
	Office of Chief Actuary		4.00%	4.70%			
	John Campbell		2.00%	3.50%			
	Peter Diamond		3.00%	4.80%			
	John Shoven		3.00%	3.50%		3.56%	
	AVERAGE						3.56%
Building Block							
	Ibbotson and Chen						
		Arithmetic			6.00%	5.00%	
		Geometric			4.00%		
	Woolridge					3.18%	
	AVERAGE						4.09%
Other Studies							
	McKinsey		3.50%	4.00%		3.75%	
	AVERAGE						3.75%
OVERALL AVERAGE							**4.13%**

Sources:

Ibbotson Associates, SBBI Yearbook, 2006.

James Claus and Jacob Thomas, "Equity Risk Premia as Low as Three Percent? Empirical Evidence from Analysts' Earnings Forecasts for Domestic and International Stock Market," *Journal of Finance*. (October 2001).

Eugene F. Fama and Kenneth R. French, "The Equity Premium," *The Journal of Finance*, April 2002.

Elroy Dimson, Paul Marsh, and Mike Staunton, "New Evidence puts Risk Premium in Context," *Corporate Finance* (March 2003)

Ivo Welch, "The Equity Risk Premium Consensus Forecast Revisited," (September 2001). Cowles Foundation Discussion Paper No. 1325.

John R. Graham and Campbell Harvey, "Expectations of Equity Risk Premia, Volatility, and Asymmetry," Duke University Working Paper, 2003.

Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, February 14, 2005.

Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002), p.14.

Roger Ibbotson and Peng Chen, "Long Run Returns: Participating in the Real Economy," *Financial Analysts Journal*, January 2003

Exhibit_(JRW-8)

Survey of Professional Forecasters
Philadelphia Federal Reserve Bank
Long-Term Forecasts

TABLE FIVE
LONG-TERM (10 YEAR) FORECASTS

SERIES: CPI INFLATION RATE		SERIES: REAL GDP GROWTH RATE	
STATISTIC		STATISTIC	
MINIMUM	1.750	MINIMUM	2.500
LOWER QUARTILE	2.300	LOWER QUARTILE	3.000
MEDIAN	2.500	MEDIAN	3.200
UPPER QUARTILE	2.725	UPPER QUARTILE	3.400
MAXIMUM	3.700	MAXIMUM	4.250
MEAN	2.512	MEAN	3.189
STD. DEV.	0.354	STD. DEV.	0.301
N	49	N	49
MISSING	4	MISSING	4

SERIES: PRODUCTIVITY GROWTH		SERIES: STOCK RETURNS (S&P 500)	
STATISTIC		STATISTIC	
MINIMUM	1.600	MINIMUM	5.000
LOWER QUARTILE	2.170	LOWER QUARTILE	6.000
MEDIAN	2.437	MEDIAN	7.000
UPPER QUARTILE	2.600	UPPER QUARTILE	8.000
MAXIMUM	3.500	MAXIMUM	15.000
MEAN	2.404	MEAN	7.340
STD. DEV.	0.355	STD. DEV.	1.800
N	46	N	41
MISSING	7	MISSING	12

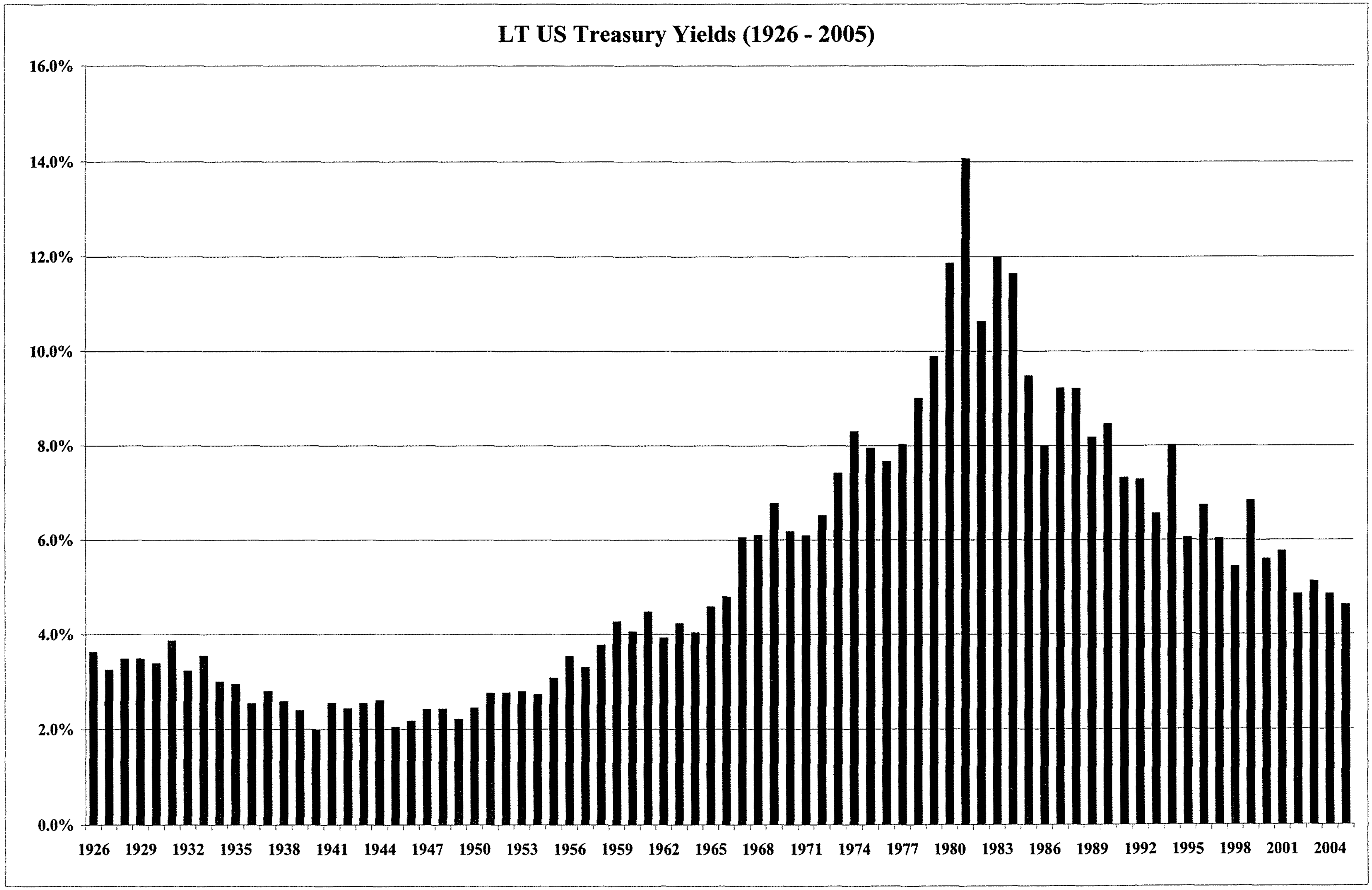
SERIES: BOND RETURNS (10-YEAR)		SERIES: BILL RETURNS (3-MONTH)	
STATISTIC		STATISTIC	
MINIMUM	4.000	MINIMUM	2.800
LOWER QUARTILE	4.842	LOWER QUARTILE	3.985
MEDIAN	5.000	MEDIAN	4.250
UPPER QUARTILE	5.500	UPPER QUARTILE	4.575
MAXIMUM	7.200	MAXIMUM	5.500
MEAN	5.146	MEAN	4.200
STD. DEV.	0.579	STD. DEV.	0.631
N	44	N	44
MISSING	9	MISSING	9

Source: Philadelphia Federal Researve Bank, Survey of Professional Forecasters, February 13, 2006.
http://www.phil.frb.org/files/spf/spfq106.pdf

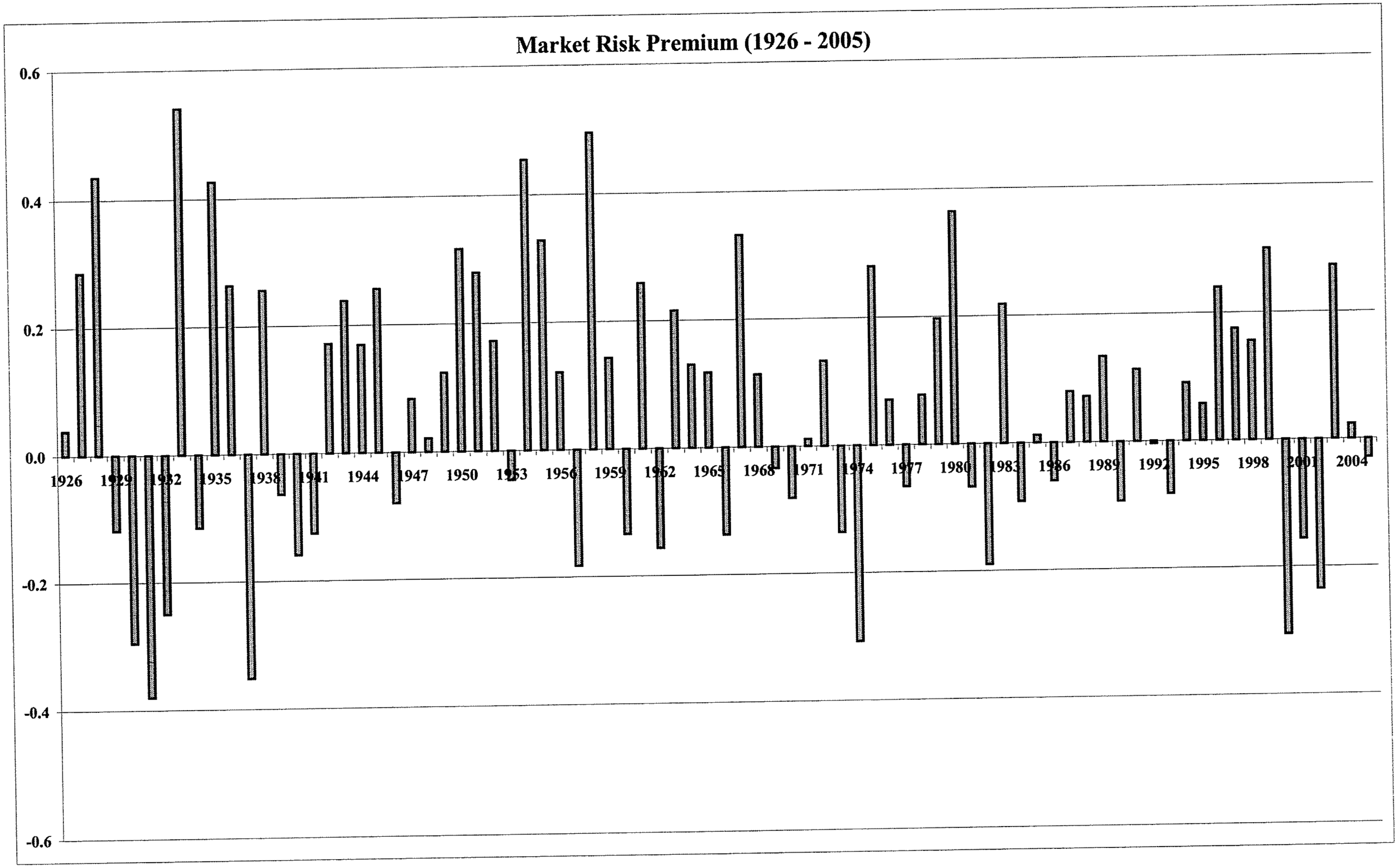
Exhibit_(JRW-8)

Duke Energy Kentucky
CAPM
Real S&P 500 EPS Growth Rate

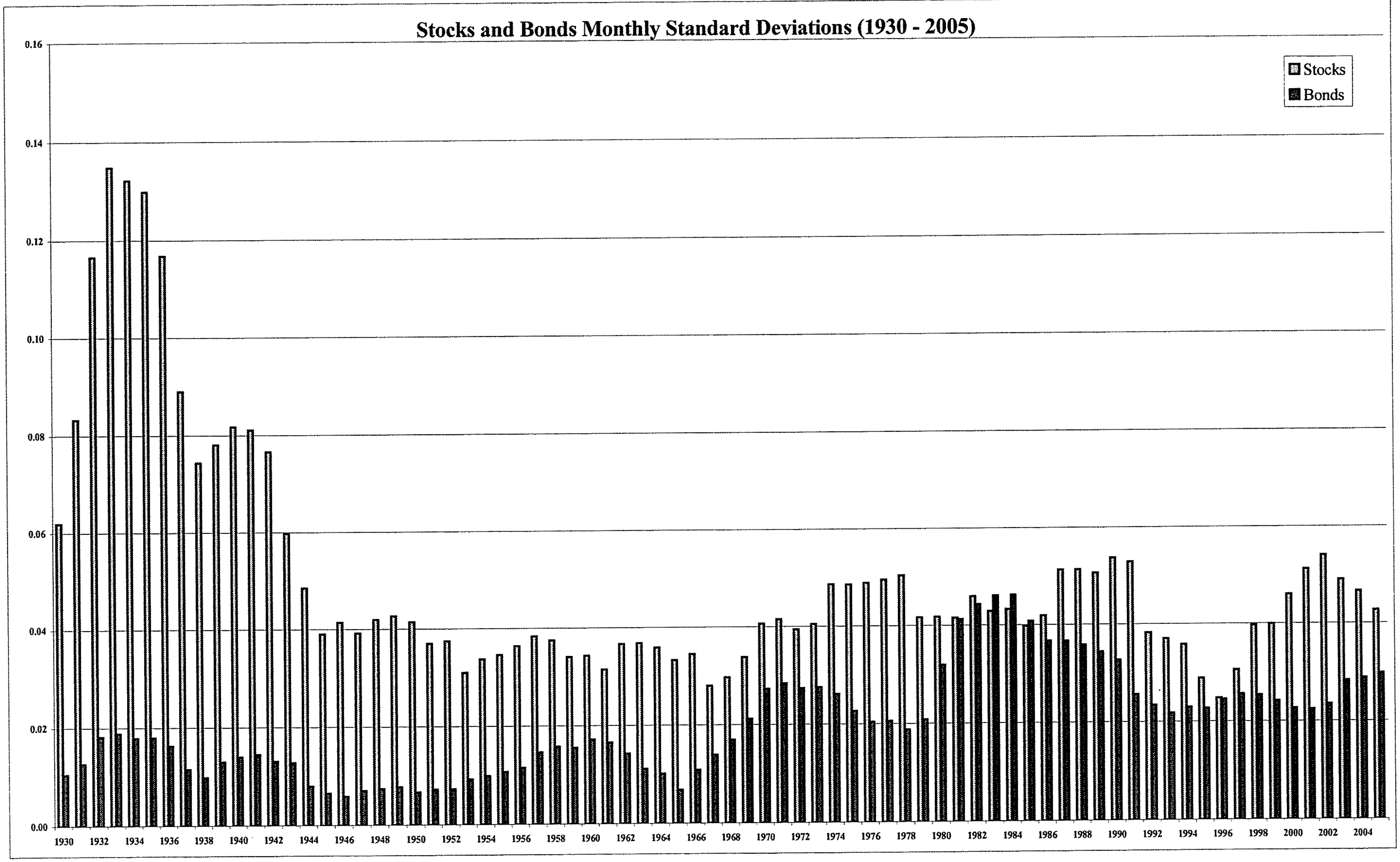
Year	S&P 500 EPS	Annual Inflation CPI	Inflation Adjustment Factor	Real S&P 500 EPS	
1960	3.10	1.4		3.10	
1961	3.37	0.7	1.0070	3.35	
1962	3.67	1.3	1.0201	3.59	
1963	4.13	1.6	1.0364	3.99	
1964	4.76	1	1.0468	4.55	
1965	5.30	1.9	1.0667	4.97	
1966	5.41	3.5	1.1040	4.90	
1967	5.46	3	1.1371	4.80	
1968	5.72	4.7	1.1906	4.81	
1969	6.10	6.2	1.2644	4.83	10-Year
1970	5.51	5.6	1.3352	4.13	2.9%
1971	5.57	3.3	1.3792	4.04	
1972	6.17	3.4	1.4261	4.33	
1973	7.96	8.7	1.5502	5.13	
1974	9.35	12.3	1.7409	5.37	
1975	7.71	6.9	1.8610	4.14	
1976	9.75	4.9	1.9522	4.99	
1977	10.87	6.7	2.0830	5.22	
1978	11.64	9	2.2705	5.13	
1979	14.55	13.3	2.5724	5.66	10-Year
1980	14.99	12.5	2.8940	5.18	2.3%
1981	15.18	8.9	3.1516	4.82	
1982	13.82	3.8	3.2713	4.23	
1983	13.29	3.8	3.3956	3.91	
1984	16.84	3.9	3.5281	4.77	
1985	15.68	3.8	3.6621	4.28	
1986	14.43	1.1	3.7024	3.90	
1987	16.04	4.4	3.8653	4.15	
1988	22.77	4.4	4.0354	5.64	
1989	24.03	4.6	4.2210	5.69	10-Year
1990	21.73	6.1	4.4785	4.85	-0.7%
1991	19.10	3.1	4.6173	4.14	
1992	18.13	2.9	4.7512	3.81	
1993	19.82	2.7	4.8795	4.06	
1994	27.05	2.7	5.0113	5.40	
1995	35.35	2.5	5.1365	6.88	
1996	35.78	3.3	5.3061	6.74	
1997	39.56	1.7	5.3963	7.33	
1998	38.23	1.6	5.4826	6.97	
1999	45.17	2.7	5.6306	8.02	10-Year
2000	52.00	3.4	5.8221	8.93	6.3%
2001	44.23	1.6	5.9152	7.48	
2002	47.24	2.4	6.0572	7.80	
2003	54.15	1.9	6.1723	8.77	
2004	67.01	3.3	6.3735	10.51	
2005	68.32	3.5	6.5978	10.35	
Data Source: http://pages.stern.nyu.edu/~adamodar/				Real EPS Growth	2.71%



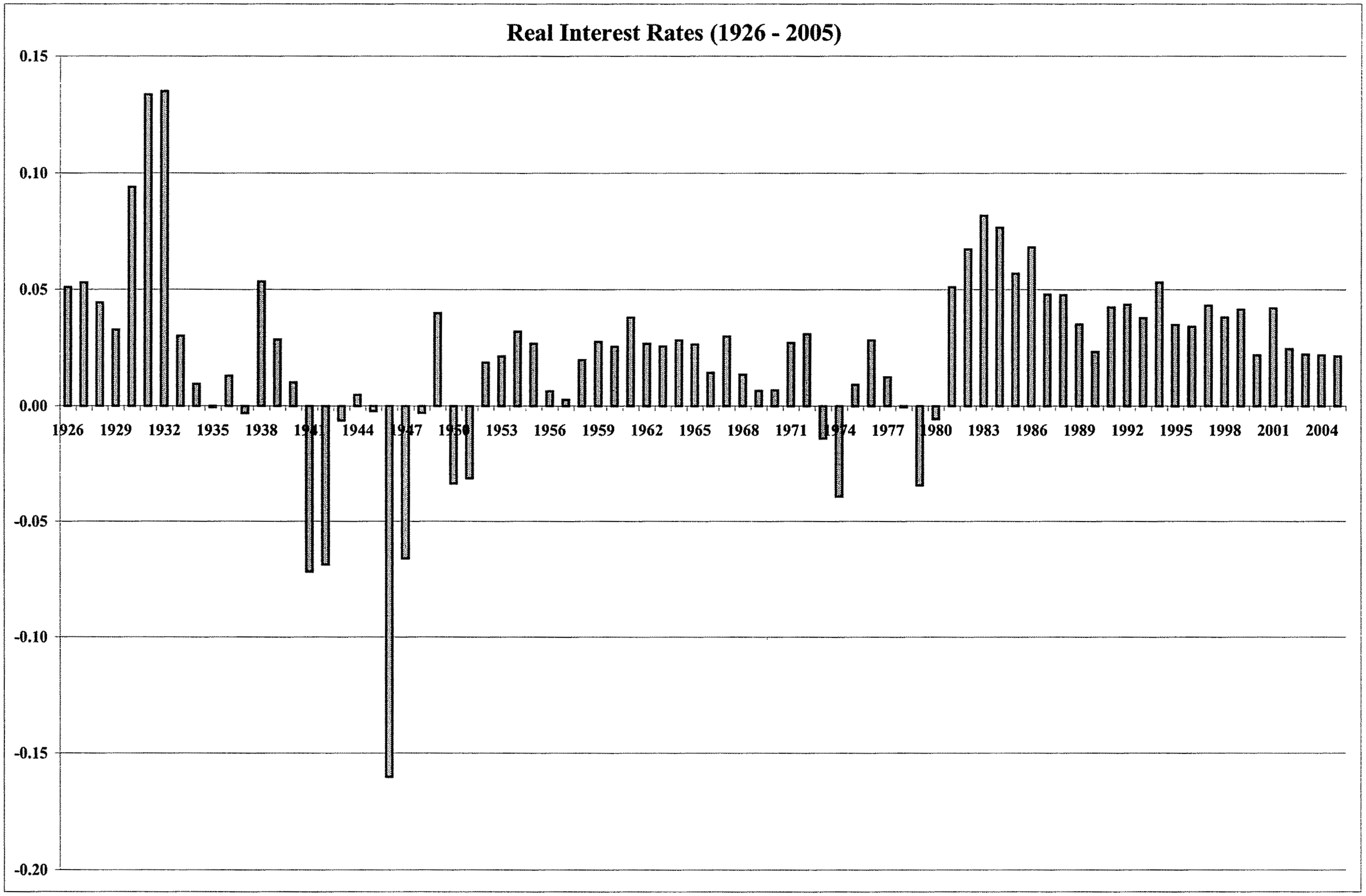
Data Source: Ibbotson Associates, *SBBI Yearbook*, 2006.



Data Source: Ibbotson Associates, *SBBI Yearbook*, 2006.



Data Source: Ibbotson Associates, *SBBI Yearbook*, 2006.



Data Source: Ibbotson Associates, *SBBI Yearbook* , 2006.

Exhibit_(JRW-10)
Rebuttal Exhibits
Growth rates
GNP, S&P 500 Price, EPS, and DPS

	GNP	S&P 500	Earnings	Dividends	
1960	529.8	58.11	3.10	1.98	
1961	531.5	71.55	3.37	2.04	
1962	579.6	63.1	3.67	2.15	
1963	606.9	75.02	4.13	2.35	
1964	654.6	84.75	4.76	2.58	
1965	701.1	92.43	5.30	2.83	
1966	775.8	80.33	5.41	2.88	
1967	823.2	96.47	5.46	2.98	
1968	885.7	103.86	5.72	3.04	
1969	967.3	92.06	6.10	3.24	
1970	1023.6	92.15	5.51	3.19	
1971	1105.8	102.09	5.57	3.16	
1972	1198.7	118.05	6.17	3.19	
1973	1346.2	97.55	7.96	3.61	
1974	1464.0	68.56	9.35	3.72	
1975	1581.4	90.19	7.71	3.73	
1976	1788.3	107.46	9.75	4.22	
1977	1960.1	95.1	10.87	4.86	
1978	2172.1	96.11	11.64	5.18	
1979	2490.1	107.94	14.55	5.97	
1980	2763.2	135.76	14.99	6.44	
1981	3084.1	122.55	15.18	6.83	
1982	3222.8	140.64	13.82	6.93	
1983	3416.9	164.93	13.29	7.12	
1984	3846.6	167.24	16.84	7.83	
1985	4145.8	211.28	15.68	8.20	
1986	4409.4	242.17	14.43	8.19	
1987	4628.2	247.08	16.04	9.17	
1988	4977.6	277.72	22.77	10.22	
1989	5390.9	353.4	24.03	11.73	
1990	5746.9	330.22	21.73	12.35	
1991	5926.3	417.09	19.10	12.97	
1992	6227.2	435.71	18.13	12.64	
1993	6580.0	466.45	19.82	12.69	
1994	6940.2	459.27	27.05	13.36	
1995	7335.8	615.93	35.35	14.17	
1996	7666.2	740.74	35.78	14.89	
1997	8142.6	970.43	39.56	15.52	
1998	8615.1	1229.23	38.23	16.20	
1999	9097.2	1469.25	45.17	16.71	
2000	9661.90	1320.28	52.00	16.27	
2001	10060.20	1148.09	44.23	15.74	
2002	10361.70	879.82	47.24	16.08	
2003	10781.30	1111.91	54.15	17.88	
2004	11546.10	1211.92	67.01	19.41	
2005	12225.00	1248.29	68.32	22.38	**Average**
Growth	**7.22%**	**7.05%**	**7.11%**	**5.54%**	**6.73%**

Data Sources: GNP - http://research.stlouisfed.org/fred2/categories/106
S&P 500, EPS and DPS - http://pages.stern.nyu.edu/~adamodar/

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

AN ADJUSTMENT OF THE	)	
ELECTRIC RATES OF THE	)	
UNION LIGHT, HEAT AND	)	CASE NO. 2006-00172
POWER COMPANY D/B/A	)	
DUKE ENERGY KENTUCKY, INC.	)	

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.
ON BEHALF OF
THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

Date: September 13, 2006

Direct Testimony
Of
Michael J. Majoros, Jr.

Direct Testimony
Of
Michael J. Majoros, Jr.

Introduction

Q. Please state your name, position and business address.

A. My name is Michael J. Majoros, Jr. I am Vice President of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"), located at 1220 L Street, N.W., Suite 410, Washington, D.C. 20005.

Q. Please describe Snavely King.

A. Snavely King is a progressive economic consulting firm, founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. We represent the interests of government agencies, businesses and individuals who are consumers of telecom, public utility and transportation services. In addition to consumer cost and anti-trust issues, we have provided our expertise in support of a clean environment and personal damages resulting from discrimination in agricultural programs.

The firm has a professional staff of 11 economists, accountants, engineers and cost analysts. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 36-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. Have you prepared a summary of your qualifications and experience?

A. Yes. Appendix A is a summary of my qualifications and experience. Appendix B contains a tabulation of my appearances as an expert witness before state and Federal regulatory agencies.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the subject of your testimony?

A. This testimony addresses depreciation.

Q. Do you have any specific experience in the field of public utility depreciation?

A. Yes. I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject before the regulatory commissions of almost every state in the country, including several appearances before the Kentucky Public Service Commission ("KPSC"). I have testified in over one hundred proceedings on the subject of public utility depreciation and represented various clients in several other proceedings in which depreciation was an issue but was settled. I have also negotiated on behalf of clients in fifteen of the Federal Communications Commissions' ("FCC") Triennial Depreciation Represcription conferences.

Q. Does your experience specifically include electric company depreciation?

A. Yes, I have testified in many proceedings on the subject of electric company depreciation, and I have prepared testimony in several other electric proceedings in which depreciation was ultimately settled.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The AG asked me to review the electric depreciation rates and proposals of the Union Light, Heat and Power Company D/B/A Duke Energy Kentucky ("ULH&P," "Union" or "the Company"), and express an opinion regarding the reasonableness of those depreciation rates and expense proposals. I was also asked to make alternative recommendations if warranted.

Proposed Electric Depreciation Rates

Q. Summarize the Company's depreciation proposal in this proceeding.

A. Mr. John Spanos sponsors ULH&P's depreciation study. Neither Mr. Spanos's testimony nor his study reveals whether he is proposing an increase or a decrease. The Company's response to AG-DR-01-005 suggests that Mr. Spanos may be proposing an increase.[1]

Q. Have you included any additional versions of Mr. Spanos' proposals?

A. Yes, Exhibit___ (MJM-1) provides Mr. Spanos' proposed depreciation accruals separated between capital recovery and net salvage. Although Mr. Spanos did not provide this separation in his initial testimony, he did provide the separated accruals in response to AG-DR-02-40. I am providing these separated accruals in order to facilitate external reporting and for regulatory

---

[1] Response to AG-DR-01-005.

analysis and rate setting purposes. ULH&P should be required to apply separated rates such that ratepayers at least will have the ability to know how much they are paying for capital recovery versus future cost of removal. This does not require any change to current accounting, it merely provides more and better information.

Present Electric Depreciation Rates

Q. When were the Company's present electric depreciation rates approved?

A. The current depreciation rates for transmission and distribution were determined in the Company's 1975 rate case. The current electric general plant rates were developed in 1997 when vintage year [amortization] accounting was implemented in accordance with FERC Accounting Release No. 15 for FERC Accounts 391, 393, 394 and 398. Current common plant depreciation rates were established pursuant to the Company's 2005 gas rate case. This is UHL&P's first study of production plant depreciation rates.[2]

Q. How were the present depreciation rates calculated?

A. Mr. Spanos says "the methods and procedures of this study are the same as those utilized in past studies of this company ...". He implies that nothing has changed other than the parameters he is proposing.[3]

Q. Do you agree?

[2] Spanos Response to AG-DR-01-169.
[3] Spanos Testimony, page 6.

A. No, at best Mr. Spanos provides a misleading impression concerning UHL&P's current depreciation rates. I will address this issue in the Credibility section of this testimony.

Conclusions

Q. Do you agree with Mr. Spanos' proposal?

A. No, Mr. Spanos' proposal results in an unreasonable perpetuation of, and an unjustified increase to, excessive depreciation expense and charges to ratepayers. Mr. Spanos uses artificially short lives for certain major accounts. Mr. Spanos proposes an unjustified switch to the equal life group procedure for all vintages of plant combined with a change from whole life to remaining life depreciation. Another primary driver of the excessive depreciation expense is excessive charges for inflated future cost of removal estimates. My conclusion is based on my analysis and depreciation study, information brought to light by Staff data requests, and by this Company's prior actions resulting from recent accounting pronouncements. My recommendations result in a $9.5 million reduction relative to Mr. Spanos's proposals based on December 31, 2005 plant balances.

Prior Testimony in Kentucky

Q. Are you providing any testimony and/or recommendations that you have made in the past?

A. Yes, I am reiterating certain points and recommendations I have made in the past, some of which the Commission rejected.

Q. If the Commission rejected your recommendations, why make them again?

A. My description of the underlying facts is truthful and my recommendations merit, and are receiving, continued consideration and acceptance by other Commissions, and even Courts. Consequently, I continue to advance the consumer interest by reiterating these arguments and bringing to this Commission's attention the consideration that has been accorded by the Court and by other Commissions.

<u>Critique of ULH&P's Testimony</u>

Q. Explain the importance of credibility in depreciation filings and testimony.

A. Depreciation is one of ULH&P's largest operating expenses, and yet, like rate of return, it relies heavily upon judgments concerning estimated lives, retirement patterns and the necessity for, and level of, components for dubious future removal expenditures. Given the magnitude of the numbers involved and the importance of these judgments, it is extremely important to have confidence in the objectivity of the resulting recommendations.

Q. Why do you raise the subject of credibility?

A. I have raised credibility as a subject because ULH&P's depreciation proposals lack credibility, not just Mr. Spanos' study, but also the very basis of the filing. For example, Mr. Spanos is proposing straight line, equal life group depreciation combined with the remaining life technique. He implies that

UHL&P's current depreciation rates were calculated using the same methods, procedure and techniques, but that is not the case.

Staff asked the Company to provide a schedule comparing by account the survivor curves, net salvage percent, annual accrual rate, and the composite remaining life for the current depreciation rates with the same information for the proposed depreciation rates shown on [Mr. Spanos'] pages III-4 through III-6.[4] UHL&P responded, "see attachment KyPSC-DR-02-006(c)."[5] Staff followed the response with another question.[6] It asked, "Explain why the attachment does not show for the current depreciation rates a composite depreciation rate for the various plant account groupings?" UHL&P responded, "Depreciation is booked at a detail account level; therefore, a composite rate does not exist."[7] This is directly contrary to ULH&P's representation to FERC. It lacks credibility

Q. Why does UHL&P's response to KyPSC-DR-03-009(a) lack credibility ?

A. UHL&P's response lacks credibility because it is at direct odds with what it reports in its annual FERC Form 1. Exhibit___(MJM-2) contains selected pages from UHL&P's 2005 FERC Form 1. At page 123.3 the Company states, "ULH&P determines the provisions for depreciation expense using the straight-line method. The depreciation rates are based on periodic studies of the estimated useful lives and net cost to remove the properties. <u>ULH&P uses</u>

[4] Response to KyPSC-DR-02-006(c).
[5] Id.
[6] Response to KYPSC-DR-03-009(a).
[7] Id.

composite depreciation rates. The rates are approved by the KPSC. The average depreciation rates for Utility Plant, excluding software, was 3.4 percent and 3.5 percent for 2005 and 2004, respectively."[8]

Electric utilities are supposed to show plant depreciation rates and parameters by account on page 337 of the FERC Form 1. UHL&P does not show anything in those cells because it uses composite depreciation rates. ULH&P's response to staff KyPSC-DR-03-009(a) is false. UHL&P does not have any credibility, even in explaining the current depreciation rates.

Q. Do you have other examples of ULH&P's lack of credibility?

A. Yes, I have several additional examples of ULH&P's lack of credibility. Although Mr. Spanos says he relied primarily upon his statistical analysis for his life and survivor curve estimates, he obviously did not. His life proposals for several major accounts are demonstrably shorter than the data indicates.

ULH&P's proposal lacks credibility because UHL&P's parent collected substantial terminal cost of removal for its newly acquired production plants, but while they were temporarily deregulated, the parent transferred the prior collections into corporate income. To add insult to injury, the company acknowledges internally that if the plants were still deregulated, they would not be allowed to charge additional terminal cost of removal to depreciation, but since the plants have now been re-regulated, they want to collect even more from ratepayers.[9]

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[8] 2005 FERC Form 1, page 123.3 (emphasis added).

[9] Response to AG-DR-01-139, Attachment p. 38 of 95, and Response to AG-DR-02-027, both of which are attached as Exhibit___(MJM-12).

The proposal lacks credibility because Mr. Spanos specifically increases the terminal cost of removal estimates for future inflation even though ULH&P does not have any plans to retire or remove the plants. There is controversy relating to collecting terminal cost of removal in these circumstances, let alone inflating the numbers. The approach Mr. Spanos supports here has been specifically found too speculative by the Kansas Court of Appeals in a decision in which it also ruled that the Kansas Corporation Commission should not have relied on this approach. The issue is discussed more fully later in my testimony.

It lacks credibility because ULH&P has a $32 million regulatory liability for non-legal cost of removal it has collected from ratepayers in the past and neither ULH&P nor Mr. Spanos discloses this fact. Nor do they identify or explain how much additional non-legal cost of removal is proposed for collection in the proposed depreciation rates, in either Mr. Spanos's testimony or study, even though Mr. Spanos was instructed by the Company to separate the cost of removal component.[10]

Mr. Spanos' incomplete net salvage study, which gives the impression that UHL&P is experiencing negative net salvage, also lacks credibility. After extracting the rest of the net salvage study from his workpapers, it can be seen UHL&P is actually experiencing positive net salvage.

[10] Exhibit___(MJM-12).

The KPSC should weigh these issues when it makes its decision concerning the legitimacy of ULH&P's depreciation proposal.

Q. Will you provide more details about each of these examples of ULH&P's lack of credibility throughout you testimony?

A. Yes, I will.

Excessive Depreciation

Q. You have used the phrase "*excessive depreciation.*" Have you provided any background information on the concept of *excessive depreciation*?

A. Yes. An *excessive depreciation rate* is one that produces more depreciation expense than necessary to return the cost of a company's capital asset over the life of the asset. Exhibit___ (MJM-3) is a brief summary of a landmark U.S. Supreme Court decision on depreciation. I am not an attorney and I do not present this as a legal argument or conclusion. I merely present this to demonstrate that the concept of *excessive depreciation* is not a new one.

Recent accounting requirements actually highlight significant amounts of excessive depreciation charged to ratepayers in the past. I have included a discussion of, and quotations from, the accounting profession's SFAS No. 143 which demonstrates that that profession is also at least cognizant of excessive depreciation.

Q. Mr. Majoros, does the fact that accumulated depreciation is deducted from rate base "moot" the concept of excess depreciation?

A. No, if ratepayers are required to pay too much for depreciation expense, they will have paid too much. The fact that ratepayers are not required to pay a return on prior excessive charges does not mean that those charges were not excessive.

Depreciation Concepts

Q. Does your testimony include a discussion of the depreciation concepts that are relevant to your testimony?

A. Yes, Exhibit___ (MJM-4) is a brief discussion of depreciation concepts that are relevant to my testimony. I have submitted this discussion as a separate exhibit in an attempt to minimize the technical aspects of my direct testimony. The discussion may be helpful to understanding this testimony.

Depreciation Parameters

Q. What are depreciation parameters?

A. Depreciation parameters are the basic assumptions upon which depreciation rate calculations are based. ULH&P's proposed depreciation rates are based on three fundamental parameters, all of which are estimates: an average service life, a retirement dispersion pattern and a net salvage ratio.

Usually, the two most significant parameters in a case are the average service life and the net salvage ratio; the shorter the service life – the higher the resulting depreciation rate. Similarly, the more negative the net salvage ratio – the higher the resulting depreciation rate. In both cases, the higher depreciation rate is charged to ratepayers.

In this case, another significant parameter is the estimated retirement dispersion pattern. Mr. Spanos used "Iowa Curves" to define these patterns. These patterns have relevance in estimating average lives and they have a direct impact on Mr. Spanos' remaining life calculations, particularly since he used the equal life group ("ELG") procedure to calculate remaining lives. ELG is very sensitive to the Iowa Curve shape and results in a shorter remaining life calculation, ergo a higher depreciation rate than other alternative procedures which have been typically used in Kentucky.

Q. Has ELG been used in Kentucky?

A. Yes, ULH&P used ELG to calculate its gas depreciation rates.

Q. How do you know that ULH&P used ELG to calculate its gas depreciation rates?

A. I was a witness in ULH&P's last gas base rate case, Case No. 2005-00042.

Q. Did you accept the ELG procedure in that case?

A. No, I explicitly stated that I did not accept the ELG procedure in that case.[11] However, because it had already been implemented by ULH&P for gas rates in a prior case, I did not challenge it.

Q. Why was ULH&P allowed to switch to ELG for its gas rates?

A. The ELG procedure was introduced for gas rates in Case No. 2001-00092. The rates approved in that case were based on a study prepared by Mr. Spanos, and those rates were not challenged during the course of that case.[12] As I stated in my testimony in Case No. 2005-00042, "the fact that no one objected is not a ringing endorsement of the ELG procedure; it merely reflects

[11] Majoros Direct Testimony, Case No. 2005-00042, p. 7.

[12] I/M/O Adjustment of Gas Rates of the Union Light, Heat and Power Company, Case No. 2001-00092, Order, Issued January 31, 2002, page 29.

budgeting constraints and how funds were allocated to witnesses."[13] I also recommended that the KPSC not consider ULH&P's use of ELG to be established as a precedent.[14]

Q. Are you accepting the ELG procedure for electric rates in this proceeding?

A. No, I am not accepting the ELG procedure in this proceeding

Q. What are your objections to Mr. Spanos's ELG quantifications?

A. I object to his retroactive application of the equal life group ("ELG") procedure.

Q. What is the ELG procedure?

A. ELG is a procedure sometimes used in depreciation calculations to calculate an average life and average remaining life once a judgmental estimate is made of the service life and retirement pattern for a group of assets. The details of the ELG procedure are complex, but from a practical standpoint, it results in a higher depreciation rate than the alternative vintage group ("VG") procedure.

Q. Would you summarize the pros and cons regarding ELG and VG?

A. Yes, from a theoretical standpoint ELG has the benefit of providing a more precise cost allocation assuming perfect foresight. On the other hand, ELG requires annual depreciation rate changes and produces precisely the wrong answer when there are forecasting inaccuracies. VG (the alternative) has the benefit of a constant depreciation rate, and also in my opinion, a higher

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[13] Majoros Direct Testimony, Case No. 2005-00042, p. 7.
[14] Majoros Direct Testimony, Case No. 2005-00042, p. 7.

probability of producing a correct overall result notwithstanding forecasting inaccuracies. On the other hand, VG is premised on the averaging concept of offsetting underecoveries with overrecoveries within a vintage.

Q. Is ELG necessary?

A. ELG is not necessary because both VG and ELG target full recovery. From a theoretical standpoint, both ELG and VG have merit. From a practical standpoint, ELG will produce a higher depreciation rate.

Q. Do you recommend the adoption of ELG?

A. No, although ELG has some theoretical merit, it also has negative aspects and it is not necessary.

Q. If the Commission were to adopt ELG for ULH&P's electric plant, do you agree with Mr. Spanos's implementation.

A. No, Mr. Spanos proposes to apply ELG retroactively to all prior vintages of plant, and then use the resulting ELG-based composite remaining life. Retroactive application overstates the theoretical reserve and thus understates the measurement of the excessive depreciation which has been collected in the past. Although he does not show it in his study, Mr. Spanos's recommendations indicate a $41.3 million depreciation reserve <u>excess</u>. In reality, however, even accepting all of Mr. Spanos's judgmental assumptions, the reserve excess is actually $71.9 million based on the existing VG procedure. Exhibit___(MJM-5) shows these calculations.

Mr. Spanos' application of ELG to all prior vintages produces a composite remaining life which is inconsistent with past depreciation practices.

Had ULH&P always used ELG, the book depreciation reserve would be even higher than it is, and the resulting remaining life depreciation rate would be much lower than Mr. Spanos has calculated.

The practical consequence is that Mr. Spanos's implementation proposal creates on overstated remaining life depreciation rate. This overstated rate artificially understates the amount of the previously collected excessive depreciation expense and results in a continuation of the overcollection.

Q. Is there an alternative implementation approach?

A. Yes, many companies subject to the Federal Communications Commission's ("FCC") jurisdiction made similar proposals in the past for retroactive application of ELG. The FCC rejected these proposals due to the reserve imbalance described above as well as the fact that ELG creates an artificial spike in revenue requirements.

The FCC's initial approach to ELG implementation was to allow ELG only on a going-forward vintage basis for new investment, and then only on a phased-in basis by groups of accounts over a series of years.

The VG procedure was continued for existing investment. For example, if ELG was approved as a result of a 1990 study, the first ELG vintage would be 1991. The company would receive the benefit in its next regularly scheduled depreciation study or in a technical update.

Q. If the KPSC approves ELG, what do you recommend?

A. The KPSC should not allow retroactive implementation of ELG. The first ELG vintage would be **2006,** and that would be reflected in the next depreciation study. The KPSC must also require the company to file depreciation studies every three (3) years to ensure proper management of the ELG rates.

Q. Have you recalculated depreciation rates using an alternative procedure?

A. Yes, my recommended depreciation rates, as summarized in Exhibit___(MJM-6) are VG remaining life depreciation rates.

<u>Service Lives</u>

Q. Have you reviewed Mr. Spanos' proposed service lives and curves?

A. Yes, I have. I reviewed all of Mr. Spanos' life studies, his responses to my data requests and his responses to Staff's data requests.

Mr. Spanos states "For 18 of the 40 plants accounts and sub accounts for which survivor curves were estimated, the statistical analyses resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 65 percent of the depreciable plant. <u>Generally, the information external to the statistics led to no significant departure from the indicated survivor curves</u>."[15]

Q. Do you agree with Mr. Spanos?

A. I disagree with his conclusions. Setting aside theoretical considerations, life studies are statistical analyses of historical data fitted to empirical curves. The

[15] Spanos Depreciation Study, page II-19-11-24, (Emphasis added.)

fitting can be done visually, but a much better result is obtained when the "least squared differences" statistical approach is applied.

I asked for Mr. Spanos' statistical fitting results, but he responded "there was no best-fit life/curve combination performed for each account, as Mr. Spanos does not conduct a statistical only analysis."[16] In other words, Mr. Spanos relied entirely upon the "visual approach" for his selections.

I examined Mr. Spanos' charts, as did the staff. It is clear that many of Mr. Spanos' selections were not the best fit. Consequently, we conducted independent least squares statistical analyses, and as a result I recommend different parameters for three accounts. Each of my recommendations is the statistical best fit to the data. My results are shown in Exhibit___(MJM-7).

<u>Cost of Removal</u>

Q. Has ULH&P collected for estimated future cost of removal in its depreciation rates?

A. Yes, it has.

Q. What is your opinion about the incorporation of estimated future cost of removal in depreciation rates?

A. I disagree with charging ratepayers for estimated future cost of removal.

Q. Why are you opposed to these charges?

A. I am opposed because I believe, and recent accounting pronouncements have proven, that the Companies are charging ratepayers far more for cost of

[16] Response to AG-DR-01-198.

removal than they will ever spend.

Q. Identify and explain the recent accounting pronouncements.

A. The Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") and the Federal Energy Regulatory Commission's ("FERC") Order No. 631 have identified and highlighted utilities' prior excess collections for future cost of removal. Order No. 631 defines these excess collections as non-legal asset retirement obligations ("non-legal AROs").

If a utility has charged cost of removal for a non-legal ARO, that amount is to be segregated within accumulated depreciation and reclassified as a regulatory liability. Furthermore, if a utility has collected too much depreciation for a legal ARO, the excess also becomes as a regulatory liability.[17] In other words, if a utility has collected for future cost of removal in its depreciation rates, but does not and never had a legal obligation to spend the money, these excesses are to be segregated and to be reported as a regulatory liability.[18] FERC identified these amounts as "non-legal" asset retirement obligations, because utilities do not have actual legal obligations and liabilities to incur these costs in the future.

[17] SFAS No. 143.
[18] Id., paragraph B.73.

ULH&P's regulatory liabilities in compliance with SFAS No. 143 are:

Union Light, Heat and Power
Summary of New Information
Regulatory Liabilities Resulting from Non-Legal AROs
($millions)[19]

December 31, 2004 Balance	**$30**
December 31, 2005 Balance	**$32**

The regulatory liability increased by the amount that ULH&P collected from ratepayers, over and above its actual removal costs in 2005.

Q. What do you recommend?

A. I recommend that the Kentucky Public Service Commission specifically **recognize a regulatory liability** for regulatory and ratemaking purposes and disallow the unjustified use of inflated future cost of removal/terminal decommissioning estimates to set current depreciation rates.

Regulatory Liabilities

Q. How does GAAP define a regulatory liability?

A. SFAS No. 71 – Accounting for the Effects of Certain Types of Regulation defines regulatory liabilities from a GAAP perspective. Paragraph 11, which is summarized below, defines a regulatory liability. Please pay particular attention to paragraphs 11 and 11. b.

SFAS No. 71 – Regulatory Liabilities[20]

> 11. Rate actions of a regulator can impose a liability on a regulated enterprise. Such liabilities are usually

[19] Response to AG-DR-02-033.
[20] SFAS No. 71, paragraph 11. Only the first sentence of each subparagraph is included.

> obligations to the enterprise's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:
>
> a. *A regulator may require refunds to customers.* …
>
> b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be recognized as liabilities and taken to income only when associated costs are incurred.
>
> c. A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. …

Q. Does ULH&P agree that its collections for non-legal AROs result in a regulatory liability?

A. Although ULH&P recognized these amounts as regulatory liabilities in its 2005 10K Report, they have not been specifically recognized as regulatory liabilities for regulatory and ratemaking purposes. FERC does not require such reporting. FERC merely requires separate identification within accumulated depreciation.

Regardless of being included in accumulated depreciation, these amounts are dollars <u>already</u> collected from ratepayers for future cost of removal. There is no reason that the utility should be entitled to keep these dollars if it turns out they are never spent on future costs of removal.

Therefore, it is obvious that the funds represent a refundable liability to ratepayers until they are spent on their intended purpose. Now that they have been identified, thanks to SFAS No. 143, they should be recognized as the regulatory liability they are.

Q. Why is it necessary for the KPSC to specifically recognize the regulatory liability?

A. The Edison Electric Institute ("EEI") and individual utilities fought hard to avoid having either the FASB or FERC require the identification and reporting of the regulatory liability that I have just described. Exhibit___ (MJM-8) contains a few pages from the Company's response to AG-DR-02-029, which requested copies of all correspondence with outside consultants/agencies regarding SFAS No. 143 and FERC Order No. 631. The pages in question relate to a survey conducted by EEI regarding the Form 1 classification of non-FAS 143 accumulated cost of removal.

As described in the email on page 9 of 286, Mr. David Stringfellow of EEI, on behalf of Mr. Jim Guest of FERC, solicited comments from EEI members on how they "would prefer to report this non-143 accumulated cost of removal – leave it in Account 108 or reclassify it as a regulatory liability for the FERC Form 1 balance sheet."[21] Note that Cinergy responded that they would prefer to leave the amount in Account 108.

[21] Exhibit___(MJM-8).

Also included in the exhibit is the completed survey, as provided to FERC.[22] Among the comments supporting the continued inclusion of these amounts in Account 108 are the following:

> For reporting this item in our FERC Form 1, [my company] prefers to keep the accumulated cost of removal in Account 108. <u>We believe moving this to a regulatory liability will create difficulties in rate cases before the state commissions, and may be a catalyst to consumer advocates suggesting rapid refunds to customers.</u>
>
> We think FERC should NOT change the current requirements regarding accounting and reporting for cost of removal. ... Additionally, some regulators could use this as an opportunity to require utilities to refund some or all of the removal amounts to customers even though companies will still continue to incur costs to remove/retire assets.

These comments indicate that some companies are fearful of the potential of losing their past excess cost of removal collections. A large regulatory liability reported in their FERC Form 1 or 2 reports would likely be considered in their next rate case. I am not advocating such a refund in this case.

On the other hand, the KPSC should be aware that ULH&P and virtually all other utilities consider amounts in accumulated depreciation, even excessive amounts, to be their money, with no refund obligation. It is certainly fair and reasonable for any Commission to at least recognize excessive cost of removal collections as a refundable regulatory liability until such time as they are actually spent on their intended purpose.

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[22] Id.

Q. Can you demonstrate that ULH&P and its parent, Cinergy Corp., considers these excess collections to be their money?

A. Yes, ULH&P's sister company, CG&E has already demonstrated this by virtue of its treatment of the excess removal costs it collected from Ohio ratepayers relating to the plants, some of which are being transferred to ULH&P. CG&E transferred these amounts into "income."

Q. How do you know CG&E transferred past accruals for cost of removal into income?

A. The Company states as much in its 2003 Annual Report to Shareholders.

> We adopted Statement 143 on January 1, 2003, and recognized a gain of $39 million (net of tax) for the cumulative effect of this change in accounting principle. **Substantially all this adjustment reflects the reversal of previously accrued cost of removal for CG&E's generating assets, which do not apply the provisions of Statement 71.**[23]

Q. Does a portion of this $39 million (net of tax) gain relate to cost of removal that was collected for the three generating plants that are now slated to be transferred to ULH&P, and re-regulated?

A. Yes. Data request AG-DR-01-075 from Case No. 2005-00042, attached as Exhibit___(MJM-9), addressed this issue:[24]

> b. Does any of this amount [$39 million gain] relate to the assets being transferred from CG&E to ULH&P (East Bend, Woodsdale and Miami Fort Generating Stations)? If so, please provide the calculation of the portion of the $39 million gain

[23] Cinergy Corp. 2003 Annual Report to Shareholders, page 60. (emphasis added).
[24] This was also included as Exhibit___(MJM-15) to my direct testimony in Case No. 2005-00042.

> that was attributable to the reversal of cost of removal collected for these assets. Please include the before-tax calculation of the amount as well.

ULH&P provided a calculation showing that the portion of the $39 million gain attributable to the transferred stations is approximately $16.5 million before-tax, or $10 million net of tax. I say "approximately" because the calculation includes Miami Fort Unit 5, which is not being transferred.[25]

Q. What is the significance of this reversal of cost of removal relating to these transferred plants?

A. These plants were deregulated in January, 2001.[26] As required by GAAP, CG&E converted its prior collections from ratepayers for cost of removal into corporate income. Now the plants are to be re-regulated. They are to be recorded by ULH&P at their original cost, less accumulated depreciation (net book value).[27] However, due to the reversal of the cost of removal collections, the book value increased.[28] Had these excess collections been established as a regulatory liability, there may have been a better chance that they would have followed the assets.

Q. What do you make of this?

A. Cinergy, through CG&E, collected excess cost of removal amounts from Ohio

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[25] See Case No. 2005-00042, Attachment AG-DR-01-075b, attached to this testimony as Exhibit___(MJM-9). The total for Miami Fort Units 5 and 6 is only $3.9 million (before-tax). East Bend is responsible for $10 million of the total, with Woodsdale contributing $2.6 million.

[26] I/M/O Application of Union Light, Heat and Power Company for a Certificate of Public Convenience to Acquire Certain Generation Resources and Related Property..., Case No. 2003-00252, Interim Order, Issued December 5, 2003, page 16.

[27] Id., page 31.

[28] Exhibit___(MJM-9). See response to AG-DR-01-075d.

ratepayers. Upon deregulation in Ohio, it transferred those collections into income. Now the plants in question are to be re-regulated in Kentucky at a net original cost value that does not recognize the previous cost of removal collections. Cinergy, through ULH&P, will begin to collect cost of removal again, this time from Kentucky ratepayers. If UHL&P's collections are not specified as regulatory liabilities for ratemaking purposes they, too, will be converted into income should the opportunity again be allowed to arise.

Q. Have other electric utilities taken past collections of cost of removal into income?

A. Yes, this is exactly what other electric utilities did when their production plants were deregulated. For example American Electric Power, which had several of its production plants deregulated, immediately took $473 million from accumulated depreciation and transferred it into income relating to those deregulated plants.[29]

In another example, Tucson Electric Power Company ("TEP") stated that:

> TEP had accrued $113 million for final decommissioning of its generating facilities.. ... this amount was reversed for 2002 and included as part of the cumulative effect adjustment of accounting adjustment when FAS 143 was adopted on January 1, 2003.[30]

This means that TEP took non-legal AROs into income.

[29] AEP 2003 Annual Report to Shareholders, page 69.
[30] Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.

TEP applied SFAS No. 71 - Accounting for the Effects of Certain Types of Regulation - to its regulated operations, which include the transmission and distribution portions of its business. As a result TEP recorded the cost of removal collected for regulated non-legal AROs as a regulatory liability. According to TEP's December 31, 2004 10K Report

> As of December 31, 2004, TEP had accrued $67 million for the net cost of removal of the interim retirements from its transmission, distribution and general plant. As of December 31, 2003, TEP had accrued $60 million for these removal costs. The amount is recorded as a regulatory liability.[31]

However, also according to TEP's December 31, 2004 10K Report:

> If TEP stopped applying FAS 71 to its remaining regulated operations, it would write off the related balances of its regulatory assets as an expense and its regulatory liabilities as income on its income statement.[32]

Q. Does ULH&P make a similar statement regarding the disposition of regulatory liabilities if they are no longer regulated?

A. ULH&P discusses SFAS No. 71 in its 2004 Annual Report to Shareholders.

> In accordance with Statement 71, we record regulatory assets and liabilities (expenses deferred for future recovery from customers or amounts provided in current rates to cover costs to be incurred in the future, respectively) on our Balance Sheets.[33]

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[31] Id., page K-60.
[32] Id.
[33] Cinergy Corp. 2004 Annual Report, page 74.

> However, to the extent Indiana or Kentucky implements deregulation legislation, the application of Statement 71 will need to be reviewed.[34]

Q. Have any other industries taken non-legal ARO amounts into income that had been previously collected from ratepayers?

A. Yes. While it was still regulated, the telephone industry collected substantial amounts of future cost of removal through depreciation, just as ULH&P is proposing here. Upon deregulation and the adoption of SFAS No. 143, the major telephone companies took $11.5 billion from accumulated depreciation into net income.[35]

Q. Does FERC Order No. 631 require non-legal AROs to be reported as regulatory liabilities?

A. FERC does not require that non-legal AROs be classified or reported as regulatory liabilities. Although the FERC has recognized and identified the amounts involved and requires separate accounting for those amounts, the FERC has deferred to the states regarding recognition of the regulatory liability. FERC Order No. 631 requires that jurisdictional entities such as ULH&P to:

> maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission [amended] the

[34] Id.

[35] Pre-tax gains of SBC ($5.9 billion), Verizon ($3.5 billion), Qwest ($0.4 billion), BellSouth ($1.3 billion) and Sprint ($0.4 billion). See Companies' 2003 10K Reports and 2003 Annual Reports to Shareholders.

> instructions of accounts 108 …in Parts 101 … to require jurisdictional entities to maintain separate records for the purposes of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals."[36]

Q. Why is it necessary for the Kentucky PSC to specifically recognize a regulatory liability for the non-legal cost of removal and dismantlement amounts?

A. Although FERC Order No. 631 provides a new transparency by requiring identification of the amounts and maintenance of separate subsidiary records for regulatory analysis and rate setting purposes, it did not establish a regulatory liability for non-legal asset retirement obligations. Therefore, at the moment, there is no regulatory recognition of such a liability and there is no provision for a refund to ratepayers if the amounts they have paid are not spent on cost of removal or dismantlement.

In other words, nothing holds ULH&P directly accountable for these excess collections from a regulatory standpoint. Regardless of the transparency provided by FERC, the issue is not even mentioned in ULH&P's depreciation study or its rate case filing in general. This is wrong. Experience indicates that it is highly unlikely that these amounts will be spent for cost of removal in the magnitude that they have been collected. Furthermore, even if it was highly probable that this money would all be spent for cost of removal, it is fair and reasonable for the Kentucky PSC to specifically recognize the ratepayers' security interest in these monies until they are actually spent on

[36] FERC Docket No. RM02-7-000, Order No. 631, paragraph 38.

their intended purpose. Unless they are explicitly identified as "subject to refund," they are merely hidden potential income to ULH&P.

Q. Would it be sufficient to report the item as a "deferred credit" of some sort?

A. No, treatment as a deferred credit would defeat the purpose. ULH&P could easily assert in the future that ratepayers have no claim to a deferred credit, in other words, ULH&P could claim that a deferred credit is its money, not ratepayer's money. The item must be specifically recognized by the PSC and reported by ULH&P as a regulatory liability for regulatory and ratemaking purposes.

Q. Have any other Commissions recognized non-legal AROs as a regulatory liability?

A. Recently, in Docket No. A.04-12-014, involving Southern California Edison Company, the California Public Utilities Commission specifically recognized that Company's non-legal ARO collections as a regulatory liability.

The Commission Should Change the Mechanism That Created ULH&P's Regulatory Liability

Q. How much non-legal ARO cost has Mr. Spanos included in ULH&P's annual depreciation expense?

A. Based on 2005 year end balances the amount is $7.3 million.[37]

Q. What is ULH&P's experience?

[37] Response to AG DR-02-040.

For the period from 2001 through 2005, the actual average was $278 thousand in <u>positive</u> net salvage. In other words, ULH&P's actual recent experience has been that gross salvage has exceeded cost of removal. Nevertheless, Mr. Spanos proposes to collect $7.3 million per year for cost of removal collections. If this pattern continues, the regulatory liability will continue to grow at an alarming rate.

Q. What should the Commission do about new non-legal AROs on a going-forward basis?

A. The next objective is to identify and stop the sort of over collections which caused ULH&P's $32 million regulatory liability to begin with. Mr. Spanos's approach will result in an ever-growing regulatory liability. The solution to that problem lies in the recognition of the excess charges inherent in the depreciation mechanism (which I will discuss in the next section of my testimony) that created the regulatory liability in the first place. On a going-forward basis, the Commission should change the mechanism it uses to allow ULH&P to collect non-legal AROs.

<u>ULH&P's Approach to Non-Legal AROs</u>

Q. Why are ULH&P's recoveries for future cost of removal grossly excessive?

A. ULH&P's recoveries for future cost of removal, also called non-legal asset retirement obligations ("AROs"), are grossly excessive due to the process it uses to derive these estimates and then convert them into depreciation expense. The process results in annual charges for future cost of removal that vastly exceed actual expenditures.

ULH&P's annual charge for cost of removal expense exceeds its actual annual cost of removal because ULH&P uses an inflated cost approach to make its future cost of removal estimates. ULH&P has bundled the inflated cost of removal factors in most of its depreciation rates, and then applied those rates for years to an ever-expanding depreciable plant base. The accruals resulting from this approach have vastly exceeded, year-by-year, the money that ULH&P actually spent or allocated for cost of removal.

Q. Why do you say "spent or allocated" for cost of removal?

A. Most of the cost of removal recorded by most of the utilities with which I am familiar, is actually an allocated or assigned portion of replacement asset costs to the cost of removal account. I am sure that ULH&P is not that much different than other utilities.

Q. How does ULH&P's approach result in inflated cost of removal factors?

A. ULH&P's net salvage studies relate removal costs (largely allocated) in current dollars to asset retirements expressed in very old historical original cost dollars. The inflation experienced between when the asset's in service date and its retirement date results in current removal cost dollars that are many multiples of the historical original cost dollars of the retired asset. Using that same ratio to predict future removal costs implicitly assumes future inflation will be the same as experienced in the past. A portion of all "future" inflation is included in the current depreciation rate and charged to today's ratepayers.

That future inflation component is compounded by virtue of being applied to an ever-increasing plant balance resulting in a regulatory liability which grows at a geometric rate. Use of the net present value rather than an inflated value would at least hold future inflation estimates to current levels.

Q. Does ULH&P's approach result in an increase to depreciation rates?

A. Yes, it does. First, as demonstrated in the concepts exhibit any negative net salvage ratio will increase a depreciation rate. ULH&P's will increase the rates even further because they depend on the relationship of the allocated cost of removal in current dollars as a percentage of the <u>original</u> cost of the assets retired. The timing mismatch within this relationship results in an inflated negative net salvage ratio. The inflated negative net salvage ratio is then bundled into the depreciation rate calculation, and applied to the gross plant balance, which also increases due to inflation. The process results in annual cost of removal charges to ratepayers vastly exceeding ULH&P's actual costs.

Q. Is ULH&P's approach used in other jurisdictions or recognized in any texts?

A. Yes, it is. ULH&P's approach has been used in various jurisdictions – including Kentucky. The NARUC's 1996 Public Utilities Depreciation Practices Manual also addressed, and is even read by some as endorsing this approach:

> Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired. <u>The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods</u>, making due

> allowance for net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if current users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized.
>
> This treatment is in harmony with generally accepted accounting principles and tends to remove from the income statement any fluctuations caused by erratic, although necessary, abandonment and removal operations. It also has the advantage that current customers pay or receive a fair share of costs associated with the property devoted to their service, even though the costs may be estimated.[38]

Q. What is at the heart of NARUC's thinking in this regard?

A. The matching principle is at the heart of NARUC's thinking. NARUC focuses on the timing or pattern of cost of removal allocation and intergenerational equity. Unfortunately, NARUC does not address the fundamental questions of whether a company will actually incur the costs, and the intergenerational **inequity** of charging these inflated amounts to ratepayers when there is some doubt that the money will ever be spent on cost of removal, and the inflation element is so overstated. Again, it is worth noting that the 1996 NARUC manual pre-dates SFAS No. 143. Thus, it reflects earlier deliberations, and did not consider, or even know about the huge regulatory liabilities emanating from the use of this approach.

[38] NARUC Manual, page 18.

Q. Is ULH&P's approach "in harmony with generally accepted accounting principles"?

A. No, ULH&P's approach is not in harmony with generally accepted accounting principles and never has been, as implicitly reaffirmed in SFAS No. 143. If NARUC were to update its 1996 manual, those words should no longer appear.

Q. Has anybody addressed these fundamental questions?

A. Yes, FASB addressed the fundamental questions in SFAS No. 143. The matching principle is in harmony with GAAP when the future costs are genuine obligations and are recognized at their fair value. However, the matching principle of accounting does not require allocation of a fallacious future expenditure to any accounting period.

NARUC focuses on an objective of achieving a particular expense recognition pattern rather than the need to recognize whether or not an actual obligation and liability exists. In paragraph B21, SFAS 143 specifically addresses the tendency to focus on the expense pattern rather than the reality of the cost, and the problems that can result:

> B21. Prior to this Statement, the objective of many accounting practices was not to recognize and measure obligations associated with the retirement of long-lived assets. Rather, the objective was to achieve a particular expense recognition pattern for those obligations over the operating life of the associated long-lived asset. Using that objective, some entities followed an approach whereby they estimated an amount that would satisfy the costs of retiring the asset and accrued a portion of that amount each period as an expense and a liability.

> Other entities used that objective and the provision in paragraph 37 of FASB Statement No 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, that allows them to increase periodic depreciation expense by increasing the depreciable base of a long-lived asset for an amount representing estimated asset retirement costs. Under either of those approaches, the amount of liability or accumulated depreciation recognized in a statement of financial position usually differs from the amount of obligation that an entity actually has incurred. <u>In effect, by focusing on an objective of achieving a particular expense recognition pattern, accounting practices developed that disregarded or circumvented the recognition and measurement requirements of FASB Concepts Statements.</u>[39]

The process focuses on achieving a particular expense pattern rather than "recognition and measurement requirements," that is, the reality of the cost. As NARUC recognizes, these are estimates - forecasts of future costs. However, thanks again to SFAS No. 143, we now know that ULH&P's future cost of removal estimates do not even meet baseline tests as liabilities.

Q. Why do you say that UHL&P's cost of removal estimates do not meet baseline tests as liabilities?

A. ULH&P does in fact have certain costs that meet these baseline tests. There are assets for which ULH&P has identified legal asset retirement obligations ("AROs") as defined by SFAS No. 143. They are discussed in the Company's 2005 10-K Report.

These legal AROs meet the definition of a liability, because "the company has a legal obligation to perform decontamination activities when the

[39] Id., paragraph B21, (emphasis supplied).

plant ceases operations. Contamination, which gives rise to the obligation, is predictable and likely of occurring and is unavoidable as a result of operating the plant. ... the obligation to perform decontamination activities at that plant results from the normal operation of the plant."[40] It is reasonable to assume that ULH&P will spend this money for its intended purpose.

On the other hand, ULH&P has collected, and will continue to collect, if the company has its way, estimates of future cost of removal relating to the rest of its plant for which it does not have any such legal retirement obligation. These are the non-legal AROs. ULH&P does not have any probable obligation to make these expenditures, as "probable" is used in SFAS No. 143. They therefore do not meet the definition of a liability.[41]

<u>All that is necessary</u> to create a legal obligation <u>is for ULH&P to promise the Commission and the public at large that it will do the work, incur the cost, and spend the money it collects for that cost on that cost.</u> No doubt ULH&P will protest that it has an implicit obligation to remove most if not all of its non-legal ARO assets. If this is true, let ULH&P make such a promise and treat all of its plant as AROs. Otherwise, it is impossible to assign any credibility to protestations that the monies will spent on their intended purpose.

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[40] Statement of Financial Accounting Standards No. 143 ("SFAS 143"), *Accounting for Asset Retirement Obligations*, paragraph A12.

[41] Id., paragraph 4. "Liabilities are *probable* future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events. Probable is used with its general meaning, rather than in a specific accounting or technical sense (such as Statement 5, par. 3), and refers to that which can reasonably expected or believed on a basis of available evidence or logic but neither certain nor proved (Webster's New World Dictionary, p.1132). Its inclusion in the definition is intended to acknowledge that business and other economic activities occur in an environment characterized by uncertainty in which few outcomes are certain."

FERC Order No. 631 defines ULH&P's future cost of removal proposals as non-legal AROs. Non-legal AROs apply to plant for which ULH&P has no "legal obligations that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."[42]

Non-legal AROs would become AROs, that is, liabilities to incur future removal costs if they were "probable (that which can be reasonably expected or believed on the basis of available evidence or logic but is neither certain nor proved) future sacrifices of economic benefits arising from present obligations of a particular entity to transfer or provide services to other entities in the future as a result of past transactions or events."[43] If ULH&P has not deemed them AROs, it is because ULH&P has determined that the costs are not such "probable . . . future sacrifices."

Whether these obligations exist is at best ambiguous; but "in most cases involving asset retirement obligations, the determination of whether a legal obligation exists should be unambiguous. However, in situations in which no law, statute, ordinance, or contract exists, but an entity makes a promise to a third party (which may include the public at large) about its intention to perform retirement activities, facts and circumstances need to be considered carefully in determining whether that promise has imposed a legal

[42] SFAS No. 143, paragraph 2.
[43] Id., paragraph 4.

obligation upon the promisor under the doctrine of promissory estoppel."[44] ULH&P has not made any specific or unambiguous promise to the Commission or the public at large about any intention to perform the retirement activities, or spend money, relating to non-legal AROs.

"A conditional obligation to perform a retirement activity <u>is</u> within the scope of SFAS No. 143," thus producing AROs. "Uncertainty about whether performance will be required does not defer the recognition of a retirement obligation; rather, that uncertainty is factored into the measurement of the fair value of the liability .... Uncertainty about performance of conditional obligations shall not prevent the determination of a reasonable estimate of fair value."[45]

Paragraph 2 of SFAS 143 "limits the obligations included within the scope to those that are unavoidable by an entity as a result of the acquisition, construction, or development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees."[46] Legal obligations, as used in SFAS No. 143, "encompass both legally enforceable obligations and constructive obligations."[47] ULH&P has neither legal, nor constructive, nor conditional obligations associated with these non-legal AROs.

"Any asset retirement obligation associated with the retirement of or the retirement and replacement of a component of a larger system [interim

[44] Id., paragraph A3.
[45] Id., paragraph A17.
[46] Id., paragraph B15.
[47] Id., paragraph B16.

retirements] qualifies for recognition provided that the obligation meets the definition of a liability."[48] ULH&P's non-legal AROs for interim retirements (if any) do not meet the definition of a liability.

"Uncertainty about the timing of the settlement date does not change the fact that an entity has a legal obligation."[49] Even the judgmental nature of plant lives does not eliminate an ARO, and yet ULH&P does not have any AROs for its non-legal ARO accounts.

ULH&P is well aware of these SFAS No. 143 requirements regarding AROs, yet it has determined for its non-ARO assets that it does not have any obligation to remove its plant or to spend the money it collects from ratepayers for that presumed purpose. As a result, ULH&P has, in effect, explicitly <u>not promised</u> to spend the money for its intended purpose, and it has recognized that it is not even reasonable to assume that it will incur these future removal costs. Given these facts, and the actual numbers I have provided to the Commission, the only reasonable conclusion is that ULH&P will never incur actual cost of removal relating to non-legal AROs at the level it is charging to ratepayers.

Q. Does the NARUC Manual recognize other approaches?

A. Yes, the NARUC Manual recognizes that some jurisdictions have reconsidered:

> Some commissions have abandoned the above procedure [gross salvage and cost of removal

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[48] Id., paragraph B17.
[49] Id., Paragraph B19.

> reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred.[50]

The NARUC depreciation manual further opines on the underlying rationale for treating removal cost as a current-period expense, instead of incorporating it in depreciation rates:

> It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current-period accounting for gross salvage and, particularly, cost of removal.[51]

Setting aside ratemaking, one of the mechanical problems with ULH&Ps approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rate is excessive; it is more than necessary to fully depreciate the plant. Therefore, at the end of its life, the accumulated depreciation account **exceeds** the plant account balance.

Q. Has anybody addressed this accumulated depreciation excess?

[50] NARUC Manual, page 157.
[51] Id., page 158.

A. SFAS No. 143 also addresses accumulated reserve excesses:

Paragraph B22 says the following:

> B22. Paragraph 37 of Statement 19 states that "estimated dismantlement, restoration, and abandonment costs ... shall be taken into account in determining amortization and depreciation rates." Application of that paragraph has the effect of accruing an expense irrespective of the requirements for liability recognition in the FASB Concepts Statements. In doing so, it results in recognition of accumulated depreciation that can exceed the historical cost of a long-lived asset. The Board concluded that an entity should be precluded from including an amount for and asset retirement obligation in the depreciable base of a long-lived asset unless that amount also meets the recognition criteria in this Statement. When an entity recognizes a liability for an asset retirement obligation, it also will recognize an increase in the carrying amount of the related long-lived asset. <u>Consequently, depreciation of that asset will not result in the recognition of accumulated depreciation in excess of the historical cost of a long-lived asset</u>.[52]

As one can see from the above, the public accounting profession does not approve of depreciating an asset beyond its original cost.

Q. Are you advocating that the Commission adopt GAAP as the single appropriate standard for ratemaking?

A. No, GAAP does not control ratemaking, but the rationale described above is both informative and makes sense.

Q. What do you conclude?

[52] SFAS No. 143, paragraph B22, (emphasis added).

A. I conclude that continued use of ULH&P's approach and its resulting cost of removal proposals will exacerbate an already bad situation. Although ULH&P acknowledges a $32 million regulatory liability resulting from its past use of this approach, it proposes to continue its use on a going-forward basis. Because its inherent inflationary and orders of magnitude mismatches are combined with plant growth, the $32 million regulatory liability will continue to grow at an exponential rate. If there is nothing other than mere speculation that ULH&P will spend all of that money on cost of removal, why let it continue to grow at the expense of ratepayers? The Commission must change the procedure it uses to provide for cost of removal.

Q. Does ULH&P's approach have any other problems?

A. The problems do not end with inherent inflationary and orders of magnitude mismatches. These mismatches assume reliable data and a relationship between the retirements and the cost of removal shown in the studies. Neither is a good assumption. There is little, if any, relationship between the cost of removal and retirements amounts in the studies. Furthermore, the data is unreliable, it is typically sporadic, and entirely subject to the control of ULH&P's accounting department.

Q. Why is there little or no relationship between the cost of removal and the retirement amounts in ULH&P's studies?

A. A majority of ULH&P's retirements result from replacements. ULH&P determines a need to replace assets in conjunction with its obligation to provide service. When it is determined that assets should be replaced, ULH&P estimates the entire replacement cost, and then assigns a portion of the replacement to cost of removal. Each assignment is unique to the replacement at hand. The cost of removal in ULH&P's studies is a function of and derived directly from plant additions - not retirements.

Most of the retirements in the studies are priced and posted after-the-fact accounting entries, bearing little if any relationship at all to the recorded cost of removal. It is doubtful that the cost of removal in any given year relates in anyway to the retirements recorded in that year.

Q. Why do you say the data in the ULH&P's studies is unreliable?

A. Not only is the data sporadic in many instances, it is subject to the control of the accounting department. Changes in accounting policies and procedures affect retirement and cost of removal reporting. As I explained, significant portions of the recorded cost of removal result from accounting assignments. Such assignments are at least somewhat arbitrary. Consequently, it is reasonable to assume that two independent estimators reviewing the same project could reach different conclusions concerning the portion of a replacement project to be assigned to cost of removal.

Q. Do you consider the amounts in the ULH&P's studies to be inaccurate?

A. I assume ULH&P has accurately recorded the amounts, but sporadic figures resulting from arbitrary assignments are unreliable for use in a procedure designed to collect hundreds of millions of dollars in advance, particularly when the Company's management has not even committed to spending the money for its ostensible purpose.

Terminal Net Salvage

Q. Please explain terminal net salvage.

A. Terminal net salvage is the amount of money the Company will spend when it retires and dismantles a production plant.

Q. Has Mr. Spanos built dismantlement or terminal net salvage costs into his production plant depreciation rates?

A. Yes, Mr. Spanos has specifically included negative net salvage ratios in his production plant depreciation rates for terminal net salvage.

Q. How has he calculated those amounts?

A. Mr. Spanos says that he used Sargent and Lundy estimates.[53] I am unable to confirm that claim because I cannot relate Mr. Spanos' starting point numbers to the Sargent and Lundy studies. I know, however, that Mr. Spanos significantly increased his starting point numbers for future inflation. He also included a component for future interim retirements.[54]

Q. Do you agree with Mr. Spanos's inclusion of these terminal net salvage costs in these depreciation rates?

A. No, I do not. The Company has no actual plans to dismantle these plants. It has not prepared any site-specific decommissioning studies, and Mr. Spanos admits that his terminal retirement dates were selected merely for use in calculating depreciation expense – they are not actual planned retirement dates. Furthermore, most utilities do not actually dismantle their production

[53] Spanos Study, page II-27.
[54] Response to AG-DR-02-172, 174, 175.

plants upon retirement. Exhibit___(MJM-11) is a study conducted by my firm which demonstrates that the majority of retired production plants are not dismantled.

Q. Have you ever accepted similar cost estimates in any prior proceedings?

A. Yes, I have accepted similar cost estimates in earlier proceedings. However, I have never, to my knowledge, accepted any such estimates with additional inflation built into the numbers. Nevertheless, my thinking and willingness to accept such factors has changed.

Q. Why has your thinking and willingness to accept such factors changed?

A. In a recent Westar electric rate case in Kansas, Mr. Spanos proposed decommissioning costs similar to those he has proposed in this case. The Kansas Corporation Commission adopted Mr. Spanos's proposal. My clients appealed to the Kansas Court of Appeals. The Appeals Court agreed that the inclusion of decommissioning costs in circumstances where no actual plans exist to decommission the plants was not acceptable.

> We are not rejecting the inclusion of terminal net salvage depreciation if and when it is supported by evidence before the Commission. We note the Commission has permitted the use of terminal net salvage depreciation in a prior rate case without any objection by the parties, which included KIC. We also note that regulatory commissions in other states have permitted terminal net salvage depreciation. However, in order to uphold an order permitting terminal net salvage depreciation, we conclude there must be *some evidence* that the utility has a reasonable and detailed plan to actually dismantle a generating facility upon retirement. Westar presented no evidence of even tentative plans in this case, even after the Commission's staff and the intervenors

vociferously objected to the lack of any plans. Instead, Spanos' testimony was based upon case studies from other areas and was completely speculative as to the realities of Westar's operations. Even the specific survey referred to by Majoros indicated that only 15 out of 86 facilities in other states were dismantled upon retirement. However, based on the Commission's order, Westar would be entitled to include terminal net salvage depreciation in 100% of its steam generation facilities.[55]

Determining an appropriate depreciation expense is a complex issue in any rate case and inherently involves "speculation" to the degree it requires projection of future events. See *Western Resources, Inc.*, 30 Kan. App. 2d at 368-73. <u>However, the need to project future events is not license for the Commission to engage in unchecked speculation.</u> The effect of the Commission's order turns on its head the general principle that changes in rates due to future or non test year events be, at least to some degree, known and measurable. See *Kansas Industrial Consumers,* 30 Kan. App. 2d at 343. The underlying assumption of the Commission's decision is that Westar will likely significantly dismantle all or most of its steam generation facilities at the end of their operating life. The Commission then multiplies the effect of this assumption by applying an inflation factor. There is no evidence in the record that comparable utilities dismantle or plan to dismantle most or all of their steam facilities. <u>Likewise, the Commission relied on no evidence that Westar had even *tentative* plans to significantly dismantle any of its facilities.</u> The cumulative effect of this lack of evidence renders the Commission's order ""so wide of the mark as to be outside the realm of fair debate. [Citations omitted.]"" *Williams Natural Gas Co. v. Kansas Corporation Comm'n,* 22 Kan. App. 2d 326, 335, 916 P.2d 52, *rev. denied* 260 Kan. 1002 (1996). Based upon a review of the entire record, we conclude the Commission's order permitting Westar to include terminal net salvage depreciation adjusted for inflation for all of its steam generation facilities was

[55] Kansas Industrial Consumers Group, Inc. v. Kansas Corporation Comm'n, 35 Kan. App. 2d___, ___P.3d___(No. 96,228, filed July 7, 2006). (no page numbers)

> not supported by substantial competent evidence and must be reversed.[56]

Finally, even if it did have actual dismantlement plans, ULH&P has already implemented SFAS No. 143 and recorded the impacts on its books. Any remaining decommissioning is primarily related to interim retirements and non-legal asset retirement obligations.

Q. The Kansas Appeals Court cites to a survey you provided in that case. Are you providing the same survey here and are the conclusions the same?

A. Yes, Exhibit___(MJM-11) is my firm's national study of steam plant retirements It demonstrates that complete dismantlement of retired steam electric plants is an infrequent occurrence at best.

<u>Alternatives to ULH&P's Approach</u>

Q. Are there any alternatives to ULH&P's approach?

A. Yes, there are alternatives. Below I will briefly discuss a "cash basis" alternative, and three "accrual basis" alternatives. There are probably more alternatives but these are the ones that I believe are reasonable.

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[56] Kansas Industrial Consumers Group, Inc. v. Kansas Corporation Comm'n, 35 Kan. App. 2d___, ___P.3d___(No. 96,228, filed July 7, 2006). (no page numbers) (Emphasis added.)

Alternatives to ULH&P's Approach

Cash Basis:	- Expensing
Accrual Basis:	- SFAS No. 143 Fair Value Approach
	- Net Present Value Approach
	- Normalized Cost of Removal Approach

Certain other state agencies have adopted all of these in one form or another.

Cash Basis Alternative

Q. What is the cash basis alternative?

A. The cash basis alternative removes non-legal removal and dismantlement costs from the depreciation rate process. Those costs would no longer be charged to accumulated depreciation, but instead be either capitalized or expensed. ULH&P allocates a portion of the cost of a replacement project to cost of removal. The allocation, like all allocations, is at least somewhat arbitrary. Thus, one component of the cash basis alternative would be to consider capitalizing the entire cost of replacements to plant in service, rather than allocating a portion to cost of removal. This would have the same effect on rate base as the Company's current accounting and would eliminate the problems created by the allocation. It would have the same effect on rate base because the current accounting debits actual cost to accumulated depreciation which increases rate base.

Q. What if the company incurs cost of removal or dismantlement which is not accompanied by a replacement?

A. If there is not a replacement, the cost of removal or dismantlement would be charged to operating expense.

Q. Is it necessary, under the cash basis alternative, to have a combination of capitalization and expensing?

A. No, ULH&P could charge all of its non-ARO cost of removal and dismantlement to operating expense. It would be eliminated from depreciation expense and treated as any other operating expense. If there are concerns that ULH&P or its customers could unduly suffer from an over-or under-estimation of this expense, the Commission could adopt balancing account treatment for the actual recorded expenses, subject to reasonableness review.

<u>Accrual Basis Alternatives</u>

Q. What are the accrual basis alternatives?

A. There are three accrual basis alternatives: the SFAS No. 143 ARO fair value approach, the net present value approach, and the normalized net salvage allowance approach.

<u>SFAS No. 143 Fair Value Accrual Approach</u>

Q. What is the SFAS No. 143 Fair Value Approach?

A. The SFAS No. 143 Fair Value Approach calculates the costs for ULH&P's non-legal AROs as if they were legal AROs. They are estimated at their future value and then reduced to their fair net present value. Several opening entries are required under SFAS No. 143 and FERC Order No. 631.

<u>Net Present Value Accrual Approach</u>

Q. What is the net present value approach?

A. The net present value approach is less complicated than the SFAS No. 143 fair value approach. The net present value would merely discount ULH&P's future cost of removal estimates back to 2005 values using the inflation factor that ULH&P used for its ARO calculations. Alternatively, the inflation implicit in ULH&P's studies could be eliminated through the use of indices such as the Handy-Whitman Index.

<u>Normalized Net Salvage Allowance Approach</u>

Q. Explain the normalized net salvage allowance approach.

A. The normalized net salvage allowance approach is similar to the cash basis approach except that the annual average net salvage, which includes cost of removal, is included as a specifically identifiable amount or rate within the annual depreciation accrual. In other words, a normalized net salvage amount is still a component of the depreciation expense accrual and is credited to accumulated depreciation and actual cost of removal continues to be charged to accumulated depreciation.

Q. Is the annual net salvage accrual a fixed amount?

A. The annual net salvage allowance could be either a fixed amount or a rolling five-year average amount.

Q. How is a normalized net salvage allowance rate calculated?

A. The normalized net salvage allowance amount (i.e., the five-year average) is merely divided by the most recent plant balance, thus producing the annual net salvage rate. The use of a rate, instead of an annual amount, will result in an annual accrual which expands with increases in gross plant balances.

<u>Going-Forward Net Salvage Recommendations</u>

Q. What do you recommend?

A. On a going-forward basis, I recommend discontinuation of ULH&P's approach and the adoption of the normalized net salvage allowance approach.

Q. Why do you propose the normalized net salvage approach as opposed to the other alternatives you have discussed?

A. The cash-basis alternative involves an accounting change. All of the other accrual basis alternatives involve the extrapolation of inflated figures into the future, and then the imposition of substantial judgment in the determination of inflation and discount rates.

There is no need for any of that. The normalized net salvage allowance approach does not require and accounting change and it eliminates the need to make predictions about inflation and discount rates. It keeps the company whole and charges its customers the correct amount. The normalized net salvage allowance approach is, in my opinion, the best approach.

Q. You mentioned earlier that the normalized net salvage allowance has been adopted in other jurisdictions?

A. The net salvage allowance method has been adopted in several recent New Jersey rate cases in which I participated. In Rockland Electric Company's 2002 rate case, the New Jersey Board of Public Utilities ("NJBPU") endorsed my testimony regarding SFAS No. 143, but used a net salvage allowance based on the average net salvage over a 10-year period, as recommended by Staff, instead of the five-year average I recommended.[57] In Jersey Central Power & Light Company's 2002 rate case, the NJBPU agreed with me that the inclusion of net salvage in depreciation rates was inappropriate. It adopted my recommendation of a $4.8 million net salvage allowance, based on the cost of removal included in JCP&L's test year budget for transmission, distribution and general plant.[58] As agreed to in the settlement of their last rate case, Atlantic City Electric Company also uses the net salvage allowance method to accrue net salvage.[59] However, their previous rates did not have a provision for net salvage at all. In Public Service Electric & Gas Company's most recent electric case, I recommended retention of the existing 2.49 percent composite rate. Some of the parties originally stipulated to a 2.75 percent rate, but the Board rejected the stipulation and adopted my 2.49 percent recommendation. That rate, which had been calculated by the Company in a previous case, did not have a provision for net salvage.[60]

Q. Have any other Commissions accepted the normalized net salvage allowance approach?

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[57] I/M/O Rockland Electric Company, BPU Docket Nos. ER02080614 and ER02100724, Initial Decision, June 10, 2003 and Summary Order, July 31, 2003.

[58] I/M/O Jersey Central Power & Light Company, BPU Docket Nos. ER0208056, ER0208057, EO02070417 and ER02030173, Summary Order, August 1, 2003.

[59] I/M/O Atlantic City Electric Company, BPU Docket Nos. ER03020110, ER04060423, EO03020091 and EM02090633, Decision and Order Adopting Initial Decision and Stipulation of Settlement, May 26, 2005.

[60] I/M/O Public Service and Gas Company, BPU Docket No. ER02050303, Decision and Order, Issued April 22, 2004.

A. Yes, the Pennsylvania Public Utility Commission uses the normalized net salvage allowance as a matter of course. Most recently, the Delaware Public Service Commission adopted the normalized net salvage allowance approach based on the five-year average for Delmarva Power & Light, the largest electric utility in that state.[61]

Snavely King Net Salvage Study

Q. Please explain Exhibit___(MJM-10).

A. The first two pages of Exhibit___(MJM-10) summarizes ULH&P's average actual net salvage experience from 2001 to 2005, and calculates my corresponding net salvage rates. Behind those pages, I have included Mr. Spanos' complete net salvage study rather than the partial study he included in his exhibit.

Summary of Recommendations

Q. Please summarize your recommendations.

A. I recommend that depreciation rates be split into separate capital recovery and cost of removal components. I recommend the alternative parameters discussed in my testimony be adopted. I recommend that the regulatory liability resulting from ULH&P's collection of excessive non-legal ARO charges be specifically recognized by the Kentucky PSC as a regulatory liability for regulatory reporting, regulatory analysis, and ratemaking purposes in Kentucky. Finally, I recommend that the KPSC adopt the normalized net

[61] I/M/O Delmarva Power & Light Company, Docket No. 05-304, Findings, Opinion and Order No. 6930, Issued June 6, 2006.

salvage alternative to ULH&P's cost of removal approach on a going-forward basis.

Recommended Depreciation Rates

Q. Have you provided your recommended depreciation rates?

A. Yes, my recommended depreciation rates are included in Exhibit___ (MJM-6). I have provided my recommendations separated between capital recovery and net salvage for each account. The two rates sum to the single rate.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES OF	**)**	
THE UNION LIGHT, HEAT AND POWER COMPANY	**)**	**CASE NO. 2006-00172**
D/B/A DUKE ENERGY KENTUCKY, INC.	**)**	

AFFIDAVIT

I, Michael J. Majoros, Jr., hereby swear and affirm that the foregoing testimony and all supporting appendices and schedules were prepared by me or under my direct supervision and are, to the best of my information and belief, true and accurate.

WASHINGTON,)
: **ss.**
DISTRICT OF COLUMBIA)

Subscribed and sworn to before me by Michael J. Majoros, Jr., this the 11th day of September, 2006.

Angel L. Finch, Notary Public

My Commission Expires: March 14, 2011

Michael J. Majoros, Jr.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. In addition to traditional regulatory engagements, Mr. Majoros has also provided consultation to the U.S. Department of Justice. His expertise has been called upon to address the accounting and plant life effects of electric plant modifications in environmental proceedings and lawsuits, and to estimate economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.

Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. –
Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
State Regulatory Agencies			
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.

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1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell

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1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban

Michael J. Majoros, Jr.

2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company
2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company

Michael J. Majoros, Jr.

2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.
2006	Delaware 24/	05-304	Delmarva Power & Light Company
2006	California 59/	A.05-12-002	Pacific Gas & Electric Co.
2006	New Jersey 1/	GR05100845	Public Service Electric and Gas Co.

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Florida 50/ 54/	030157-EI	Progress Energy Florida

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Association of Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	59/ The Utility Reform Network
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	

Exhibits

Attorney General Second Set Data Requests
Duke Energy Kentucky Case No. 2006-00172
Date Received: August 09, 2006
Response Due Date: August 23, 2006

AG-DR-02-040

REQUEST:

40. Provide the calculation of the annual amount of future net salvage incorporated into ULH&P's existing depreciation rates and in its proposed depreciation rates by account. If the amount is reduced by the total amount of non-legal AROs included in year-end accumulated depreciation, show that calculation.

RESPONSE:

The breakdown of the future net salvage incorporated in Duke Energy Kentucky's existing depreciation rates is not able to be calculated. See Attachment AG-DR-02-040 for the amount of future net salvage in the proposed depreciation rates by account.

WITNESS RESPONSIBLE: John J. Spanos

DUKE ENERGY KENTUCKY

COMPARISON OF ANNUAL ACCRUALS BY COMPONENT
AS OF DECEMBER 31, 2005

	ACCOUNT	TOTAL ANNUAL ACCRUALS	CAPITAL RECOVERY ACCRUALS	NET SALVAGE ACCRUALS
	(1)	(2)	(3)	(4)=(2)-(3)
	COMMON PLANT			
1900	STRUCTURES & IMPROVEMENTS			
	ERLANGER OPERATIONS CENTER	142,413	142,413	0
	FLORENCE SERVICE BUILDING	112,773	98,477	14,296
	KENTUCKY SERVICE BUILDING - 19TH & AUGUSTINE	105,459	77,749	27,710
	MINOR STRUCTURES	172	172	0
	TOTAL STRUCTURES & IMPROVEMENTS	360,817	318,811	42,006
1910	OFFICE FURNITURE AND EQUIPMENT	49,176	49,176	0
1930	STORES AND EQUIPMENT	2,696	2,696	0
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	11,654	11,654	0
1970	COMMUNICATION EQUIPMENT	5,346	5,346	0
1980	MISCELLANEOUS EQUIPMENT	756	756	0
	TOTAL COMMON PLANT	**430,445**	**388,439**	**42,006**
	STEAM PRODUCTION PLANT			
	MIAMI FORT UNIT 6			
3110	STRUCTURES AND IMPROVEMENTS	10,793	0	10,793
3120	BOILER PLANT	2,179,502	1,723,699	455,803
3122	BOILER PLANT - RETROFIT PRECIPITATORS	171,143	42,718	128,425
3140	TURBOGENERATOR UNITS	144,615	60,832	83,783
3150	ACCESSORY ELECTRIC EQUIPMENT	49,280	34,443	14,837
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	40,027	40,027	0
	TOTAL MIAMI FORT UNIT 6	2,595,360	1,901,719	693,641
	EAST BEND			
3110	STRUCTURES AND IMPROVEMENTS	500,678	416,438	84,240
3120	BOILER PLANT	9,329,691	6,029,437	3,300,254
3123	BOILER PLANT - CATALYST	340,771	340,771	0
3140	TURBOGENERATOR UNITS	1,891,524	1,413,497	478,027
3150	ACCESSORY ELECTRIC EQUIPMENT	510,292	423,090	87,202
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	182,751	182,751	0
	TOTAL EAST BEND	12,755,707	8,805,984	3,949,723
	TOTAL STEAM PRODUCTION PLANT	**15,351,067**	**10,707,703**	**4,643,364**
	OTHER PRODUCTION PLANT			
3401	RIGHTS OF WAY	23,633	23,633	0
3410	STRUCTURES AND IMPROVEMENTS	701,426	650,519	50,907
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	276,826	253,418	23,408
3430	PRIME MOVERS	7,146	6,556	590
3440	GENERATORS	4,673,413	4,216,143	457,270
3450	ACCESSORY ELECTRIC EQUIPMENT	302,976	302,976	0
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	78,229	78,229	0
	TOTAL OTHER PRODUCTION PLANT	**6,063,649**	**5,531,474**	**532,175**

DUKE ENERGY KENTUCKY

COMPARISON OF ANNUAL ACCRUALS BY COMPONENT
AS OF DECEMBER 31, 2005

	ACCOUNT	TOTAL ANNUAL ACCRUALS	CAPITAL RECOVERY ACCRUALS	NET SALVAGE ACCRUALS
	(1)	(2)	(3)	(4)=(2)-(3)
	TRANSMISSION PLANT			
3501	RIGHTS OF WAY	13,409	13,409	0
3520	STRUCTURES AND IMPROVEMENTS	1,569	825	744
3530	STATION EQUIPMENT	156,736	145,097	11,639
3532	STATION EQUIPMENT - MAJOR	93,449	77,372	16,077
3535	STATION EQUIPMENT - ELECTRONIC	1,320	1,320	0
3550	POLES AND FIXTURES	116,514	71,597	44,917
3560	OVERHEAD CONDUCTORS AND DEVICES	100,929	81,808	19,121
	TOTAL TRANSMISSION PLANT	483,926	391,428	92,498
	DISTRIBUTION PLANT			
3601	RIGHTS OF WAY	47,526	47,526	0
3610	STRUCTURES AND IMPROVEMENTS	2,895	2,309	586
3620	STATION EQUIPMENT	625,622	542,338	83,284
3622	STATION EQUIPMENT - MAJOR	496,342	436,303	60,039
3635	STATION EQUIPMENT - ELECTRONIC	10,226	10,226	0
3640	POLES, TOWERS AND FIXTURES	1,413,852	1,133,207	280,645
3650	OVERHEAD CONDUCTORS AND DEVICES	1,908,852	1,170,914	737,938
3660	UNDERGROUND CONDUIT	302,258	238,917	63,341
3670	UNDERGROUND CONDUCTORS AND DEVICES	1,034,795	681,983	352,812
3680	LINE TRANSFORMERS	1,472,550	1,336,582	135,968
3682	LINE TRANSFORMERS - CUSTOMER	472	0	472
3691	SERVICES - UNDERGROUND	14,891	9,978	4,913
3692	SERVICES - OVERHEAD	308,945	80,750	228,195
3700	METERS	589,342	589,342	0
3701	LEASED METERS	199,506	199,506	0
3720	LEASED PROPERTY ON CUSTOMER PREMISES	0	0	0
3731	STREET LIGHTING - OVERHEAD	25,245	17,821	7,424
3732	STREET LIGHTING - BOULEVARD	102,793	93,885	8,908
3733	STREET LIGHTING - CUSTOMER POLES	27,858	14,383	13,475
	TOTAL DISTRIBUTION PLANT	8,583,970	6,605,970	1,978,000
	GENERAL PLANT			
3900	STRUCTURES AND IMPROVEMENTS	568	506	62
3910	OFFICE FURNITURE AND EQUIPMENT	6,684	6,684	0
3921	TRAILERS	6,499	6,499	0
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	19,330	19,330	0
3960	POWER OPERATED EQUIPMENT	0	0	0
3970	COMMUNICATION EQUIPMENT	5,852	5,852	0
	TOTAL GENERAL PLANT	38,933	38,871	62
	TOTAL DEPRECIABLE PLANT	30,951,990	23,663,885	7,288,105
	TOTAL COMMON AND ELECTRIC PLANT	30,951,990	23,663,885	7,288,105

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Union Light, Heat and Power Company, The	End of 2005/Q4

(g) Energy Purchases and Fuel Costs

The expenses associated with electric and gas services include electricity purchased from parent company (CG&E), natural gas purchased from others, and the associated transportation costs. These expenses are shown in **ULH&P's** Statements of Income as *Operation Expense* (Account 401).

(h) Cash and Cash Equivalents

ULH&P defines cash and cash equivalents as investments with maturities of three months or less when acquired, which includes *Cash* (Account 131) and *Working Fund* (Account 135).

During 2005 and 2004, **ULH&P** made cash interest payments of $6.6 million and $4.8 million (net of amounts capitalized), respectively. **ULH&P** had a cash income tax receipt of $2.7 million in 2005 and mad a cash income tax payment of $2.8 million in 2004.

(i) Inventory

ULH&P's inventories are accounted for at the lower of cost or market, with cost being determined using the weighted-average method.

Materials and supplies inventory is accounted for on a weighted-average cost basis.

(j) Utility Plant

Utility Plant (Accounts 101-106 and 114) includes the utility and equipment that is in use, being held for future use, or under construction. **ULH&P** reports our *Utility Plant* at its original cost, which includes:

materials;
contractor fees;
salaries;
payroll taxes;
fringe benefits;
allowance for funds used during construction (AFUDC) (described in *(ii)*); and
other miscellaneous amounts.

ULH&P capitalizes costs for utility plant that are associated with the replacement or the addition of equipment that is considered a property unit. Property units are intended to describe an item or group of items. The cost of normal repairs and maintenance is expensed as incurred. When utility plant is retired, **ULH&P** charges the original cost, plus cost of removal, less salvage, to *Accumulated provision for depreciation* (Account 108), which is consistent with the composite method of depreciation. A gain or loss is recorded on the sale of utility plant if an entire operating unit, as defined by the FERC, is sold.

(i) Depreciation

ULH&P determines the provisions for depreciation expense using the straight-line method. The depreciation rates are based on periodic studies of the estimated useful lives and the net cost to remove the properties. **ULH&P** uses composite depreciation rates. These rates are approved by the KPSC. The average depreciation rates for *Utility Plant*, excluding software, was 3.4 percent and 3.5 percent for 2005 and 2004, respectively.

(ii) AFUDC

ULH&P finances construction projects with borrowed funds and equity funds. The KPSC allows **ULH&P** to record the costs of these funds as part of the cost of construction projects. AFUDC is calculated using a methodology authorized by the KPSC. These costs are credited on the Statements of Income to *Other Income* (Account 419.1) and *Other Interest Expense* (Account 431) for the equity and

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			207,544		207,544
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	666,124				666,124
8	Distribution Plant	8,528,706				8,528,706
9	General Plant	6,154		15,257		21,411
10	Common Plant-Electric	135,602		985,508		1,121,110
11	TOTAL	9,336,586		1,208,309		10,544,895

B. Basis for Amortization Charges

Page 336 does not include depreciation provided for Transportation, Power Operated Equipment, or Trailers as these amounts are charged to a Transportation Clearing Account

The Respondent determines its monthly Provision for Depreciation by the application of rates to the previous month-end balances of property capitalized in each primary plant account plus property in Account 106-Completed Construction not Classified.

In 1997, the Respondent adopted vintage year accounting for General Plant Accounts in accordance with FERC Accounting Research Release No. 15

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Union Light, Heat and Power Company, The	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2005/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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13							
14							
15							
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Excessive Depreciation

An excessive depreciation rate is one that produces depreciation expense which is more than necessary to return a company's capital investment over the life of the asset. The concept of excessive depreciation is not new, and in fact was explained by the U.S. Supreme Court in a landmark 1934 decision, Lindheimer v. Illinois Bell Telephone Company, as follows:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies

> of the "behavior of large groups" of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, are always present. <u>The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience</u>.[1]

Excessive depreciation rates produce excessive depreciation expense. In other words, if an excessive depreciation rate is applied to the plant balance, it results in excessive depreciation expense. Since depreciation expense flows dollar-for-dollar into the revenue requirement, excessive depreciation expense results in an excessive revenue requirement.

Excessive depreciation also flows dollar-for-dollar into the accumulated depreciation reserve account. This can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rate is excessive; it is more than necessary to fully depreciate the plant. This is what the Court was talking about in Lindheimer. Therefore, at the end of its life, this results in an accumulated depreciation account which *exceeds* the original cost in the plant account.

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[1] <u>Lindheimer v. Illinois Bell Telephone Company</u>, 292 U.S. 151, 168-170, 54 S.Ct. 658, 665-666 (1934). (Emphasis added; footnote deleted.)

The public accounting profession, through the Financial Accounting Standards Board ("FASB") has also addressed accumulated reserve excesses in its SFAS No. 143.[2] Paragraph B22 says the following:

> B22. Paragraph 37 of Statement 19 states that "estimated dismantlement, restoration, and abandonment costs...shall be taken into account in determining amortization and depreciation rates." Application of that paragraph has the effect of accruing an expense irrespective of the requirements for liability recognition in the FASB Concepts Statements. In doing so, it results in recognition of accumulated depreciation that can exceed the historical cost of a long-lived asset. The Board concluded that an entity should be precluded from including an amount for an asset retirement obligation in the depreciable base of a long-lived asset unless that amount also meets the recognition criteria in this Statement. When an entity recognizes a liability for an asset retirement obligation, it also will recognize an increase in the carrying amount of the related long-lived asset. <u>Consequently, depreciation of that asset will not result in the recognition of accumulated depreciation in excess of the historical cost of a long-lived asset</u>.[3]

As one can see from the above, as recently as 2002, the public accounting profession does not approve of depreciating an asset beyond its original cost. It actually used the word "excess," and it is obvious that it frowns upon accumulated depreciation balances that exceed the original cost of plant.

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[2] Statement of Financial Accounting Standards No. 143 ("SFAS No. 143") – Accounting for Asset Retirement Obligations.

[3] SFAS No. 143, paragraph B22 (emphasis added).

GAAP does not control ratemaking, but the rationale described above is both informative and makes sense.

Ultimately, ratepayers pay for excessive depreciation rates. As the U.S. Supreme Court said, the result is the extraction of capital contributions from ratepayers, which the Court decided was inappropriate. Current GAAP accounting rules highlight these amounts associated with negative net salvage and require that they be reported as Regulatory Liabilities ("amounts owed") to ratepayers.

Depreciation Concepts

Public Utility Depreciation

From a regulator's perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances.

There are several unique factors driving public utility depreciation rates. First, public utility depreciation is based on a "group life" as opposed to the lives of individual assets. Second, the cost of removing or disposing of an asset that is retired from service is charged to the accumulated depreciation reserve, as opposed to being recognized as an operating expense in the year incurred. Third, the original cost of a retired asset is also recorded in the accumulated depreciation reserve, as opposed to being written off in the year of the asset's retirement/disposal. Fourth, in certain jurisdictions public utility depreciation rates incorporate net salvage factors as discussed above. This is not the case for unregulated entities. Each of these factors affects the depreciation rates that are ultimately determined for the group of assets that are recorded in plant accounts designated by the FERC Uniform System of Accounts ("USOA").

Depreciation expense is one of the primary cost drivers of public utility revenue requirement calculations because these companies are capital intensive. An excessive depreciation rate can unreasonably increase the utility's revenue requirement and resulting service rates; thereby unnecessarily charging millions of dollars to a utility's customers.

Depreciation is a legitimate expense, but it is a major expense based on a substantial amount of judgment and complex analytical procedures, and it drives utility prices. Therefore, the measurement of depreciation and the calculation of the expense warrant careful regulatory consideration and scrutiny.

I discuss the fundamentals of public utility depreciation below, including the difference between the whole-life and remaining life techniques and the impact of life and net salvage estimation on depreciation rates.

Plant Additions, Retirements and Balances

Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Additions, retirements and balances refer to individual plant accounts. For example, account 369 - Services, is a plant account. An annual addition is the original cost of plant added to the account during the year. An annual retirement is the original cost of a prior addition which is now removed from service. The plant balance is what is left.

Depreciation Expense

Depreciation expense is a charge to operating expense to reflect the recovery of the cost of an asset. Public utility depreciation expense is typically straight-line over service life, which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant [and equipment] is in service.[1] Annual depreciation expense is a cost included in a public utility's revenue requirement.

Annual depreciation expense is calculated by applying a depreciation rate to plant balances. The resulting expense (also called accrual) is charged, just as any other expense, to the revenue requirement and from there it is charged to the utility's customers.

Depreciation is a non-cash expense in contrast to payroll expense, for example, which involves the current outlay of cash. That is, depreciation expense does not involve a specific payment during the current or test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service.

Accumulated depreciation (hereinafter called reserve or accumulated depreciation) is, in essence, a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. It can be considered a measure of the depreciation recovered from ratepayers.

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[1] Public Utility Depreciation Practices, August, 1996. National Association of Regulatory Utility Commissioners ("NARUC Manual"), p. 321.

Depreciation Rates

Depreciation rates such as ULH&P's are founded upon three fundamental parameters: a service life, a dispersion pattern and a net salvage ratio. ULH&P has used the remaining life technique to compute its rates. In order to understand remaining life depreciation, it is useful to first address whole-life depreciation.

Whole-Life Technique

The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life. This example does not include net salvage.

Table 1

Straight-Line Whole-Life Depreciation Rate
Assuming 10-Year Life

$$\frac{100\%}{10 \text{ yrs.}} = 10.0\%$$

Each year the 10.0 percent depreciation rate would be applied to plant in service to produce an annual depreciation expense. All things equal, at the end of 10 years, the plant balance will be 100%, and the depreciation reserve balance will be 100%. This equality is important to an understanding of certain issues in this case.

ULH&P includes net salvage in the depreciation rate calculation. A central issue in this case is negative net salvage. I will, therefore, use negative net salvage in my example. Negative net salvage is the net cost of removal of the asset after completion of its service life. For the remainder of this discussion I use the terms negative net salvage, decommissioning and cost of removal interchangeably. Assuming a negative 5 percent (-5%) net salvage ratio, the equation above with a value for negative net salvage is as follows:

Table 2

Straight-Line Whole-Life Depreciation Rate
Assuming 10-Year Life and -5% Net Salvage

$$\frac{100\%-(-5\%)}{10 \text{ yrs.}} = 10.5\%$$

Negative net salvage increases the resulting whole-life depreciation rate from 10.0% to 10.5%. This happens because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 105%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset.

At the end of life under this scenario the plant balance will be 100% but the reserve will be 105%. In other words, unlike the "zero net salvage scenario" in Table 1; when negative net salvage is included in a depreciation rate there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset.

Under these circumstances, equality will only be achieved if the Company actually spends the additional money at the end of the asset's life. However, unless the Company has a legal liability to remove the asset, it is not required to spend the money. Furthermore, since accumulated depreciation is an "unfunded account", even though the Company collected unnecessary cost of removal amounts in the past, it will have already spent that money on whatever it chose: salaries, dividends, etc.

Remaining Life Technique

The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather than the whole life of the asset.

If the hypothetical 10-year asset discussed above is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 31.5 percent of the original cost because the 10.5 percent depreciation rate from Table 2 would have been applied for three years (3 x 10.5% = 31.5%). The remaining life depreciation rate would then be calculated as follows:

Table 3

Straight-Line Remaining Depreciation Life Rate
Assuming 10-year Life, 7-year Remaining Life
And -5% Net Salvage

$$\frac{100\% - (-5\%) - 31.5\%}{7 \text{ years}} = 10.5\%$$

In the examples shown in Tables 2 and 3, the remaining life depreciation rate and the whole-life depreciation rates are the same (10.5 percent), because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 5 percent net salvage ratio, exactly the right amount of depreciation (31.5 percent) has been charged and collected in the past,

If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage.

The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

The remaining life technique has been accepted and used in many jurisdictions. Its primary failing is that if there is a reserve imbalance, positive or negative, it results in the application of an incorrect rate to new plant additions. In other words, the remaining life technique perpetuates the same imbalances it attempts to cure. This problem can be resolved by using whole-life rates and separate treatment for any reserve imbalances.

Impact of Life and Net Salvage Estimation

Utilities own thousands of assets, represented by millions of dollars of investment. Given the capital intensity of the industry, it is very difficult to track and depreciate every single asset that a utility owns. Public utility depreciation is, therefore, based on a group concept, which relies on averages of the service lives and remaining lives of the assets within a specific group.

These factors are necessarily estimates of the average service lives and average remaining lives of groups of assets. These estimates are in turn based on complex analytical procedures which involve not only the age of existing and retired assets, but also retirement dispersion patterns called "Iowa curves." The important point to remember is that service life, average age and Iowa curves are all used in the estimation of an average service life and average remaining life of a group of assets and are ultimately used to calculate the depreciation rate for that group of assets.

In depreciation analysis it is axiomatic that the shorter the life, the higher the resulting depreciation rate. If ULH&P's depreciation rates are based on lives which are too short, the depreciation rates will be too high. What if the 10-year life I used in the earlier examples really should have been 30 years? For example, assume that the analyst conducted statistical analyses which indicated that the average life is actually 30 years. The following table shows the impact of continuing to use a shorter life.

Table 4

Impact of Reducing a Life From 30 Years to 10 Years

30 year life = 100%/30 = 3.3%

10 year life = 100%/10 = 10.0%

If the life should have been 30 years, the rate should have been 3.3 percent rather than the 10 percent depreciation rate based on a 10 year life. The shorter the life, the higher the rate. If the life is too short, the resulting rate is obviously excessive.

The estimation of future net salvage also has an impact on depreciation rates. Many of ULH&P's proposed depreciation rates contain negative net salvage factors which charge too much for future cost of removal because they are too negative. They result in excessive depreciation rates. The next table shows the impact on depreciation rates of increasing the cost of removal ratio.

Table 5

Impact of Increasing Cost of Removal Ratio

-5% ratio = 100 %-(-5)/30 = 3.5 %

-50% ratio = 100 %-(-50)/30 = 5.0 %

Increasing a cost of removal ratio from -5% to -50% increases the depreciation rate from 3.5% to 5.0%. If the estimated -50% cost of removal ratio is not supportable, obviously, the resulting 5.0% depreciation rate is excessive. The combination of these two factors, i.e., understated lives and overstated cost of removal ratios, compounds the excessive depreciation rate problem.

DUKE ENERGY KENTUCKY
COMPARISON OF BOOK RESERVE AND SPANOS CALCULATED THEORETICAL RESERVE - USING ELG PROCEDURE
AS OF DECEMBER 31, 2005

	ACCOUNT	ORIGINAL COST	A.S.L	SURVIVOR CURVE	REMAINING LIFE	NET SALVAGE PERCENT	BOOK RESERVE	CALCULATED RESERVE	RESERVE EXCESS / (DEFICIENCY)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(7)-(8)
	COMMON PLANT								
1900	STRUCTURES & IMPROVEMENTS								
	ERLANGER OPERATIONS CENTER	2,100,000	15	SQ	14.5	0	35,018	69,930	(34,912)
	FLORENCE SERVICE BUILDING	4,438,064	100	R1	31.0	(10)	1,383,066	1,435,776	(52,710)
	KENTUCKY SERVICE BUILDING - 19TH & AUGUSTINE	1,776,850	100	R1	6.4	(10)	1,279,475	1,328,237	(48,762)
	MINOR STRUCTURES	5,371	40	R1	25.0	0	1,066	1,107	(41)
	TOTAL STRUCTURES & IMPROVEMENTS	8,320,285					2,698,625	2,835,050	(136,425)
1910	OFFICE FURNITURE AND EQUIPMENT	397,768	20	SQ	5.0	0	153,338	277,335	(123,997)
1930	STORES AND EQUIPMENT	5,563	20	SQ	8.5	0	(17,351)	3,199	(20,550)
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	185,828	25	SQ	9.4	0	76,299	91,704	(15,405)
1970	COMMUNICATION EQUIPMENT	39,252	15	SQ	8.5	0	(6,193)	17,008	(23,201)
1980	MISCELLANEOUS EQUIPMENT	11,372	15	SQ	14.5	0	405	379	26
	TOTAL COMMON PLANT	**8,960,068**					**2,905,123**	**3,224,675**	**(319,552)**
	STEAM PRODUCTION PLANT								
	MIAMI FORT UNIT 6								
3110	STRUCTURES AND IMPROVEMENTS	3,056,617	100	R2.5	14.2	(5)	3,056,617	2,405,059	651,558
3120	BOILER PLANT	37,142,776	45	S1	12.5	(15)	15,442,532	23,193,107	(7,750,575)
3122	BOILER PLANT - RETROFIT PRECIPITATORS	11,772,654	50	S1.5	13.8	(15)	11,185,190	7,623,139	3,562,051
3140	TURBOGENERATOR UNITS	11,501,259	52	R2	13.7	(10)	10,666,041	7,761,532	2,904,509
3150	ACCESSORY ELECTRIC EQUIPMENT	4,075,296	55	R2.5	13.9	(5)	3,594,119	2,745,206	848,913
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	724,421	55	S0.5	13.6	0	179,022	237,413	(58,391)
	TOTAL MIAMI FORT UNIT 6	68,273,023					44,123,521	43,965,456	158,065
	EAST BEND								
3110	STRUCTURES AND IMPROVEMENTS	35,078,476	100	R2.5	33.3	(8)	21,201,735	15,412,574	5,789,161
3120	BOILER PLANT	276,530,866	45	S1	23.0	(26)	134,227,951	138,490,628	(4,262,677)
3123	BOILER PLANT - CATALYST	2,230,486	8	S2.5	4.0	0	863,994	1,039,184	(175,190)
3140	TURBOGENERATOR UNITS	66,989,483	52	R2	25.5	(18)	30,880,436	30,732,074	148,362
3150	ACCESSORY ELECTRIC EQUIPMENT	25,101,926	55	R2.5	26.0	(9)	14,093,892	13,015,717	1,078,175
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	8,496,040	55	S0.5	26.3	0	3,688,681	2,849,175	839,506
	TOTAL EAST BEND	414,427,278					204,956,689	201,539,352	3,417,337
	TOTAL STEAM PRODUCTION PLANT	**482,700,301**					**249,080,210**	**245,504,808**	**3,575,402**
	OTHER PRODUCTION PLANT								
3401	RIGHTS OF WAY	651,684	40	SQ	26.5	0	25,416	219,943	(194,527)
3410	STRUCTURES AND IMPROVEMENTS	33,725,782	SQUARE		26.5	(4)	16,487,033	11,834,591	4,652,442
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	15,507,516	SQUARE		26.5	(4)	8,791,938	5,413,424	3,378,514
3430	PRIME MOVERS	173,729	SQUARE		26.5	(9)	-	3,503	(3,503)
3440	GENERATORS	188,960,592	70	R2.5	24.8	(6)	84,509,517	61,602,980	22,906,537
3450	ACCESSORY ELECTRIC EQUIPMENT	16,867,010	55	S2	24.0	0	9,606,254	6,061,573	3,544,681
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	3,701,280	40	R2.5	21.3	0	2,031,473	1,244,512	786,961
	TOTAL OTHER PRODUCTION PLANT	**259,587,594**					**121,451,631**	**86,380,526**	**35,071,105**

DUKE ENER[illegible]TUCKY
COMPARISON OF BOOK RESERVE AND SPANOS CALCULA[illegible]ED THEORETICAL RESERVE - USING ELG PROCEDURE
AS OF DECEMBER 31, 2005

	ACCOUNT	ORIGINAL COST	A.S.L	SURVIVOR CURVE	REMAINING LIFE	NET SALVAGE PERCENT	BOOK RESERVE	CALCULATED RESERVE	RESERVE EXCESS / (DEFICIENCY)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(7)-(8)
	TRANSMISSION PLANT								
3501	RIGHTS OF WAY	905,970	65	R4	32.8	0	465,555	440,750	24,805
3520	STRUCTURES AND IMPROVEMENTS	381,059	55	R3	27.9	(5)	356,286	261,748	94,538
3530	STATION EQUIPMENT	6,955,555	50	R1.5	31.0	(5)	2,437,097	1,762,224	674,873
3532	STATION EQUIPMENT - MAJOR	3,373,233	45	R2.5	29.2	(10)	979,197	991,477	(12,280)
3535	STATION EQUIPMENT - ELECTRONIC	13,820	15	R2	10.3	0	221	640	(419)
3550	POLES AND FIXTURES	5,114,856	50	R1.5	29.8	(25)	2,926,128	2,110,039	816,089
3560	OVERHEAD CONDUCTORS AND DEVICES	4,363,508	44	R0.5	23.9	(10)	2,388,861	1,981,009	407,852
	TOTAL TRANSMISSION PLANT	**21,108,001**					**9,553,345**	**7,547,887**	**2,005,458**
	DISTRIBUTION PLANT								
3601	RIGHTS OF WAY	4,459,567	70	R3	45.4	0	2,303,086	1,501,650	801,436
3610	STRUCTURES AND IMPROVEMENTS	309,259	55	R3	35.4	(5)	222,370	191,146	31,224
3620	STATION EQUIPMENT	18,814,186	46	R2	25.3	(10)	4,876,157	6,817,243	(1,941,086)
3622	STATION EQUIPMENT - MAJOR	15,065,670	45	R2.5	26.9	(10)	3,243,435	4,948,568	(1,705,133)
3635	STATION EQUIPMENT - ELECTRONIC	106,006	15	R2	10.3	0	380	6,221	(5,841)
3640	POLES, TOWERS AND FIXTURES	43,026,869	44	R0.5	23.3	(15)	16,468,681	16,820,124	(351,443)
3650	OVERHEAD CONDUCTORS AND DEVICES	61,492,932	44	R1	25.7	(30)	30,858,196	25,135,705	5,722,491
3660	UNDERGROUND CONDUIT	14,352,678	65	R3	47.9	(20)	2,747,147	2,967,779	(220,632)
3670	UNDERGROUND CONDUCTORS AND DEVICES	33,231,540	60	R2	38.3	(40)	6,861,708	10,920,913	(4,059,205)
3680	LINE TRANSFORMERS	49,013,367	35	R1	19.5	(5)	22,757,847	20,776,549	1,981,298
3682	LINE TRANSFORMERS - CUSTOMER	273,661	50	R1.5	29.0	(5)	273,661	179,729	93,932
3691	SERVICES - UNDERGROUND	515,126	55	R2	35.6	(30)	140,227	140,535	(308)
3692	SERVICES - OVERHEAD	10,257,449	47	R1	27.3	(60)	7,968,400	6,042,861	1,925,539
3700	METERS	10,121,655	28	S0	12.9	0	2,501,214	5,280,006	(2,778,792)
3701	LEASED METERS	3,558,486	28	S0	16.8	0	210,492	652,357	(441,865)
3720	LEASED PROPERTY ON CUSTOMER PREMISES	9,647	25	L2	-	0	9,648	8,240	1,408
3731	STREET LIGHTING - OVERHEAD	2,754,323	30	L1	18.5	(5)	2,424,552	1,270,988	1,153,564
3732	STREET LIGHTING - BOULEVARD	2,840,524	30	L1	16.6	(5)	1,276,667	1,031,291	245,376
3733	STREET LIGHTING - CUSTOMER POLES	1,618,092	30	R1	17.8	(15)	1,364,604	796,627	567,977
	TOTAL DISTRIBUTION PLANT	**271,821,035**					**106,508,472**	**105,488,532**	**1,019,940**
	GENERAL PLANT								
3900	STRUCTURES AND IMPROVEMENTS	32,124	35	R2.5	25.9	(5)	18,990	16,000	2,990
3910	OFFICE FURNITURE AND EQUIPMENT	36,019	20	SQ	2.6	0	18,683	31,536	(12,853)
3921	TRAILERS	99,599	15	SQ	10.2	0	33,373	38,049	(4,676)
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	466,595	25	SQ	13.0	0	214,835	231,098	(16,263)
3960	POWER OPERATED EQUIPMENT	12,045	14	R3	-	0	12,045	10,641	1,404
3970	COMMUNICATION EQUIPMENT	84,463	15	SQ	2.5	0	69,833	70,383	(550)
	TOTAL GENERAL PLANT	**730,844**					**367,759**	**397,707**	**(29,948)**
	TOTAL DEPRECIABLE PLANT	**1,044,907,843**					**489,866,540**	**448,544,135**	**41,322,405**

Source: Cols. (2) - (7) from Spanos Study, pp. III-4 through III-6. Col. (8) from Spanos Study, pp. III-164 through III-243.

DUKE ENERGY KENTUCKY
COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE - USING VG PROCEDURE AND SPANOS PARAMETERS
AS OF DECEMBER 31, 2005

	ACCOUNT	ORIGINAL COST	A.S.L	SURVIVOR CURVE	REMAINING LIFE	NET SALVAGE PERCENT	BOOK RESERVE	CALCULATED RESERVE	RESERVE EXCESS / (DEFICIENCY)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(7)-(8)
	COMMON PLANT								
1900	STRUCTURES & IMPROVEMENTS								
	ERLANGER OPERATIONS CENTER	2,100,000	15	SQ	14.5 1/	0	35,018	69,930	(34,912)
	FLORENCE SERVICE BUILDING	4,438,064	100	R1	31.0 1/	(10)	1,383,066	1,435,776	(52,710)
	KENTUCKY SERVICE BUILDING - 19TH & AUGUSTINE	1,776,850	100	R1	6.4 1/	(10)	1,279,475	1,328,237	(48,762)
	MINOR STRUCTURES	5,371	40	R1	25.0 1/	0	1,066	1,107	(41)
	TOTAL STRUCTURES & IMPROVEMENTS	8,320,285					2,698,625	2,835,050	(136,425)
1910	OFFICE FURNITURE AND EQUIPMENT	397,768	20	SQ	5.0 1/	0	153,338	277,335	(123,997)
1930	STORES AND EQUIPMENT	5,563	20	SQ	8.5 1/	0	(17,351)	3,199	(20,550)
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	185,828	25	SQ	9.4 1/	0	76,299	91,704	(15,405)
1970	COMMUNICATION EQUIPMENT	39,252	15	SQ	8.5 1/	0	(6,193)	17,008	(23,201)
1980	MISCELLANEOUS EQUIPMENT	11,372	15	SQ	14.5 1/	0	405	379	26
	TOTAL COMMON PLANT	**8,960,068**					**2,905,123**	**3,224,675**	**(319,552)**
	STEAM PRODUCTION PLANT								
	MIAMI FORT UNIT 6								
3110	STRUCTURES AND IMPROVEMENTS	3,056,617	100	R2.5	14.2 1/	(5)	3,056,617	2,405,059	651,558
3120	BOILER PLANT	37,142,776	45	S1	12.5 1/	(15)	15,442,532	23,193,107	(7,750,575)
3122	BOILER PLANT - RETROFIT PRECIPITATORS	11,772,654	50	S1.5	13.8 1/	(15)	11,185,190	7,623,139	3,562,051
3140	TURBOGENERATOR UNITS	11,501,259	52	R2	13.7 1/	(10)	10,666,041	7,761,532	2,904,509
3150	ACCESSORY ELECTRIC EQUIPMENT	4,075,296	55	R2.5	13.9 1/	(5)	3,594,119	2,745,206	848,913
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	724,421	55	S0.5	13.6 1/	0	179,022	237,413	(58,391)
	TOTAL MIAMI FORT UNIT 6	68,273,023					44,123,521	43,965,456	158,065
	EAST BEND								
3110	STRUCTURES AND IMPROVEMENTS	35,078,476	100	R2.5	33.3 1/	(8)	21,201,735	15,412,574	5,789,161
3120	BOILER PLANT	276,530,866	45	S1	23.0 1/	(26)	134,227,951	138,490,628	(4,262,677)
3123	BOILER PLANT - CATALYST	2,230,486	8	S2.5	4.0 1/	0	863,994	1,039,184	(175,190)
3140	TURBOGENERATOR UNITS	66,989,483	52	R2	25.5 1/	(18)	30,880,436	30,732,074	148,362
3150	ACCESSORY ELECTRIC EQUIPMENT	25,101,926	55	R2.5	26.0 1/	(9)	14,093,892	13,015,717	1,078,175
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	8,496,040	55	S0.5	26.3 1/	0	3,688,681	2,849,175	839,506
	TOTAL EAST BEND	414,427,278					204,956,689	201,539,352	3,417,337
	TOTAL STEAM PRODUCTION PLANT	**482,700,301**					**249,080,210**	**245,504,808**	**3,575,402**
	OTHER PRODUCTION PLANT								
3401	RIGHTS OF WAY	651,684	40	SQ	26.5 1/	0	25,416	219,943	(194,527)
3410	STRUCTURES AND IMPROVEMENTS	33,725,782	SQUARE		26.5 1/	(4)	16,487,033	11,834,591	4,652,442
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	15,507,516	SQUARE		26.5 1/	(4)	8,791,938	5,413,424	3,378,514
3430	PRIME MOVERS	173,729	SQUARE		26.5 1/	(9)	-	3,503	(3,503)
3440	GENERATORS	188,960,592	70	R2.5	24.8 1/	(6)	84,509,517	61,602,980	22,906,537
3450	ACCESSORY ELECTRIC EQUIPMENT	16,867,010	55	S2	24.0 1/	0	9,606,254	6,061,573	3,544,681
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	3,701,280	40	R2.5	21.3 1/	0	2,031,473	1,244,512	786,961
	TOTAL OTHER PRODUCTION PLANT	**259,587,594**					**121,451,631**	**86,380,526**	**35,071,105**

DUKE ENERGY KENTUCKY
COMPARISON OF BOOK RESERVE AND THEORETICAL RESERVE - USING VG PROCEDURE AND SPANOS PARAMETERS
AS OF DECEMBER 31, 2005

	ACCOUNT (1)	ORIGINAL COST (2)	A.S.L (3)	SURVIVOR CURVE (4)	REMAINING LIFE (5)	NET SALVAGE PERCENT (6)	BOOK RESERVE (7)	CALCULATED RESERVE (8)	RESERVE EXCESS / (DEFICIENCY) (9)=(7)-(8)
	TRANSMISSION PLANT								
3501	RIGHTS OF WAY	905,970	65	R4	35.0	0	465,555	418,758	46,797
3520	STRUCTURES AND IMPROVEMENTS	381,059	55	R3	21.7	(5)	356,286	242,232	114,054
3530	STATION EQUIPMENT	6,955,555	50	R1.5	41.0	(5)	2,437,097	1,313,689	1,123,408
3532	STATION EQUIPMENT - MAJOR	3,373,233	45	R2.5	34.3	(10)	979,197	880,152	99,045
3535	STATION EQUIPMENT - ELECTRONIC	13,820	15	R2	14.5	0	221	416	(195)
3550	POLES AND FIXTURES	5,114,856	50	R1.5	37.4	(25)	2,926,128	1,609,074	1,317,054
3560	OVERHEAD CONDUCTORS AND DEVICES	4,363,508	44	R0.5	32.1	(10)	2,388,861	1,296,283	1,092,578
	TOTAL TRANSMISSION PLANT	**21,108,001**					**9,553,345**	**5,760,604**	**3,792,741**
	DISTRIBUTION PLANT								
3601	RIGHTS OF WAY	4,459,567	70	R3	49.0	0	2,303,086	1,340,665	962,421
3610	STRUCTURES AND IMPROVEMENTS	309,259	55	R3	24.4	(5)	222,370	180,550	41,820
3620	STATION EQUIPMENT	18,814,186	46	R2	33.4	(10)	4,876,157	5,656,449	(780,292)
3622	STATION EQUIPMENT - MAJOR	15,065,670	45	R2.5	33.4	(10)	3,243,435	4,267,379	(1,023,944)
3635	STATION EQUIPMENT - ELECTRONIC	106,006	15	R2	14.4	0	380	4,177	(3,797)
3640	POLES, TOWERS AND FIXTURES	43,026,869	44	R0.5	34.7	(15)	16,468,681	10,439,817	6,028,864
3650	OVERHEAD CONDUCTORS AND DEVICES	61,492,932	44	R1	34.4	(30)	30,858,196	17,356,898	13,501,298
3660	UNDERGROUND CONDUIT	14,352,678	65	R3	55.1	(20)	2,747,147	2,624,277	122,870
3670	UNDERGROUND CONDUCTORS AND DEVICES	33,231,540	60	R2	49.0	(40)	6,861,708	8,561,390	(1,699,682)
3680	LINE TRANSFORMERS	49,013,367	35	R1	24.8	(5)	22,757,847	15,049,417	7,708,430
3682	LINE TRANSFORMERS - CUSTOMER	273,661	50	R1.5	24.0	(5)	273,661	149,407	124,254
3691	SERVICES - UNDERGROUND	515,126	55	R2	45.4	(30)	140,227	116,506	23,721
3692	SERVICES - OVERHEAD	10,257,449	47	R1	34.7	(60)	7,968,400	4,279,128	3,689,272
3700	METERS	10,121,655	28	S0	17.0	0	2,501,214	3,970,289	(1,469,075)
3701	LEASED METERS	3,558,486	28	S0	24.7	0	210,492	422,598	(212,106)
3720	LEASED PROPERTY ON CUSTOMER PREMISES	9,647	25	L2	6.89	0	9,648	6,989	2,659
3731	STREET LIGHTING - OVERHEAD	2,754,323	30	L1	20.4	(5)	2,424,552	921,842	1,502,710
3732	STREET LIGHTING - BOULEVARD	2,840,524	30	L1	22.9	(5)	1,276,667	709,077	567,590
3733	STREET LIGHTING - CUSTOMER POLES	1,618,092	30	R1	20.3	(15)	1,364,604	599,441	765,163
	TOTAL DISTRIBUTION PLANT	**271,821,035**					**106,508,472**	**76,656,298**	**29,852,174**
	GENERAL PLANT								
3900	STRUCTURES AND IMPROVEMENTS	32,124	35	R2.5	19.06	(5)	18,990	15,360	3,630
3910	OFFICE FURNITURE AND EQUIPMENT	36,019	20	SQ	2.6 1/	0	18,683	31,536	(12,853)
3921	TRAILERS	99,599	15	SQ	10.2 1/	0	33,373	38,049	(4,676)
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	466,595	25	SQ	13.0 1/	0	214,835	231,098	(16,263)
3960	POWER OPERATED EQUIPMENT	12,045	14	R3	2.22	0	12,045	10,136	1,909
3970	COMMUNICATION EQUIPMENT	84,463	15	SQ	2.5 1/	0	69,833	70,383	(550)
	TOTAL GENERAL PLANT	**730,844**					**367,759**	**396,562**	**(28,803)**
	TOTAL DEPRECIABLE PLANT	**1,044,907,843**					**489,866,540**	**417,923,472**	**71,943,068**

1/ Remaining life, and theoretical reserve based on ELG procedure (Spanos calculation).

Source: Cols. (2) - (4) and (6) from Spanos Study, pp. III-4 through III-6. Col. (5) from Exhibit___(MJM-7) for Transmission, Distribution and selected General accounts. All other Col. (5) figures from Spanos Study, pp. III-4 through III-6. Col. (8) from Exhibit___(MJM-7) for Transmission, Distribution and selected General accounts. All other Col. (8) figures from Spanos Study, pp. III-164 through III-243.

DUKE ENERGY KENTUCKY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2005
SNAVELY KING RECOMMENDATIONS

	ACCOUNT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	ASL/ SURVIVOR CURVE	COMPOSITE REMAINING LIFE	CAPITAL RECOVERY ACCRUAL	CAPITAL RECOVERY RATE	NET SALVAGE RATE	NET SALVAGE ACCRUAL	TOTAL RATE	TOTAL ACCRUAL
	(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)=(4)/(6)	(8)=(7)/(2)	(9)	(10)=(2)*(9)	(11)=(8)+(9)	(12)=(7)+(10)
	COMMON PLANT											
1900	STRUCTURES & IMPROVEMENTS											
	ERLANGER OPERATIONS CENTER	2,100,000	35,018	2,064,982	15-SQ	14.5 1/	142,413	6.782	0.674	14,153	7.46	156,565
	FLORENCE SERVICE BUILDING	4,438,064	1,383,066	3,054,998	100-R1 *	31.0 1/	98,548	2.221	0.674	29,910	2.89	128,458
	KENTUCKY SERVICE BUILDING - 19TH & AUGUSTINE	1,776,850	1,279,475	497,375	100-R1 *	6.4 1/	77,715	4.374	0.674	11,975	5.05	89,690
	MINOR STRUCTURES	5,371	1,066	4,305	40-R1	25.0 1/	172	3.206	0.674	36	3.88	208
	TOTAL STRUCTURES & IMPROVEMENTS	8,320,285	2,698,625	5,621,660		17.6	318,848	3.832	0.674	56,074	4.51	374,922
1910	OFFICE FURNITURE AND EQUIPMENT	397,768	153,338	244,430	20-SQ	5.0 1/	48,886	12.290	-	-	12.29	48,886
1930	STORES AND EQUIPMENT	5,563	(17,351)	22,914	20-SQ	8.5 1/	2,696	48.460	-	-	48.46	2,696
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	185,828	76,299	109,529	25-SQ	9.4 1/	11,652	6.270	0.011	21	6.28	11,673
1970	COMMUNICATION EQUIPMENT	39,252	(6,193)	45,445	15-SQ	8.5 1/	5,346	13.621	0.110	43	13.73	5,389
1980	MISCELLANEOUS EQUIPMENT	11,372	405	10,967	15-SQ	14.5 1/	756	6.651	-	-	6.65	756
	TOTAL COMMON PLANT	**8,960,068**	**2,905,123**	**6,054,945**		**15.6**	**388,184**	**4.332**	**0.627**	**56,138**	**4.96**	**444,322**
	STEAM PRODUCTION PLANT											
	MIAMI FORT UNIT 6											
3110	STRUCTURES AND IMPROVEMENTS	3,056,617	3,056,617	(0)	100-R2.5 *	14.2 1/	0	-	-	-	-	-
3120	BOILER PLANT	37,142,776	15,442,532	21,700,244	45-S1 *	12.5 1/	1,736,020	4.674	0.074	27,631	4.75	1,763,650
3122	BOILER PLANT - RETROFIT PRECIPITATORS	11,772,654	11,185,190	587,464	50-S1.5 *	13.8 1/	42,570	0.362	-	-	0.36	42,570
3140	TURBOGENERATOR UNITS	11,501,259	10,666,041	835,218	52-R2 *	13.7 1/	60,965	0.530	0.011	1,262	0.54	62,227
3150	ACCESSORY ELECTRIC EQUIPMENT	4,075,296	3,594,119	481,177	55-R2.5 *	13.9 1/	34,617	0.849	-	-	0.85	34,617
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	724,421	179,022	545,399	55-S0.5 *	13.6 1/	40,103	5.536	(0.004)	(27)	5.53	40,076
	TOTAL MIAMI FORT UNIT 6	68,273,023	44,123,521	24,149,502		12.6	1,914,274	2.804	0.042	28,866	2.85	1,943,140
	EAST BEND											
3110	STRUCTURES AND IMPROVEMENTS	35,078,476	21,201,735	13,876,741	100-R2.5 *	33.3 1/	416,719	1.188	-	-	1.19	416,719
3120	BOILER PLANT	276,530,866	134,227,951	142,302,915	45-S1 *	23.0 1/	6,187,083	2.237	0.074	205,714	2.31	6,392,797
3123	BOILER PLANT - CATALYST	2,230,486	863,994	1,366,492	8-S2.5	4.0 1/	341,623	15.316	-	-	15.32	341,623
3140	TURBOGENERATOR UNITS	66,989,483	30,880,436	36,109,047	52-R2 *	25.5 1/	1,416,041	2.114	0.011	7,353	2.12	1,423,394
3150	ACCESSORY ELECTRIC EQUIPMENT	25,101,926	14,093,892	11,008,034	55-R2.5 *	26.0 1/	423,386	1.687	-	-	1.69	423,386
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	8,496,040	3,688,681	4,807,359	55-S0.5 *	26.3 1/	182,789	2.151	(0.004)	(318)	2.15	182,471
	TOTAL EAST BEND	414,427,278	204,956,689	209,470,589		23.4	8,967,642	2.164	0.051	212,749	2.22	9,180,390
	TOTAL STEAM PRODUCTION PLANT	**482,700,301**	**249,080,210**	**233,620,091**		**21.5**	**10,881,916**	2.254	**0.050**	**241,615**		11,123,531

DUKE ENERGY KENTUCKY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED
ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2005
SNAVELY KING RECOMMENDATIONS

	ACCOUNT	ORIGINAL COST	BOOK RESERVE	FUTURE ACCRUALS	ASL/ SURVIVOR CURVE	COMPOSITE REMAINING LIFE	CAPITAL RECOVERY ACCRUAL	CAPITAL RECOVERY RATE	NET SALVAGE RATE	NET SALVAGE ACCRUAL	TOTAL RATE	TOTAL ACCRUAL
	(1)	(2)	(3)	(4)=(2)-(3)	(5)	(6)	(7)=(4)/(6)	(8)=(7)/(2)	(9)	(10)=(2)*(9)	(11)=(8)+(9)	(12)=(7)+(10)
	OTHER PRODUCTION PLANT											
3401	RIGHTS OF WAY	651,684	25,416	626,268	40-SQ	26.5 1/	23,633	3.626	-	-	3.63	23,633
3410	STRUCTURES AND IMPROVEMENTS	33,725,782	16,487,033	17,238,749	SQUARE *	26.5 1/	650,519	1.929	-	-	1.93	650,519
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	15,507,516	8,791,938	6,715,578	SQUARE *	26.5 1/	253,418	1.634	-	-	1.63	253,418
3430	PRIME MOVERS	173,729	0	173,729	SQUARE *	26.5 1/	6,556	3.774	-	-	3.77	6,556
3440	GENERATORS	188,960,592	84,509,517	104,451,075	70-R2.5 *	24.8 1/	4,211,737	2.229	(0.531)	(1,002,977)	1.70	3,208,760
3450	ACCESSORY ELECTRIC EQUIPMENT	16,867,010	9,606,254	7,260,756	55-S2 *	24.0 1/	302,531	1.794	-	-	1.79	302,531
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	3,701,280	2,031,473	1,669,807	40-R2.5 *	21.3 1/	78,395	2.118	-	-	2.12	78,395
	TOTAL OTHER PRODUCTION PLANT	**259,587,594**	**121,451,631**	**138,135,963**		**25.0**	**5,526,789**	**2.13**	**(0.386)**	**(1,002,977)**	**1.74**	**4,523,812**
	TRANSMISSION PLANT											
3501	RIGHTS OF WAY	905,970	465,555	440,415	65-R4	34.96	12,598	1.391	-	-	1.39	12,598
3520	STRUCTURES AND IMPROVEMENTS	381,059	356,286	24,773	55-R3	21.70	1,142	0.300	-	-	0.30	1,142
3530	STATION EQUIPMENT	6,955,555	2,437,097	4,518,458	50-R1.5	41.01	110,179	1.584	0.003	243	1.59	110,422
3532	STATION EQUIPMENT - MAJOR	3,373,233	979,197	2,394,036	45-R2.5	34.33	69,736	2.067	0.473	15,954	2.54	85,690
3535	STATION EQUIPMENT - ELECTRONIC	13,820	221	13,599	15-R2	14.55	935	6.763	-	-	6.76	935
3550	POLES AND FIXTURES	5,114,856	2,926,128	2,188,728	50-R1.5	37.42	58,491	1.144	0.196	10,012	1.34	68,503
3560	OVERHEAD CONDUCTORS AND DEVICES	4,363,508	2,388,861	1,974,647	44-R0.5	32.12	61,477	1.409	0.109	4,745	1.52	66,222
	TOTAL TRANSMISSION PLANT	**21,108,001**	**9,553,345**	**11,554,656**		**36.7**	**314,557**	**1.49**	**0.147**	**30,954**	**1.64**	**345,511**
	DISTRIBUTION PLANT											
3601	RIGHTS OF WAY	4,459,567	2,303,086	2,156,481	70-R3	48.96	44,049	0.988	-	-	0.99	44,049
3610	STRUCTURES AND IMPROVEMENTS	309,259	222,370	86,889	55-R3	24.42	3,558	1.151	-	-	1.15	3,558
3620	STATION EQUIPMENT	18,814,186	4,876,157	13,938,029	46-R2	33.43	416,964	2.216	0.081	15,209	2.30	432,173
3622	STATION EQUIPMENT - MAJOR	15,065,670	3,243,435	11,822,235	45-R2.5	33.41	353,827	2.349	0.004	581	2.35	354,408
3635	STATION EQUIPMENT - ELECTRONIC	106,006	380	105,626	15-R2	14.41	7,331	6.915	-	-	6.92	7,331
3640	POLES, TOWERS AND FIXTURES	43,026,869	16,468,681	26,558,188	52-L0 2/	43.52	610,285	1.418	0.140	60,415	1.56	670,700
3650	OVERHEAD CONDUCTORS AND DEVICES	61,492,932	30,858,196	30,634,736	60-L0 2/	51.99	589,194	0.958	0.346	213,048	1.30	802,242
3660	UNDERGROUND CONDUIT	14,352,678	2,747,147	11,605,531	65-R3	55.10	210,642	1.468	0.009	1,346	1.48	211,988
3670	UNDERGROUND CONDUCTORS AND DEVICES	33,231,540	6,861,708	26,369,832	60-R2	48.96	538,613	1.621	0.072	24,045	1.69	562,658
3680	LINE TRANSFORMERS	49,013,367	22,757,847	26,255,520	35-R1	24.77	1,060,183	2.163	0.053	26,201	2.22	1,086,384
3682	LINE TRANSFORMERS - CUSTOMER	273,661	273,661	(0)	50-R1.5	24.00	0	-	-	-	-	-
3691	SERVICES - UNDERGROUND	515,126	140,227	374,899	55-R2	45.43	8,252	1.602	0.005	25	1.61	8,277
3692	SERVICES - OVERHEAD	10,257,449	7,968,400	2,289,049	47-R1	34.75	65,880	0.642	0.258	26,423	0.90	92,303
3700	METERS	10,121,655	2,501,214	7,620,441	28-S0	17.02	447,819	4.424	0.156	15,800	4.58	463,619
3701	LEASED METERS	3,558,486	210,492	3,347,994	28-S0	24.67	135,685	3.813	-	-	3.81	135,685
3720	LEASED PROPERTY ON CUSTOMER PREMISES	9,647	9,648	(1)	25-L2	6.89	0	-	-	-	-	-
3731	STREET LIGHTING - OVERHEAD	2,754,323	2,424,552	329,771	30-L1	20.44	16,136	0.586	0.268	7,383	0.85	23,519
3732	STREET LIGHTING - BOULEVARD	2,840,524	1,276,667	1,563,857	30-L1	22.87	68,387	2.408	0.032	909	2.44	69,296
3733	STREET LIGHTING - CUSTOMER POLES	1,618,092	1,364,604	253,488	37-R1.5 2/	26.13	9,703	0.600	0.597	9,665	1.20	19,368
	TOTAL DISTRIBUTION PLANT	**271,821,035**	**106,508,472**	**165,312,563**		**36.0**	**4,586,506**	**1.69**	**0.148**	**401,050**	**1.83**	**4,987,556**

DUKE ENERGY KENTUCKY
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2005
SNAVELY KING RECOMMENDATIONS

	ACCOUNT (1)	ORIGINAL COST (2)	BOOK RESERVE (3)	FUTURE ACCRUALS (4)=(2)-(3)	ASL/ SURVIVOR CURVE (5)	COMPOSITE REMAINING LIFE (6)		CAPITAL RECOVERY ACCRUAL (7)=(4)/(6)	CAPITAL RECOVERY RATE (8)=(7)/(2)	NET SALVAGE RATE (9)	NET SALVAGE ACCRUAL (10)=(2)*(9)	TOTAL RATE (11)=(8)+(9)	TOTAL ACCRUAL (12)=(7)+(10)
	GENERAL PLANT												
3900	STRUCTURES AND IMPROVEMENTS	32,124	18,990	13,134	35-R2.5	19.06		689	2.145	-	-	2.14	689
3910	OFFICE FURNITURE AND EQUIPMENT	36,019	18,683	17,336	20-SQ	2.60	1/	6,668	18.512	-	-	18.51	6,668
3921	TRAILERS	99,599	33,373	66,226	15-SQ	10.20	1/	6,493	6.519	(0.028)	(28)	6.49	6,465
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	466,595	214,835	251,760	25-SQ	13.00	1/	19,366	4.151	(0.013)	(60)	4.14	19,306
3960	POWER OPERATED EQUIPMENT	12,045	12,045	0	14-R3	2.22		0	-	-	-	-	-
3970	COMMUNICATION EQUIPMENT	84,463	69,833	14,630	15-SQ	2.5	1/	5,852	6.928	-	-	6.93	5,852
	TOTAL GENERAL PLANT	**730,844**	**367,759**	**363,086**		**9.3**		**39,068**	**5.35**	**(0.012)**	**(88)**	**5.33**	**38,980**
	TOTAL DEPRECIABLE PLANT	**1,044,907,843**	**489,866,540**	**555,041,303**		**25.5**		**21,737,020**	**2.08**	**(0.026)**	**(273,308)**	**2.05**	**21,463,712**

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.

1/ Remaining life is Spanos calculated ELG life.
2/ Reflects Snavely King change in service live/curve.

Source: Cols. (2), (3) & (5) from Spanos Study, pp. III-4 through III-6.
Cols. (5) (for SK changed lives) and (6) from Exhibit___ (MJM-7).
Col. (9) from Exhibit___(MJM-10), pages 1-2.

DUKE ENERGY KENTUCKY
Summary of Life Analysis with BG/VG Average Remaining Life Calculation
AS OF DECEMBER 31, 2005

	ACCOUNT		SURVIVOR CURVE	ORIGINAL COST	BG/VG ARL	BG/VG ARL With SK Recommended ASL
	TRANSMISSION PLANT					
3501	RIGHTS OF WAY		65-R4	905,970.01	34.96	34.96
3520	STRUCTURES AND IMPROVEMENTS		55-R3	381,058.99	21.70	21.70
3530	STATION EQUIPMENT		50-R1.5	6,955,554.64	41.01	41.01
3532	STATION EQUIPMENT - MAJOR		45-R2.5	3,373,232.83	34.33	34.33
3535	STATION EQUIPMENT - ELECTRONIC		15-R2	13,820.02	14.55	14.55
3550	POLES AND FIXTURES		50-R1.5	5,114,855.84	37.42	37.42
3560	OVERHEAD CONDUCTORS AND DEVICES		44-R0.5	4,363,508.45	32.12	32.12
	TOTAL TRANSMISSION PLANT			**21,108,000.78**		
	DISTRIBUTION PLANT					
3601	RIGHTS OF WAY		70-R3	4,459,567.36	48.96	48.96
3610	STRUCTURES AND IMPROVEMENTS		55-R3	309,258.74	24.42	24.42
3620	STATION EQUIPMENT		46-R2	18,814,186.03	33.43	33.43
3622	STATION EQUIPMENT - MAJOR		45-R2.5	15,065,669.50	33.41	33.41
3635	STATION EQUIPMENT - ELECTRONIC		15-R2	106,006.41	14.41	14.41
3640	POLES, TOWERS AND FIXTURES	*	52-L0	43,026,868.56	34.72	43.52
3650	OVERHEAD CONDUCTORS AND DEVICES	*	60-L0	61,492,931.54	34.45	51.99
3660	UNDERGROUND CONDUIT		65-R3	14,352,677.62	55.10	55.10
3670	UNDERGROUND CONDUCTORS AND DEVICES		60-R2	33,231,540.23	48.96	48.96
3680	LINE TRANSFORMERS		35-R1	49,013,366.64	24.77	24.77
3682	LINE TRANSFORMERS - CUSTOMER		50-R1.5	273,660.52	24.00	24.00
3691	SERVICES - UNDERGROUND		55-R2	515,125.88	45.43	45.43
3692	SERVICES - OVERHEAD		47-R1	10,257,448.65	34.75	34.75
3700	METERS		28-S0	10,121,655.21	17.02	17.02
3701	LEASED METERS		28-S0	3,558,485.58	24.67	24.67
3720	LEASED PROPERTY ON CUSTOMER PREMISES		25-L2	9,647.36	6.89	6.89
3731	STREET LIGHTING - OVERHEAD		30-L1	2,754,323.09	20.44	20.44
3732	STREET LIGHTING - BOULEVARD		30-L1	2,840,524.03	22.87	22.87
3733	STREET LIGHTING - CUSTOMER POLES	*	37-R1.5	1,618,092.14	20.34	26.13
	TOTAL DISTRIBUTION PLANT			**271,821,035.09**		
	GENERAL PLANT					
3900	STRUCTURES AND IMPROVEMENTS		35-R2.5	32,123.51	19.06	19.06
3910	OFFICE FURNITURE AND EQUIPMENT		20-SQ	36,019.42		
3921	TRAILERS		15-SQ	99,599.04		
3940	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ	466,595.20		
3960	POWER OPERATED EQUIPMENT		14-R3	12,044.52	2.22	2.22
3970	COMMUNICATION EQUIPMENT		15-SQ	84,462.76		
	TOTAL GENERAL PLANT			**730,844.45**		

Duke Energy Kentucky

350.10 - Rights of Way

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 65 R4 34.96

			BG/VG Average			
Year	**Age**	**Surviving Investment**	**Service Life**	**Remaining Life**	**ASL Weights**	**RL Weights**
(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)=(3)/(4)**	**(7)=(6)*(5)**
1992	13.5	3,992	65.00	51.55	61	3,166
1989	16.5	7,057	65.00	48.58	109	5,275
1988	17.5	18,298	65.00	47.60	282	13,399
1983	22.5	346,751	65.00	42.72	5,335	227,871
1982	23.5	0	65.00	41.75	0	0
1981	24.5	85,665	65.00	40.79	1,318	53,753
1977	28.5	275	65.00	36.98	4	157
1976	29.5	14,598	65.00	36.05	225	8,096
1975	30.5	1,579	65.00	35.12	24	853
1974	31.5	26,321	65.00	34.20	405	13,848
1973	32.5	34,777	65.00	33.28	535	17,806
1972	33.5	25,173	65.00	32.37	387	12,538
1971	34.5	8,895	65.00	31.47	137	4,307
1970	35.5	46	65.00	30.58	1	22
1969	36.5	1,092	65.00	29.70	17	499
1968	37.5	4,756	65.00	28.83	73	2,109
1967	38.5	86,314	65.00	27.97	1,328	37,139
1966	39.5	3,845	65.00	27.12	59	1,604
1965	40.5	75,276	65.00	26.27	1,158	30,428
1964	41.5	0	65.00	25.44	0	0
1963	42.5	22,089	65.00	24.62	340	8,368
1962	43.5	235	65.00	23.81	4	86
1961	44.5	50,048	65.00	23.02	770	17,723
1960	45.5	2,355	65.00	22.23	36	806
1959	46.5	1,963	65.00	21.46	30	648
1958	47.5	79,809	65.00	20.70	1,228	25,410
1957	48.5	363	65.00	19.95	6	111
1956	49.5	2,704	65.00	19.21	42	799
1950	55.5	1,695	65.00	15.00	26	391
		905,970			13,938	487,212

AVERAGE SERVICE LIFE 65.00
AVERAGE REMAINING LIFE 34.96

Duke Energy Kentucky

352.00 - Structures and Improvements

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 55 R3 21.70

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1993	12.5	21,996	55.00	42.92	400	17,167
1976	29.5	147,482	55.00	27.94	2,681	74,932
1975	30.5	0	55.00	27.14	0	0
1974	31.5	0	55.00	26.34	0	0
1973	32.5	0	55.00	25.55	0	0
1972	33.5	0	55.00	24.77	0	0
1971	34.5	2,028	55.00	24.01	37	885
1970	35.5	0	55.00	23.25	0	0
1969	36.5	0	55.00	22.50	0	0
1968	37.5	1,912	55.00	21.77	35	757
1967	38.5	2,611	55.00	21.04	47	999
1966	39.5	0	55.00	20.33	0	0
1965	40.5	1,231	55.00	19.63	22	439
1964	41.5	0	55.00	18.94	0	0
1963	42.5	0	55.00	18.27	0	0
1962	43.5	0	55.00	17.61	0	0
1961	44.5	0	55.00	16.96	0	0
1960	45.5	71,981	55.00	16.33	1,309	21,365
1959	46.5	0	55.00	15.71	0	0
1958	47.5	55,518	55.00	15.10	1,009	15,245
1957	48.5	0	55.00	14.51	0	0
1956	49.5	0	55.00	13.94	0	0
1955	50.5	76,299	55.00	13.39	1,387	18,572
		381,059			6,928	150,362

AVERAGE SERVICE LIFE 55.00
AVERAGE REMAINING LIFE 21.70

Duke Energy Kentucky

353.00 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 50 R1.5 41.01

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	561,057	50.00	49.59	11,221	556,420
2003	2.5	1,775,525	50.00	47.95	35,510	1,702,727
2002	3.5	750,412	50.00	47.14	15,008	707,465
2000	5.5	732,749	50.00	45.53	14,655	667,232
1999	6.5	17,968	50.00	44.73	359	16,075
1998	7.5	103,785	50.00	43.94	2,076	91,204
1996	9.5	3,899	50.00	42.37	78	3,304
1995	10.5	509,124	50.00	41.59	10,182	423,472
1992	13.5	879,384	50.00	39.28	17,588	690,853
1991	14.5	144,506	50.00	38.52	2,890	111,330
1986	19.5	16,639	50.00	34.80	333	11,580
1985	20.5	68,625	50.00	34.07	1,373	46,759
1983	22.5	299,132	50.00	32.63	5,983	195,207
1982	23.5	42,064	50.00	31.92	841	26,852
1979	26.5	4,386	50.00	29.83	88	2,616
1978	27.5	1,810	50.00	29.14	36	1,055
1976	29.5	247,232	50.00	27.80	4,945	137,454
1975	30.5	2,654	50.00	27.14	53	1,441
1974	31.5	407	50.00	26.49	8	216
1973	32.5	92,882	50.00	25.84	1,858	48,003
1971	34.5	48,032	50.00	24.58	961	23,610
1968	37.5	3,985	50.00	22.75	80	1,813
1967	38.5	329	50.00	22.16	7	146
1966	39.5	2,976	50.00	21.58	60	1,284
1965	40.5	196,895	50.00	21.00	3,938	82,709
1961	44.5	2,480	50.00	18.81	50	933
1960	45.5	81,579	50.00	18.29	1,632	29,846
1958	47.5	297,122	50.00	17.28	5,942	102,686
1956	49.5	1,859	50.00	16.31	37	606
1955	50.5	45,327	50.00	15.84	907	14,360
1951	54.5	9,867	50.00	14.07	197	2,776
1943	62.5	10,864	50.00	10.99	217	2,388
		6,955,555			139,111	5,704,422

AVERAGE SERVICE LIFE	50.00
AVERAGE REMAINING LIFE	41.01

Duke Energy Kentucky

353.20 - Station Equipment - Major

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 45 R2.5 34.33

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2005	0.5	219,078	45.00	44.53	4,868	216,772
2004	1.5	0	45.00	43.58	0	0
2003	2.5	1,011,826	45.00	42.65	22,485	958,915
2002	3.5	780,657	45.00	41.71	17,348	723,646
2001	4.5	125,473	45.00	40.79	2,788	113,721
2000	5.5	264,763	45.00	39.86	5,884	234,532
1992	13.5	34,444	45.00	32.69	765	25,024
1985	20.5	122,680	45.00	26.82	2,726	73,116
1984	21.5	0	45.00	26.02	0	0
1983	22.5	111,783	45.00	25.22	2,484	62,658
1978	27.5	26,247	45.00	21.42	583	12,492
1977	28.5	0	45.00	20.69	0	0
1976	29.5	40,616	45.00	19.97	903	18,028
1975	30.5	0	45.00	19.27	0	0
1974	31.5	0	45.00	18.58	0	0
1973	32.5	11,684	45.00	17.90	260	4,648
1972	33.5	0	45.00	17.24	0	0
1971	34.5	4,093	45.00	16.59	91	1,509
1965	40.5	65,041	45.00	13.01	1,445	18,810
1958	47.5	280,975	45.00	9.67	6,244	60,381
1955	50.5	25,012	45.00	8.52	556	4,737
1954	51.5	222,863	45.00	8.18	4,953	40,495
1951	54.5	4,301	45.00	7.23	96	691
1950	55.5	10,834	45.00	6.94	241	1,671
1943	62.5	10,864	45.00	5.17	241	1,248
		3,373,233			74,961	2,573,095

AVERAGE SERVICE LIFE 45.00
AVERAGE REMAINING LIFE 34.33

Duke Energy Kentucky

353.50 - Station Equipment - Electronic

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 15 R2 14.55

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	13,820	15.00	14.55	921	13,404
		13,820			921	13,404

AVERAGE SERVICE LIFE 15.00
AVERAGE REMAINING LIFE 14.55

Duke Energy Kentucky

355.00 - Poles and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 50 R1.5 37.42

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	287,115	50.00	49.59	5,742	284,742
2004	1.5	645,818	50.00	48.77	12,916	629,880
2003	2.5	252,688	50.00	47.95	5,054	242,327
2002	3.5	53,643	50.00	47.14	1,073	50,573
2001	4.5	12,580	50.00	46.33	252	11,657
2000	5.5	45,669	50.00	45.53	913	41,586
1999	6.5	264,767	50.00	44.73	5,295	236,870
1998	7.5	54,040	50.00	43.94	1,081	47,489
1997	8.5	112,299	50.00	43.15	2,246	96,915
1996	9.5	64,411	50.00	42.37	1,288	54,578
1995	10.5	277,940	50.00	41.59	5,559	231,181
1994	11.5	84,121	50.00	40.81	1,682	68,667
1993	12.5	110,191	50.00	40.05	2,204	88,252
1992	13.5	262,595	50.00	39.28	5,252	206,297
1991	14.5	80,641	50.00	38.52	1,613	62,127
1990	15.5	65,712	50.00	37.77	1,314	49,633
1989	16.5	43,295	50.00	37.02	866	32,052
1988	17.5	402,748	50.00	36.27	8,055	292,162
1987	18.5	36,502	50.00	35.53	730	25,939
1986	19.5	9,513	50.00	34.80	190	6,621
1985	20.5	67,183	50.00	34.07	1,344	45,777
1984	21.5	14,002	50.00	33.35	280	9,338
1983	22.5	477,020	50.00	32.63	9,540	311,294
1982	23.5	9,765	50.00	31.92	195	6,234
1981	24.5	215,841	50.00	31.21	4,317	134,747
1980	25.5	24,043	50.00	30.52	481	14,674
1979	26.5	24,488	50.00	29.83	490	14,608
1978	27.5	3,299	50.00	29.14	66	1,923
1977	28.5	12,076	50.00	28.47	242	6,876
1976	29.5	94,359	50.00	27.80	1,887	52,461
1975	30.5	265,581	50.00	27.14	5,312	144,147
1974	31.5	0	50.00	26.49	0	0
1973	32.5	154,277	50.00	25.84	3,086	79,733
1972	33.5	24,646	50.00	25.20	493	12,424
1971	34.5	113,874	50.00	24.58	2,277	55,974

Duke Energy Kentucky

355.00 - Poles and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 50 R1.5 37.42

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1970	35.5	7,159	50.00	23.96	143	3,431
1969	36.5	22,003	50.00	23.35	440	10,275
1968	37.5	177	50.00	22.75	4	80
1967	38.5	9,119	50.00	22.16	182	4,041
1966	39.5	14,348	50.00	21.58	287	6,191
1965	40.5	40,984	50.00	21.00	820	17,216
1964	41.5	170,552	50.00	20.44	3,411	69,725
1963	42.5	15,152	50.00	19.89	303	6,027
1962	43.5	631	50.00	19.35	13	244
1961	44.5	77,825	50.00	18.81	1,557	29,285
1960	45.5	7,826	50.00	18.29	157	2,863
1959	46.5	11,550	50.00	17.78	231	4,108
1958	47.5	67,092	50.00	17.28	1,342	23,187
1957	48.5	0	50.00	16.79	0	0
1956	49.5	1,239	50.00	16.31	25	404
1955	50.5	2,180	50.00	15.84	44	691
1954	51.5	0	50.00	15.38	0	0
1953	52.5	0	50.00	14.93	0	0
1952	53.5	0	50.00	14.49	0	0
1951	54.5	0	50.00	14.07	0	0
1950	55.5	0	50.00	13.65	0	0
1949	56.5	193	50.00	13.24	4	51
1948	57.5	0	50.00	12.84	0	0
1947	58.5	0	50.00	12.46	0	0
1946	59.5	81	50.00	12.08	2	20
		5,114,856			102,297	3,827,596

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 37.42

Duke Energy Kentucky

356.00 - Overhead Conductors and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R0.5 32.12

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	60,364	44.00	43.69	1,372	59,939
2004	1.5	256,399	44.00	43.07	5,827	250,982
2003	2.5	228,703	44.00	42.45	5,198	220,660
2002	3.5	48,509	44.00	41.84	1,102	46,124
2001	4.5	34,984	44.00	41.22	795	32,776
2000	5.5	73,286	44.00	40.61	1,666	67,641
1999	6.5	213,957	44.00	40.00	4,863	194,509
1998	7.5	2,372	44.00	39.39	54	2,124
1997	8.5	13,937	44.00	38.79	317	12,285
1996	9.5	53,985	44.00	38.18	1,227	46,845
1995	10.5	228,572	44.00	37.58	5,195	195,206
1994	11.5	6,562	44.00	36.98	149	5,515
1993	12.5	51,461	44.00	36.37	1,170	42,543
1992	13.5	406,902	44.00	35.78	9,248	330,849
1991	14.5	60,593	44.00	35.18	1,377	48,444
1990	15.5	66,664	44.00	34.58	1,515	52,396
1989	16.5	0	44.00	33.99	0	0
1988	17.5	484,055	44.00	33.40	11,001	367,392
1987	18.5	602	44.00	32.80	14	449
1986	19.5	3,490	44.00	32.22	79	2,555
1985	20.5	37,339	44.00	31.63	849	26,842
1984	21.5	0	44.00	31.05	0	0
1983	22.5	602,300	44.00	30.47	13,689	417,040
1982	23.5	0	44.00	29.89	0	0
1981	24.5	232,307	44.00	29.31	5,280	154,770
1980	25.5	11,092	44.00	28.74	252	7,246
1979	26.5	6,783	44.00	28.18	154	4,343
1978	27.5	0	44.00	27.61	0	0
1977	28.5	22,993	44.00	27.05	523	14,137
1976	29.5	102,769	44.00	26.50	2,336	61,891
1975	30.5	21,710	44.00	25.95	493	12,803
1974	31.5	170,926	44.00	25.40	3,885	98,679
1973	32.5	134,406	44.00	24.86	3,055	75,941
1972	33.5	11,834	44.00	24.32	269	6,542
1971	34.5	79,645	44.00	23.79	1,810	43,067

Duke Energy Kentucky

356.00 - Overhead Conductors and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R0.5 32.12

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1970	35.5	1,112	44.00	23.27	25	588
1969	36.5	33,817	44.00	22.74	769	17,481
1968	37.5	92	44.00	22.23	2	47
1967	38.5	10,642	44.00	21.72	242	5,252
1966	39.5	20,937	44.00	21.21	476	10,093
1965	40.5	73,095	44.00	20.71	1,661	34,405
1964	41.5	251,553	44.00	20.22	5,717	115,573
1963	42.5	11,584	44.00	19.73	263	5,193
1962	43.5	869	44.00	19.24	20	380
1961	44.5	81,927	44.00	18.76	1,862	34,932
1960	45.5	17,927	44.00	18.29	407	7,451
1959	46.5	7,413	44.00	17.82	168	3,002
1958	47.5	114,465	44.00	17.35	2,601	45,145
1957	48.5	87	44.00	16.89	2	33
1956	49.5	3,685	44.00	16.44	84	1,377
1955	50.5	3,183	44.00	15.99	72	1,157
1954	51.5	0	44.00	15.55	0	0
1953	52.5	0	44.00	15.11	0	0
1952	53.5	0	44.00	14.67	0	0
1951	54.5	0	44.00	14.24	0	0
1950	55.5	0	44.00	13.81	0	0
1949	56.5	1,311	44.00	13.39	30	399
1925	80.5	308	44.00	3.59	7	25
		4,363,508			99,171	3,185,069

AVERAGE SERVICE LIFE	44.00
AVERAGE REMAINING LIFE	32.12

Duke Energy Kentucky

360.10 - Rights of Way

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 70 R3 48.96

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2000	5.5	18,278	70.00	64.61	261	16,870
1996	9.5	66,779	70.00	60.73	954	57,938
1995	10.5	178,951	70.00	59.77	2,556	152,800
1994	11.5	142,884	70.00	58.81	2,041	120,048
1993	12.5	166,625	70.00	57.86	2,380	137,722
1992	13.5	206,935	70.00	56.91	2,956	168,228
1991	14.5	284,100	70.00	55.96	4,059	227,113
1990	15.5	238,356	70.00	55.02	3,405	187,331
1989	16.5	273,358	70.00	54.08	3,905	211,173
1988	17.5	162,262	70.00	53.14	2,318	123,182
1987	18.5	374,183	70.00	52.21	5,345	279,089
1986	19.5	226,882	70.00	51.28	3,241	166,221
1985	20.5	222,229	70.00	50.36	3,175	159,889
1984	21.5	140,618	70.00	49.45	2,009	99,332
1983	22.5	238,309	70.00	48.54	3,404	165,239
1982	23.5	114,830	70.00	47.63	1,640	78,136
1981	24.5	123,971	70.00	46.73	1,771	82,762
1980	25.5	120,457	70.00	45.84	1,721	78,878
1979	26.5	71,128	70.00	44.95	1,016	45,674
1978	27.5	62,310	70.00	44.07	890	39,226
1977	28.5	52,603	70.00	43.19	751	32,457
1976	29.5	75,551	70.00	42.32	1,079	45,677
1975	30.5	61,889	70.00	41.46	884	36,654
1974	31.5	140,806	70.00	40.60	2,012	81,668
1973	32.5	78,177	70.00	39.75	1,117	44,394
1972	33.5	67,572	70.00	38.91	965	37,557
1971	34.5	45,736	70.00	38.07	653	24,874
1970	35.5	47,116	70.00	37.24	673	25,066
1969	36.5	31,019	70.00	36.42	443	16,137
1968	37.5	34,611	70.00	35.60	494	17,603
1967	38.5	37,661	70.00	34.79	538	18,719
1966	39.5	28,568	70.00	33.99	408	13,873
1965	40.5	47,057	70.00	33.20	672	22,318
1964	41.5	21,298	70.00	32.41	304	9,862
1963	42.5	23,590	70.00	31.64	337	10,662

Duke Energy Kentucky

360.10 - Rights of Way

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 70 R3 48.96

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1962	43.5	30,066	70.00	30.87	430	13,258
1961	44.5	35,962	70.00	30.11	514	15,467
1960	45.5	17,228	70.00	29.35	246	7,224
1959	46.5	11,598	70.00	28.61	166	4,740
1958	47.5	14,105	70.00	27.87	202	5,616
1957	48.5	13,905	70.00	27.14	199	5,392
1956	49.5	14,045	70.00	26.42	201	5,302
1955	50.5	4,761	70.00	25.72	68	1,749
1954	51.5	9,503	70.00	25.02	136	3,396
1953	52.5	2,604	70.00	24.33	37	905
1952	53.5	12,727	70.00	23.65	182	4,299
1951	54.5	8,347	70.00	22.98	119	2,740
1950	55.5	1,738	70.00	22.32	25	554
1949	56.5	8,676	70.00	21.67	124	2,686
1948	57.5	3,349	70.00	21.03	48	1,006
1947	58.5	1,800	70.00	20.41	26	525
1946	59.5	782	70.00	19.79	11	221
1945	60.5	331	70.00	19.19	5	91
1944	61.5	462	70.00	18.60	7	123
1943	62.5	4,898	70.00	18.03	70	1,261
1942	63.5	5,164	70.00	17.46	74	1,288
1941	64.5	1,574	70.00	16.91	22	380
1940	65.5	3,031	70.00	16.38	43	709
1939	66.5	567	70.00	15.85	8	128
1938	67.5	4,556	70.00	15.34	65	998
1937	68.5	21,091	70.00	14.84	301	4,473
		4,459,567			63,708	3,118,902

AVERAGE SERVICE LIFE	70.00
AVERAGE REMAINING LIFE	48.96

Duke Energy Kentucky

3610 - Structures and Improvements

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 55 R3 24.42

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2005	0.5	0	55.00	54.51	0	0
2004	1.5	47,303	55.00	53.52	860	46,033
1998	7.5	31,741	55.00	47.68	577	27,519
1975	30.5	92	55.00	27.14	2	45
1974	31.5	94,229	55.00	26.34	1,713	45,127
1969	36.5	6,838	55.00	22.50	124	2,798
1968	37.5	0	55.00	21.77	0	0
1967	38.5	2,238	55.00	21.04	41	856
1964	41.5	2,440	55.00	18.94	44	840
1963	42.5	0	55.00	18.27	0	0
1962	43.5	3,728	55.00	17.61	68	1,193
1958	47.5	2,969	55.00	15.10	54	815
1955	50.5	713	55.00	13.39	13	174
1954	51.5	786	55.00	12.85	14	184
1953	52.5	11,764	55.00	12.33	214	2,637
1950	55.5	272	55.00	10.87	5	54
1946	59.5	490	55.00	9.16	9	82
1943	62.5	1,679	55.00	8.05	31	246
1942	63.5	1,572	55.00	7.71	29	220
1941	64.5	0	55.00	7.38	0	0
1940	65.5	475	55.00	7.07	9	61
1939	66.5	28,192	55.00	6.76	513	3,466
1929	76.5	46,882	55.00	4.08	852	3,474
1928	77.5	5,002	55.00	3.82	91	347
1927	78.5	8,081	55.00	3.56	147	523
1926	79.5	0	55.00	3.30	0	0
1925	80.5	10,863	55.00	3.05	198	602
1902	103.5	911	55.00	0.50	17	8
		309,259			5,623	137,306

AVERAGE SERVICE LIFE	55.00
AVERAGE REMAINING LIFE	24.42

Duke Energy Kentucky

362.00 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 46 R2 33.43

			BG/VG Average			
Year (1)	Age (2)	Surviving Investment (3)	Service Life (4)	Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	1,735,915	46.00	45.55	37,737	1,718,780
2004	1.5	1,274,942	46.00	44.64	27,716	1,237,377
2003	2.5	1,218,822	46.00	43.75	26,496	1,159,176
2002	3.5	950,093	46.00	42.86	20,654	885,214
2001	4.5	1,625,081	46.00	41.97	35,328	1,482,868
2000	5.5	20,779	46.00	41.10	452	18,564
1999	6.5	16,243	46.00	40.22	353	14,203
1998	7.5	21,561	46.00	39.36	469	18,448
1997	8.5	299,051	46.00	38.50	6,501	250,293
1996	9.5	216,481	46.00	37.65	4,706	177,175
1995	10.5	748,296	46.00	36.80	16,267	598,676
1994	11.5	148,493	46.00	35.96	3,228	116,096
1993	12.5	1,006,212	46.00	35.13	21,874	768,509
1992	13.5	783,851	46.00	34.31	17,040	584,645
1991	14.5	1,497,099	46.00	33.49	32,546	1,090,074
1990	15.5	66,705	46.00	32.69	1,450	47,397
1988	17.5	861,429	46.00	31.09	18,727	582,262
1987	18.5	128,175	46.00	30.31	2,786	84,452
1986	19.5	10,311	46.00	29.53	224	6,620
1985	20.5	16,349	46.00	28.77	355	10,224
1984	21.5	328,448	46.00	28.01	7,140	199,982
1983	22.5	586,116	46.00	27.26	12,742	347,319
1982	23.5	358,020	46.00	26.52	7,783	206,394
1981	24.5	140,928	46.00	25.79	3,064	79,005
1980	25.5	453,173	46.00	25.07	9,852	246,948
1979	26.5	160,022	46.00	24.36	3,479	84,726
1977	28.5	584,507	46.00	22.96	12,707	291,775
1976	29.5	1,234,721	46.00	22.28	26,842	598,077
1975	30.5	1,028	46.00	21.61	22	483
1974	31.5	270,408	46.00	20.95	5,878	123,165
1973	32.5	147,226	46.00	20.30	3,201	64,983
1972	33.5	54,331	46.00	19.67	1,181	23,228
1971	34.5	378,133	46.00	19.04	8,220	156,517
1970	35.5	48,432	46.00	18.43	1,053	19,401
1969	36.5	147,385	46.00	17.82	3,204	57,110

Duke Energy Kentucky

362.00 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 46 R2 33.43

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1968	37.5	4,356	46.00	17.23	95	1,632
1967	38.5	53,026	46.00	16.66	1,153	19,201
1966	39.5	112,726	46.00	16.09	2,451	39,432
1965	40.5	25,456	46.00	15.54	553	8,599
1964	41.5	193,551	46.00	15.00	4,208	63,108
1963	42.5	4,723	46.00	14.47	103	1,486
1962	43.5	9,507	46.00	13.96	207	2,884
1961	44.5	24,589	46.00	13.46	535	7,193
1960	45.5	115,033	46.00	12.97	2,501	32,426
1959	46.5	21,867	46.00	12.49	475	5,938
1958	47.5	167,819	46.00	12.03	3,648	43,885
1957	48.5	66,283	46.00	11.58	1,441	16,685
1956	49.5	32,873	46.00	11.14	715	7,963
1955	50.5	162,252	46.00	10.72	3,527	37,805
1954	51.5	26,947	46.00	10.31	586	6,037
1953	52.5	5,829	46.00	9.91	127	1,255
1952	53.5	23,745	46.00	9.52	516	4,913
1951	54.5	221	46.00	9.14	5	44
1950	55.5	10,362	46.00	8.77	225	1,977
1949	56.5	20,994	46.00	8.42	456	3,842
1948	57.5	604	46.00	8.07	13	106
1945	60.5	632	46.00	7.08	14	97
1944	61.5	15,645	46.00	6.77	340	2,302
1942	63.5	1,513	46.00	6.16	33	203
1941	64.5	1,923	46.00	5.86	42	245
1940	65.5	0	46.00	5.56	0	0
1939	66.5	849	46.00	5.27	18	97
1938	67.5	85,766	46.00	4.97	1,864	9,274
1927	78.5	34,803	46.00	1.84	757	1,396
1926	79.5	51,525	46.00	1.58	1,120	1,770
		18,814,186			409,004	13,671,960

AVERAGE SERVICE LIFE 46.00
AVERAGE REMAINING LIFE 33.43

Duke Energy Kentucky

362.20 - Station Equipment - Major

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 45 R2.5 33.41

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	1,106,127	45.00	44.53	24,581	1,094,486
2004	1.5	948,700	45.00	43.58	21,082	918,859
2003	2.5	627,864	45.00	42.65	13,953	595,031
2002	3.5	611,211	45.00	41.71	13,582	566,574
2001	4.5	2,876,704	45.00	40.79	63,927	2,607,261
2000	5.5	1,228,112	45.00	39.86	27,291	1,087,887
1999	6.5	0	45.00	38.94	0	0
1998	7.5	0	45.00	38.03	0	0
1997	8.5	0	45.00	37.13	0	0
1996	9.5	0	45.00	36.22	0	0
1995	10.5	202,678	45.00	35.33	4,504	159,132
1994	11.5	0	45.00	34.44	0	0
1993	12.5	939,636	45.00	33.56	20,881	700,864
1992	13.5	377,797	45.00	32.69	8,395	274,470
1991	14.5	1,100,146	45.00	31.83	24,448	778,128
1990	15.5	34,369	45.00	30.97	764	23,655
1989	16.5	101,134	45.00	30.12	2,247	67,701
1988	17.5	83,801	45.00	29.28	1,862	54,534
1987	18.5	154,116	45.00	28.45	3,425	97,447
1986	19.5	41,970	45.00	27.63	933	25,771
1985	20.5	0	45.00	26.82	0	0
1984	21.5	411,606	45.00	26.02	9,147	237,972
1983	22.5	698,321	45.00	25.22	15,518	391,432
1982	23.5	353,462	45.00	24.44	7,855	191,982
1981	24.5	249,701	45.00	23.67	5,549	131,340
1980	25.5	374,457	45.00	22.91	8,321	190,623
1979	26.5	199,177	45.00	22.16	4,426	98,071
1978	27.5	0	45.00	21.42	0	0
1977	28.5	406,264	45.00	20.69	9,028	186,791
1976	29.5	608,954	45.00	19.97	13,532	270,295
1975	30.5	0	45.00	19.27	0	0
1974	31.5	275,341	45.00	18.58	6,119	113,677
1973	32.5	37,552	45.00	17.90	834	14,938
1972	33.5	58,972	45.00	17.24	1,310	22,589
1971	34.5	201,756	45.00	16.59	4,483	74,366

Duke Energy Kentucky

362.20 - Station Equipment - Major

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 45 R2.5 33.41

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1970	35.5	9,367	45.00	15.95	208	3,320
1969	36.5	98,485	45.00	15.33	2,189	33,552
1968	37.5	0	45.00	14.73	0	0
1967	38.5	15,812	45.00	14.14	351	4,968
1966	39.5	270,348	45.00	13.57	6,008	81,512
1965	40.5	0	45.00	13.01	0	0
1964	41.5	121,290	45.00	12.48	2,695	33,637
1963	42.5	26,873	45.00	11.96	597	7,144
1962	43.5	55,641	45.00	11.47	1,236	14,178
1961	44.5	0	45.00	10.99	0	0
1960	45.5	40,319	45.00	10.53	896	9,434
1959	46.5	366	45.00	10.09	8	82
1958	47.5	14,414	45.00	9.67	320	3,098
1957	48.5	0	45.00	9.27	0	0
1956	49.5	0	45.00	8.89	0	0
1955	50.5	101,678	45.00	8.52	2,260	19,259
1954	51.5	0	45.00	8.18	0	0
1953	52.5	0	45.00	7.85	0	0
1952	53.5	0	45.00	7.53	0	0
1951	54.5	0	45.00	7.23	0	0
1950	55.5	1,151	45.00	6.94	26	178
		15,065,670			334,793	11,186,234

AVERAGE SERVICE LIFE	45.00
AVERAGE REMAINING LIFE	33.41

Duke Energy Kentucky

363.50 - Station Equipment - Electronic

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: **15** **R2** **14.41**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	89,349	15.00	14.55	5,957	86,661
2004	1.5	16,657	15.00	13.66	1,110	15,168
		106,006			7,067	101,830

AVERAGE SERVICE LIFE	15.00
AVERAGE REMAINING LIFE	14.41

Duke Energy Kentucky

Depreciation Life Analysis Study Through 2005

Account: **364.00 - Poles, Towers and Fixtures**

Balance: **43,026,869**

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Comments: Company's T-Cut and Curve Selection Proposed life and curve seems arbitrarily selected. OLT (as described in Company study) provides excellent data for analysis. Full Curve Best fit (using Company's OLT) shows 52-L0. Industry range is between 3 and 55. Therefore the best fit of 52-L0 is recommended.

Company:

Observed Life Table Results
Duke Energy Kentucky
Account: 364.00 - Poles, Towers and Fixtures

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		**1956 - 2005**			
0	49,341,219	90,944	0.0018	0.9982	1.0000
0.5	45,133,474	312,320	0.0069	0.9931	0.9982
1.5	43,732,707	358,665	0.0082	0.9918	0.9913
2.5	42,384,108	396,863	0.0094	0.9906	0.9832
3.5	41,603,230	350,643	0.0084	0.9916	0.9740
4.5	40,602,026	337,414	0.0083	0.9917	0.9658
5.5	39,209,631	330,708	0.0084	0.9916	0.9578
6.5	37,466,334	327,752	0.0087	0.9913	0.9498
7.5	35,664,352	326,383	0.0092	0.9908	0.9415
8.5	34,099,216	374,463	0.0110	0.9890	0.9328
9.5	32,259,564	305,926	0.0095	0.9905	0.9225
10.5	30,146,314	227,617	0.0076	0.9924	0.9137
11.5	27,906,294	346,029	0.0124	0.9876	0.9068
12.5	25,646,675	225,516	0.0088	0.9912	0.8956
13.5	23,639,749	264,495	0.0112	0.9888	0.8877
14.5	21,878,341	263,337	0.0120	0.9880	0.8778
15.5	20,548,284	301,726	0.0147	0.9853	0.8673
16.5	18,388,152	231,066	0.0126	0.9874	0.8546
17.5	17,357,400	219,040	0.0126	0.9874	0.8438
18.5	15,971,351	206,653	0.0129	0.9871	0.8332
19.5	14,926,262	235,977	0.0158	0.9842	0.8225
20.5	13,931,761	190,119	0.0136	0.9864	0.8095
21.5	13,082,198	179,041	0.0137	0.9863	0.7985
22.5	12,221,650	212,123	0.0174	0.9826	0.7876
23.5	11,321,966	175,221	0.0155	0.9845	0.7739
24.5	10,392,759	135,642	0.0131	0.9869	0.7619
25.5	9,351,143	132,480	0.0142	0.9858	0.7519
26.5	8,615,846	127,920	0.0148	0.9852	0.7412
27.5	8,054,896	135,268	0.0168	0.9832	0.7302
28.5	7,475,389	133,238	0.0178	0.9822	0.7179
29.5	6,974,834	129,827	0.0186	0.9814	0.7051
30.5	6,486,952	128,411	0.0198	0.9802	0.6920
31.5	5,944,411	136,795	0.0230	0.9770	0.6783
32.5	5,306,442	103,700	0.0195	0.9805	0.6627
33.5	4,831,522	114,174	0.0236	0.9764	0.6498
34.5	4,431,757	78,737	0.0178	0.9822	0.6345
35.5	4,077,761	104,050	0.0255	0.9745	0.6232
36.5	3,743,570	88,437	0.0236	0.9764	0.6073
37.5	3,438,418	80,208	0.0233	0.9767	0.5930
38.5	3,186,458	70,307	0.0221	0.9779	0.5792
39.5	2,940,109	59,766	0.0203	0.9797	0.5664
40.5	2,674,280	53,805	0.0201	0.9799	0.5549
41.5	2,418,026	34,615	0.0143	0.9857	0.5437
42.5	2,198,704	40,130	0.0183	0.9817	0.5359
43.5	1,983,981	34,289	0.0173	0.9827	0.5261
44.5	1,751,315	30,108	0.0172	0.9828	0.5170
45.5	1,613,209	31,601	0.0196	0.9804	0.5081

Observed Life Table Results
Duke Energy Kentucky
Account: 364.00 - Poles, Towers and Fixtures

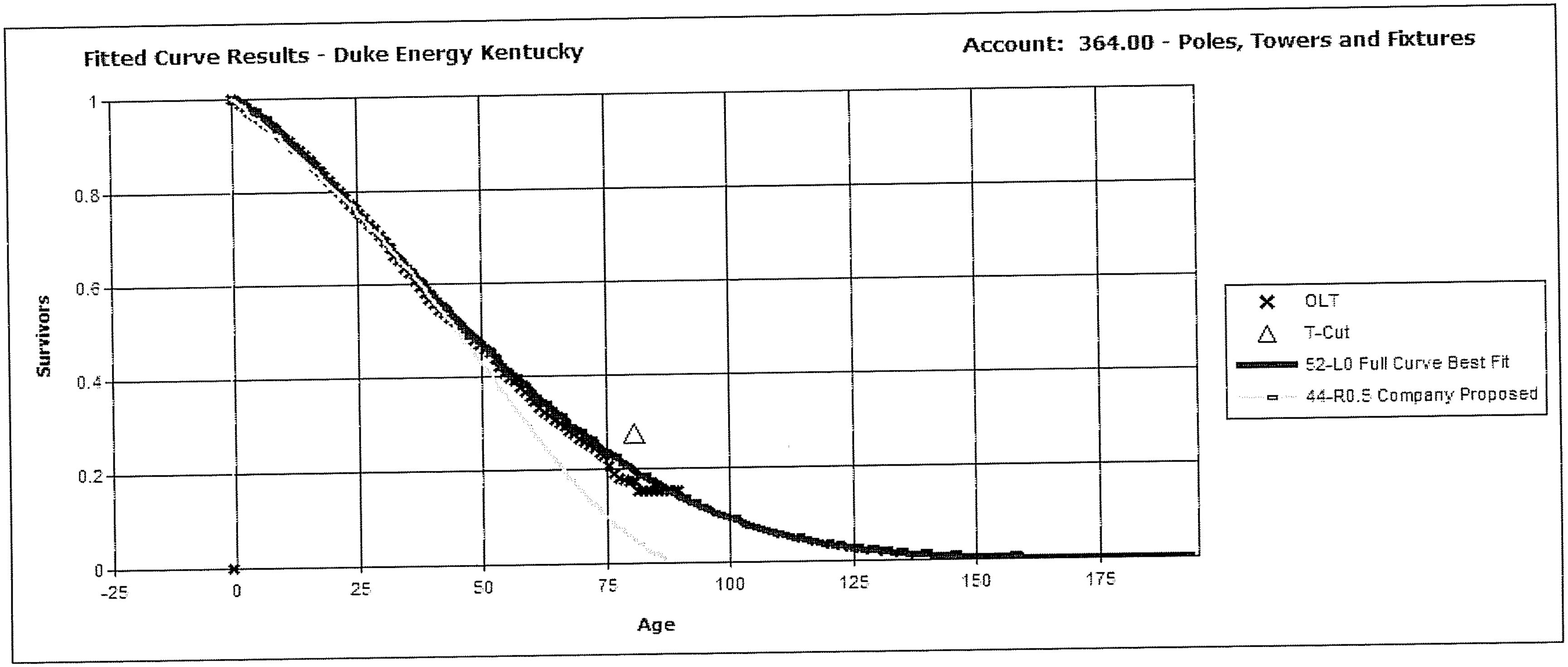
Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
46.5	1,457,232	28,304	0.0194	0.9806	0.4981
47.5	1,310,576	26,924	0.0205	0.9795	0.4884
48.5	1,165,763	22,042	0.0189	0.9811	0.4784
49.5	1,045,932	23,015	0.0220	0.9780	0.4694
50.5	914,937	18,388	0.0201	0.9799	0.4591
51.5	809,973	21,716	0.0268	0.9732	0.4499
52.5	706,263	28,841	0.0408	0.9592	0.4378
53.5	591,551	16,876	0.0285	0.9715	0.4199
54.5	515,374	12,740	0.0247	0.9753	0.4079
55.5	442,794	10,285	0.0232	0.9768	0.3978
56.5	389,002	12,542	0.0322	0.9678	0.3886
57.5	350,490	10,814	0.0309	0.9691	0.3761
58.5	303,756	7,286	0.0240	0.9760	0.3645
59.5	281,810	7,836	0.0278	0.9722	0.3558
60.5	261,022	9,758	0.0374	0.9626	0.3459
61.5	242,823	7,049	0.0290	0.9710	0.3330
62.5	230,066	6,475	0.0281	0.9719	0.3233
63.5	202,197	5,224	0.0258	0.9742	0.3142
64.5	181,308	3,979	0.0219	0.9781	0.3061
65.5	157,967	3,929	0.0249	0.9751	0.2994
66.5	138,471	4,798	0.0346	0.9654	0.2919
67.5	122,767	3,284	0.0267	0.9733	0.2818
68.5	107,123	3,210	0.0300	0.9700	0.2743
69.5	100,572	3,088	0.0307	0.9693	0.2661
70.5	85,277	2,309	0.0271	0.9729	0.2579
71.5	69,565	2,189	0.0315	0.9685	0.2509
72.5	54,328	2,383	0.0439	0.9561	0.2430
73.5	43,147	1,269	0.0294	0.9706	0.2323
74.5	28,530	2,260	0.0792	0.9208	0.2255
75.5	21,398	1,881	0.0879	0.9121	0.2076
76.5	15,506	766	0.0494	0.9506	0.1894
77.5	10,167	136	0.0134	0.9866	0.1800
78.5	7,359	157	0.0213	0.9787	0.1776
79.5	4,254	52	0.0122	0.9878	0.1738
80.5	934	100	0.1071	0.8929	0.1717
81.5	651	0	0.0000	1.0000	0.1533
82.5	608	0	0.0000	1.0000	0.1533
83.5	514	0	0.0000	1.0000	0.1533
84.5	472	0	0.0000	1.0000	0.1533
85.5	358	0	0.0000	1.0000	0.1533
86.5	227	0	0.0000	1.0000	0.1533
87.5	183	0	0.0000	1.0000	0.1533
88.5	131	0	0.0000	1.0000	0.1533
89.5	131	0	0.0000	1.0000	0.1533

Best Fit Curve Results
Duke Energy Kentucky
Account: 364.00 - Poles, Towers and Fixtures

Curve	Life	Sum of Squared Differences
BAND	**1956 - 2005**	
L0	52.0	10,070.602
L0.5	51.0	10,184.710
S-0.5	49.0	10,270.383
O1	48.0	10,333.404
O2	53.0	10,422.626
R0.5	49.0	10,577.852
L1	51.0	10,975.478
S0	49.0	11,445.131
R1	49.0	12,350.715
L1.5	51.0	12,657.996
S0.5	50.0	13,288.536
R1.5	50.0	14,983.524
L2	51.0	15,246.105
O3	55.0	15,317.886
S1	50.0	15,972.561
R2	50.0	18,799.911
S1.5	51.0	19,277.118
L3	51.0	22,988.834
R2.5	51.0	23,322.060
S2	51.0	23,342.833
O4	55.0	27,188.752
R3	51.0	28,997.942
S3	51.0	32,302.221
L4	51.0	35,281.957
R4	51.0	39,892.141
S4	50.0	44,495.347
L5	50.0	47,523.685
R5	50.0	52,838.644
S5	50.0	55,927.381
S6	49.0	65,743.346
SQ	47.0	84,998.020

Analytical Parameters

OLT Placement Band:	1915 - 2005
OLT Experience Band:	1956 - 2005
Minimum Life Parameter:	3
Maximum Life Parameter:	55
Life Increment Parameter:	1
Max Age (T-Cut):	82.0



Analytical Parameters

OLT Placement Band:	1915 - 2005
OLT Experience Band:	1956 - 2005
Minimum Life Parameter:	3
Maximum Life Parameter:	55
Life Increment Parameter:	1
Max Age (T-Cut):	82.0

Duke Energy Kentucky

364.00 - Poles, Towers and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 52 L0 43.52

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	4,438,391	52.00	51.54	85,354	4,399,296
2004	1.5	1,271,185	52.00	50.75	24,446	1,240,552
2003	2.5	1,191,632	52.00	50.02	22,916	1,146,156
2002	3.5	620,243	52.00	49.33	11,928	588,386
2001	4.5	851,515	52.00	48.68	16,375	797,123
2000	5.5	1,180,999	52.00	48.06	22,712	1,091,451
1999	6.5	1,565,897	52.00	47.46	30,113	1,429,223
1998	7.5	1,593,397	52.00	46.89	30,642	1,436,747
1997	8.5	1,330,308	52.00	46.33	25,583	1,185,355
1996	9.5	1,525,791	52.00	45.80	29,342	1,343,813
1995	10.5	1,857,515	52.00	45.28	35,721	1,617,404
1994	11.5	2,051,825	52.00	44.77	39,458	1,766,670
1993	12.5	1,938,986	52.00	44.28	37,288	1,651,190
1992	13.5	1,854,834	52.00	43.80	35,670	1,562,452
1991	14.5	1,547,974	52.00	43.34	29,769	1,290,061
1990	15.5	1,117,601	52.00	42.88	21,492	921,588
1989	16.5	1,909,109	52.00	42.43	36,714	1,557,893
1988	17.5	838,491	52.00	42.00	16,125	677,191
1987	18.5	1,198,162	52.00	41.57	23,042	957,804
1986	19.5	856,295	52.00	41.15	16,467	677,598
1985	20.5	806,856	52.00	40.74	15,516	632,072
1984	21.5	713,244	52.00	40.33	13,716	553,171
1983	22.5	750,259	52.00	39.93	14,428	576,113
1982	23.5	747,852	52.00	39.54	14,382	568,601
1981	24.5	840,859	52.00	39.15	16,170	633,029
1980	25.5	983,500	52.00	38.76	18,913	733,146
1979	26.5	653,501	52.00	38.38	12,567	482,372
1978	27.5	503,901	52.00	38.01	9,690	368,299
1977	28.5	498,787	52.00	37.63	9,592	360,985
1976	29.5	402,519	52.00	37.26	7,741	288,456
1975	30.5	377,103	52.00	36.90	7,252	267,591
1974	31.5	418,993	52.00	36.54	8,058	294,401
1973	32.5	501,463	52.00	36.18	9,644	348,891
1972	33.5	375,229	52.00	35.82	7,216	258,504
1971	34.5	285,941	52.00	35.47	5,499	195,059

Duke Energy Kentucky

364.00 - Poles, Towers and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 52 L0 43.52

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1970	35.5	276,706	52.00	35.12	5,321	186,907
1969	36.5	230,917	52.00	34.78	4,441	154,448
1968	37.5	217,160	52.00	34.44	4,176	143,821
1967	38.5	172,857	52.00	34.10	3,324	113,356
1966	39.5	177,292	52.00	33.77	3,409	115,124
1965	40.5	206,582	52.00	33.43	3,973	132,825
1964	41.5	202,449	52.00	33.11	3,893	128,889
1963	42.5	184,708	52.00	32.78	3,552	116,439
1962	43.5	174,620	52.00	32.46	3,358	108,998
1961	44.5	198,376	52.00	32.14	3,815	122,608
1960	45.5	111,712	52.00	31.82	2,148	68,366
1959	46.5	124,376	52.00	31.51	2,392	75,367
1958	47.5	118,352	52.00	31.20	2,276	71,010
1957	48.5	117,915	52.00	30.89	2,268	70,051
1956	49.5	97,789	52.00	30.59	1,881	57,522
1955	50.5	111,588	52.00	30.29	2,146	64,992
1954	51.5	86,576	52.00	29.99	1,665	49,927
1953	52.5	81,994	52.00	29.69	1,577	46,818
1952	53.5	85,872	52.00	29.40	1,651	48,547
1951	54.5	59,300	52.00	29.11	1,140	33,193
1950	55.5	59,840	52.00	28.82	1,151	33,164
1949	56.5	43,507	52.00	28.53	837	23,873
1948	57.5	25,970	52.00	28.25	499	14,109
1947	58.5	35,920	52.00	27.97	691	19,321
1946	59.5	14,660	52.00	27.69	282	7,807
1945	60.5	12,953	52.00	27.42	249	6,830
1944	61.5	8,441	52.00	27.14	162	4,406
1943	62.5	5,708	52.00	26.87	110	2,950
1942	63.5	21,394	52.00	26.61	411	10,946
1941	64.5	15,665	52.00	26.34	301	7,935
1940	65.5	19,361	52.00	26.08	372	9,709
1939	66.5	15,567	52.00	25.81	299	7,728
1938	67.5	10,906	52.00	25.56	210	5,360
1937	68.5	12,360	52.00	25.30	238	6,013
1936	69.5	3,340	52.00	25.04	64	1,609
1935	70.5	12,208	52.00	24.79	235	5,820

Duke Energy Kentucky

364.00 - Poles, Towers and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 52 L0 43.52

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1934	71.5	13,403	52.00	24.54	258	6,325
1933	72.5	13,049	52.00	24.29	251	6,096
1932	73.5	8,798	52.00	24.05	169	4,068
1931	74.5	13,348	52.00	23.80	257	6,110
1930	75.5	4,872	52.00	23.56	94	2,208
1929	76.5	4,012	52.00	23.32	77	1,799
1928	77.5	4,573	52.00	23.08	88	2,030
1927	78.5	2,672	52.00	22.85	51	1,174
1926	79.5	2,948	52.00	22.61	57	1,282
1925	80.5	3,268	52.00	22.38	63	1,406
1924	81.5	183	52.00	22.15	4	78
1923	82.5	43	52.00	21.92	1	18
1922	83.5	94	52.00	21.69	2	39
1921	84.5	42	52.00	21.47	1	17
1920	85.5	114	52.00	21.24	2	47
1919	86.5	131	52.00	21.02	3	53
1918	87.5	45	52.00	20.80	1	18
1917	88.5	52	52.00	20.59	1	21
1916	89.5	0	52.00	20.37	0	0
1915	90.5	131	52.00	20.15	3	51
		43,026,869			827,440	36,008,269

AVERAGE SERVICE LIFE 52.00
AVERAGE REMAINING LIFE 43.52

Duke Energy Kentucky

364.00 - Poles, Towers and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R0.5 34.72

			BG/VG Average			
Year (1)	Age (2)	Surviving Investment (3)	Service Life (4)	Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	4,438,391	44.00	43.69	100,873	4,407,144
2004	1.5	1,271,185	44.00	43.07	28,891	1,244,329
2003	2.5	1,191,632	44.00	42.45	27,083	1,149,725
2002	3.5	620,243	44.00	41.84	14,096	589,748
2001	4.5	851,515	44.00	41.22	19,353	797,769
2000	5.5	1,180,999	44.00	40.61	26,841	1,090,030
1999	6.5	1,565,897	44.00	40.00	35,589	1,423,563
1998	7.5	1,593,397	44.00	39.39	36,214	1,426,529
1997	8.5	1,330,308	44.00	38.79	30,234	1,172,652
1996	9.5	1,525,791	44.00	38.18	34,677	1,323,989
1995	10.5	1,857,515	44.00	37.58	42,216	1,586,365
1994	11.5	2,051,825	44.00	36.98	46,632	1,724,246
1993	12.5	1,938,986	44.00	36.37	44,068	1,602,967
1992	13.5	1,854,834	44.00	35.78	42,155	1,508,149
1991	14.5	1,547,974	44.00	35.18	35,181	1,237,620
1990	15.5	1,117,601	44.00	34.58	25,400	878,395
1989	16.5	1,909,109	44.00	33.99	43,389	1,474,704
1988	17.5	838,491	44.00	33.40	19,057	636,404
1987	18.5	1,198,162	44.00	32.80	27,231	893,305
1986	19.5	856,295	44.00	32.22	19,461	626,970
1985	20.5	806,856	44.00	31.63	18,338	580,025
1984	21.5	713,244	44.00	31.05	16,210	503,271
1983	22.5	750,259	44.00	30.47	17,051	519,488
1982	23.5	747,852	44.00	29.89	16,997	508,005
1981	24.5	840,859	44.00	29.31	19,110	560,207
1980	25.5	983,500	44.00	28.74	22,352	642,476
1979	26.5	653,501	44.00	28.18	14,852	418,480
1978	27.5	503,901	44.00	27.61	11,452	316,231
1977	28.5	498,787	44.00	27.05	11,336	306,681
1976	29.5	402,519	44.00	26.50	9,148	242,412
1975	30.5	377,103	44.00	25.95	8,571	222,388
1974	31.5	418,993	44.00	25.40	9,523	241,892
1973	32.5	501,463	44.00	24.86	11,397	283,333
1972	33.5	375,229	44.00	24.32	8,528	207,434
1971	34.5	285,941	44.00	23.79	6,499	154,619

Duke Energy Kentucky

364.00 - Poles, Towers and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R0.5 34.72

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1970	35.5	276,706	44.00	23.27	6,289	146,314
1969	36.5	230,917	44.00	22.74	5,248	119,365
1968	37.5	217,160	44.00	22.23	4,935	109,706
1967	38.5	172,857	44.00	21.72	3,929	85,317
1966	39.5	177,292	44.00	21.21	4,029	85,467
1965	40.5	206,582	44.00	20.71	4,695	97,236
1964	41.5	202,449	44.00	20.22	4,601	93,013
1963	42.5	184,708	44.00	19.73	4,198	82,805
1962	43.5	174,620	44.00	19.24	3,969	76,358
1961	44.5	198,376	44.00	18.76	4,509	84,585
1960	45.5	111,712	44.00	18.29	2,539	46,428
1959	46.5	124,376	44.00	17.82	2,827	50,366
1958	47.5	118,352	44.00	17.35	2,690	46,678
1957	48.5	117,915	44.00	16.89	2,680	45,276
1956	49.5	97,789	44.00	16.44	2,222	36,538
1955	50.5	111,588	44.00	15.99	2,536	40,555
1954	51.5	86,576	44.00	15.55	1,968	30,591
1953	52.5	81,994	44.00	15.11	1,864	28,152
1952	53.5	85,872	44.00	14.67	1,952	28,633
1951	54.5	59,300	44.00	14.24	1,348	19,192
1950	55.5	59,840	44.00	13.81	1,360	18,787
1949	56.5	43,507	44.00	13.39	989	13,241
1948	57.5	25,970	44.00	12.97	590	7,656
1947	58.5	35,920	44.00	12.56	816	10,250
1946	59.5	14,660	44.00	12.14	333	4,046
1945	60.5	12,953	44.00	11.73	294	3,455
1944	61.5	8,441	44.00	11.33	192	2,173
1943	62.5	5,708	44.00	10.93	130	1,417
1942	63.5	21,394	44.00	10.52	486	5,117
1941	64.5	15,665	44.00	10.12	356	3,605
1940	65.5	19,361	44.00	9.73	440	4,280
1939	66.5	15,567	44.00	9.33	354	3,301
1938	67.5	10,906	44.00	8.94	248	2,215
1937	68.5	12,360	44.00	8.54	281	2,399
1936	69.5	3,340	44.00	8.14	76	618
1935	70.5	12,208	44.00	7.75	277	2,150

Duke Energy Kentucky

364.00 - Poles, Towers and Fixtures

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R0.5 34.72

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1934	71.5	13,403	44.00	7.35	305	2,239
1933	72.5	13,049	44.00	6.95	297	2,061
1932	73.5	8,798	44.00	6.55	200	1,309
1931	74.5	13,348	44.00	6.14	303	1,863
1930	75.5	4,872	44.00	5.73	111	635
1929	76.5	4,012	44.00	5.32	91	485
1928	77.5	4,573	44.00	4.89	104	509
1927	78.5	2,672	44.00	4.47	61	271
1926	79.5	2,948	44.00	4.03	67	270
1925	80.5	3,268	44.00	3.59	74	266
1924	81.5	183	44.00	3.13	4	13
1923	82.5	43	44.00	2.68	1	3
1922	83.5	94	44.00	2.21	2	5
1921	84.5	42	44.00	1.75	1	2
1920	85.5	114	44.00	1.28	3	3
1919	86.5	131	44.00	0.83	3	2
1918	87.5	45	44.00	0.50	1	1
1917	88.5	52	44.00	0.50	1	1
1916	89.5	0	44.00	0.50	0	0
1915	90.5	131	44.00	0.50	3	1
		43,026,869			977,883	33,948,766

AVERAGE SERVICE LIFE	44.00
AVERAGE REMAINING LIFE	34.72

Duke Energy Kentucky

Depreciation Life Analysis Study Through 2005

Account: **365.00 - Overhead Conductor and Devices**

Balance: **61,492,932**

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Comments: Company's T-Cut and Curve Selection Proposed life and curve seems arbitrarily selected. OLT (as described in Company study) provides excellent data for analysis. Full Curve Best fit (using Company's OLT) shows 60-L0 and T-Cut at Company's arbitrarily selected value provides a 59-L0. Industry range is between 4 and 100. Therefore, 60-L0 is recommended.

Company:

Observed Life Table Results
Duke Energy Kentucky
Account: 365.00 - Overhead Conductor and Devices

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1956 - 2005			
0	68,358,043	42,908	0.0006	0.9994	1.0000
0.5	67,664,802	238,414	0.0035	0.9965	0.9994
1.5	63,103,999	314,578	0.0050	0.9950	0.9959
2.5	57,748,656	426,113	0.0074	0.9926	0.9909
3.5	57,113,212	383,610	0.0067	0.9933	0.9836
4.5	54,477,700	504,582	0.0093	0.9907	0.9770
5.5	46,984,793	246,615	0.0052	0.9948	0.9679
6.5	44,688,539	361,272	0.0081	0.9919	0.9629
7.5	42,196,858	426,450	0.0101	0.9899	0.9551
8.5	40,835,407	401,121	0.0098	0.9902	0.9455
9.5	39,043,671	326,692	0.0084	0.9916	0.9362
10.5	36,545,998	317,926	0.0087	0.9913	0.9283
11.5	32,647,062	440,204	0.0135	0.9865	0.9202
12.5	30,083,798	254,625	0.0085	0.9915	0.9078
13.5	27,570,857	279,616	0.0101	0.9899	0.9001
14.5	24,997,138	199,012	0.0080	0.9920	0.8910
15.5	23,360,313	324,383	0.0139	0.9861	0.8839
16.5	20,419,827	179,605	0.0088	0.9912	0.8716
17.5	19,503,855	212,918	0.0109	0.9891	0.8639
18.5	17,880,440	215,449	0.0120	0.9880	0.8545
19.5	16,587,264	272,067	0.0164	0.9836	0.8442
20.5	15,166,107	165,300	0.0109	0.9891	0.8304
21.5	14,220,644	158,568	0.0112	0.9888	0.8213
22.5	12,947,308	228,168	0.0176	0.9824	0.8121
23.5	11,969,327	130,618	0.0109	0.9891	0.7978
24.5	11,246,965	114,905	0.0102	0.9898	0.7891
25.5	10,165,646	118,306	0.0116	0.9884	0.7811
26.5	9,325,283	115,302	0.0124	0.9876	0.7720
27.5	8,906,748	113,340	0.0127	0.9873	0.7624
28.5	8,450,390	111,311	0.0132	0.9868	0.7527
29.5	7,941,067	102,737	0.0129	0.9871	0.7428
30.5	7,684,480	105,632	0.0137	0.9863	0.7332
31.5	6,947,163	128,735	0.0185	0.9815	0.7232
32.5	6,062,502	111,785	0.0184	0.9816	0.7098
33.5	5,518,332	150,051	0.0272	0.9728	0.6967
34.5	4,872,687	89,498	0.0184	0.9816	0.6777
35.5	4,299,656	36,712	0.0085	0.9915	0.6652
36.5	4,025,696	93,535	0.0232	0.9768	0.6595
37.5	3,665,552	45,998	0.0125	0.9875	0.6442
38.5	3,378,947	63,519	0.0188	0.9812	0.6361
39.5	2,998,716	62,387	0.0208	0.9792	0.6241
40.5	2,650,821	41,757	0.0158	0.9842	0.6111
41.5	2,295,590	23,780	0.0104	0.9896	0.6014
42.5	2,053,393	31,103	0.0151	0.9849	0.5951
43.5	1,828,730	17,858	0.0098	0.9902	0.5861
44.5	1,598,126	11,439	0.0072	0.9928	0.5804

Observed Life Table Results
Duke Energy Kentucky
Account: 365.00 - Overhead Conductor and Devices

Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
45.5	1,483,511	10,482	0.0071	0.9929	0.5762
46.5	1,393,229	19,896	0.0143	0.9857	0.5721
47.5	1,268,314	11,585	0.0091	0.9909	0.5639
48.5	1,161,812	24,948	0.0215	0.9785	0.5588
49.5	1,046,535	17,998	0.0172	0.9828	0.5468
50.5	938,608	6,028	0.0064	0.9936	0.5374
51.5	826,869	12,082	0.0146	0.9854	0.5340
52.5	770,139	28,467	0.0370	0.9630	0.5262
53.5	631,971	14,751	0.0233	0.9767	0.5067
54.5	560,279	7,721	0.0138	0.9862	0.4949
55.5	461,906	10,658	0.0231	0.9769	0.4881
56.5	415,005	13,106	0.0316	0.9684	0.4768
57.5	385,036	6,956	0.0181	0.9819	0.4617
58.5	348,432	8,331	0.0239	0.9761	0.4533
59.5	327,649	3,936	0.0120	0.9880	0.4425
60.5	319,073	3,191	0.0100	0.9900	0.4372
61.5	315,051	3,158	0.0100	0.9900	0.4328
62.5	306,033	5,537	0.0181	0.9819	0.4285
63.5	290,085	331	0.0011	0.9989	0.4207
64.5	277,790	10,202	0.0367	0.9633	0.4202
65.5	267,068	2,128	0.0080	0.9920	0.4048
66.5	254,945	16,357	0.0642	0.9358	0.4016
67.5	218,888	11,024	0.0504	0.9496	0.3758
68.5	207,864	15,959	0.0768	0.9232	0.3569
69.5	191,928	2,501	0.0130	0.9870	0.3295

Observed Life Table Results
Duke Energy Kentucky
Account: 365.00 - Overhead Conductor and Devices

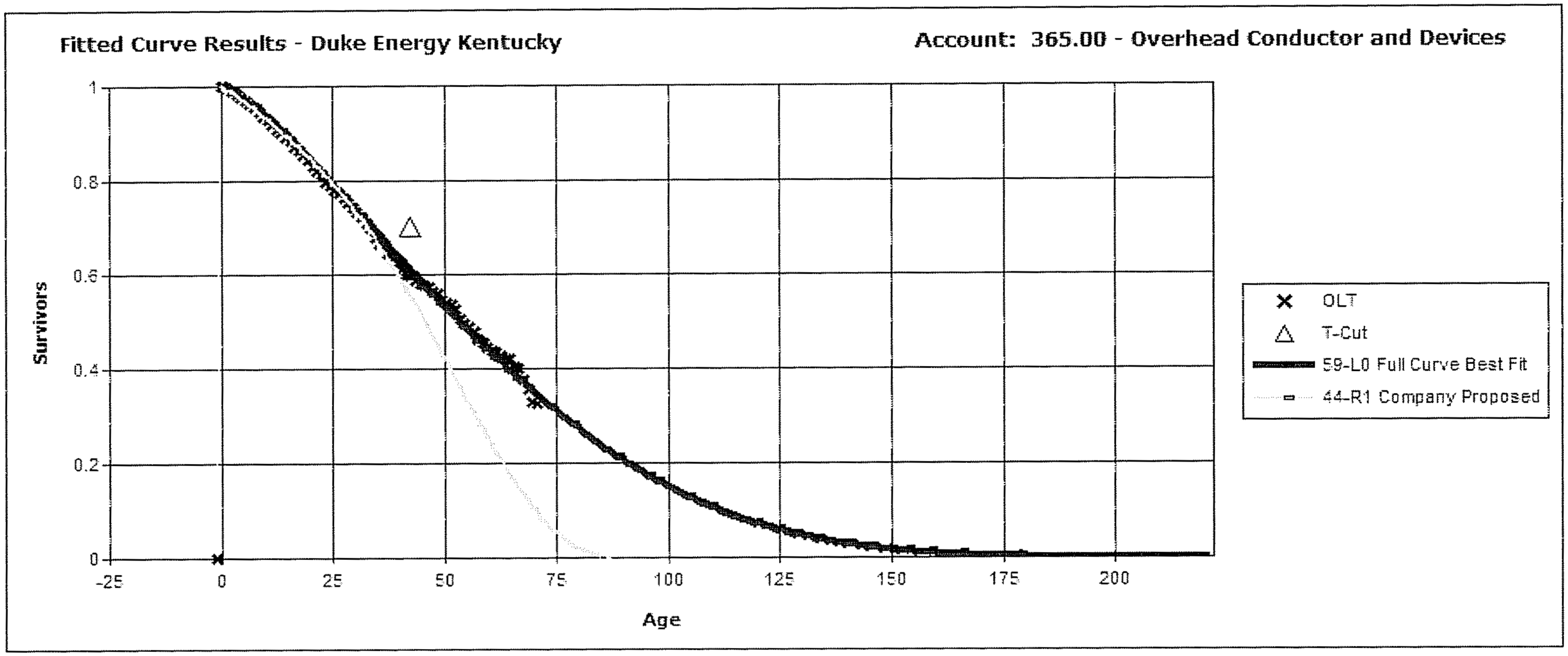
Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
70.5	189,427	1,036	0.0055	0.9945	0.3252

Best Fit Curve Results
Duke Energy Kentucky
Account: 365.00 - Overhead Conductor and Devices

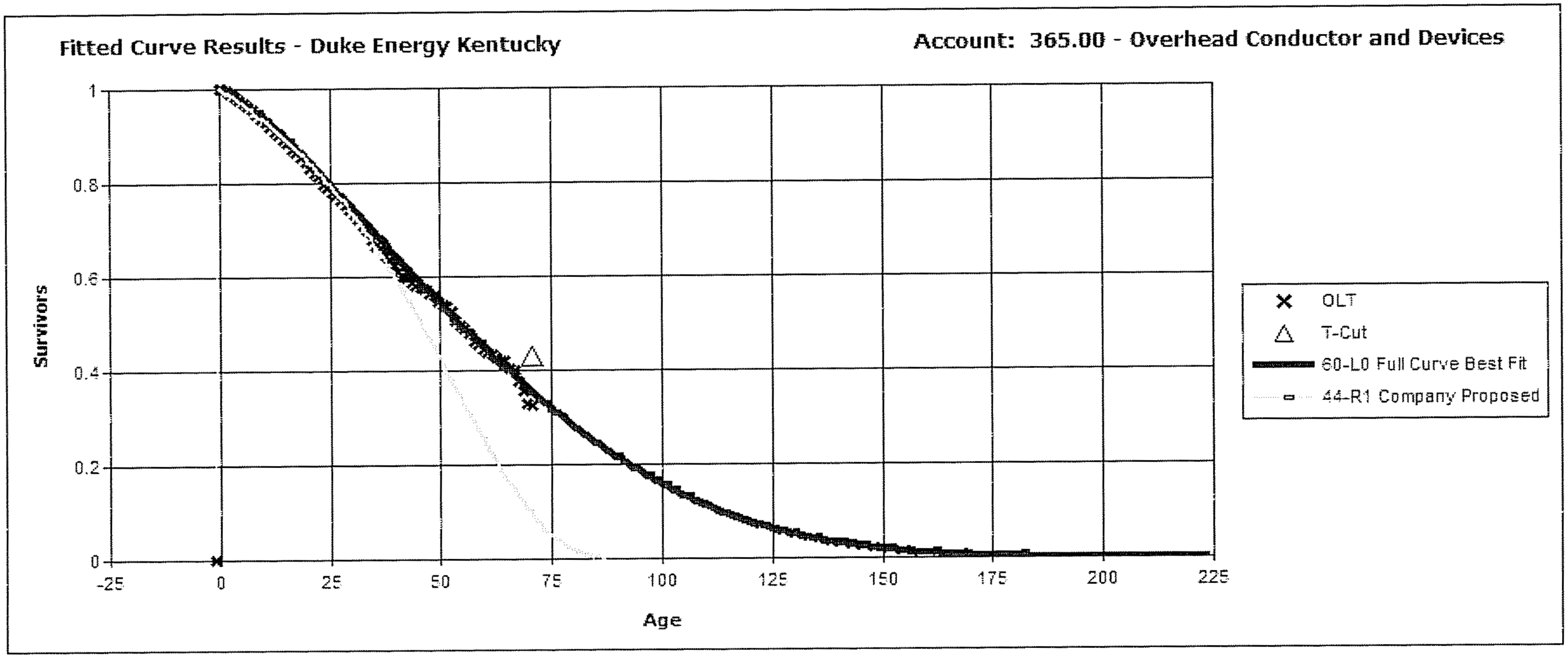
Curve	Life	Sum of Squared Differences
BAND	**1956 - 2005**	
L0	60.0	10,055.331
S-0.5	55.0	10,203.244
O1	56.0	10,251.378
O2	63.0	10,258.938
R0.5	54.0	10,290.475
L0.5	58.0	10,375.582
O3	83.0	10,748.491
S0	54.0	11,057.117
L1	57.0	11,199.378
R1	53.0	11,220.911
O4	100.0	11,643.059
S0.5	54.0	12,467.211
L1.5	56.0	12,844.246
R1.5	53.0	12,991.545
S1	54.0	14,494.640
L2	56.0	15,286.609
R2	54.0	15,596.985
S1.5	54.0	17,049.781
R2.5	54.0	19,053.926
S2	54.0	20,211.917
L3	55.0	21,970.219
R3	55.0	23,341.155
S3	55.0	27,445.892
L4	55.0	31,577.871
R4	56.0	32,725.328
S4	56.0	38,221.095
L5	56.0	42,275.628
R5	57.0	46,146.793
S5	57.0	49,787.998
S6	57.0	60,822.691
SQ	56.0	82,027.933

Analytical Parameters

OLT Placement Band:	1925 - 2005
OLT Experience Band:	1956 - 2005
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	72.0



Analytical Parameters	
OLT Placement Band:	1925 - 2005
OLT Experience Band:	1956 - 2005
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	44.0



Analytical Parameters

OLT Placement Band:	1925 - 2005
OLT Experience Band:	1956 - 2005
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	72.0

Duke Energy Kentucky

365.00 - Overhead Conductor and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 60 L0 51.99

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2005	0.5	825,613	60.00	59.54	13,760	819,265
2004	1.5	4,529,100	60.00	58.73	75,485	4,433,405
2003	2.5	5,162,589	60.00	57.98	86,043	4,989,201
2002	3.5	459,061	60.00	57.28	7,651	438,265
2001	4.5	2,420,864	60.00	56.61	40,348	2,284,226
2000	5.5	7,131,015	60.00	55.97	118,850	6,652,347
1999	6.5	2,158,325	60.00	55.36	35,972	1,991,296
1998	7.5	2,188,084	60.00	54.76	36,468	1,997,098
1997	8.5	1,010,197	60.00	54.19	16,837	912,336
1996	9.5	1,426,634	60.00	53.63	23,777	1,275,176
1995	10.5	2,184,676	60.00	53.09	36,411	1,933,031
1994	11.5	3,587,179	60.00	52.56	59,786	3,142,456
1993	12.5	2,138,429	60.00	52.05	35,640	1,855,009
1992	13.5	2,308,906	60.00	51.55	38,482	1,983,615
1991	14.5	2,320,790	60.00	51.06	38,680	1,974,880
1990	15.5	1,450,510	60.00	50.58	24,175	1,222,740
1989	16.5	2,653,191	60.00	50.11	44,220	2,215,854
1988	17.5	935,766	60.00	49.65	15,596	774,357
1987	18.5	1,410,524	60.00	49.20	23,509	1,156,641
1986	19.5	1,077,911	60.00	48.76	17,965	875,960
1985	20.5	1,149,170	60.00	48.32	19,153	925,554
1984	21.5	780,414	60.00	47.90	13,007	623,006
1983	22.5	1,115,401	60.00	47.48	18,590	882,626
1982	23.5	750,583	60.00	47.07	12,510	588,772
1981	24.5	592,556	60.00	46.66	9,876	460,791
1980	25.5	967,938	60.00	46.26	16,132	746,222
1979	26.5	745,763	60.00	45.86	12,429	570,010
1978	27.5	357,829	60.00	45.47	5,964	271,164
1977	28.5	369,561	60.00	45.08	6,159	277,668
1976	29.5	407,487	60.00	44.70	6,791	303,557
1975	30.5	480,745	60.00	44.32	8,012	355,085
1974	31.5	632,431	60.00	43.94	10,541	463,148
1973	32.5	756,012	60.00	43.57	12,600	548,941
1972	33.5	433,086	60.00	43.20	7,218	311,789
1971	34.5	495,716	60.00	42.83	8,262	353,843
1970	35.5	483,886	60.00	42.46	8,065	342,460
1969	36.5	237,937	60.00	42.10	3,966	166,963
1968	37.5	267,390	60.00	41.74	4,457	186,034
1967	38.5	241,449	60.00	41.39	4,024	166,557
1966	39.5	316,835	60.00	41.04	5,281	216,701
1965	40.5	285,846	60.00	40.69	4,764	193,842
1964	41.5	313,474	60.00	40.34	5,225	210,769
1963	42.5	218,680	60.00	40.00	3,645	145,781
1962	43.5	193,570	60.00	39.66	3,226	127,944
1961	44.5	212,747	60.00	39.32	3,546	139,422

Duke Energy Kentucky

365.00 - Overhead Conductor and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 60 L0 51.99

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1960	45.5	105,205	60.00	38.99	1,753	68,358
1959	46.5	79,800	60.00	38.65	1,330	51,409
1958	47.5	105,019	60.00	38.32	1,750	67,080
1957	48.5	94,917	60.00	38.00	1,582	60,111
1956	49.5	90,329	60.00	37.67	1,505	56,718
1955	50.5	91,444	60.00	37.35	1,524	56,928
1954	51.5	105,711	60.00	37.03	1,762	65,249
1953	52.5	44,647	60.00	36.72	744	27,323
1952	53.5	109,701	60.00	36.41	1,828	66,561
1951	54.5	56,941	60.00	36.09	949	34,254
1950	55.5	90,651	60.00	35.79	1,511	54,067
1949	56.5	36,244	60.00	35.48	604	21,432
1948	57.5	16,863	60.00	35.18	281	9,887
1947	58.5	29,647	60.00	34.88	494	17,233
1946	59.5	12,452	60.00	34.58	208	7,176
1945	60.5	4,649	60.00	34.28	77	2,656
1944	61.5	831	60.00	33.99	14	471
1943	62.5	5,860	60.00	33.70	98	3,291
1942	63.5	10,411	60.00	33.41	174	5,797
1941	64.5	11,963	60.00	33.12	199	6,604
1940	65.5	521	60.00	32.84	9	285
1939	66.5	9,998	60.00	32.55	167	5,425
1938	67.5	19,700	60.00	32.27	328	10,596
1932	73.5	173	60.00	30.64	3	88
1927	78.5	30	60.00	29.33	0	15
1926	79.5	4	60.00	29.07	0	2
1925	80.5	173,351	60.00	28.82	2,889	83,263
		61,492,932			1,024,882	53,288,085

AVERAGE SERVICE LIFE 60.00
AVERAGE REMAINING LIFE 51.99

Duke Energy Kentucky

365.00 - Overhead Conductor and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R1 34.45

			BG/VG Average			
Year (1)	Age (2)	Surviving Investment (3)	Service Life (4)	Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	825,613	44.00	43.63	18,764	818,639
2004	1.5	4,529,100	44.00	42.89	102,934	4,414,853
2003	2.5	5,162,589	44.00	42.16	117,332	4,946,344
2002	3.5	459,061	44.00	41.43	10,433	432,236
2001	4.5	2,420,864	44.00	40.71	55,020	2,239,620
2000	5.5	7,131,015	44.00	39.99	162,069	6,480,733
1999	6.5	2,158,325	44.00	39.27	49,053	1,926,497
1998	7.5	2,188,084	44.00	38.56	49,729	1,917,788
1997	8.5	1,010,197	44.00	37.86	22,959	869,226
1996	9.5	1,426,634	44.00	37.16	32,423	1,204,830
1995	10.5	2,184,676	44.00	36.46	49,652	1,810,416
1994	11.5	3,587,179	44.00	35.77	81,527	2,916,154
1993	12.5	2,138,429	44.00	35.08	48,601	1,704,906
1992	13.5	2,308,906	44.00	34.39	52,475	1,804,820
1991	14.5	2,320,790	44.00	33.71	52,745	1,778,096
1990	15.5	1,450,510	44.00	33.03	32,966	1,088,934
1989	16.5	2,653,191	44.00	32.36	60,300	1,951,084
1988	17.5	935,766	44.00	31.68	21,267	673,850
1987	18.5	1,410,524	44.00	31.02	32,057	994,322
1986	19.5	1,077,911	44.00	30.35	24,498	743,611
1985	20.5	1,149,170	44.00	29.70	26,118	775,575
1984	21.5	780,414	44.00	29.04	17,737	515,111
1983	22.5	1,115,401	44.00	28.39	25,350	719,793
1982	23.5	750,583	44.00	27.75	17,059	473,413
1981	24.5	592,556	44.00	27.12	13,467	365,170
1980	25.5	967,938	44.00	26.49	21,999	582,639
1979	26.5	745,763	44.00	25.86	16,949	438,335
1978	27.5	357,829	44.00	25.24	8,132	205,304
1977	28.5	369,561	44.00	24.63	8,399	206,912
1976	29.5	407,487	44.00	24.03	9,261	222,563
1975	30.5	480,745	44.00	23.44	10,926	256,071
1974	31.5	632,431	44.00	22.85	14,373	328,417
1973	32.5	756,012	44.00	22.27	17,182	382,618
1972	33.5	433,086	44.00	21.70	9,843	213,549
1971	34.5	495,716	44.00	21.13	11,266	238,069

Duke Energy Kentucky

365.00 - Overhead Conductor and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R1 34.45

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1970	35.5	483,886	44.00	20.57	10,997	226,263
1969	36.5	237,937	44.00	20.02	5,408	108,288
1968	37.5	267,390	44.00	19.48	6,077	118,405
1967	38.5	241,449	44.00	18.95	5,487	103,993
1966	39.5	316,835	44.00	18.43	7,201	132,680
1965	40.5	285,846	44.00	17.91	6,497	116,342
1964	41.5	313,474	44.00	17.40	7,124	123,959
1963	42.5	218,680	44.00	16.90	4,970	83,981
1962	43.5	193,570	44.00	16.40	4,399	72,166
1961	44.5	212,747	44.00	15.92	4,835	76,966
1960	45.5	105,205	44.00	15.44	2,391	36,917
1959	46.5	79,800	44.00	14.97	1,814	27,148
1958	47.5	105,019	44.00	14.51	2,387	34,622
1957	48.5	94,917	44.00	14.05	2,157	30,308
1956	49.5	90,329	44.00	13.60	2,053	27,922
1955	50.5	91,444	44.00	13.16	2,078	27,349
1954	51.5	105,711	44.00	12.73	2,403	30,573
1953	52.5	44,647	44.00	12.30	1,015	12,479
1952	53.5	109,701	44.00	11.88	2,493	29,613
1951	54.5	56,941	44.00	11.46	1,294	14,835
1950	55.5	90,651	44.00	11.06	2,060	22,779
1949	56.5	36,244	44.00	10.66	824	8,777
1948	57.5	16,863	44.00	10.26	383	3,933
1947	58.5	29,647	44.00	9.87	674	6,653
1946	59.5	12,452	44.00	9.49	283	2,686
1945	60.5	4,649	44.00	9.12	106	963
1944	61.5	831	44.00	8.75	19	165
1943	62.5	5,860	44.00	8.38	133	1,116
1942	63.5	10,411	44.00	8.02	237	1,898
1941	64.5	11,963	44.00	7.67	272	2,086
1940	65.5	521	44.00	7.32	12	87
1939	66.5	9,998	44.00	6.98	227	1,587
1938	67.5	19,700	44.00	6.65	448	2,976
1937	68.5	0	44.00	6.32	0	0
1936	69.5	0	44.00	5.99	0	0
1935	70.5	0	44.00	5.67	0	0

Duke Energy Kentucky

365.00 - Overhead Conductor and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 44 R1 34.45

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1934	71.5	0	44.00	5.35	0	0
1933	72.5	0	44.00	5.04	0	0
1932	73.5	173	44.00	4.74	4	19
1931	74.5	0	44.00	4.44	0	0
1930	75.5	0	44.00	4.14	0	0
1929	76.5	0	44.00	3.84	0	0
1928	77.5	0	44.00	3.55	0	0
1927	78.5	30	44.00	3.25	1	2
1926	79.5	4	44.00	2.95	0	0
1925	80.5	173,351	44.00	2.65	3,940	10,439
		61,492,932			1,397,567	48,141,471

AVERAGE SERVICE LIFE 44.00
AVERAGE REMAINING LIFE 34.45

Duke Energy Kentucky

366.00 - Underground Conduit

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 65 R3 55.10

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	292,290	65.00	64.51	4,497	290,070
2004	1.5	205,318	65.00	63.52	3,159	200,652
2003	2.5	3,053,325	65.00	62.54	46,974	2,937,840
2002	3.5	164,211	65.00	61.56	2,526	155,526
2001	4.5	256,186	65.00	60.59	3,941	238,786
2000	5.5	457,855	65.00	59.61	7,044	419,895
1999	6.5	1,880,462	65.00	58.64	28,930	1,696,438
1998	7.5	840,018	65.00	57.67	12,923	745,293
1997	8.5	904,712	65.00	56.70	13,919	789,247
1996	9.5	805,397	65.00	55.74	12,391	690,682
1995	10.5	837,278	65.00	54.78	12,881	705,666
1994	11.5	1,070,352	65.00	53.83	16,467	886,369
1993	12.5	841,200	65.00	52.88	12,942	684,291
1992	13.5	626,412	65.00	51.93	9,637	500,436
1991	14.5	59,346	65.00	50.98	913	46,550
1990	15.5	168,193	65.00	50.05	2,588	129,498
1989	16.5	179,330	65.00	49.11	2,759	135,497
1988	17.5	130,374	65.00	48.18	2,006	96,643
1987	18.5	17,293	65.00	47.26	266	12,573
1986	19.5	53,543	65.00	46.34	824	38,172
1985	20.5	6,010	65.00	45.43	92	4,200
1984	21.5	101,438	65.00	44.52	1,561	69,477
1983	22.5	17,891	65.00	43.62	275	12,006
1982	23.5	39,977	65.00	42.72	615	26,276
1981	24.5	0	65.00	41.83	0	0
1980	25.5	130,443	65.00	40.95	2,007	82,181
1979	26.5	4,510	65.00	40.07	69	2,781
1978	27.5	6,322	65.00	39.21	97	3,813
1977	28.5	33,989	65.00	38.34	523	20,050
1976	29.5	187,168	65.00	37.49	2,880	107,945
1975	30.5	209,974	65.00	36.64	3,230	118,357
1974	31.5	78,643	65.00	35.80	1,210	43,312
1973	32.5	123,986	65.00	34.96	1,907	66,693
1972	33.5	22,501	65.00	34.14	346	11,818
1971	34.5	89,173	65.00	33.32	1,372	45,711

Duke Energy Kentucky

366.00 - Underground Conduit

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 65 R3 55.10

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1970	35.5	38,208	65.00	32.51	588	19,110
1969	36.5	23,234	65.00	31.71	357	11,334
1968	37.5	141	65.00	30.91	2	67
1967	38.5	8,661	65.00	30.13	133	4,014
1966	39.5	1,027	65.00	29.35	16	464
1965	40.5	14,253	65.00	28.58	219	6,267
1964	41.5	5,675	65.00	27.82	87	2,429
1963	42.5	82,709	65.00	27.07	1,272	34,443
1962	43.5	11,849	65.00	26.33	182	4,799
1961	44.5	19,245	65.00	25.59	296	7,577
1960	45.5	1,184	65.00	24.87	18	453
1959	46.5	3,734	65.00	24.16	57	1,388
1958	47.5	9,745	65.00	23.45	150	3,516
1957	48.5	6,541	65.00	22.76	101	2,290
1956	49.5	9,017	65.00	22.08	139	3,063
1955	50.5	24,731	65.00	21.41	380	8,145
1954	51.5	3,990	65.00	20.75	61	1,274
1953	52.5	3,460	65.00	20.10	53	1,070
1952	53.5	12,387	65.00	19.46	191	3,709
1951	54.5	5,433	65.00	18.84	84	1,575
1950	55.5	19,951	65.00	18.23	307	5,596
1949	56.5	13,364	65.00	17.63	206	3,625
1948	57.5	134	65.00	17.05	2	35
1947	58.5	2,521	65.00	16.48	39	639
1946	59.5	1	65.00	15.92	0	0
1945	60.5	1,053	65.00	15.38	16	249
1944	61.5	265	65.00	14.85	4	60
1943	62.5	2,278	65.00	14.34	35	503
1942	63.5	2,327	65.00	13.84	36	495
1941	64.5	10,128	65.00	13.35	156	2,081
1940	65.5	52,417	65.00	12.88	806	10,390
1939	66.5	1	65.00	12.43	0	0
1938	67.5	27,594	65.00	11.99	425	5,089
1937	68.5	117	65.00	11.56	2	21
1936	69.5	0	65.00	11.15	0	0
1935	70.5	1,937	65.00	10.75	30	320

Duke Energy Kentucky

366.00 - Underground Conduit

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 65 R3 55.10

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1934	71.5	43	65.00	10.37	1	7
1933	72.5	230	65.00	10.00	4	35
1932	73.5	3,079	65.00	9.64	47	457
1931	74.5	13,618	65.00	9.29	210	1,947
1930	75.5	272	65.00	8.96	4	38
1929	76.5	8,876	65.00	8.63	137	1,179
1928	77.5	226	65.00	8.32	3	29
1927	78.5	2,174	65.00	8.02	33	268
1926	79.5	846	65.00	7.72	13	101
1925	80.5	0	65.00	7.43	0	0
1924	81.5	116	65.00	7.15	2	13
1923	82.5	7,158	65.00	6.88	110	757
1922	83.5	0	65.00	6.61	0	0
1921	84.5	0	65.00	6.34	0	0
1920	85.5	197	65.00	6.08	3	18
1919	86.5	0	65.00	5.82	0	0
1918	87.5	0	65.00	5.56	0	0
1917	88.5	0	65.00	5.30	0	0
1916	89.5	941	65.00	5.04	14	73
1915	90.5	0	65.00	4.79	0	0
1914	91.5	0	65.00	4.53	0	0
1913	92.5	0	65.00	4.27	0	0
1912	93.5	0	65.00	4.02	0	0
1911	94.5	469	65.00	3.76	7	27
		14,352,678			220,810	12,165,780

AVERAGE SERVICE LIFE 65.00
AVERAGE REMAINING LIFE 55.10

Duke Energy Kentucky

367.00 - Underground Conductor and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 60 R2 48.96

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	988,232	60.00	59.55	16,471	980,744
2004	1.5	1,185,751	60.00	58.64	19,763	1,158,930
2003	2.5	2,607,748	60.00	57.74	43,462	2,509,710
2002	3.5	604,940	60.00	56.85	10,082	573,182
2001	4.5	2,203,731	60.00	55.96	36,729	2,055,365
2000	5.5	2,788,829	60.00	55.08	46,480	2,559,919
1999	6.5	2,332,975	60.00	54.19	38,883	2,107,241
1998	7.5	752,597	60.00	53.32	12,543	668,792
1997	8.5	1,155,812	60.00	52.45	19,264	1,010,324
1996	9.5	736,075	60.00	51.58	12,268	632,796
1995	10.5	757,464	60.00	50.72	12,624	640,313
1994	11.5	1,105,961	60.00	49.86	18,433	919,130
1993	12.5	1,697,749	60.00	49.01	28,296	1,386,871
1992	13.5	1,099,624	60.00	48.17	18,327	882,776
1991	14.5	1,090,069	60.00	47.33	18,168	859,838
1990	15.5	1,267,847	60.00	46.49	21,131	982,432
1989	16.5	1,351,475	60.00	45.66	22,525	1,028,564
1988	17.5	1,015,506	60.00	44.84	16,925	758,931
1987	18.5	1,292,043	60.00	44.02	21,534	947,993
1986	19.5	642,404	60.00	43.21	10,707	462,654
1985	20.5	566,126	60.00	42.41	9,435	400,116
1984	21.5	728,065	60.00	41.61	12,134	504,866
1983	22.5	451,106	60.00	40.81	7,518	306,850
1982	23.5	273,063	60.00	40.03	4,551	182,159
1981	24.5	297,593	60.00	39.24	4,960	194,650
1980	25.5	475,227	60.00	38.47	7,920	304,707
1979	26.5	658,744	60.00	37.70	10,979	413,946
1978	27.5	271,868	60.00	36.94	4,531	167,390
1977	28.5	509,653	60.00	36.19	8,494	307,392
1976	29.5	588,378	60.00	35.44	9,806	347,545
1975	30.5	201,765	60.00	34.70	3,363	116,691
1974	31.5	264,099	60.00	33.97	4,402	149,516
1973	32.5	409,226	60.00	33.24	6,820	226,727
1972	33.5	100,131	60.00	32.52	1,669	54,278
1971	34.5	102,379	60.00	31.81	1,706	54,284
1970	35.5	87,297	60.00	31.11	1,455	45,264
1969	36.5	26,383	60.00	30.41	440	13,374
1968	37.5	15,830	60.00	29.73	264	7,843
1967	38.5	19,255	60.00	29.05	321	9,322
1966	39.5	14,155	60.00	28.38	236	6,695
1965	40.5	28,112	60.00	27.71	469	12,985
1964	41.5	37,146	60.00	27.06	619	16,752
1963	42.5	72,575	60.00	26.41	1,210	31,948
1962	43.5	8,126	60.00	25.77	135	3,491
1961	44.5	15,417	60.00	25.15	257	6,461
1960	45.5	11,688	60.00	24.53	195	4,777
1959	46.5	17,788	60.00	23.92	296	7,090
1958	47.5	3,916	60.00	23.31	65	1,521

Duke Energy Kentucky

367.00 - Underground Conductor and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 60 R2 48.96

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1957	48.5	9,143	60.00	22.72	152	3,462
1956	49.5	20,193	60.00	22.14	337	7,450
1955	50.5	97,063	60.00	21.56	1,618	34,884
1954	51.5	6,027	60.00	21.00	100	2,109
1953	52.5	2,368	60.00	20.45	39	807
1952	53.5	2,573	60.00	19.90	43	853
1951	54.5	6,116	60.00	19.37	102	1,974
1950	55.5	32,302	60.00	18.84	538	10,143
1949	56.5	11,936	60.00	18.32	199	3,645
1947	58.5	3,279	60.00	17.32	55	947
1945	60.5	1,255	60.00	16.36	21	342
1943	62.5	294	60.00	15.44	5	76
1942	63.5	433	60.00	15.00	7	108
1941	64.5	1,121	60.00	14.56	19	272
1940	65.5	78,262	60.00	14.13	1,304	18,434
1939	66.5	1,065	60.00	13.72	18	243
1938	67.5	18,452	60.00	13.31	308	4,093
1937	68.5	364	60.00	12.91	6	78
1935	70.5	191	60.00	12.14	3	39
1933	72.5	323	60.00	11.40	5	61
1932	73.5	326	60.00	11.05	5	60
1931	74.5	1,204	60.00	10.70	20	215
1930	75.5	0	60.00	10.35	0	0
1929	76.5	3,049	60.00	10.02	51	509
1927	78.5	210	60.00	9.37	3	33
1926	79.5	384	60.00	9.05	6	58
1923	82.5	1,485	60.00	8.12	25	201
1922	83.5	25	60.00	7.82	0	3
1916	89.5	159	60.00	6.06	3	16
		33,231,540			553,859	27,116,262

AVERAGE SERVICE LIFE 60.00
AVERAGE REMAINING LIFE 48.96

Duke Energy Kentucky

368.00 - Line Transformers

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 35 R1 24.77

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	959,956	35.00	34.63	27,427	949,779
2004	1.5	2,067,481	35.00	33.89	59,071	2,002,026
2003	2.5	2,593,420	35.00	33.16	74,098	2,457,185
2002	3.5	710,492	35.00	32.44	20,300	658,467
2001	4.5	977,794	35.00	31.72	27,937	886,135
2000	5.5	2,418,755	35.00	31.01	69,107	2,142,795
1999	6.5	1,819,251	35.00	30.30	51,979	1,574,952
1998	7.5	1,886,441	35.00	29.60	53,898	1,595,306
1997	8.5	2,239,116	35.00	28.90	63,975	1,848,989
1996	9.5	1,473,687	35.00	28.21	42,105	1,187,789
1995	10.5	1,564,245	35.00	27.52	44,693	1,230,051
1994	11.5	2,632,767	35.00	26.84	75,222	2,018,897
1993	12.5	2,110,389	35.00	26.16	60,297	1,577,387
1992	13.5	1,628,276	35.00	25.49	46,522	1,185,671
1991	14.5	2,059,222	35.00	24.82	58,835	1,460,102
1990	15.5	2,041,792	35.00	24.15	58,337	1,409,020
1989	16.5	2,149,949	35.00	23.50	61,427	1,443,247
1988	17.5	2,179,632	35.00	22.84	62,275	1,422,603
1987	18.5	1,343,610	35.00	22.20	38,389	852,213
1986	19.5	1,149,454	35.00	21.56	32,842	708,146
1985	20.5	1,152,209	35.00	20.93	32,920	689,133
1984	21.5	1,060,514	35.00	20.31	30,300	615,476
1983	22.5	1,149,051	35.00	19.70	32,830	646,756
1982	23.5	678,442	35.00	19.10	19,384	370,172
1981	24.5	911,211	35.00	18.50	26,035	481,705
1980	25.5	752,035	35.00	17.92	21,487	384,997
1979	26.5	664,247	35.00	17.34	18,978	329,144
1978	27.5	683,542	35.00	16.78	19,530	327,667
1977	28.5	533,720	35.00	16.22	15,249	247,379
1976	29.5	350,419	35.00	15.68	10,012	156,959
1975	30.5	454,406	35.00	15.14	12,983	196,585
1974	31.5	733,810	35.00	14.62	20,966	306,445
1973	32.5	633,042	35.00	14.10	18,087	255,043
1972	33.5	534,234	35.00	13.60	15,264	207,520
1971	34.5	492,529	35.00	13.10	14,072	184,346
1970	35.5	461,053	35.00	12.61	13,173	166,165
1969	36.5	319,484	35.00	12.14	9,128	110,795
1968	37.5	241,755	35.00	11.67	6,907	80,614
1967	38.5	161,679	35.00	11.21	4,619	51,799
1966	39.5	198,589	35.00	10.77	5,674	61,081
1965	40.5	124,122	35.00	10.33	3,546	36,619
1964	41.5	161,092	35.00	9.90	4,603	45,544
1963	42.5	71,198	35.00	9.47	2,034	19,271
1962	43.5	53,738	35.00	9.06	1,535	13,911
1961	44.5	65,255	35.00	8.66	1,864	16,137
1960	45.5	46,384	35.00	8.26	1,325	10,944
1959	46.5	52,094	35.00	7.87	1,488	11,713
1958	47.5	37,342	35.00	7.49	1,067	7,989
1957	48.5	14,488	35.00	7.11	414	2,945
1956	49.5	66,558	35.00	6.75	1,902	12,833
1955	50.5	46,548	35.00	6.39	1,330	8,497
1954	51.5	28,896	35.00	6.04	826	4,985

Duke Energy Kentucky

368.00 - Line Transformers

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: **35** **R1** **24.77**

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1953	52.5	8,030	35.00	5.69	229	1,306
1952	53.5	12,475	35.00	5.36	356	1,909
1951	54.5	18,960	35.00	5.02	542	2,722
1950	55.5	8,752	35.00	4.70	250	1,175
1949	56.5	3,942	35.00	4.38	113	494
1948	57.5	1,945	35.00	4.07	56	226
1947	58.5	2,479	35.00	3.76	71	267
1946	59.5	521	35.00	3.46	15	52
1945	60.5	615	35.00	3.17	18	56
1944	61.5	24	35.00	2.87	1	2
1943	62.5	18	35.00	2.58	1	1
1942	63.5	330	35.00	2.28	9	22
1941	64.5	2,149	35.00	1.97	61	121
1940	65.5	2,829	35.00	1.65	81	133
1939	66.5	267	35.00	1.32	8	10
1938	67.5	184	35.00	1.00	5	5
1937	68.5	2,258	35.00	0.70	65	45
1936	69.5	1,653	35.00	0.50	47	24
1935	70.5	67	35.00	0.50	2	1
1933	72.5	183	35.00	0.50	5	3
1932	73.5	374	35.00	0.50	11	5
1930	75.5	186	35.00	0.50	5	3
1929	76.5	179	35.00	0.50	5	3
1928	77.5	181	35.00	0.50	5	3
1927	78.5	389	35.00	0.50	11	6
1926	79.5	325	35.00	0.50	9	5
1925	80.5	2,170	35.00	0.50	62	31
1923	82.5	244	35.00	0.50	7	3
1922	83.5	654	35.00	0.50	19	9
1921	84.5	118	35.00	0.50	3	2
1920	85.5	388	35.00	0.50	11	6
1917	88.5	39	35.00	0.50	1	1
1916	89.5	93	35.00	0.50	3	1
1910	95.5	933	35.00	0.50	27	13
		49,013,367			1,400,382	34,680,589

AVERAGE SERVICE LIFE 35.00
AVERAGE REMAINING LIFE 24.77

Duke Energy Kentucky

368.20 - Line Transformers - Customer

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 50 R1.5 24.00

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1990	15.5	20,802	50.00	37.77	416	15,712
1989	16.5	1,093	50.00	37.02	22	809
1988	17.5	0	50.00	36.27	0	0
1987	18.5	0	50.00	35.53	0	0
1986	19.5	6,577	50.00	34.80	132	4,577
1985	20.5	0	50.00	34.07	0	0
1984	21.5	5,956	50.00	33.35	119	3,972
1978	27.5	16,191	50.00	29.14	324	9,437
1977	28.5	7,355	50.00	28.47	147	4,188
1976	29.5	23,133	50.00	27.80	463	12,861
1975	30.5	5,213	50.00	27.14	104	2,829
1974	31.5	2,241	50.00	26.49	45	1,187
1973	32.5	5,633	50.00	25.84	113	2,911
1972	33.5	5,022	50.00	25.20	100	2,532
1971	34.5	21,631	50.00	24.58	433	10,632
1970	35.5	4,780	50.00	23.96	96	2,291
1969	36.5	25,291	50.00	23.35	506	11,810
1968	37.5	26,876	50.00	22.75	538	12,228
1967	38.5	2,141	50.00	22.16	43	949
1966	39.5	6,770	50.00	21.58	135	2,921
1965	40.5	5,116	50.00	21.00	102	2,149
1964	41.5	4,393	50.00	20.44	88	1,796
1963	42.5	14,251	50.00	19.89	285	5,669
1962	43.5	3,983	50.00	19.35	80	1,541
1961	44.5	5,230	50.00	18.81	105	1,968
1959	46.5	2,698	50.00	17.78	54	960
1958	47.5	214	50.00	17.28	4	74
1957	48.5	2,433	50.00	16.79	49	817
1956	49.5	28,512	50.00	16.31	570	9,300
1955	50.5	582	50.00	15.84	12	184
1954	51.5	0	50.00	15.38	0	0
1953	52.5	1,453	50.00	14.93	29	434
1952	53.5	49	50.00	14.49	1	14
1951	54.5	5,955	50.00	14.07	119	1,675
1950	55.5	416	50.00	13.65	8	114

Duke Energy Kentucky

368.20 - Line Transformers - Customer

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 50 R1.5 24.00

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1949	56.5	3,857	50.00	13.24	77	1,022
1948	57.5	401	50.00	12.84	8	103
1947	58.5	2,310	50.00	12.46	46	576
1946	59.5	749	50.00	12.08	15	181
1945	60.5	1,859	50.00	11.71	37	435
1942	63.5	11	50.00	10.65	0	2
1941	64.5	2,262	50.00	10.31	45	466
1938	67.5	220	50.00	9.33	4	41
1937	68.5	1	50.00	9.02	0	0
		273,661			5,473	131,368

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 24.00

Duke Energy Kentucky

369.10 - Services - Underground

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 55 R2 45.43

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2004	1.5	197	55.00	53.64	4	192
2003	2.5	329,996	55.00	52.75	6,000	316,471
2002	3.5	59,413	55.00	51.85	1,080	56,013
2000	5.5	21	55.00	50.08	0	19
1999	6.5	1,419	55.00	49.20	26	1,269
1996	9.5	16	55.00	46.60	0	13
1987	18.5	2,060	55.00	39.11	37	1,464
1977	28.5	870	55.00	31.41	16	497
1976	29.5	528	55.00	30.68	10	295
1975	30.5	485	55.00	29.96	9	264
1974	31.5	0	55.00	29.25	0	0
1973	32.5	775	55.00	28.55	14	402
1972	33.5	628	55.00	27.85	11	318
1971	34.5	3,470	55.00	27.16	63	1,714
1970	35.5	11,078	55.00	26.49	201	5,335
1969	36.5	16,508	55.00	25.82	300	7,749
1968	37.5	6,368	55.00	25.16	116	2,913
1967	38.5	8,596	55.00	24.51	156	3,830
1966	39.5	10,815	55.00	23.87	197	4,693
1965	40.5	5,004	55.00	23.23	91	2,114
1964	41.5	7,490	55.00	22.61	136	3,079
1963	42.5	9,823	55.00	22.00	179	3,929
1962	43.5	4,052	55.00	21.40	74	1,576
1961	44.5	4,995	55.00	20.80	91	1,889
1960	45.5	1,748	55.00	20.22	32	643
1959	46.5	2,216	55.00	19.65	40	792
1958	47.5	4,391	55.00	19.09	80	1,524
1957	48.5	1,743	55.00	18.54	32	587
1956	49.5	5,252	55.00	18.00	95	1,719
1955	50.5	5,689	55.00	17.47	103	1,807
1954	51.5	2	55.00	16.95	0	1
1953	52.5	2,097	55.00	16.44	38	627
1952	53.5	161	55.00	15.94	3	47
1951	54.5	964	55.00	15.46	18	271
1950	55.5	2,722	55.00	14.98	49	741

Duke Energy Kentucky

369.10 - Services - Underground

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 55 R2 45.43

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1949	56.5	711	55.00	14.52	13	188
1948	57.5	33	55.00	14.06	1	8
1947	58.5	1	55.00	13.62	0	0
1946	59.5	113	55.00	13.19	2	27
1945	60.5	55	55.00	12.76	1	13
1944	61.5	8	55.00	12.35	0	2
1943	62.5	40	55.00	11.95	1	9
1942	63.5	79	55.00	11.56	1	17
1941	64.5	61	55.00	11.18	1	12
1940	65.5	42	55.00	10.80	1	8
1939	66.5	0	55.00	10.44	0	0
1938	67.5	285	55.00	10.08	5	52
1937	68.5	2,103	55.00	9.73	38	372
		515,126			9,366	425,506

AVERAGE SERVICE LIFE	55.00
AVERAGE REMAINING LIFE	45.43

Duke Energy Kentucky

369.20 - Services - Overhead

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 47 R1 34.75

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	2,214	47.00	46.63	47	2,196
2004	1.5	19,268	47.00	45.89	410	18,813
2003	2.5	1,504,782	47.00	45.16	32,017	1,445,738
2001	4.5	15,226	47.00	43.70	324	14,158
2000	5.5	546,621	47.00	42.98	11,630	499,899
1999	6.5	235,023	47.00	42.27	5,000	211,357
1998	7.5	267,864	47.00	41.56	5,699	236,837
1997	8.5	307,603	47.00	40.85	6,545	267,347
1996	9.5	450,937	47.00	40.15	9,594	385,177
1995	10.5	319,818	47.00	39.45	6,805	268,421
1994	11.5	297,196	47.00	38.75	6,323	245,036
1993	12.5	317,732	47.00	38.06	6,760	257,288
1992	13.5	315,336	47.00	37.37	6,709	250,726
1991	14.5	242,844	47.00	36.68	5,167	189,544
1990	15.5	252,845	47.00	36.00	5,380	193,677
1989	16.5	266,526	47.00	35.32	5,671	200,305
1988	17.5	278,541	47.00	34.65	5,926	205,329
1987	18.5	311,027	47.00	33.97	6,618	224,828
1986	19.5	301,035	47.00	33.31	6,405	213,324
1985	20.5	267,031	47.00	32.64	5,682	185,453
1984	21.5	321,446	47.00	31.98	6,839	218,730
1983	22.5	229,635	47.00	31.33	4,886	153,053
1982	23.5	230,115	47.00	30.68	4,896	150,188
1981	24.5	261,820	47.00	30.03	5,571	167,286
1980	25.5	214,710	47.00	29.39	4,568	134,263
1979	26.5	211,555	47.00	28.76	4,501	129,435
1978	27.5	213,319	47.00	28.13	4,539	127,662
1977	28.5	178,569	47.00	27.51	3,799	104,502
1976	29.5	162,587	47.00	26.89	3,459	93,018
1975	30.5	166,978	47.00	26.28	3,553	93,365
1974	31.5	168,598	47.00	25.68	3,587	92,109
1973	32.5	117,094	47.00	25.08	2,491	62,487
1972	33.5	123,971	47.00	24.49	2,638	64,604
1971	34.5	118,248	47.00	23.91	2,516	60,159
1970	35.5	93,127	47.00	23.34	1,981	46,240
1969	36.5	92,075	47.00	22.77	1,959	44,607
1968	37.5	70,256	47.00	22.21	1,495	33,199
1967	38.5	81,591	47.00	21.66	1,736	37,597

Duke Energy Kentucky

369.20 - Services - Overhead

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 47 R1 34.75

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1966	39.5	68,226	47.00	21.11	1,452	30,647
1965	40.5	62,152	47.00	20.57	1,322	27,208
1964	41.5	55,039	47.00	20.04	1,171	23,474
1963	42.5	53,568	47.00	19.52	1,140	22,250
1962	43.5	53,636	47.00	19.01	1,141	21,691
1961	44.5	57,344	47.00	18.50	1,220	22,571
1960	45.5	54,360	47.00	18.00	1,157	20,817
1959	46.5	45,693	47.00	17.51	972	17,019
1958	47.5	39,163	47.00	17.02	833	14,181
1957	48.5	32,917	47.00	16.54	700	11,584
1956	49.5	33,935	47.00	16.07	722	11,602
1955	50.5	19,915	47.00	15.60	424	6,612
1954	51.5	15,557	47.00	15.15	331	5,013
1953	52.5	11,544	47.00	14.70	246	3,609
1952	53.5	10,263	47.00	14.25	218	3,112
1951	54.5	7,107	47.00	13.81	151	2,089
1950	55.5	7,721	47.00	13.38	164	2,198
1949	56.5	6,318	47.00	12.96	134	1,742
1948	57.5	5,406	47.00	12.54	115	1,442
1947	58.5	3,751	47.00	12.13	80	968
1946	59.5	2,572	47.00	11.72	55	642
1945	60.5	1,215	47.00	11.32	26	293
1944	61.5	1,143	47.00	10.93	24	266
1943	62.5	1,155	47.00	10.54	25	259
1942	63.5	862	47.00	10.16	18	186
1941	64.5	1,698	47.00	9.78	36	354
1940	65.5	1,508	47.00	9.41	32	302
1939	66.5	1,426	47.00	9.05	30	274
1938	67.5	659	47.00	8.69	14	122
1936	69.5	8	47.00	7.98	0	1
1931	74.5	32	47.00	6.31	1	4
1930	75.5	8	47.00	5.99	0	1
1925	80.5	26,354	47.00	4.46	561	2,502
1910	95.5	27	47.00	0.50	1	0
		10,257,449			218,244	7,582,994

AVERAGE SERVICE LIFE 47.00
AVERAGE REMAINING LIFE 34.75

Duke Energy Kentucky

370.00 - Meters

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 28 S0 17.02

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1998	7.5	889,040	28.00	22.05	31,751	700,132
1997	8.5	1,365,535	28.00	21.39	48,769	1,043,178
1996	9.5	432,445	28.00	20.75	15,444	320,474
1995	10.5	384,983	28.00	20.13	13,749	276,760
1994	11.5	521,312	28.00	19.52	18,618	363,509
1993	12.5	593,522	28.00	18.94	21,197	401,380
1992	13.5	723,091	28.00	18.36	25,825	474,162
1991	14.5	499,189	28.00	17.80	17,828	317,329
1990	15.5	533,993	28.00	17.25	19,071	328,977
1989	16.5	510,143	28.00	16.71	18,219	304,480
1988	17.5	425,721	28.00	16.18	15,204	246,073
1987	18.5	351,586	28.00	15.67	12,557	196,720
1986	19.5	352,514	28.00	15.16	12,590	190,837
1985	20.5	202,659	28.00	14.66	7,238	106,093
1984	21.5	180,244	28.00	14.17	6,437	91,192
1983	22.5	164,299	28.00	13.68	5,868	80,283
1982	23.5	189,213	28.00	13.20	6,758	89,233
1981	24.5	160,589	28.00	12.73	5,735	73,036
1980	25.5	142,558	28.00	12.27	5,091	62,473
1979	26.5	210,878	28.00	11.81	7,531	88,962
1978	27.5	146,377	28.00	11.36	5,228	59,386
1977	28.5	161,318	28.00	10.91	5,761	62,873
1976	29.5	106,831	28.00	10.47	3,815	39,951
1975	30.5	81,422	28.00	10.03	2,908	29,178
1974	31.5	97,650	28.00	9.60	3,488	33,486
1973	32.5	87,269	28.00	9.17	3,117	28,593
1972	33.5	76,610	28.00	8.75	2,736	23,941
1971	34.5	70,977	28.00	8.33	2,535	21,117
1970	35.5	69,864	28.00	7.91	2,495	19,748
1969	36.5	57,221	28.00	7.50	2,044	15,332
1968	37.5	52,557	28.00	7.09	1,877	13,316
1967	38.5	50,716	28.00	6.69	1,811	12,115
1966	39.5	61,320	28.00	6.29	2,190	13,768
1965	40.5	55,985	28.00	5.89	1,999	11,772
1964	41.5	30,070	28.00	5.49	1,074	5,898
1963	42.5	3,743	28.00	5.10	134	682
1962	43.5	3,888	28.00	4.71	139	654
1960	45.5	3,613	28.00	3.94	129	508
1959	46.5	4,669	28.00	3.55	167	593
1958	47.5	3,930	28.00	3.18	140	446
1957	48.5	8,502	28.00	2.80	304	850

Duke Energy Kentucky

370.00 - Meters

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 28 S0 17.02

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1956	49.5	4,946	28.00	2.42	177	428
1955	50.5	3,225	28.00	2.05	115	237
1954	51.5	2,817	28.00	1.69	101	170
1953	52.5	6,461	28.00	1.33	231	306
1952	53.5	4,861	28.00	0.98	174	170
1951	54.5	1,774	28.00	0.65	63	41
1950	55.5	3,206	28.00	0.50	115	57
1949	56.5	2,016	28.00	0.50	72	36
1948	57.5	3,089	28.00	0.50	110	55
1947	58.5	4,290	28.00	0.50	153	77
1946	59.5	828	28.00	0.50	30	15
1945	60.5	256	28.00	0.50	9	5
1944	61.5	439	28.00	0.50	16	8
1943	62.5	204	28.00	0.50	7	4
1942	63.5	1,273	28.00	0.50	45	23
1941	64.5	2,158	28.00	0.50	77	39
1940	65.5	759	28.00	0.50	27	14
1939	66.5	1,187	28.00	0.50	42	21
1938	67.5	159	28.00	0.50	6	3
1937	68.5	1,349	28.00	0.50	48	24
1936	69.5	900	28.00	0.50	32	16
1935	70.5	241	28.00	0.50	9	4
1934	71.5	350	28.00	0.50	12	6
1933	72.5	26	28.00	0.50	1	0
1931	74.5	867	28.00	0.50	31	15
1930	75.5	703	28.00	0.50	25	13
1929	76.5	1,512	28.00	0.50	54	27
1928	77.5	759	28.00	0.50	27	14
1927	78.5	916	28.00	0.50	33	16
1926	79.5	394	28.00	0.50	14	7
1925	80.5	596	28.00	0.50	21	11
1924	81.5	338	28.00	0.50	12	6
1923	82.5	404	28.00	0.50	14	7
1922	83.5	146	28.00	0.50	5	3
1921	84.5	33	28.00	0.50	1	1
1920	85.5	125	28.00	0.50	4	2
		10,121,655			361,488	6,151,366

AVERAGE SERVICE LIFE 28.00
AVERAGE REMAINING LIFE 17.02

Duke Energy Kentucky

370.10 - Leased Meters

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA:			28	S0		24.67
			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2005	0.5	432,256	28.00	27.52	15,438	424,778
2004	1.5	376,864	28.00	26.61	13,459	358,113
2003	2.5	490,225	28.00	25.75	17,508	450,912
2002	3.5	218,588	28.00	24.95	7,807	194,761
2001	4.5	375,478	28.00	24.18	13,410	324,229
2000	5.5	1,233,673	28.00	23.44	44,060	1,032,837
1999	6.5	431,402	28.00	22.73	15,407	350,258
		3,558,486			127,089	3,135,887

AVERAGE SERVICE LIFE	28.00
AVERAGE REMAINING LIFE	24.67

Duke Energy Kentucky

372.00 - Leased property on Customer Premises

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 25 L2 6.89

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1969	36.5	9,647	25.00	6.89	386	2,658
		9,647			386	2,658

AVERAGE SERVICE LIFE	25.00
AVERAGE REMAINING LIFE	6.89

Duke Energy Kentucky

373.10 - Street Lighting - Overhead

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 30 L1 20.44

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	300,040	30.00	29.53	10,001	295,303
2004	1.5	260,883	30.00	28.60	8,696	248,731
2001	4.5	37,093	30.00	26.00	1,236	32,147
2000	5.5	123,327	30.00	25.20	4,111	103,591
1999	6.5	181,713	30.00	24.44	6,057	148,008
1998	7.5	133,863	30.00	23.71	4,462	105,798
1997	8.5	104,687	30.00	23.03	3,490	80,350
1996	9.5	76,907	30.00	22.38	2,564	57,374
1995	10.5	94,177	30.00	21.77	3,139	68,355
1994	11.5	97,142	30.00	21.21	3,238	68,670
1993	12.5	98,402	30.00	20.68	3,280	67,819
1992	13.5	56,516	30.00	20.18	1,884	38,013
1991	14.5	17,850	30.00	19.71	595	11,729
1990	15.5	51,013	30.00	19.27	1,700	32,770
1989	16.5	74,465	30.00	18.85	2,482	46,798
1988	17.5	29,377	30.00	18.45	979	18,069
1987	18.5	20,372	30.00	18.06	679	12,265
1986	19.5	37,559	30.00	17.68	1,252	22,133
1985	20.5	57,188	30.00	17.30	1,906	32,983
1984	21.5	18,629	30.00	16.93	621	10,515
1983	22.5	15,693	30.00	16.57	523	8,668
1982	23.5	18,612	30.00	16.21	620	10,059
1981	24.5	28,336	30.00	15.86	945	14,985
1980	25.5	54,272	30.00	15.52	1,809	28,078
1979	26.5	52,571	30.00	15.18	1,752	26,606
1978	27.5	23,600	30.00	14.85	787	11,683
1977	28.5	17,483	30.00	14.53	583	8,465
1976	29.5	12,464	30.00	14.20	415	5,902
1975	30.5	26,022	30.00	13.89	867	12,047
1974	31.5	22,157	30.00	13.58	739	10,029
1973	32.5	56,937	30.00	13.27	1,898	25,193
1972	33.5	52,515	30.00	12.97	1,750	22,711
1971	34.5	71,049	30.00	12.68	2,368	30,029
1970	35.5	64,957	30.00	12.39	2,165	26,825
1969	36.5	65,084	30.00	12.10	2,169	26,257
1968	37.5	16,989	30.00	11.82	566	6,695
1967	38.5	33,570	30.00	11.54	1,119	12,918
1966	39.5	53,040	30.00	11.27	1,768	19,928

Duke Energy Kentucky

373.10 - Street Lighting - Overhead

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 30 L1 20.44

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1965	40.5	64,666	30.00	11.00	2,156	23,717
1964	41.5	22,339	30.00	10.74	745	7,996
1963	42.5	28,184	30.00	10.48	939	9,843
1962	43.5	30,122	30.00	10.22	1,004	10,261
1961	44.5	26,180	30.00	9.97	873	8,697
1960	45.5	10,439	30.00	9.72	348	3,381
1959	46.5	6,035	30.00	9.47	201	1,905
1958	47.5	1,179	30.00	9.23	39	362
1957	48.5	539	30.00	8.99	18	162
1956	49.5	1,492	30.00	8.75	50	435
1955	50.5	423	30.00	8.52	14	120
1954	51.5	173	30.00	8.29	6	48
1953	52.5	265	30.00	8.06	9	71
1952	53.5	288	30.00	7.83	10	75
1951	54.5	145	30.00	7.61	5	37
1950	55.5	56	30.00	7.39	2	14
1949	56.5	206	30.00	7.17	7	49
1948	57.5	94	30.00	6.96	3	22
1947	58.5	1,289	30.00	6.75	43	290
1946	59.5	102	30.00	6.54	3	22
1945	60.5	76	30.00	6.33	3	16
1944	61.5	22	30.00	6.13	1	4
1943	62.5	10	30.00	5.92	0	2
1942	63.5	25	30.00	5.72	1	5
1941	64.5	396	30.00	5.52	13	73
1940	65.5	114	30.00	5.33	4	20
1939	66.5	26	30.00	5.13	1	4
1938	67.5	171	30.00	4.94	6	28
1925	80.5	2,630	30.00	2.51	88	220
1910	95.5	79	30.00	0.50	3	1
		2,754,320			91,811	1,876,378

AVERAGE SERVICE LIFE 30.00
AVERAGE REMAINING LIFE 20.44

Duke Energy Kentucky

373.20 - Street Lighting - Blvd

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 30 L1 22.87

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	41,177	30.00	29.53	1,373	40,527
2004	1.5	375,978	30.00	28.60	12,533	358,465
2002	3.5	88,031	30.00	26.84	2,934	78,748
2001	4.5	22,698	30.00	26.00	757	19,672
2000	5.5	158,103	30.00	25.20	5,270	132,801
1999	6.5	659,083	30.00	24.44	21,969	536,833
1998	7.5	145,025	30.00	23.71	4,834	114,619
1997	8.5	146,299	30.00	23.03	4,877	112,288
1996	9.5	118,232	30.00	22.38	3,941	88,204
1995	10.5	136,090	30.00	21.77	4,536	98,776
1994	11.5	89,847	30.00	21.21	2,995	63,514
1993	12.5	79,715	30.00	20.68	2,657	54,940
1992	13.5	148,022	30.00	20.18	4,934	99,561
1991	14.5	48,812	30.00	19.71	1,627	32,072
1990	15.5	136,060	30.00	19.27	4,535	87,404
1989	16.5	93,024	30.00	18.85	3,101	58,462
1988	17.5	71,225	30.00	18.45	2,374	43,809
1987	18.5	59,651	30.00	18.06	1,988	35,914
1986	19.5	21,063	30.00	17.68	702	12,412
1985	20.5	39,197	30.00	17.30	1,307	22,607
1984	21.5	12,877	30.00	16.93	429	7,268
1983	22.5	2,408	30.00	16.57	80	1,330
1982	23.5	10,785	30.00	16.21	359	5,829
1981	24.5	12,793	30.00	15.86	426	6,765
1980	25.5	17,168	30.00	15.52	572	8,882
1979	26.5	13,587	30.00	15.18	453	6,876
1978	27.5	14,756	30.00	14.85	492	7,305
1977	28.5	7,719	30.00	14.53	257	3,737
1976	29.5	7,316	30.00	14.20	244	3,464
1975	30.5	4,518	30.00	13.89	151	2,092
1974	31.5	18,600	30.00	13.58	620	8,419
1973	32.5	13,625	30.00	13.27	454	6,029
1972	33.5	1,582	30.00	12.97	53	684
1970	35.5	401	30.00	12.39	13	165
1965	40.5	4,918	30.00	11.00	164	1,804

Duke Energy Kentucky

373.20 - Street Lighting - Blvd

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 30 L1 22.87

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1964	41.5	0	30.00	10.74	0	0
1963	42.5	254	30.00	10.48	8	89
1962	43.5	273	30.00	10.22	9	93
1961	44.5	29	30.00	9.97	1	10
1960	45.5	21	30.00	9.72	1	7
1959	46.5	294	30.00	9.47	10	93
1958	47.5	509	30.00	9.23	17	157
1956	49.5	566	30.00	8.75	19	165
1955	50.5	361	30.00	8.52	12	103
1954	51.5	171	30.00	8.29	6	47
1952	53.5	114	30.00	7.83	4	30
1951	54.5	1,257	30.00	7.61	42	319
1950	55.5	171	30.00	7.39	6	42
1943	62.5	284	30.00	5.92	9	56
1942	63.5	27	30.00	5.72	1	5
1941	64.5	1,449	30.00	5.52	48	267
1939	66.5	63	30.00	5.13	2	11
1938	67.5	291	30.00	4.94	10	48
1937	68.5	148	30.00	4.75	5	23
1936	69.5	54	30.00	4.56	2	8
1933	72.5	354	30.00	3.99	12	47
1932	73.5	603	30.00	3.81	20	76
1931	74.5	1,869	30.00	3.62	62	226
1930	75.5	53	30.00	3.44	2	6
1929	76.5	3,725	30.00	3.26	124	404
1928	77.5	1,452	30.00	3.07	48	149
1927	78.5	1,996	30.00	2.89	67	192
1923	82.5	3,482	30.00	2.13	116	247
1922	83.5	269	30.00	1.93	9	17
		2,840,524			94,684	2,165,212

AVERAGE SERVICE LIFE	30.00
AVERAGE REMAINING LIFE	22.87

Duke Energy Kentucky

Depreciation Life Analysis Study Through 2005

Account: **373.30 - Street Lighting - Customer Poles**

Balance: **1,618,092**

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Comments: Company's T-Cut and Curve Selection Proposed life and curve seems arbitrarily selected. OLT (as described in Company study) provides excellent data for analysis. Full Curve Best fit (using Company's OLT) shows 37-R1.5. Industry range is between 1 and 60. Therefore the best fit of 37 R1.5 is recommended.

Company:

Observed Life Table Results
Duke Energy Kentucky
Account: 373.30 - Street Lighting - Customer Poles

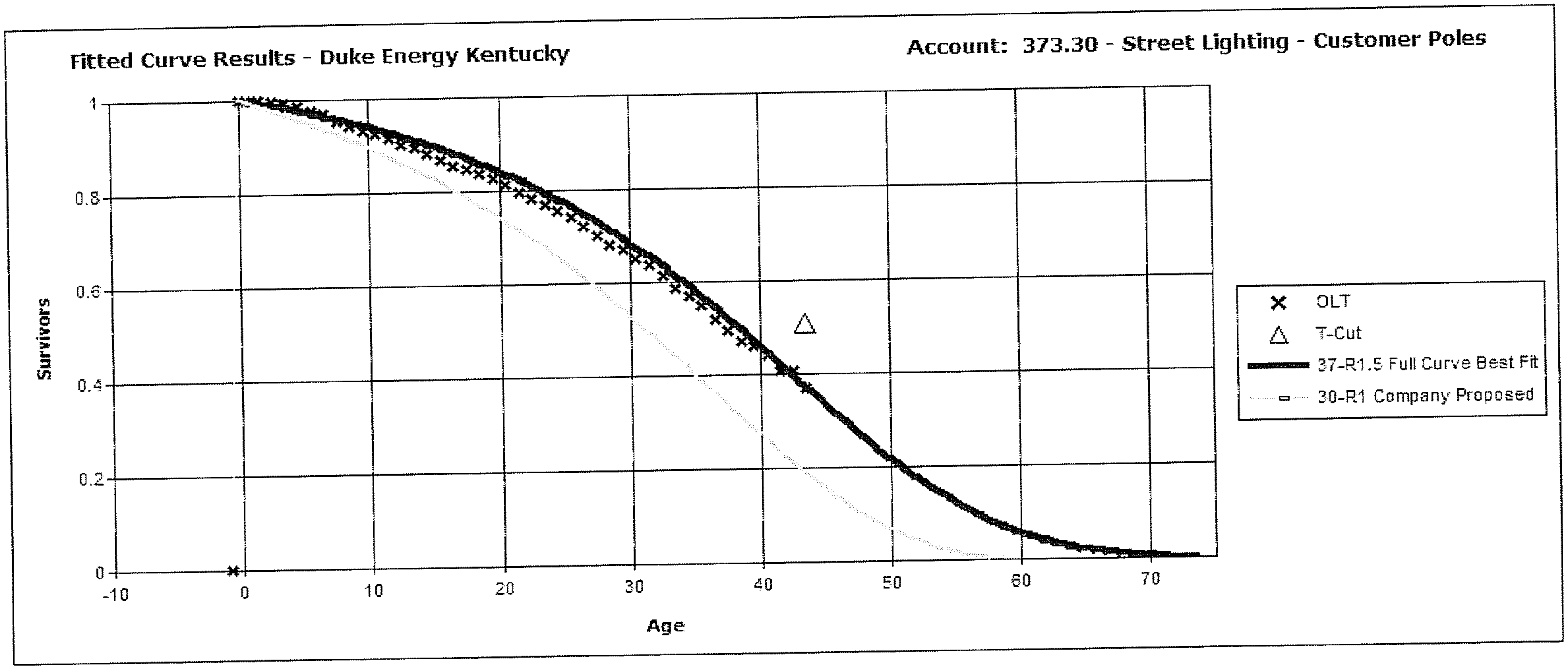
Age	Exposures	Retirements	Retirement Ratio (%)	Survivor Ratio (%)	Cumulative Survivors
BAND		1963 - 2005			
0	1,952,860	0	0.0000	1.0000	1.0000
0.5	1,953,996	532	0.0003	0.9997	1.0000
1.5	1,646,668	3,157	0.0019	0.9981	0.9997
2.5	1,643,511	9,292	0.0057	0.9943	0.9978
3.5	1,632,787	11,845	0.0073	0.9927	0.9921
4.5	1,548,903	11,301	0.0073	0.9927	0.9849
5.5	1,507,346	15,245	0.0101	0.9899	0.9777
6.5	1,445,727	21,349	0.0148	0.9852	0.9678
7.5	1,347,729	15,168	0.0113	0.9887	0.9535
8.5	1,257,509	12,107	0.0096	0.9904	0.9427
9.5	1,184,375	10,039	0.0085	0.9915	0.9337
10.5	1,108,354	11,434	0.0103	0.9897	0.9258
11.5	1,043,916	15,299	0.0147	0.9853	0.9163
12.5	971,633	10,171	0.0105	0.9895	0.9028
13.5	895,653	12,454	0.0139	0.9861	0.8933
14.5	817,372	13,554	0.0166	0.9834	0.8809
15.5	748,854	9,732	0.0130	0.9870	0.8663
16.5	714,166	7,267	0.0102	0.9898	0.8550
17.5	687,162	6,096	0.0089	0.9911	0.8463
18.5	660,086	8,555	0.0130	0.9870	0.8388
19.5	625,918	11,142	0.0178	0.9822	0.8279
20.5	594,969	12,841	0.0216	0.9784	0.8132
21.5	564,444	8,537	0.0151	0.9849	0.7956
22.5	542,904	10,687	0.0197	0.9803	0.7836
23.5	498,868	7,272	0.0146	0.9854	0.7682
24.5	453,399	8,779	0.0194	0.9806	0.7570
25.5	377,512	9,896	0.0262	0.9738	0.7423
26.5	318,534	10,003	0.0314	0.9686	0.7229
27.5	273,886	7,565	0.0276	0.9724	0.7002
28.5	246,204	4,053	0.0165	0.9835	0.6809
29.5	210,860	5,455	0.0259	0.9741	0.6697
30.5	180,232	4,375	0.0243	0.9757	0.6524
31.5	146,582	5,108	0.0348	0.9652	0.6365
32.5	119,613	5,619	0.0470	0.9530	0.6143
33.5	103,086	2,562	0.0249	0.9751	0.5854
34.5	87,179	3,357	0.0385	0.9615	0.5708
35.5	70,648	4,094	0.0579	0.9421	0.5488
36.5	55,321	2,257	0.0408	0.9592	0.5170
37.5	37,691	1,987	0.0527	0.9473	0.4959
38.5	31,448	627	0.0199	0.9801	0.4698
39.5	21,546	854	0.0396	0.9604	0.4605
40.5	14,551	1,140	0.0783	0.9217	0.4423
41.5	5,523	526	0.0952	0.9048	0.4077
42.5	1,284	0	0.0000	1.0000	0.4077
43.5	154	0	0.0000	1.0000	0.3689

Best Fit Curve Results
Duke Energy Kentucky
Account: 373.30 - Street Lighting - Customer Poles

Curve	Life	Sum of Squared Differences
BAND	**1963 - 2005**	
R1.5	37.0	10,052.612
S0	39.0	10,079.033
S0.5	38.0	10,088.235
L1	42.0	10,117.388
R1	38.0	10,126.007
L0.5	44.0	10,230.662
L1.5	41.0	10,241.219
S1	38.0	10,384.225
R2	37.0	10,407.600
S-0.5	41.0	10,452.509
L0	46.0	10,573.260
R0.5	40.0	10,580.302
L2	40.0	10,772.862
S1.5	37.0	10,946.105
R2.5	37.0	11,184.969
O2	49.0	11,214.292
O1	43.0	11,216.202
S2	37.0	11,784.796
O3	60.0	12,143.489
R3	37.0	12,383.533
L3	38.0	12,682.105
S3	37.0	14,047.471
R4	37.0	15,518.622
L4	38.0	15,839.921
O4	60.0	17,876.235
S4	37.0	18,025.823
L5	38.0	20,006.471
R5	38.0	20,915.803
S5	38.0	22,812.003
S6	39.0	28,280.856
SQ	38.0	42,590.630

Analytical Parameters

OLT Placement Band:	1961 - 2005
OLT Experience Band:	1963 - 2005
Minimum Life Parameter:	1
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	45.0



Analytical Parameters

OLT Placement Band:	1961 - 2005
OLT Experience Band:	1963 - 2005
Minimum Life Parameter:	1
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	45.0

Duke Energy Kentucky

373.30 - Street Lighting - Customer Poles

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 37 R1.5 26.13

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	0	37.00	36.59	0	0
2004	1.5	307,183	37.00	35.77	8,302	296,958
2003	2.5	1,432	37.00	34.96	39	1,353
2002	3.5	0	37.00	34.15	0	0
2001	4.5	72,039	37.00	33.35	1,947	64,930
2000	5.5	30,256	37.00	32.55	818	26,621
1999	6.5	43,649	37.00	31.77	1,180	37,475
1998	7.5	76,649	37.00	30.99	2,072	64,190
1997	8.5	75,052	37.00	30.21	2,028	61,281
1996	9.5	61,027	37.00	29.44	1,649	48,562
1995	10.5	65,982	37.00	28.68	1,783	51,145
1994	11.5	53,004	37.00	27.92	1,433	40,003
1993	12.5	56,984	37.00	27.18	1,540	41,854
1992	13.5	65,576	37.00	26.43	1,772	46,850
1991	14.5	65,827	37.00	25.70	1,779	45,722
1990	15.5	54,965	37.00	24.97	1,486	37,097
1989	16.5	24,957	37.00	24.25	675	16,359
1988	17.5	19,736	37.00	23.54	533	12,558
1987	18.5	20,980	37.00	22.84	567	12,951
1986	19.5	25,613	37.00	22.15	692	15,332
1985	20.5	19,807	37.00	21.47	535	11,491
1984	21.5	17,685	37.00	20.79	478	9,938
1983	22.5	13,004	37.00	20.13	351	7,074
1982	23.5	33,349	37.00	19.48	901	17,555
1981	24.5	38,197	37.00	18.84	1,032	19,446
1980	25.5	67,107	37.00	18.21	1,814	33,022
1979	26.5	49,082	37.00	17.59	1,327	23,334
1978	27.5	34,645	37.00	16.98	936	15,904
1977	28.5	20,117	37.00	16.39	544	8,912
1976	29.5	31,290	37.00	15.81	846	13,372
1975	30.5	25,173	37.00	15.25	680	10,372
1974	31.5	29,275	37.00	14.69	791	11,624
1973	32.5	21,861	37.00	14.15	591	8,362
1972	33.5	10,908	37.00	13.63	295	4,017
1971	34.5	13,345	37.00	13.11	361	4,730

Duke Energy Kentucky

373.30 - Street Lighting - Customer Poles

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: **37** **R1.5** **26.13**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1970	35.5	13,174	37.00	12.62	356	4,492
1969	36.5	11,233	37.00	12.13	304	3,684
1968	37.5	15,373	37.00	11.66	415	4,846
1967	38.5	4,255	37.00	11.21	115	1,289
1966	39.5	9,274	37.00	10.77	251	2,699
1965	40.5	6,141	37.00	10.34	166	1,716
1964	41.5	7,888	37.00	9.93	213	2,116
1963	42.5	3,712	37.00	9.53	100	956
1962	43.5	1,130	37.00	9.14	31	279
1961	44.5	154	37.00	8.76	4	37
		1,618,092			43,732	1,142,510

AVERAGE SERVICE LIFE 37.00
AVERAGE REMAINING LIFE 26.13

Duke Energy Kentucky

373.30 - Street Lighting - Customer Poles

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 30 R1 20.34

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	0	30.00	29.63	0	0
2004	1.5	307,183	30.00	28.89	10,239	295,851
2003	2.5	1,432	30.00	28.17	48	1,344
2002	3.5	0	30.00	27.44	0	0
2001	4.5	72,039	30.00	26.73	2,401	64,186
2000	5.5	30,256	30.00	26.02	1,009	26,244
1999	6.5	43,649	30.00	25.32	1,455	36,840
1998	7.5	76,649	30.00	24.62	2,555	62,915
1997	8.5	75,052	30.00	23.93	2,502	59,878
1996	9.5	61,027	30.00	23.25	2,034	47,294
1995	10.5	65,982	30.00	22.57	2,199	49,637
1994	11.5	53,004	30.00	21.89	1,767	38,682
1993	12.5	56,984	30.00	21.22	1,899	40,315
1992	13.5	65,576	30.00	20.56	2,186	44,945
1991	14.5	65,827	30.00	19.91	2,194	43,678
1990	15.5	54,965	30.00	19.26	1,832	35,284
1989	16.5	24,957	30.00	18.62	832	15,488
1988	17.5	19,736	30.00	17.99	658	11,834
1987	18.5	20,980	30.00	17.37	699	12,145
1986	19.5	25,613	30.00	16.76	854	14,306
1985	20.5	19,807	30.00	16.16	660	10,667
1984	21.5	17,685	30.00	15.57	589	9,176
1983	22.5	13,004	30.00	14.99	433	6,497
1982	23.5	33,349	30.00	14.42	1,112	16,032
1981	24.5	38,197	30.00	13.87	1,273	17,655
1980	25.5	67,107	30.00	13.32	2,237	29,802
1979	26.5	49,082	30.00	12.79	1,636	20,927
1978	27.5	34,645	30.00	12.27	1,155	14,171
1977	28.5	20,117	30.00	11.76	671	7,887
1976	29.5	31,290	30.00	11.26	1,043	11,749
1975	30.5	25,173	30.00	10.78	839	9,045
1974	31.5	29,275	30.00	10.30	976	10,055
1973	32.5	21,861	30.00	9.84	729	7,171
1972	33.5	10,908	30.00	9.39	364	3,413
1971	34.5	13,345	30.00	8.95	445	3,979

Duke Energy Kentucky

373.30 - Street Lighting - Customer Poles

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 30 R1 20.34

			BG/VG Average			
		Surviving	Service	Remaining	ASL	RL
Year	Age	Investment	Life	Life	Weights	Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1970	35.5	13,174	30.00	8.51	439	3,738
1969	36.5	11,233	30.00	8.09	374	3,030
1968	37.5	15,373	30.00	7.68	512	3,936
1967	38.5	4,255	30.00	7.28	142	1,032
1966	39.5	9,274	30.00	6.88	309	2,128
1965	40.5	6,141	30.00	6.50	205	1,331
1964	41.5	7,888	30.00	6.13	263	1,611
1963	42.5	3,712	30.00	5.76	124	713
1962	43.5	1,130	30.00	5.40	38	204
1961	44.5	154	30.00	5.05	5	26
		1,618,092			53,936	1,096,839

AVERAGE SERVICE LIFE 30.00
AVERAGE REMAINING LIFE 20.34

Duke Energy Kentucky

390.0 - Structures and Improvements

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 35 R2.5 19.06

			BG/VG Average			
Year (1)	**Age** (2)	**Surviving Investment** (3)	**Service Life** (4)	**Remaining Life** (5)	**ASL Weights** (6)=(3)/(4)	**RL Weights** (7)=(6)*(5)
2005	0.5	15,837	35.00	34.53	452	15,623
1977	28.5	3,297	35.00	11.86	94	1,117
1952	53.5	0	35.00	2.94	0	0
1951	54.5	328	35.00	2.72	9	26
1950	55.5	0	35.00	2.50	0	0
1949	56.5	0	35.00	2.27	0	0
1948	57.5	12,661	35.00	2.02	362	730
		32,124			918	17,495

AVERAGE SERVICE LIFE 35.00
AVERAGE REMAINING LIFE 19.06

Duke Energy Kentucky

396.00 - Power Operated Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Procedures
Related to Original Cost as of December 31, 2005

Survivor Curve .. IOWA: 14 R3 2.22

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2005	0.5	0	14.00	13.51	0	0
2004	1.5	0	14.00	12.53	0	0
2003	2.5	0	14.00	11.57	0	0
2002	3.5	0	14.00	10.63	0	0
2001	4.5	0	14.00	9.71	0	0
2000	5.5	0	14.00	8.81	0	0
1999	6.5	0	14.00	7.95	0	0
1998	7.5	0	14.00	7.12	0	0
1997	8.5	0	14.00	6.33	0	0
1996	9.5	0	14.00	5.58	0	0
1995	10.5	0	14.00	4.87	0	0
1994	11.5	0	14.00	4.21	0	0
1993	12.5	0	14.00	3.62	0	0
1992	13.5	0	14.00	3.08	0	0
1991	14.5	0	14.00	2.62	0	0
1990	15.5	12,045	14.00	2.22	860	1,909
		12,045			860	1,909

AVERAGE SERVICE LIFE	14.00
AVERAGE REMAINING LIFE	2.22

Attorney General Second Set Data Requests
Duke Energy Kentucky Case No. 2006-00172
Date Received: August 09, 2006
Response Due Date: August 23, 2006

AG-DR-02-029

REQUEST:

29. Provide complete copies of all correspondence with the following parties regarding the Company's implementation of FASB Statement No. 143, FIN 47 and the FERC NOPR and Order 631 in RM02-7-000:

    a. External auditors and other public accounting firms.

    b. Consultants

    c. External counsel

    d. Federal and State regulatory agencies

    e. Internal Revenue Service

RESPONSE:

See Attachment AG-DR-02-029 and Attachment AG-DR-02-029 Supplemental. This response consists, in part, of documents produced by Duke Energy Kentucky in response to a similar data request in Case No. 2005-00042.

WITNESS RESPONSIBLE: Carl J. Council, Jr.

Laub, Peggy

om:	Ritchie, Brett
ent:	Thursday, April 01, 2004 8:38 AM
To:	Pate, Gwen; Howe, Lee
Cc:	Lawler, Sarah
Subject:	FW: FERC Form 1 classification of non-143 cost of removal costs
Attachments:	Form 1 Classification of non- FAS 143 accumulated cost of removal.doc; RE: Form 1 Classification of non- FAS 143 accumulated cost of removal

Form 1 assification of non- RE: Form 1 Classification of n...

See attached, I also included the Cinergy response.

-----Original Message-----
From: David Stringfellow [mailto:DStringfellow@eei.org]
Sent: Wednesday, March 31, 2004 5:14 PM
To: Accounting Standards Committee
Subject: FERC Form 1 classification of non-143 cost of removal costs

TO: EEI Accounting Standards Committee Members

Attached is the summary of the Committee survey on the FERC Form 1 classification of non-Statement 143 cost of removal costs. I sent this summary to Jim Guest at the FERC.

avid Stringfellow
Edison Electric Institute

Tracking:	**Recipient**	**Read**
	Pate, Gwen	Read: 4/1/2004 2:50 PM
	Howe, Lee	
	Lawler, Sarah	Read: 4/1/2004 8:40 AM

3/24/04

TO: EEI Accounting Standards Committee Members

As everyone is likely very aware, the SEC staff has definitively said that for its filings (Form 10K and 10Q) the non-Statement 143 accumulated cost of removal for operations that continue to be subject to the provisions of Statement 71 should be broken out from accumulated depreciation and reclassified as a regulatory liability on the balance sheet.

What is still uncertain is whether this same format should be used for the FERC Form 1 for 2003. The FERC staff has not issued any definitive guidance on whether the SEC preference should be followed for the FERC Form 1 balance sheet.

I have informally spoken with Jim Guest at the FERC. He asked if I could receive some feedback on how companies would prefer to report this non-143 accumulated cost of removal - leave it in Account 108 or reclassify it as a regulatory liability for the FERC Form 1 balance sheet.

I can pass on your comments on a summary basis (no company names used) back to Jim Guest at the FERC. This would help the FERC in issuing some guidance on this issue.

Thank you.

David Stringfellow
Edison Electric Institute

Twenty-one responses (some respondents are at the holding company level representing several operating companies) support leaving the accumulated cost of removal in Account 108.

Among the comments received –

The Commission in Order 631 specifically chose not to require reclassification.

I believe that non-ARO accumulated cost of removal should continue to be classified in account 108 for regulatory accounting and reporting purposes. Reclassifying such amounts as a regulatory liability in the FERC Form 1 may have unintended consequences with various state commissions that follow the FERC U.S. of A. Do we want each state commission independently debating whether non-ARO accumulated cost of removal is really a regulatory liability and coming to different conclusions? Nothing has changed from the industry's historical regulatory accounting and reporting model except that someone at the SEC has successfully used SFAS 143 as an opportunity to force a pet agenda item upon the industry without bothering to follow a due process that includes public comment. Let sleeping dogs lie. For your background, [my company] is planning to report non-ARO accumulated cost of removal in account 108 in our FERC Form 1. We are including a footnote on page 123 of the FERC Form 1 that explains the difference between how non-ARO accumulated cost of removal is treated in the FERC report versus in our 10-K.

For reporting this item in our FERC Form 1, [my company] prefers to keep the accumulated cost of removal in Account 108. We believe moving this to a regulatory liability will create difficulties in rate cases before the state commissions, and may be a catalyst to consumer advocates suggesting rapid refunds to customers.

[My company] would prefer to leave it in account 108 for Form 1 purposes –
one of our operating company rate plans is based on a return on asset formula and moving these amounts would trigger a rate change unless otherwise excluded.

We believe the FERC has already addressed the issue. Our understanding is that the FERC Order 631, Par. 36 still requires "removal costs that are not asset retirement obligations are included as a component of the depreciation expense and recorded in accumulated depreciation". It would seem to me that the FERC would need to go through a formal rulemaking process to change this (but then the SEC didn't go through a rulemaking process to redefine GAAP either). There have been various times in the past where SEC disclosure and FERC reporting have been different, such differences have been handled in other disclosures in the Form 1.

We're not even sure why companies are asking this question based on paragraphs 37 & 38 of FERC's order on acctg. for AROs. Para. 37 says that non-legal retire. obligations, such as cost of removal, aren't in the scope of FERC's rule. Para. 38 instead requires companies to maintain subsidiary records for cost of removal for non-legal retire. obli. recorded in accum. depr. Based on FERC's rule, Acct. 108 is where COR should remain for FERC reporting so in our mind, FERC has already told us what to do.

We would say a reclassification with regards to FERC reporting is not necessary:
1) COR is included in our depreciation rates as approved by the states.
2) COR as presented in the SEC documents is based on a theoretical amount of COR included in accumulated depreciation.
3) Most (all?) companies do not and will not have systems in place to capture this information through their existing fixed plant systems.
4) If COR is reclassified, then should COR as it is incurred be re-pointed against the liability account?

We think FERC should NOT change the current requirements regarding accounting and reporting for cost of removal. Property taxes in some jurisdictions are calculated under the cost approach based on net plant values. Some taxing authorities use FERC forms to calculate the taxable base. If FERC requires non-aro removal costs to be recorded as a regulatory liability, property taxes could increase for some utilities. Additionally, some regulators could use this as an opportunity to require utilities to refund some or all of the removal amounts to customers even though companies will still continue to incur costs to remove/retire assets.

Three respondents support breaking out the accumulated cost of removal as a regulatory liability or asset.

Among the comments received –

[C]onform to the SEC presentation. It's one less thing to reconcile between the FERC form and our external financial presentation.

[My] company is planning to show as a regulatory liability for Form 1.

One respondent favored using Account 108 for 2003, but change for future years -

We have classified the non-ARO COR in a subaccount of Account 108 consistent with FERC's April 2003 accounting ruling. Since our FERC Form 1 is the basis of our state Form 1 (which is due 3/31/04) we are nearing completion of our filing & would not support change at this point for the 12/31/03 filing. However, I do support this change going forward.

Laub, Peggy

rom:	Ritchie, Brett
ent:	Monday, March 29, 2004 2:20 PM
To:	'David Stringfellow (E-mail)'
Subject: .	RE: Form 1 Classification of non- FAS 143 accumulated cost of removal

Cinergy would prefer to leave the amount in 108

-----Original Message-----
From: David Stringfellow [mailto:DStringfellow@eei.org]
Sent: Wednesday, March 24, 2004 10:23 AM
To: Accounting Standards Committee
Subject: Form 1 Classification of non- FAS 143 accumulated cost of removal

TO: EEI Accounting Standards Committee Members

As everyone is likely very aware, the SEC staff has definitively said that for its filings (Form 10K and 10Q) the non-Statement 143 accumulated cost of removal for operations that continue to be subject to the provisions of Statement 71 should be broken out from accumulated depreciation and reclassified as a regulatory liability on the balance sheet.

What is still uncertain is whether this same format should be used for the FERC Form 1 for 2003. The FERC staff has not issued any definitive guidance on whether the SEC preference should be followed for the FERC Form 1 balance sheet.

I have informally spoken with Jim Guest at the FERC. He asked if I could receive some feedback on how companies would prefer to report this non-143 accumulated cost of removal - leave it in Account 108 or reclassify it as a regulatory liability for the FERC Form 1 balance sheet.

can pass on your comments on a summary basis (no company names used) back to Jim Guest at the FERC. This would nelp the FERC in issuing some guidance on this issue.

Thank you.

David Stringfellow
Edison Electric Institute

You are currently subscribed to asc as: [brett.ritchie@cinergy.com] To unsubscribe, forward this message to leave-asc-32506W@ls.eei.org

Attorney General First Set Data Requests
ULH&P Case No. 2005-00042
Date Received: April 6, 2005
Response Due Date: April 19, 2005

AG-DR-01-075

REQUEST:

75. Please refer to page 60 of the Cinergy Corp. 2003 Annual Report as provided in response to filing requirement 807 KAR 5:001 Section 10 (9)(l).

    a. Please provide the calculation and supporting workpapers for the $39 million (net of tax) gain related to the cumulative effect of the adoption of SFAS No. 143, as discussed on this page.
    b. Does any of this amount relate to the assets being transferred from CG&E to ULH&P (East Bend, Woodsdale and Miami Fort Generating stations)? If so, please provide the calculation of the portion of the $39 million gain that was attributable to the reversal of cost of removal collected for these assets. Please include the before-tax calculation of the amount as well.
    c. Was the portion of the $39 million attributable to the reversal of cost of removal removed from accumulated depreciation?
    d. Please explain in detail the impact that this reversal of collected cost of removal had, or would have had, on the transfer price of these assets.

RESPONSE:

a. See Attachment AG-DR-01-075a.
b. See Attachment AG-DR-01-075b.
c. Yes.
d. Since the amount was removed from accumulated depreciation, the net book value of the plant would increase by the amount of the reversal.

WITNESS RESPONSIBLE: Peggy A. Laub

	Before- tax Amount FERC account 435	Tax	Net of Tax
	$	$	$
CGE			
CGE Non-Reg - Historical Cost of Removal	79,862,659.00		
-RWIP @12/31/2002	-6,474,743.59		
-RWIP @12/31/2002 (Jointly Owned Plants)	-8,090,112.08		
East Bend ARO	-654,281.84		
Zimmer ARO	-153,680.70		
Miami Fort ARO	-119,293.76		
Adjust Power plant entries for Jan & Feb deprec	3,197.72		
Adjust Power plant entries for Jan & Feb Accretion	8,961.16		
Total for CGE	64,382,705.91	25,205,829.00	39,176,876.91
International Companies			
Corp 420	-180,986.00		
Corp 426	-86,292.00		
Corp 427	-45,704.00		
	-312,982.00	-109,544.00	-203,438.00
Total Cinergy Corp	64,069,723.91	25,096,285.00	38,973,438.91

Attorney General First Set Data Request
ULH&P Case No. 2005-00042
Attachment AG-DR-01-075b

		$
Woodsdale		
	3410	2,116,405.00
	3420	1,167,466.00
	RWIP	-657,611.94
Total		2,626,259.06
East Bend		
	311	1,010,350.00
	312	9,973,086.00
	314	2,097,036.00
	315	681,204.00
	316	161,254.00
	RWIP	-3,956,266.48
Total		9,966,663.52
Miami Fort 5 & 6 (1)		
	311	719,163.00
	312	2,481,540.00
	314	1,058,837.00
	315	299,418.00
	316	58,324.00
	RWIP	-725,651.07
Total		3,891,630.93
Grand Total (1)		16,484,553.51
Tax		6,453,703.00
Total net of Tax		10,030,850.51

(1) Only Miami Fort Unit 6 is being transferred to ULH&P. Further analysis would have to be done to split the amount between the two units.

DUKE ENERGY KENTUCKY
SUMMARY OF FIVE-YEAR AVERAGE NET SALVAGE EXPERIENCE AND
CALCULATION OF ANNUAL NET SALVAGE DEPRECIATION RATES AS OF DECEMBER 31, 2005

	ACCOUNT	ORIGINAL COST	5-YEAR AVERAGE NET SALVAGE	ANNUAL NET SALVAGE RATE
	(1)	(2)	(3)	(4)=((3)/(2))*-1
	COMMON PLANT			
1900	TOTAL STRUCTURES & IMPROVEMENTS	8,320,285	(56,074)	0.674
1910	OFFICE FURNITURE AND EQUIPMENT	397,768	0	0.000
1930	STORES AND EQUIPMENT	5,563	0	0.000
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	185,828	(21)	0.011
1970	COMMUNICATION EQUIPMENT	39,252	(43)	0.110
1980	MISCELLANEOUS EQUIPMENT	11,372	0	0.000
	TOTAL COMMON PLANT	**8,960,068**	**(56,138)**	**0.627**
	STEAM PRODUCTION PLANT			
3110	STRUCTURES AND IMPROVEMENTS	38,135,093	0	0.000
3120	BOILER PLANT	313,673,642	(233,345)	0.074
3122	BOILER PLANT - RETROFIT PRECIPITATORS	14,003,140	0	0.000
3140	TURBOGENERATOR UNITS	78,490,741	(8,615)	0.011
3150	ACCESSORY ELECTRIC EQUIPMENT	29,177,222	0	0.000
3160	MISCELLANEOUS POWER PLANT - EXCLUDING SHOP	9,220,461	345	-0.004
	TOTAL STEAM PRODUCTION PLANT	**482,700,301**	**(241,615)**	**0.050**
	OTHER PRODUCTION PLANT			
3401	RIGHTS OF WAY	651,684	0	0.000
3410	STRUCTURES AND IMPROVEMENTS	33,725,782	0	0.000
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	15,507,516	0	0.000
3430	PRIME MOVERS	173,729	0	0.000
3440	GENERATORS	188,960,592	1,002,977	-0.531
3450	ACCESSORY ELECTRIC EQUIPMENT	16,867,010	0	0.000
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	3,701,280	0	0.000
	TOTAL OTHER PRODUCTION PLANT	**259,587,594**	**1,002,977**	**-0.386**
	TRANSMISSION PLANT			
3501	RIGHTS OF WAY	905,970	0	0.000
3520	STRUCTURES AND IMPROVEMENTS	381,059	0	0.000
3530	STATION EQUIPMENT	6,955,555	(243)	0.003
3532	STATION EQUIPMENT - MAJOR	3,373,233	(15,954)	0.473
3535	STATION EQUIPMENT - ELECTRONIC	13,820	0	0.000
3550	POLES AND FIXTURES	5,114,856	(10,012)	0.196
3560	OVERHEAD CONDUCTORS AND DEVICES	4,363,508	(4,745)	0.109
	TOTAL TRANSMISSION PLANT	**21,108,001**	**(30,954)**	**0.147**

DUKE ENERGY KENTUCKY
SUMMARY OF FIVE-YEAR AVERAGE NET SALVAGE EXPERIENCE AND
CALCULATION OF ANNUAL NET SALVAGE DEPRECIATION RATES AS OF DECEMBER 31, 2005

	ACCOUNT	ORIGINAL COST	5-YEAR AVERAGE NET SALVAGE	ANNUAL NET SALVAGE RATE
	(1)	(2)	(3)	(4)=((3)/(2))*-1
	DISTRIBUTION PLANT			
3601	RIGHTS OF WAY	4,459,567	0	0.000
3610	STRUCTURES AND IMPROVEMENTS	309,259	0	0.000
3620	STATION EQUIPMENT	18,814,186	(15,209)	0.081
3622	STATION EQUIPMENT - MAJOR	15,065,670	(581)	0.004
3635	STATION EQUIPMENT - ELECTRONIC	106,006	0	0.000
3640	POLES, TOWERS AND FIXTURES	43,026,869	(60,415)	0.140
3650	OVERHEAD CONDUCTORS AND DEVICES	61,492,932	(213,048)	0.346
3660	UNDERGROUND CONDUIT	14,352,678	(1,346)	0.009
3670	UNDERGROUND CONDUCTORS AND DEVICES	33,231,540	(24,045)	0.072
3680	LINE TRANSFORMERS	49,013,367	(26,201)	0.053
3682	LINE TRANSFORMERS - CUSTOMER	273,661	0	0.000
3691	SERVICES - UNDERGROUND	515,126	(25)	0.005
3692	SERVICES - OVERHEAD	10,257,449	(26,423)	0.258
3700	METERS	10,121,655	(15,800)	0.156
3701	LEASED METERS	3,558,486	0	0.000
3720	LEASED PROPERTY ON CUSTOMER PREMISES	9,647	0	0.000
3731	STREET LIGHTING - OVERHEAD	2,754,323	(7,383)	0.268
3732	STREET LIGHTING - BOULEVARD	2,840,524	(909)	0.032
3733	STREET LIGHTING - CUSTOMER POLES	1,618,092	(9,665)	0.597
	TOTAL DISTRIBUTION PLANT	**271,821,035**	**(401,050)**	**0.148**
	GENERAL PLANT			
3900	STRUCTURES AND IMPROVEMENTS	32,124	0	0.000
3910	OFFICE FURNITURE AND EQUIPMENT	36,019	0	0.000
3921	TRAILERS	99,599	28	-0.028
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	466,595	60	-0.013
3960	POWER OPERATED EQUIPMENT	12,045	4,529	-37.602
3970	COMMUNICATION EQUIPMENT	84,463	0	0.000
	TOTAL GENERAL PLANT	**730,844**	**4,617**	**-0.632**
	TOTAL DEPRECIABLE PLANT	**1,044,907,843**	**277,837**	

Source: Col. (2) from Spanos Study, pp. III-4 through III-6. Col. (3) from AG-DR-01-138(d).pdf, attached as pages 3 through 68.

DUKE ENERGY KENTUCKY

ACCOUNT 1030 MISCELLANEOUS INTANGIBLE PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004	9,395,003	0		0		0	
2005	160,987	0		0		0	
TOTAL	9,555,990	0		0		0	
FIVE-YEAR AVERAGE							
01-05	1,911,198	0		0		0	

DUKE ENERGY KENTUCKY

ACCOUNT 1890 LAND AND LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2004	214,908	651-	0	160,334	75	160,985	75
2005							
TOTAL	214,908	651-	0	160,334	75	160,985	75
FIVE-YEAR AVERAGE							
01-05	42,982	130-	0	32,067	75	32,197	75

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 1891.0

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1998	3,546	0		0		0	
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	3,546	0		0		0	
THREE-YEAR MOVING AVERAGES							
98-00	1,182	0		0		0	
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

DUKE ENERGY KENTUCKY

ACCOUNT 1900 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990		204,571				204,571-	
1991	10,904	93,952	862	156	1	93,796-	860-
1992	44,601	33,254	75		0	33,254-	75-
1993	3,829	2,179	57		0	2,179-	57-
1994	8,622	107,169			0	107,169-	
1995		46,859				46,859-	
1996	20,300	22,697	112		0	22,697-	112-
1997							
1998	236,952	1,816	1		0	1,816-	1-
1999							
2000							
2001							
2002	466,414	124,993	27		0	124,993-	27-
2003	360,388	117,298	33		0	117,298-	33-
2004	1,563,054	14,188	1		0	14,188-	1-
2005	67,932	23,891	35		0	23,891-	35-
TOTAL	2,782,996	792,867	28	156	0	792,711-	28-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
90-92	18,502	110,592	598	52	0	110,540-	597-
91-93	19,778	43,128	218	52	0	43,076-	218-
92-94	19,017	47,534	250		0	47,534-	250-
93-95	4,150	52,069			0	52,069-	
94-96	9,641	58,908	611		0	58,908-	611-
95-97	6,767	23,185	343		0	23,185-	343-
96-98	85,751	8,171	10		0	8,171-	10-
97-99	78,984	605	1		0	605-	1-
98-00	78,984	605	1		0	605-	1-
99-01							
00-02	155,471	41,664	27		0	41,664-	27-
01-03	275,601	80,764	29		0	80,764-	29-
02-04	796,619	85,493	11		0	85,493-	11-
03-05	663,791	51,792	8		0	51,792-	8-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
01-05	491,557	56,074	11		0	56,074-	11-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 1900 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	SALES	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004				413,152-		413,152-	
2005							
TOTAL				413,152-		413,152-	

DUKE ENERGY KENTUCKY

ACCOUNT 1910 OFFICE FURNITURE AND EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	7,797		0	4,460	57	4,460	57
1991	3,952		0	703	18	703	18
1992	215	87	40	894	416	807	375
1993	8,663		0		0		0
1994	1,737	57	3	1,230	71	1,173	68
1995	292		0	1,235	423	1,235	423
1996	456		0		0		0
1997	80,110		0		0		0
1998	493	17	3		0	17-	3-
1999	2,395		0		0		0
2000							
2001							
2002	16,263		0		0		0
2003	6,850		0		0		0
2004	17,874		0		0		0
2005	325,947		0		0		0
TOTAL	473,044	161	0	8,522	2	8,361	2

THREE-YEAR MOVING AVERAGES

90-92	3,988	29	1	2,019	51	1,990	50
91-93	4,276	29	1	532	12	503	12
92-94	3,538	48	1	708	20	660	19
93-95	3,564	19	1	821	23	802	23
94-96	828	19	2	821	99	802	97
95-97	26,952		0	412	2	412	2
96-98	27,019	6	0		0	6-	0
97-99	27,666	6	0		0	6-	0
98-00	962	6	1		0	6-	1-
99-01	798		0		0		0
00-02	5,421		0		0		0
01-03	7,704		0		0		0
02-04	13,662		0		0		0
03-05	116,890		0		0		0

FIVE-YEAR AVERAGE

01-05	73,387		0		0		0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 1911 OFFICE FURNITURE EQUIPMENT - EDP EQUIP.

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1991	138,999		0	528-	0	528-	0
1992							
1993							
1994							
1995							
1996							
1997	19,017		0		0		0
1998							
1999							
2000							
2001							
2002							
2003							
2004	12,981		0		0		0
2005							
TOTAL	170,997		0	528-	0	528-	0
THREE-YEAR MOVING AVERAGES							
91-93	46,333		0	176-	0	176-	0
92-94							
93-95							
94-96							
95-97	6,339		0		0		0
96-98	6,339		0		0		0
97-99	6,339		0		0		0
98-00							
99-01							
00-02							
01-03							
02-04	4,327		0		0		0
03-05	4,327		0		0		0
FIVE-YEAR AVERAGE							
01-05	2,596		0		0		0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 1920 AUTOS & TRUCKS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990				11,722		11,722	
1991	34,642		0	23,960	69	23,960	69
1992	23,681		0	1,280	5	1,280	5
1993				3,310		3,310	
1994	28,310		0		0		0
1995	17,996	528	3	1,640	9	1,112	6
1996	12,209	928-	8-	8,185	67	9,113	75
1997	83,716	14,165-	17-		0	14,165	17
1998	99,300	23,377-	24-		0	23,377	24
1999	46,997	3,843-	8-		0	3,843	8
2000							
2001	44,259		0	8,279	19	8,279	19
2002	32,425		0	10,011	31	10,011	31
2003	19,197		0	2,325	12	2,325	12
2004	5,078		0		0		0
2005							
TOTAL	447,810	41,785-	9-	70,712	16	112,497	25

THREE-YEAR MOVING AVERAGES

90-92	19,441		0	12,321	63	12,321	63
91-93	19,441		0	9,517	49	9,517	49
92-94	17,330		0	1,530	9	1,530	9
93-95	15,435	176	1	1,650	11	1,474	10
94-96	19,505	133-	1-	3,275	17	3,408	17
95-97	37,973	4,855-	13-	3,275	9	8,130	21
96-98	65,075	12,823-	20-	2,728	4	15,551	24
97-99	76,671	13,795-	18-		0	13,795	18
98-00	48,766	9,073-	19-		0	9,073	19
99-01	30,419	1,281-	4-	2,760	9	4,041	13
00-02	25,562		0	6,097	24	6,097	24
01-03	31,960		0	6,872	22	6,872	22
02-04	18,900		0	4,112	22	4,112	22
03-05	8,092		0	775	10	775	10

FIVE-YEAR AVERAGE

01-05	20,192		0	4,123	20	4,123	20

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 1922.0

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1999	34,435	0		0		0	
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	34,435	0		0		0	
THREE-YEAR MOVING AVERAGES							
99-01	11,478	0		0		0	
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

DUKE ENERGY KENTUCKY

ACCOUNT 1930 STORES EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1995	35,148		0	4,192	12	4,192	12
1996				29,800		29,800	
1997	10,236		0		0		0
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	45,384		0	33,992	75	33,992	75
THREE-YEAR MOVING AVERAGES							
95-97	15,128		0	11,330	75	11,330	75
96-98	3,412		0	9,933	291	9,933	291
97-99	3,412		0		0		0
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 1940 TOOLS, SHOP AND GARAGE EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1991	69		0		0		0
1992	188		0		0		0
1993							
1994	1,789		0		0		0
1995	8,656		0	44,074	509	44,074	509
1996				22,316		22,316	
1997	23,740		0		0		0
1998							
1999							
2000							
2001							
2002	168		0		0		0
2003							
2004	21,190	106	1		0	106-	1-
2005	2,513		0		0		0
TOTAL	58,313	106	0	66,390	114	66,284	114
THREE-YEAR MOVING AVERAGES							
91-93	86		0		0		0
92-94	659		0		0		0
93-95	3,482		0	14,691	422	14,691	422
94-96	3,482		0	22,130	636	22,130	636
95-97	10,798		0	22,130	205	22,130	205
96-98	7,913		0	7,439	94	7,439	94
97-99	7,913		0		0		0
98-00							
99-01							
00-02	56		0		0		0
01-03	56		0		0		0
02-04	7,119	35	0		0	35-	0
03-05	7,901	35	0		0	35-	0
FIVE-YEAR AVERAGE							
01-05	4,774	21	0		0	21-	0

DUKE ENERGY KENTUCKY

ACCOUNT 1960.0

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1999		13,330-				13,330	
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL		13,330-				13,330	
THREE-YEAR MOVING AVERAGES							
99-01		4,443-				4,443	
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

DUKE ENERGY KENTUCKY

ACCOUNT 1970 COMMUNICATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2004	23,683	216	1	0		216-	1-
2005							
TOTAL	23,683	216	1	0		216-	1-
FIVE-YEAR AVERAGE							
01-05	4,737	43	1	0		43-	1-

DUKE ENERGY KENTUCKY

ACCOUNT 1980 MISCELLANEOUS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1997	4,905		0		0		0
1998							
1999							
2000							
2001							
2002							
2003	4,825		0		0		0
2004	14,910		0		0		0
2005							
TOTAL	24,640		0		0		0
THREE-YEAR MOVING AVERAGES							
97-99	1,635		0		0		0
98-00							
99-01							
00-02							
01-03	1,608		0		0		0
02-04	6,578		0		0		0
03-05	6,578		0		0		0
FIVE-YEAR AVERAGE							
01-05	3,947		0		0		0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3110 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1991	42,371		0		0		0
1992	2,324		0		0		0
1993	106,507		0		0		0
1994	69,982		0		0		0
1995	93,406		0		0		0
1996							
1997	23,706		0		0		0
1998	1,523		0		0		0
1999	30,871		0		0		0
2000							
2001							
2002							
2003	139,027		0		0		0
2004							
2005	35,327		0		0		0
TOTAL	545,044		0		0		0
THREE-YEAR MOVING AVERAGES							
91-93	50,401		0		0		0
92-94	59,604		0		0		0
93-95	89,965		0		0		0
94-96	54,463		0		0		0
95-97	39,038		0		0		0
96-98	8,410		0		0		0
97-99	18,700		0		0		0
98-00	10,798		0		0		0
99-01	10,290		0		0		0
00-02							
01-03	46,342		0		0		0
02-04	46,342		0		0		0
03-05	58,118		0		0		0
FIVE-YEAR AVERAGE							
01-05	34,871		0		0		0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3120 BOILER PLANT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	422,833		0		0		0
1991	1,469,830		0		0		0
1992	1,290,307		0		0		0
1993	707,064		0		0		0
1994	861,329		0		0		0
1995	2,682,145		0		0		0
1996	32,885		0		0		0
1997	161,263		0		0		0
1998	758,949		0		0		0
1999	1,804,001		0		0		0
2000							
2001							
2002							
2003	7,226,804	1,220,923	17	54,200	1	1,166,723-	16-
2004	2,486,903		0		0		0
2005	3,191,937		0		0		0
TOTAL	23,096,250	1,220,923	5	54,200	0	1,166,723-	5-
THREE-YEAR MOVING AVERAGES							
90-92	1,060,990		0		0		0
91-93	1,155,734		0		0		0
92-94	952,900		0		0		0
93-95	1,416,846		0		0		0
94-96	1,192,120		0		0		0
95-97	958,764		0		0		0
96-98	317,699		0		0		0
97-99	908,071		0		0		0
98-00	854,316		0		0		0
99-01	601,334		0		0		0
00-02							
01-03	2,408,935	406,974	17	18,067	1	388,907-	16-
02-04	3,237,902	406,974	13	18,067	1	388,907-	12-
03-05	4,301,881	406,974	9	18,067	0	388,907-	9-
FIVE-YEAR AVERAGE							
01-05	2,581,129	244,185	9	10,840	0	233,345-	9-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3140 TURBOGENERATOR UNITS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1991	847,893		0		0		0
1992	538,297		0		0		0
1993	102,328		0		0		0
1994	555,226		0		0		0
1995	66,228		0		0		0
1996	5,992		0		0		0
1997	229,904		0		0		0
1998	210,493		0		0		0
1999	40,715		0		0		0
2000							
2001							
2002							
2003	311,366	43,075	14		0	43,075-	14-
2004	582,032		0		0		0
2005	850,980		0		0		0
TOTAL	4,341,454	43,075	1		0	43,075-	1-
THREE-YEAR MOVING AVERAGES							
91-93	496,173		0		0		0
92-94	398,617		0		0		0
93-95	241,260		0		0		0
94-96	209,149		0		0		0
95-97	100,708		0		0		0
96-98	148,796		0		0		0
97-99	160,371		0		0		0
98-00	83,736		0		0		0
99-01	13,572		0		0		0
00-02							
01-03	103,789	14,358	14		0	14,358-	14-
02-04	297,799	14,358	5		0	14,358-	5-
03-05	581,459	14,358	2		0	14,358-	2-
FIVE-YEAR AVERAGE							
01-05	348,876	8,615	2		0	8,615-	2-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3150 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1990	32,390		0		0		0
1991	71,444		0		0		0
1992	32,766		0		0		0
1993							
1994							
1995	259,537		0		0		0
1996	69,143		0		0		0
1997	68,288		0		0		0
1998							
1999							
2000							
2001							
2002							
2003	75,714		0		0		0
2004	729,582		0		0		0
2005	69,401		0		0		0
TOTAL	1,408,265		0		0		0
THREE-YEAR MOVING AVERAGES							
90-92	45,533		0		0		0
91-93	34,737		0		0		0
92-94	10,922		0		0		0
93-95	86,512		0		0		0
94-96	109,560		0		0		0
95-97	132,323		0		0		0
96-98	45,810		0		0		0
97-99	22,763		0		0		0
98-00							
99-01							
00-02							
01-03	25,238		0		0		0
02-04	268,432		0		0		0
03-05	291,566		0		0		0
FIVE-YEAR AVERAGE							
01-05	174,939		0		0		0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3160 MISCELLANEOUS POWER PLANT - EXCLUDING SHOP

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	46,577		0		0		0
1991	17,681		0		0		0
1992							
1993							
1994	19,547		0		0		0
1995	13,008		0		0		0
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003	138,740		0		0		0
2004							
2005	113,268	775	1	2,500	2	1,725	2
TOTAL	348,821	775	0	2,500	1	1,725	0
THREE-YEAR MOVING AVERAGES							
90-92	21,420		0		0		0
91-93	5,894		0		0		0
92-94	6,516		0		0		0
93-95	10,852		0		0		0
94-96	10,852		0		0		0
95-97	4,336		0		0		0
96-98							
97-99							
98-00							
99-01							
00-02							
01-03	46,247		0		0		0
02-04	46,247		0		0		0
03-05	84,003	258	0	833	1	575	1
FIVE-YEAR AVERAGE							
01-05	50,402	155	0	500	1	345	1

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3420 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004	42,403	0		0		0	
2005							
TOTAL	42,403	0		0		0	
FIVE-YEAR AVERAGE							
01-05	8,481	0		0		0	

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3440 GENERATORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2003	5,187		0		0		0
2004	32,402		0		0		0
2005	8,425,368		0	5,014,886	60	5,014,886	60
TOTAL	8,462,957		0	5,014,886	59	5,014,886	59
THREE-YEAR MOVING AVERAGES							
03-05	2,820,986		0	1,671,629	59	1,671,629	59
FIVE-YEAR AVERAGE							
01-05	1,692,591		0	1,002,977	59	1,002,977	59

DUKE ENERGY KENTUCKY

ACCOUNT 3450 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2003	52,428	0		0		0	
2004							
2005							
TOTAL	52,428	0		0		0	
THREE-YEAR MOVING AVERAGES							
03-05	17,476	0		0		0	
FIVE-YEAR AVERAGE							
01-05	10,486	0		0		0	

DUKE ENERGY KENTUCKY

ACCOUNT 3460 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	37,219	0		0		0	
2004							
2005	23,673	0		0		0	
TOTAL	60,892	0		0		0	
THREE-YEAR MOVING AVERAGES							
03-05	20,297	0		0		0	
FIVE-YEAR AVERAGE							
01-05	12,178	0		0		0	

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3500 LAND AND LAND RIGHTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1994	2,509		0		0		0
1995							
1996							
1997							
1998	104		0		0		0
1999							
2000							
2001							
2002							
2003							
2004	36,913		0	2,588	7	2,588	7
2005							
TOTAL	39,526		0	2,588	7	2,588	7
THREE-YEAR MOVING AVERAGES							
94-96	836		0		0		0
95-97							
96-98	35		0		0		0
97-99	35		0		0		0
98-00	35		0		0		0
99-01							
00-02							
01-03							
02-04	12,304		0	863	7	863	7
03-05	12,304		0	863	7	863	7
FIVE-YEAR AVERAGE							
01-05	7,383		0	518	7	518	7

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3501 RIGHTS OF WAY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1992	3,700		0		0		0
1993	940		0		0		0
1994	327	39	12		0	39-	12-
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	4,967	39	1		0	39-	1-

THREE-YEAR MOVING AVERAGES

92-94	1,656	13	1		0	13-	1-
93-95	422	13	3		0	13-	3-
94-96	109	13	12		0	13-	12-
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							

FIVE-YEAR AVERAGE

01-05

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3520 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1994	1,042		0		0		0
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	1,042		0		0		0
THREE-YEAR MOVING AVERAGES							
94-96	347		0		0		0
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

DUKE ENERGY KENTUCKY

ACCOUNT 3530 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1996	5,552	1,770	32		0	1,770-	32-
1997							
1998							
1999	4,924		0		0		0
2000							
2001							
2002							
2003	8,271	971	12		0	971-	12-
2004	28,699		0		0		0
2005	8,525	244	3		0	244-	3-
TOTAL	55,971	2,985	5		0	2,985-	5-

THREE-YEAR MOVING AVERAGES

96-98	1,851	590	32		0	590-	32-
97-99	1,641		0		0		0
98-00	1,641		0		0		0
99-01	1,641		0		0		0
00-02							
01-03	2,757	324	12		0	324-	12-
02-04	12,323	324	3		0	324-	3-
03-05	15,165	405	3		0	405-	3-

FIVE-YEAR AVERAGE

01-05	9,099	243	3		0	243-	3-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3532 STATION EQUIPMENT - MAJOR

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2002	40,579		0		0		0
2003	683,187	13,017	2		0	13,017-	2-
2004	60,919	63,346	104		0	63,346-	104-
2005	70,331	3,406	5		0	3,406-	5-
TOTAL	855,016	79,769	9		0	79,769-	9-
THREE-YEAR MOVING AVERAGES							
02-04	261,562	25,454	10		0	25,454-	10-
03-05	271,479	26,590	10		0	26,590-	10-
FIVE-YEAR AVERAGE							
01-05	171,003	15,954	9		0	15,954-	9-

DUKE ENERGY KENTUCKY

ACCOUNT 3532 STATION EQUIPMENT - MAJOR

SUMMARY OF BOOK SALVAGE

YEAR	SALES	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003				100,878		100,878	
2004							
2005							
TOTAL				100,878		100,878	

DUKE ENERGY KENTUCKY

ACCOUNT 3550 POLES AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	763	972	127	1,766	231	794	104
1991	14,549	4,066	28	17,670	121	13,604	94
1992	8,323	6,604	79	1,262	15	5,342-	64-
1993	27,199	4,929	18	12,384	46	7,455	27
1994	83,911	17,032	20	150,518	179	133,486	159
1995	46,396	8,076	17	8,057	17	19-	0
1996	109,925	9,135	8		0	9,135-	8-
1997	4,381	5,437	124	279	6	5,158-	118-
1998	4,211	862	20	5,114	121	4,252	101
1999	50,612	14,338	28	18,395	36	4,057	8
2000	9,767	3,084	32		0	3,084-	32-
2001	117,966	20,992	18		0	20,992-	18-
2002	13,673	6,716	49		0	6,716-	49-
2003	517	1,763	341		0	1,763-	341-
2004	12,902	5,311	41		0	5,311-	41-
2005	36,647	17,279	47	2,000	5	15,279-	42-
TOTAL	541,742	126,596	23	217,445	40	90,849	17

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
90-92	7,878	3,880	49	6,899	88	3,019	38
91-93	16,690	5,200	31	10,439	63	5,239	31
92-94	39,811	9,521	24	54,721	137	45,200	114
93-95	52,502	10,012	19	56,986	109	46,974	89
94-96	80,077	11,414	14	52,858	66	41,444	52
95-97	53,567	7,549	14	2,779	5	4,770-	9-
96-98	39,506	5,145	13	1,798	5	3,347-	8-
97-99	19,735	6,879	35	7,929	40	1,050	5
98-00	21,530	6,095	28	7,836	36	1,741	8
99-01	59,448	12,805	22	6,132	10	6,673-	11-
00-02	47,135	10,264	22		0	10,264-	22-
01-03	44,052	9,823	22		0	9,823-	22-
02-04	9,031	4,597	51		0	4,597-	51-
03-05	16,689	8,118	49	667	4	7,451-	45-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
01-05	36,341	10,412	29	400	1	10,012-	28-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3560 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	399	425	107	26	7	399-	100-
1991	5,146	752	15	11,297	220	10,545	205
1992	6,930	5,658	82	584	8	5,074-	73-
1993	10,050	915	9	385	4	530-	5-
1994	74,663	15,269	20		0	15,269-	20-
1995	47,175	6,437	14	7,803	17	1,366	3
1996	115,748		0		0		0
1997							
1998	50		0		0		0
1999	38,345	27,198-	71-	1,288	3	28,486	74
2000							
2001	140,500	13,093	9		0	13,093-	9-
2002	2,879	3,919	136		0	3,919-	136-
2003		1,834				1,834-	
2004	5,376	6,881	128		0	6,881-	128-
2005	20,039		0	2,000	10	2,000	10
TOTAL	467,300	27,985	6	23,383	5	4,602-	1-

THREE-YEAR MOVING AVERAGES

90-92	4,158	2,279	55	3,969	95	1,690	41
91-93	7,375	2,442	33	4,089	55	1,647	22
92-94	30,547	7,281	24	323	1	6,958-	23-
93-95	43,963	7,540	17	2,729	6	4,811-	11-
94-96	79,195	7,235	9	2,601	3	4,634-	6-
95-97	54,308	2,146	4	2,601	5	455	1
96-98	38,599		0		0		0
97-99	12,798	9,066-	71-	429	3	9,495	74
98-00	12,798	9,066-	71-	429	3	9,495	74
99-01	59,615	4,702-	8-	429	1	5,131	9
00-02	47,793	5,670	12		0	5,670-	12-
01-03	47,793	6,282	13		0	6,282-	13-
02-04	2,752	4,211	153		0	4,211-	153-
03-05	8,472	2,905	34	667	8	2,238-	26-

FIVE-YEAR AVERAGE

01-05	33,759	5,145	15	400	1	4,745-	14-

DUKE ENERGY KENTUCKY

ACCOUNT 3560 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	SALES		COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1994					97,380		97,380	
1995								
1996								
1997								
1998								
1999								
2000								
2001								
2002								
2003								
2004								
2005			47,476-				47,476	
TOTAL			47,476-		97,380		144,856	

DUKE ENERGY KENTUCKY

ACCOUNT 3600 LAND

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1994	9,783	0		0		0	
1995							
1996							
1997	21,922	0		0		0	
1998	6,577	0		0		0	
1999							
2000							
2001							
2002							
2003	12,518	480	4	18,560	148	18,080	144
2004	25,376	55,574-	219-	6,372	25	61,946	244
2005	6,014	0		16,000	266	16,000	266
TOTAL	82,190	55,094-	67-	40,932	50	96,026	117
THREE-YEAR MOVING AVERAGES							
94-96	3,261	0		0		0	
95-97	7,307	0		0		0	
96-98	9,500	0		0		0	
97-99	9,500	0		0		0	
98-00	2,192	0		0		0	
99-01							
00-02							
01-03	4,173	160	4	6,187	148	6,027	144
02-04	12,631	18,365-	145-	8,311	66	26,676	211
03-05	14,636	18,365-	125-	13,644	93	32,009	219
FIVE-YEAR AVERAGE							
01-05	8,782	11,019-	125-	8,186	93	19,205	219

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3601 RIGHTS OF WAY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	5,113	150	3		0	150-	3-
1991	21,499	269	1		0	269-	1-
1992	10,192	130	1		0	130-	1-
1993	11,387	33	0		0	33-	0
1994	704	83	12		0	83-	12-
1995	6,467		0		0		0
1996							
1997							
1998							
1999	7,680	60	1		0	60-	1-
2000							
2001							
2002	110		0		0		0
2003							
2004							
2005							
TOTAL	63,152	725	1		0	725-	1-
THREE-YEAR MOVING AVERAGES							
90-92	12,268	183	1		0	183-	1-
91-93	14,359	144	1		0	144-	1-
92-94	7,428	82	1		0	82-	1-
93-95	6,186	38	1		0	38-	1-
94-96	2,390	28	1		0	28-	1-
95-97	2,156		0		0		0
96-98							
97-99	2,560	20	1		0	20-	1-
98-00	2,560	20	1		0	20-	1-
99-01	2,560	20	1		0	20-	1-
00-02	37		0		0		0
01-03	37		0		0		0
02-04	37		0		0		0
03-05							
FIVE-YEAR AVERAGE							
01-05	22		0		0		0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3610 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1992	930	2,208	237	0		2,208-	237-
1993							
1994							
1995							
1996							
1997							
1998	1,925	0		0		0	
1999	1,918	370-	19-	0		370	19
2000							
2001							
2002							
2003							
2004							
2005	34,703	0		0		0	
TOTAL	39,476	1,838	5	0		1,838-	5-
THREE-YEAR MOVING AVERAGES							
92-94	310	736	237	0		736-	237-
93-95							
94-96							
95-97							
96-98	642	0		0		0	
97-99	1,281	123-	10-	0		123	10
98-00	1,281	123-	10-	0		123	10
99-01	639	123-	19-	0		123	19
00-02							
01-03							
02-04							
03-05	11,568	0		0		0	
FIVE-YEAR AVERAGE							
01-05	6,941	0		0		0	

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3610 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	SALES	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2005		34,938				34,938-	
TOTAL		34,938				34,938-	

DUKE ENERGY KENTUCKY

ACCOUNT 3620 STATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	35,343	23,601	67		0	23,601-	67-
1991		14,827				14,827-	
1992	39,324	3,732	9		0	3,732-	9-
1993	395,717	4,265	1		0	4,265-	1-
1994	608,354	59,357	10	2,449-	0	61,806-	10-
1995	141,231	28,005	20	214	0	27,791-	20-
1996	35,982	13,491	37	16	0	13,475-	37-
1997	63,344	7,053	11	70	0	6,983-	11-
1998	686,272	3,445-	1-		0	3,445	1
1999	181,674-	7,267	4-	5,655	3-	1,612-	1
2000							
2001							
2002							
2003	134,044	50,103	37		0	50,103-	37-
2004	3,033	857	28		0	857-	28-
2005	121,086	25,083	21		0	25,083-	21-
TOTAL	2,082,056	234,196	11	3,506	0	230,690-	11-
THREE-YEAR MOVING AVERAGES							
90-92	24,889	14,053	56		0	14,053-	56-
91-93	145,014	7,608	5		0	7,608-	5-
92-94	347,799	22,452	6	816-	0	23,268-	7-
93-95	381,768	30,543	8	745-	0	31,288-	8-
94-96	261,856	33,618	13	740-	0	34,358-	13-
95-97	80,186	16,183	20	100	0	16,083-	20-
96-98	261,866	5,700	2	28	0	5,672-	2-
97-99	189,314	3,625	2	1,908	1	1,717-	1-
98-00	168,199	1,274	1	1,885	1	611	0
99-01	60,558-	2,422	4-	1,885	3-	537-	1
00-02							
01-03	44,681	16,701	37		0	16,701-	37-
02-04	45,692	16,987	37		0	16,987-	37-
03-05	86,054	25,348	29		0	25,348-	29-
FIVE-YEAR AVERAGE							
01-05	51,633	15,209	29		0	15,209-	29-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3622 STATION EQUIPMENT - MAJOR

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
2000	24,335		0		0		0
2001							
2002							
2003							
2004	9,210	2,907	32		0	2,907-	32-
2005	35,537		0		0		0
TOTAL	69,082	2,907	4		0	2,907-	4-
THREE-YEAR MOVING AVERAGES							
00-02	8,112		0		0		0
01-03							
02-04	3,070	969	32		0	969-	32-
03-05	14,916	969	6		0	969-	6-
FIVE-YEAR AVERAGE							
01-05	8,949	581	6		0	581-	6-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3622 STATION EQUIPMENT - MAJOR

SUMMARY OF BOOK SALVAGE

YEAR	SALES	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2005		28,909-				28,909	
TOTAL		28,909-				28,909	

DUKE ENERGY KENTUCKY

ACCOUNT 3640 POLES, TOWERS AND FIXTURES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1990	217,732	98,829	45	151,720	70	52,891	24
1991	220,355	160,349	73	133,244	60	27,105-	12-
1992	838,996	181,086	22	373,355	45	192,269	23
1993	187,297	118,920	63	213,890	114	94,970	51
1994	383,269	194,529	51	144,301	38	50,228-	13-
1995	477,684	171,827	36	380,720	80	208,893	44
1996	174,965	58,850	34	32,929-	19-	91,779-	52-
1997	147,637	45,107-	31-	107,087	73	152,194	103
1998	207,158	27,024	13	20,768	10	6,256-	3-
1999	395,043	108,686	28	7,371	2	101,315-	26-
2000	102,198	7,376-	7-		0	7,376	7
2001	548,586	74,872	14	12,273	2	62,599-	11-
2002	101,028	5,918	6		0	5,918-	6-
2003	138,540	153,817	111		0	153,817-	111-
2004	504,478	3,253	1		0	3,253-	1-
2005	656,916	76,489	12	4	0	76,485-	12-
TOTAL	5,301,882	1,381,966	26	1,511,804	29	129,838	2
THREE-YEAR MOVING AVERAGES							
90-92	425,694	146,755	34	219,440	52	72,685	17
91-93	415,549	153,452	37	240,163	58	86,711	21
92-94	469,854	164,845	35	243,849	52	79,004	17
93-95	349,417	161,759	46	246,304	70	84,545	24
94-96	345,306	141,735	41	164,031	48	22,296	6
95-97	266,762	61,857	23	151,626	57	89,769	34
96-98	176,586	13,589	8	31,642	18	18,053	10
97-99	249,946	30,201	12	45,076	18	14,875	6
98-00	234,800	42,778	18	9,380	4	33,398-	14-
99-01	348,609	58,728	17	6,548	2	52,180-	15-
00-02	250,604	24,471	10	4,091	2	20,380-	8-
01-03	262,718	78,202	30	4,091	2	74,111-	28-
02-04	248,015	54,329	22		0	54,329-	22-
03-05	433,311	77,853	18	1	0	77,852-	18-
FIVE-YEAR AVERAGE							
01-05	389,910	62,870	16	2,455	1	60,415-	15-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3650 OVERHEAD CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	303,463	136,626	45	75,581	25	61,045-	20-
1991	227,749	147,390	65	155,875	68	8,485	4
1992	313,481	219,476	70	84,048	27	135,428-	43-
1993	240,027	136,014	57	84,089	35	51,925-	22-
1994	611,884	406,780	66	170,730	28	236,050-	39-
1995	596,355	234,379	39	342,025	57	107,646	18
1996	312,145	12,935	4	18,101-	6-	31,036-	10-
1997	80,667	130,365	162	19,621	24	110,744-	137-
1998	138,235	14,622	11	16,660	12	2,038	1
1999	393,713	121,417	31	2,920	1	118,497-	30-
2000	130,205	844	1		0	844-	1-
2001	729,041	196,330	27	45,423	6	150,907-	21-
2002	25,330-	55,995	221-		0	55,995-	221
2003	118,377	362,994	307		0	362,994-	307-
2004	836,373	35,574	4		0	35,574-	4-
2005	813,573	459,814	57	44	0	459,770-	57-
TOTAL	5,819,958	2,671,555	46	978,915	17	1,692,640-	29-

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
90-92	281,564	167,831	60	105,168	37	62,663-	22-
91-93	260,419	167,627	64	108,004	41	59,623-	23-
92-94	388,464	254,090	65	112,956	29	141,134-	36-
93-95	482,755	259,057	54	198,948	41	60,109-	12-
94-96	506,795	218,031	43	164,885	33	53,146-	10-
95-97	329,723	125,893	38	114,515	35	11,378-	3-
96-98	177,016	52,641	30	6,060	3	46,581-	26-
97-99	204,205	88,801	43	13,067	6	75,734-	37-
98-00	220,718	45,628	21	6,527	3	39,101-	18-
99-01	417,653	106,197	25	16,114	4	90,083-	22-
00-02	277,972	84,390	30	15,141	5	69,249-	25-
01-03	274,029	205,106	75	15,141	6	189,965-	69-
02-04	309,807	151,521	49		0	151,521-	49-
03-05	589,441	286,127	49	15	0	286,112-	49-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
01-05	494,407	222,141	45	9,093	2	213,048-	43-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3660 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	2,240	6,496	290	9,926	443	3,430	153
1991	3,988	2,036	51	3,033-	76-	5,069-	127-
1992	8,711	3,249	37	2,761	32	488-	6-
1993	2,058	1,169	57		0	1,169-	57-
1994	2,013	894	44		0	894-	44-
1995	1,881	1,411	75		0	1,411-	75-
1996							
1997	1,360	217-	16-		0	217	16
1998							
1999	1,518	505	33		0	505-	33-
2000							
2001							
2002	4,609		0		0		0
2003	6,541	1,563	24		0	1,563-	24-
2004	3,222		0		0		0
2005	22,393	5,165	23		0	5,165-	23-
TOTAL	60,534	22,271	37	9,654	16	12,617-	21-
THREE-YEAR MOVING AVERAGES							
90-92	4,980	3,927	79	3,218	65	709-	14-
91-93	4,919	2,152	44	90-	2-	2,242-	46-
92-94	4,261	1,771	42	920	22	851-	20-
93-95	1,984	1,158	58		0	1,158-	58-
94-96	1,298	768	59		0	768-	59-
95-97	1,080	398	37		0	398-	37-
96-98	453	72-	16-		0	72	16
97-99	959	96	10		0	96-	10-
98-00	506	168	33		0	168-	33-
99-01	506	168	33		0	168-	33-
00-02	1,536		0		0		0
01-03	3,717	521	14		0	521-	14-
02-04	4,790	521	11		0	521-	11-
03-05	10,718	2,243	21		0	2,243-	21-
FIVE-YEAR AVERAGE							
01-05	7,353	1,346	18		0	1,346-	18-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3670 UNDERGROUND CONDUCTORS AND DEVICES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	87,401	30,394	35	23,927	27	6,467-	7-
1991	31,879	17,356	54	36,234	114	18,878	59
1992	42,260	14,850	35	9,879	23	4,971-	12-
1993	69,647	24,244	35	15,918	23	8,326-	12-
1994	97,300	39,946	41	35,687	37	4,259-	4-
1995	75,590	44,001	58	261,764-	346-	305,765-	405-
1996	34,498	3,291	10	1,099	3	2,192-	6-
1997	3,146	11,711-	372-	6,457	205	18,168	577
1998	1,662	5,918	356	2,565	154	3,353-	202-
1999	27,742	5,107	18		0	5,107-	18-
2000							
2001	8,202		0		0		0
2002	29,273		0		0		0
2003	50,583	20,187	40		0	20,187-	40-
2004	221,372	75-	0		0	75	0
2005	199,633	100,118	50	7	0	100,111-	50-
TOTAL	980,188	293,626	30	129,991-	13-	423,617-	43-
THREE-YEAR MOVING AVERAGES							
90-92	53,847	20,867	39	23,347	43	2,480	5
91-93	47,929	18,817	39	20,677	43	1,860	4
92-94	69,736	26,346	38	20,495	29	5,851-	8-
93-95	80,846	36,064	45	70,053-	87-	106,117-	131-
94-96	69,129	29,079	42	74,993-	108-	104,072-	151-
95-97	37,745	11,860	31	84,736-	224-	96,596-	256-
96-98	13,102	834-	6-	3,374	26	4,208	32
97-99	10,850	229-	2-	3,008	28	3,237	30
98-00	9,802	3,675	37	855	9	2,820-	29-
99-01	11,982	1,702	14		0	1,702-	14-
00-02	12,492		0		0		0
01-03	29,353	6,729	23		0	6,729-	23-
02-04	100,409	6,704	7		0	6,704-	7-
03-05	157,196	40,077	25	2	0	40,075-	25-
FIVE-YEAR AVERAGE							
01-05	101,813	24,046	24	1	0	24,045-	24-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3680 LINE TRANSFORMERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1990	362,018	281,670	78	218,313	60	63,357-	18-
1991	266,727	70,694	27	165,931	62	95,237	36
1992	375,952	101,792	27	115,679	31	13,887	4
1993	487,171	39,446	8	170,173	35	130,727	27
1994	574,496	167,718	29	241,011	42	73,293	13
1995	482,193	63,494	13	336,495	70	273,001	57
1996	446,033	16,438	4	148,036	33	131,598	30
1997	265,872	15,936	6	177,691	67	161,755	61
1998	215,514	3,437	2	110,476	51	107,039	50
1999	264,966	21,062	8	110,002	42	88,940	34
2000	13,975	6,880-	49-		0	6,880	49
2001	551,332	14,567	3	1,066	0	13,501-	2-
2002	334,527	2,260	1		0	2,260-	1-
2003	310,036	41,328	13		0	41,328-	13-
2004	376,438	861	0		0	861-	0
2005	563,912	73,053	13		0	73,053-	13-
TOTAL	5,891,162	906,876	15	1,794,873	30	887,997	15
THREE-YEAR MOVING AVERAGES							
90-92	334,899	151,385	45	166,641	50	15,256	5
91-93	376,616	70,644	19	150,595	40	79,951	21
92-94	479,206	102,985	21	175,621	37	72,636	15
93-95	514,620	90,219	18	249,227	48	159,008	31
94-96	500,908	82,550	16	241,848	48	159,298	32
95-97	398,033	31,956	8	220,741	55	188,785	47
96-98	309,140	11,937	4	145,401	47	133,464	43
97-99	248,784	13,478	5	132,723	53	119,245	48
98-00	164,818	5,873	4	73,493	45	67,620	41
99-01	276,758	9,583	3	37,023	13	27,440	10
00-02	299,945	3,315	1	355	0	2,960-	1-
01-03	398,632	19,385	5	355	0	19,030-	5-
02-04	340,334	14,816	4		0	14,816-	4-
03-05	416,795	38,414	9		0	38,414-	9-
FIVE-YEAR AVERAGE							
01-05	427,249	26,414	6	213	0	26,201-	6-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3691 SERVICES - UNDERGROUND

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	85	73	86	78	92	5	6
1991				39		39	
1992							
1993							
1994	39	14	36	1	3	13-	33-
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005	17	123	724		0	123-	724-
TOTAL	141	210	149	118	84	92-	65-
THREE-YEAR MOVING AVERAGES							
90-92	28	24	86	39	139	15	54
91-93				13		13	
92-94	13	5	38		0	5-	38-
93-95	13	5	38		0	5-	38-
94-96	13	5	38		0	5-	38-
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05	6	41	683		0	41-	683-
FIVE-YEAR AVERAGE							
01-05	3	25	833		0	25-	833-

DUKE ENERGY KENTUCKY

ACCOUNT 3692 SERVICES - OVERHEAD

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1990	53,435	55,343	104	12,488	23	42,855-	80-
1991	67,772	63,859	94		0	63,859-	94-
1992	52,070	46,374	89	8,328	16	38,046-	73-
1993	57,132	54,546	95	8,066	14	46,480-	81-
1994	62,625	37,267	60	11,629	19	25,638-	41-
1995	68,188	31,387	46	34,873	51	3,486	5
1996	56,475	33,400	59	2,906	5	30,494-	54-
1997	49,435	5,919	12	6,259	13	340	1
1998	72,403	41,964	58	7,514	10	34,450-	48-
1999	68,815	19,196	28		0	19,196-	28-
2000	2,737	3,885-	142-		0	3,885	142
2001	77,480	13,283	17	308	0	12,975-	17-
2002	10,930		0		0		0
2003	47,881	3,299	7		0	3,299-	7-
2004	262,044		0		0		0
2005	146,306	115,846	79		0	115,846-	79-
TOTAL	1,155,728	517,798	45	92,371	8	425,427-	37-
THREE-YEAR MOVING AVERAGES							
90-92	57,759	55,192	96	6,939	12	48,253-	84-
91-93	58,991	54,926	93	5,465	9	49,461-	84-
92-94	57,276	46,062	80	9,341	16	36,721-	64-
93-95	62,648	41,066	66	18,189	29	22,877-	37-
94-96	62,430	34,018	54	16,469	26	17,549-	28-
95-97	58,033	23,568	41	14,679	25	8,889-	15-
96-98	59,438	27,094	46	5,560	9	21,534-	36-
97-99	63,551	22,360	35	4,591	7	17,769-	28-
98-00	47,985	19,092	40	2,505	5	16,587-	35-
99-01	49,678	9,531	19	103	0	9,428-	19-
00-02	30,383	3,133	10	103	0	3,030-	10-
01-03	45,430	5,527	12	103	0	5,424-	12-
02-04	106,952	1,100	1		0	1,100-	1-
03-05	152,077	39,715	26		0	39,715-	26-
FIVE-YEAR AVERAGE							
01-05	108,928	26,485	24	62	0	26,423-	24-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3700 METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	93,976	11,420	12	81,341	87	69,921	74
1991	90,291	7,855	9	89,564	99	81,709	90
1992	255,062	9,174	4	84,464	33	75,290	30
1993	329,246	8,920	3	89,303	27	80,383	24
1994	283,205	15,510	5	59,032	21	43,522	15
1995	155,278	13,244	9	49,500	32	36,256	23
1996	240,095	10,670	4	64,189	27	53,519	22
1997	239,605	19,453	8	75,142	31	55,689	23
1998	329,257	19,083	6	61,248	19	42,165	13
1999	670,128	2,766	0	11,691	2	8,925	1
2000							
2001	447,957		0		0		0
2002							
2003	387,642	104,633	27	25,649	7	78,984-	20-
2004	269,506	16	0		0	16-	0
2005	376,467		0		0		0
TOTAL	4,167,715	222,744	5	691,123	17	468,379	11

THREE-YEAR MOVING AVERAGES

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
90-92	146,443	9,483	6	85,123	58	75,640	52
91-93	224,866	8,649	4	87,777	39	79,128	35
92-94	289,171	11,201	4	77,600	27	66,399	23
93-95	255,909	12,558	5	65,945	26	53,387	21
94-96	226,193	13,141	6	57,574	25	44,433	20
95-97	211,659	14,455	7	62,944	30	48,489	23
96-98	269,653	16,402	6	66,860	25	50,458	19
97-99	412,997	13,767	3	49,360	12	35,593	9
98-00	333,128	7,283	2	24,313	7	17,030	5
99-01	372,695	922	0	3,897	1	2,975	1
00-02	149,319		0		0		0
01-03	278,533	34,878	13	8,550	3	26,328-	9-
02-04	219,049	34,883	16	8,550	4	26,333-	12-
03-05	344,538	34,883	10	8,550	2	26,333-	8-

FIVE-YEAR AVERAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
01-05	296,314	20,930	7	5,130	2	15,800-	5-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3701 LEASED METERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2004	28,337	0		0		0	
2005	200,047	0		0		0	
TOTAL	228,384	0		0		0	
FIVE-YEAR AVERAGE							
01-05	45,677	0		0		0	

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3731 STREET LIGHTING - OVERHEAD

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1990	20,216	7,522	37	4,336	21	3,186-	16-
1991	9,619	6,948	72	3,286	34	3,662-	38-
1992	9,688	4,726	49	1,156	12	3,570-	37-
1993	16,190	4,106	25	1,333	8	2,773-	17-
1994	28,579	5,619	20	13,033	46	7,414	26
1995	29,964	6,883	23	46,611	156	39,728	133
1996	18,285	4,333	24	7	0	4,326-	24-
1997	5,424	1,902-	35-	108	2	2,010	37
1998	13,430	2,834	21	8	0	2,826-	21-
1999	29,130	5,860	20		0	5,860-	20-
2000	5,110	1,868-	37-		0	1,868	37
2001	512,299	6,338	1	234	0	6,104-	1-
2002	10,538	461	4		0	461-	4-
2003	14,022	105	1		0	105-	1-
2004	77,153	288	0		0	288-	0
2005	121,631	29,975	25	14	0	29,961-	25-
TOTAL	921,278	82,228	9	70,126	8	12,102-	1-
THREE-YEAR MOVING AVERAGES							
90-92	13,174	6,399	49	2,926	22	3,473-	26-
91-93	11,832	5,260	44	1,925	16	3,335-	28-
92-94	18,152	4,817	27	5,174	29	357	2
93-95	24,911	5,536	22	20,326	82	14,790	59
94-96	25,609	5,612	22	19,883	78	14,271	56
95-97	17,891	3,104	17	15,575	87	12,471	70
96-98	12,379	1,755	14	41	0	1,714-	14-
97-99	15,994	2,264	14	39	0	2,225-	14-
98-00	15,890	2,275	14	3	0	2,272-	14-
99-01	182,179	3,443	2	78	0	3,365-	2-
00-02	175,982	1,644	1	78	0	1,566-	1-
01-03	178,953	2,302	1	78	0	2,224-	1-
02-04	33,904	285	1		0	285-	1-
03-05	70,935	10,123	14	5	0	10,118-	14-
FIVE-YEAR AVERAGE							
01-05	147,129	7,433	5	50	0	7,383-	5-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3732 STREET LIGHTING - BOULEVARD

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	3,523	2,720	77	6,087	173	3,367	96
1991	15,833	5,713	36	4,585	29	1,128-	7-
1992	18,138	7,473	41	11,314	62	3,841	21
1993	9,699	2,227	23	9,587	99	7,360	76
1994	6,263	3,760	60	6,179	99	2,419	39
1995	11,168	1,070	10	1,952	17	882	8
1996	15,106	4,906	32		0	4,906-	32-
1997	9,535	761-	8-		0	761	8
1998	29,706	703	2		0	703-	2-
1999	24,055	3,273	14		0	3,273-	14-
2000							
2001	10,627		0		0		0
2002	22,424		0		0		0
2003	3,503	1,182	34		0	1,182-	34-
2004	20,786		0		0		0
2005	30,122	3,362	11		0	3,362-	11-
TOTAL	230,488	35,628	15	39,704	17	4,076	2
THREE-YEAR MOVING AVERAGES							
90-92	12,498	5,302	42	7,329	59	2,027	16
91-93	14,557	5,138	35	8,495	58	3,357	23
92-94	11,367	4,486	39	9,027	79	4,541	40
93-95	9,043	2,352	26	5,906	65	3,554	39
94-96	10,845	3,245	30	2,710	25	535-	5-
95-97	11,936	1,738	15	651	5	1,087-	9-
96-98	18,116	1,616	9		0	1,616-	9-
97-99	21,098	1,072	5		0	1,072-	5-
98-00	17,920	1,326	7		0	1,326-	7-
99-01	11,561	1,091	9		0	1,091-	9-
00-02	11,017		0		0		0
01-03	12,185	394	3		0	394-	3-
02-04	15,571	394	3		0	394-	3-
03-05	18,137	1,515	8		0	1,515-	8-
FIVE-YEAR AVERAGE							
01-05	17,492	909	5		0	909-	5-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3733 STREET LIGHTING - SECURITY

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	50,637	8,814	17	3,300	7	5,514-	11-
1991	27,156	15,496	57	11,821	44	3,675-	14-
1992	23,087	13,123	57	5,159	22	7,964-	34-
1993	23,870	9,722	41	2,151	9	7,571-	32-
1994	28,547	10,620	37	2,667	9	7,953-	28-
1995	30,221	14,882	49	2,433	8	12,449-	41-
1996	26,883	7,686	29	37	0	7,649-	28-
1997	32,974	301-	1-	5-	0	296	1
1998	38,832	7,785	20	421	1	7,364-	19-
1999	29,017	10,110	35		0	10,110-	35-
2000	359	53-	15-		0	53	15
2001	177,694	8,915	5		0	8,915-	5-
2002	6,178		0		0		0
2003	10,245	122	1		0	122-	1-
2004	49,285	13-	0		0	13	0
2005	89,573	39,459	44	162	0	39,297-	44-
TOTAL	644,558	146,367	23	28,146	4	118,221-	18-

THREE-YEAR MOVING AVERAGES

90-92	33,627	12,478	37	6,760	20	5,718-	17-
91-93	24,704	12,781	52	6,377	26	6,404-	26-
92-94	25,168	11,155	44	3,325	13	7,830-	31-
93-95	27,546	11,742	43	2,417	9	9,325-	34-
94-96	28,550	11,063	39	1,712	6	9,351-	33-
95-97	30,026	7,422	25	822	3	6,600-	22-
96-98	32,897	5,057	15	151	0	4,906-	15-
97-99	33,608	5,865	17	139	0	5,726-	17-
98-00	22,736	5,947	26	140	1	5,807-	26-
99-01	69,023	6,324	9		0	6,324-	9-
00-02	61,410	2,954	5		0	2,954-	5-
01-03	64,706	3,012	5		0	3,012-	5-
02-04	21,902	36	0		0	36-	0
03-05	49,701	13,189	27	54	0	13,135-	26-

FIVE-YEAR AVERAGE

01-05	66,595	9,697	15	32	0	9,665-	15-

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3891.0

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1992	125,421	0		0		0	
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	125,421	0		0		0	
THREE-YEAR MOVING AVERAGES							
92-94	41,807	0		0		0	
93-95							
94-96							
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3900 STRUCTURES AND IMPROVEMENTS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1991	2,935	410,094		0		410,094-	
1992	345,562	8,335	2	432,883	125	424,548	123
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	348,497	418,429	120	432,883	124	14,454	4

THREE-YEAR MOVING AVERAGES

91-93	116,166	139,476	120	144,294	124	4,818	4
92-94	115,187	2,778	2	144,294	125	141,516	123
93-95							
94-96							
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							

FIVE-YEAR AVERAGE

01-05

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3910 OFFICE FURNITURE AND EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	2,532		0		0		0
1991							
1992							
1993							
1994		689		1,550		861	
1995				441		441	
1996							
1997	13,748		0		0		0
1998							
1999							
2000							
2001							
2002	398		0		0		0
2003	1,165		0		0		0
2004	8,389		0		0		0
2005	1,003		0		0		0
TOTAL	27,235	689	3	1,991	7	1,302	5
THREE-YEAR MOVING AVERAGES							
90-92	844		0		0		0
91-93							
92-94		230		517		287	
93-95		230		664		434	
94-96		230		664		434	
95-97	4,583		0	147	3	147	3
96-98	4,583		0		0		0
97-99	4,583		0		0		0
98-00							
99-01							
00-02	133		0		0		0
01-03	521		0		0		0
02-04	3,317		0		0		0
03-05	3,519		0		0		0
FIVE-YEAR AVERAGE							
01-05	2,191		0		0		0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3914.0

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1997	988	0		0		0	
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	988	0		0		0	
THREE-YEAR MOVING AVERAGES							
97-99	329	0		0		0	
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3920 TRANSPORTATION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	97,145	626	1	37,984	39	37,358	38
1991	804,338	514	0	152,221	19	151,707	19
1992	298,020	56	0	18,975	6	18,919	6
1993	46,286		0	8,560	18	8,560	18
1994	27,348	100	0	885	3	785	3
1995	389,701	2,003	1	40,314	10	38,311	10
1996	144,593	14,251-	10-	2,000	1	16,251	11
1997	58,576	8,259-	14-		0	8,259	14
1998	155,469	7,918-	5-		0	7,918	5
1999	218,049	23,552-	11-		0	23,552	11
2000							
2001	1,060,541	27,944-	3-	59,251	6	87,195	8
2002	1,264,120		0	94,693	7	94,693	7
2003	639,084	41,583-	7-	27,300-	4-	14,283	2
2004	123,636		0	13,096	11	13,096	11
2005							
TOTAL	5,326,906	120,208-	2-	400,679	8	520,887	10

THREE-YEAR MOVING AVERAGES

90-92	399,834	399	0	69,727	17	69,328	17
91-93	382,881	190	0	59,919	16	59,729	16
92-94	123,885	52	0	9,473	8	9,421	8
93-95	154,445	701	0	16,586	11	15,885	10
94-96	187,214	4,050-	2-	14,400	8	18,450	10
95-97	197,623	6,836-	3-	14,105	7	20,941	11
96-98	119,546	10,143-	8-	667	1	10,810	9
97-99	144,031	13,243-	9-		0	13,243	9
98-00	124,506	10,490-	8-		0	10,490	8
99-01	426,197	17,165-	4-	19,750	5	36,915	9
00-02	774,887	9,315-	1-	51,315	7	60,630	8
01-03	987,915	23,176-	2-	42,215	4	65,391	7
02-04	675,613	13,861-	2-	26,830	4	40,691	6
03-05	254,240	13,861-	5-	4,735-	2-	9,126	4

FIVE-YEAR AVERAGE

01-05	617,476	13,905-	2-	27,948	5	41,853	7

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3921 TRANSPORTATION - TRAILERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	605		0		0		0
1991	5,340	40	1	735	14	695	13
1992	8,212		0	3,910	48	3,910	48
1993							
1994							
1995	10,407	309	3	323	3	14	0
1996							
1997	44,002		0		0		0
1998	18,745		0		0		0
1999	23,244		0		0		0
2000							
2001	8,635		0	160	2	160	2
2002	10,236		0		0		0
2003	20,304	9,494-	47-	9,494-	47-		0
2004	1,820		0	20-	1-	20-	1-
2005							
TOTAL	151,550	9,145-	6-	4,386-	3-	4,759	3
THREE-YEAR MOVING AVERAGES							
90-92	4,719	13	0	1,548	33	1,535	33
91-93	4,517	13	0	1,548	34	1,535	34
92-94	2,737		0	1,303	48	1,303	48
93-95	3,469	103	3	108	3	5	0
94-96	3,469	103	3	108	3	5	0
95-97	18,136	103	1	108	1	5	0
96-98	20,916		0		0		0
97-99	28,664		0		0		0
98-00	13,996		0		0		0
99-01	10,626		0	53	0	53	0
00-02	6,290		0	53	1	53	1
01-03	13,058	3,165-	24-	3,111-	24-	54	0
02-04	10,787	3,165-	29-	3,171-	29-	6-	0
03-05	7,375	3,165-	43-	3,171-	43-	6-	0
FIVE-YEAR AVERAGE							
01-05	8,199	1,899-	23-	1,871-	23-	28	0

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3930 STORES EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1997	605		0		0		0
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	605		0		0		0
THREE-YEAR MOVING AVERAGES							
97-99	202		0		0		0
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3940 TOOLS, SHOP AND GARAGE EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1990	297	4	1		0	4-	1-
1991				61		61	
1992	514		0		0		0
1993	2,517		0	1,706	68	1,706	68
1994							
1995	918		0		0		0
1996							
1997	50,116		0		0		0
1998							
1999							
2000							
2001							
2002							
2003							
2004	3,602	33	1		0	33-	1-
2005	511		0	335	66	335	66
TOTAL	58,475	37	0	2,102	4	2,065	4
THREE-YEAR MOVING AVERAGES							
90-92	270	1	0	20	7	19	7
91-93	1,010		0	589	58	589	58
92-94	1,010		0	569	56	569	56
93-95	1,145		0	569	50	569	50
94-96	306		0		0		0
95-97	17,011		0		0		0
96-98	16,705		0		0		0
97-99	16,705		0		0		0
98-00							
99-01							
00-02							
01-03							
02-04	1,201	11	1		0	11-	1-
03-05	1,371	11	1	112	8	101	7
FIVE-YEAR AVERAGE							
01-05	823	7	1	67	8	60	7

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3950 LABORATORY AND TEST EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1997	3,563	0		0		0	
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	3,563	0		0		0	
THREE-YEAR MOVING AVERAGES							
97-99	1,188	0		0		0	
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3960 POWER OPERATED EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	COST OF REMOVAL PCT	GROSS SALVAGE AMOUNT	GROSS SALVAGE PCT	NET SALVAGE AMOUNT	NET SALVAGE PCT
1991	26,356	132	1	10,350	39	10,218	39
1992	13,984		0	3,405	24	3,405	24
1993	72,991		0	21,640	30	21,640	30
1994	8,093	101	1	852	11	751	9
1995							
1996							
1997							
1998	16,943	1,030-	6-		0	1,030	6
1999							
2000							
2001	33,087		0	4,880	15	4,880	15
2002							
2003							
2004	33,349		0		0		0
2005	35,307	17,765-	50-		0	17,765	50
TOTAL	240,110	18,562-	8-	41,127	17	59,689	25
THREE-YEAR MOVING AVERAGES							
91-93	37,777	44	0	11,798	31	11,754	31
92-94	31,689	34	0	8,632	27	8,598	27
93-95	27,028	34	0	7,497	28	7,463	28
94-96	2,698	34	1	284	11	250	9
95-97							
96-98	5,648	343-	6-		0	343	6
97-99	5,648	343-	6-		0	343	6
98-00	5,648	343-	6-		0	343	6
99-01	11,029		0	1,627	15	1,627	15
00-02	11,029		0	1,627	15	1,627	15
01-03	11,029		0	1,627	15	1,627	15
02-04	11,116		0		0		0
03-05	22,885	5,922-	26-		0	5,922	26
FIVE-YEAR AVERAGE							
01-05	20,349	3,553-	17-	976	5	4,529	22

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3970 COMMUNICATION EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1991	13,923	0		0		0	
1992							
1993							
1994							
1995							
1996							
1997							
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	13,923	0		0		0	
THREE-YEAR MOVING AVERAGES							
91-93	4,641	0		0		0	
92-94							
93-95							
94-96							
95-97							
96-98							
97-99							
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 3980 MISCELLANEOUS EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1997	1,441		0		0		0
1998							
1999							
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	1,441		0		0		0
THREE-YEAR MOVING AVERAGES							
97-99	480		0		0		0
98-00							
99-01							
00-02							
01-03							
02-04							
03-05							
FIVE-YEAR AVERAGE							
01-05							

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 4526.0

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1992	930		0		0		0
1993							
1994	1,042		0		0		0
1995							
1996							
1997							
1998	1,925		0		0		0
1999	1,918		0		0		0
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	5,815		0		0		0

THREE-YEAR MOVING AVERAGES

92-94	657		0		0		0
93-95	347		0		0		0
94-96	347		0		0		0
95-97							
96-98	642		0		0		0
97-99	1,281		0		0		0
98-00	1,281		0		0		0
99-01	639		0		0		0
00-02							
01-03							
02-04							
03-05							

FIVE-YEAR AVERAGE

01-05

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 1920 & 3920 TRANSPORTATION

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT PCT	GROSS SALVAGE AMOUNT PCT	NET SALVAGE AMOUNT PCT
1990	97,145	0	0	0
1991	838,980	0	0	0
1992	321,701	0	0	0
1993	46,286	0	0	0
1994	55,658	0	0	0
1995	407,697	0	0	0
1996	156,801	0	0	0
1997	142,291	0	0	0
1998	254,770	0	0	0
1999	265,046	0	0	0
2000				
2001				
2002				
2003				
2004				
2005				
TOTAL	2,586,375	0	0	0
THREE-YEAR MOVING AVERAGES				
90-92	419,275	0	0	0
91-93	402,322	0	0	0
92-94	141,215	0	0	0
93-95	169,880	0	0	0
94-96	206,719	0	0	0
95-97	235,596	0	0	0
96-98	184,621	0	0	0
97-99	220,702	0	0	0
98-00	173,272	0	0	0
99-01	88,349	0	0	0
00-02				
01-03				
02-04				
03-05				
FIVE-YEAR AVERAGE				
01-05				

Source: AG-DR-01-138(d).pdf

DUKE ENERGY KENTUCKY

ACCOUNT 4922.0

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
1991	26,356	0		0		0	
1992	13,984	0		0		0	
1993	72,991	0		0		0	
1994	8,093	0		0		0	
1995							
1996							
1997							
1998	16,943	0		0		0	
1999	34,435	0		0		0	
2000							
2001							
2002							
2003							
2004							
2005							
TOTAL	172,802	0		0		0	

THREE-YEAR MOVING AVERAGES

91-93	37,777	0		0		0	
92-94	31,689	0		0		0	
93-95	27,028	0		0		0	
94-96	2,698	0		0		0	
95-97							
96-98	5,648	0		0		0	
97-99	17,126	0		0		0	
98-00	17,126	0		0		0	
99-01	11,478	0		0		0	
00-02							
01-03							
02-04							
03-05							

FIVE-YEAR AVERAGE

01-05

Source: AG-DR-01-138(d).pdf

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)								
State **Company** **Plant**	**Unit #**	**Nameplate Rating MW**	**Unit Type**	**Primary Energy Source**	**In Service Date**	**Year Retired**	**Age**	**Status**
Alabama								
Alabama Power Co.								
Gorgas	5	69	ST	BIT	1944	1989	55	retired in place
Arizona								
Tucson Electric Pwr. Co.								
De Moss Petrie	4	57.5	ST	Nat Gas	1954	1991	37	dismantled
California								
Pacific G&E Co.								
Potrero	1	50	ST	FO6	1931	1983	52	retired in place
	2	50	ST	FO6	1931	1983	52	retired in place
Contra Costa	1	118.8	ST	Nat Gas	1951	1994	43	retired in place
	2	103.5	ST	Nat Gas	1951	1994	43	retired in place
	3	103.5	ST	Nat Gas	1951	1994	43	retired in place
	4	112.5	ST	Nat Gas	1953	1994	41	retired in place
	5	112.5	ST	Nat Gas	1953	1994	41	retired in place
Kern	1	66	ST	Nat Gas	1948	1994	46	retired in place
	2	99.5	ST	FO6	1949	1994	45	retired in place
Moss Landing	1	107.6	ST	Nat Gas	1950	1994	44	retired in place
	2	111	ST	Nat Gas	1950	1994	44	retired in place
	3	107.6	ST	Nat Gas	1951	1994	43	retired in place
	4	112.5	ST	Nat Gas	1952	1994	42	retired in place
	5	112.5	ST	Nat Gas	1952	1994	42	retired in place
Southern Cal. Edison								
Long Beach	11	106	ST	FO6	1930	1983	53	retired in place
San Onofre	**1	456	NP	Uranium	1967	1992	25	perm. Mothball
City of Los Angeles								
Harbor Gen. Station	1	65	ST	Nat Gas	1943	1988	45	dismantled
	2	65	ST	Nat Gas	1947	1988	41	dismantled
	3	86.4	ST	Nat Gas	1949	1991	42	retired in place
	4	86.3	ST	Nat Gas	1948	1997	49	retired in place

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)								
State Company Plant	Unit #	Nameplate Rating MW	Unit Type	Primary Energy Source	In Service Date	Year Retired	Age	Status
Connecticut								
Conn. Light & Power Co.								
Middletown	1	69	ST	FO6	1954	1991	37	sold to NRG energy
Florida								
Florida P&L Co.								
Palatka	2	75	ST	FO6	1956	1983	27	greenfield
Riviera	2	75	ST	Nat Gas	1953	1991	38	removed parts; generator intact
JEA								
J D Kennedy (Duval)	10	149.6	ST	RFO	1961	2000	39	
Southside Generating	3	50	ST	FO6	1955	1998	43	
Georgia								
Georgia Power Co.								
Atkinson	ST1	60	ST	FO2	1930	1993	63	
		60	ST	FO2	1930	1993	63	retired in place
		60	ST	FO2	1930	1993	63	
Illinois								
Central Ill. Light Co.								
R S Wallace	6	85.9	ST	BIT	1952	1985	33	greenfield
	7	113.6	ST	BIT	1958	1985	27	greenfield
Indiana								
Indiana Michigan Pwr. Co								
Breed	1	495.6	ST	BIT	1960	1994	34	
		495.6	ST	BIT	1960	1994	34	removed parts
		495.6	ST	BIT	1960	1994	34	
Iowa								
Iowa Public Service Co.								
Maynard Station	7	54.4	ST	BIT	1958	1988	30	

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)								
State Company Plant	Unit #	Nameplate Rating MW	Unit Type	Primary Energy Source	In Service Date	Year Retired	Age	Status
Kentucky								
Louisville G&E Co.								
Paddy's Run	5	74.7	ST	BIT	1950	1983	33	retired in place
Cane Run	1	92	ST	BIT	1954	1985	31	retired in place
	2	90	ST	BIT	1955	1985	30	retired in place
	3	147.1	ST	Nat Gas	1958	`1995	94	retired in place
Louisiana								
Entergy								
Ninemile Point	4	783	ST	Nat Gas	1971	1992	21	back on line
CLECKO Corporation								
Coughlin	5	65.3	ST	Nat Gas	1958	1998	40	Repowered & back in service
Maryland								
Baltimore Gas Electric Co.								
Riverside	1	60	ST	FO6	1942	1991	49	retired in place
	2	60	ST	FO6	1944	1993	49	retired in place
	3	60	ST	FO6	1948	1993	45	retired in place
	5	81.3	ST	FO6	1953	1993	40	retired in place
Westport	3	60	ST	FO6	1941	1993	52	retired in place
	4	69	ST	FO6	1950	1993	43	retired in place
Massachusetts								
Western Mass. Elec. Co.								
West Springfield	2	50	ST	FO6	1952	1991	39	sold to NRG energy
Michigan								
Consumers Power								
Morrow, BE	3	50	ST	NG	1941	1982	41	retired in place
	4	66	ST	NG	1949	1982	33	retired in place
B C Cobb	1	66	ST	BIT	1948	1990	42	back on line
	2	66	ST	BIT	1948	1990	42	back on line
	3	66	ST	BIT	1950	1990	40	back on line
Detroit Edison Co.								

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)								
State **Company** **Plant**	**Unit #**	**Nameplate Rating MW**	**Unit Type**	**Primary Energy Source**	**In Service Date**	**Year Retired**	**Age**	**Status**
Conner's Creek	13	60	ST	FO2	1937	1983	46	dismantled
	14	60	ST	FO2	1936	1983	47	dismantled
Delray	11	50	ST	FO6	1929	1983	54	dismantled
	12	50	ST	FO6	1929	1983	54	dismantled
	13	50	ST	FO6	1933	1983	50	dismantled
	16	75	ST	FO6	1942	1983	41	dismantled
	14	75	ST	FO6	!938	1987	49	dismantled
	15	75	ST	FO6	1940	1987	47	dismantled
Enrico Fermi	1	158	ST	FO2	1966	1983	17	dismantled
Minnesota								
Northern States Pwr. Co.								
Riverside	6	75	ST	Nat Gas	1949	1987	38	
Missouri								
Kansas City P&L Co.								
Hawthorn	1	69	ST	BIT	1951	1984	33	retired in place
(these units are about to go back on line)	2	69	ST	BIT	1951	1984	33	retired in place
	3	112.5	ST	BIT	1953	1984	31	retired in place
	4	142.8	ST	BIT	1955	1984	29	retired in place
Montana								
Montana Power Co.								
Frank Bird	1	69	ST	Nat Gas	1951	1997	46	greenfield
Nebraska								
Omaha Public Power Corp.								
Jones Street	12	49	ST	FO2	1951	1988	37	retired in place
New Jersey								
Jersey Central Pwr.&Lt. Co.								
Gilbert	3	69	ST	FO6	1949	1996	47	retired in place
Werner	4	60	ST	FO6	1953	1996	43	retired in place
Public Service Elec. & Gas								
Burlington	5	125	ST	FO6	1940	1984	44	dismantled
	6	125	ST	FO6	1943	1984	41	dismantled

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)

State Company Plant	Unit #	Nameplate Rating MW	Unit Type	Primary Energy Source	In Service Date	Year Retired	Age	Status
	7	205	ST	FO6	1955	1997	42	dismantled
Essex	1	117	ST	FO6	1974	1984	10	dismantled
Linden	4	93.5	ST	FO6	1972	1996	24	retired in place
Sewaren	5	389	ST	FO6	1962	1991	29	dismantled
Atlantic City Electric Co.								
Deepwater	5	53	ST	FO6	1930	1991	61	retired in place
New York								
Consolidated Edison Co. NY Inc.								
East River	5	156.3	ST	FO6	1951	1996	45	dismantled
Hudson Avenue	8	160	ST	FO6	1932	1986	54	dismantled
	7	160	ST	FO6	1931	1987	56	dismantled
	10	60	ST	FO6	1951	1997	46	dismantled
Waterside	4	50	ST	Nat Gas	1937	1990	53	dismantled
	14	60	ST	Nat Gas	1948	1992	44	dismantled
	15	75	ST	Nat Gas	1949	1992	43	dismantled
	7	81.3	ST	Nat Gas	1941	1992	51	dismantled
	5	66.3	ST	Nat Gas	1938	1995	57	dismantled
74th Street	10	69	ST	FO6	1956	1992	36	demolition in progress
	9	75	ST	FO6	1959	1992	33	demolition in progress
59th Street	13	57.5	ST	FO6	1952	1990	38	dismantled
Astoria	ST1	200	ST	Nat Gas	1953	1993	40	retired in place
	2	200	ST	Nat Gas	1954	1993	39	back in service
Niagra Mohawk Pwr. Co.								
Oswego	ST1	92	ST	FO6	1940	1995	55	sold to NRG in 1999
	2	92	ST	FO6	1941	1995	54	6 units
	3	92	ST	Nat Gas	1948	1995	47	portions were
	4	100	ST	FO6	1951	1995	44	dismantled
Rochester Gas & Electric								
Rochester 3	12	81.6	ST	BIT	1959	1999	40	

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)								
State								
Company	Unit #	Nameplate	Unit	Primary Energy	In Service	Year	Age	Status
Plant		Rating MW	Type	Source	Date	Retired		
Ohio								
Cincinnati G&E Co.								
Miami Fort	3	65	ST	FO2	1938	1982	44	retired in place
	4	65	ST	FO2	1942	1982	40	retired in place
Cleveland Elec Illum Co.								
Ashtabula	B1	50	ST	FO6	1930	1983	53	retired in place
	B2	50	ST	FO6	1930	1983	53	retired in place
	B3	50	ST	FO6	1931	1983	52	retired in place
	B4	50	ST	FO6	1938	1983	45	retired in place
Avon Lake	5	50	ST	FO6	1943	1983	40	retired in place
	8	233	ST	BIT	1959	1987	28	retired in place
	6	86	ST	BIT	1949	1997	48	retired in place
	7	86	ST	BIT	1949	1997	48	retired in place
Lake Shore	14	60	ST	FO6	1941	1992	51	retired in place
	15	60	ST	FO6	1942	1992	50	retired in place
	16	69	ST	FO6	1951	1992	41	retired in place
	17	69	ST	FO6	1951	1992	41	retired in place
Columbus Southern								
Power Company								
Poston	3	69	ST	BIT	1952	1987	35	dismantled
	4	75	ST	BIT	1953	1987	34	dismantled
Dayton Pwr.&Light Co.								
Frank M Tait	4	147.1	ST	BIT	1958	1987	29	greenfield
	5	147.1	ST	BIT	1959	1987	28	greenfield
Toledo Edison Co.								
Acme	5	72	ST	BIT	1941	1992	51	retired in place
	6	112.5	ST	BIT	1949	1992	43	retired in place
Oklahoma								
Public Service Co.of Okl.								
Tulsa	3	95	ST	Nat Gas	1958	1997	39	recommish.
								back in service
Pennsylvania								

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)								
State								
Company	**Unit #**	**Nameplate**	**Unit**	**Primary Energy**	**In Service**	**Year**	**Age**	**Status**
Plant		**Rating MW**	**Type**	**Source**	**Date**	**Retired**		
Philadelphia Elec. Co.								
Richmond	12	165	ST	Coal	1935	1983	48	retired in place
	9	189.7	ST	FO6	1950	1985	35	retired in place
Southwark	1	172.5	ST	FO6	1947	1985	38	retired in place
	2	172.5	ST	FO6	1948	1985	37	retired in place
Pennsylvania Elec. Co.								
Front Street	5	50	ST	BIT	1952	1991	39	retired in place
PP&I Inc.								
Holtwood	17	75	ST	ANT	1954	1999	45	dismantled
Rhode Island								
New England Power Co.								
South Street	12	62.5	ST	Nat Gas	1955	1992	37	
Texas								
Entergy								
Neches	7	114	ST	Nat Gas	1956	1983	27	boiler exploded; left in place
Southwestern Pub. Ser. Co.								
Denver City	4	50	ST	Nat Gas	1955	1984	29	dismantled
Moore County	3	49	ST	Nat Gas	1954	1984	30	placed back in service in 1995
Reliant Energy								
Greens Bayou	3	112.5	ST	Nat Gas	1953	1985	32	retired in place
	4	112.5	ST	Nat Gas	1953	1985	32	retired in place
	1	75	ST	Nat Gas	1949	1986	37	retired in place
	2	75	ST	Nat Gas	1949	1986	37	retired in place
Hiram Clark	ST3	75	ST	Nat Gas	1950	1985	35	retired in place
	ST4	75	ST	Nat Gas	1951	1985	34	retired in place
Webster	1	112.5	ST	Nat Gas	1954	1985	31	retired in place
	2	112.5	ST	Nat Gas	1954	1985	31	retired in place
T H Wharton	1	75	ST	Nat Gas	1958	1986	28	retired in place
Texas Utilities Elec. Co.								

STATUS of RETIRED ELECTRIC GENERATING UNITS (50MW or GREATER)								
State								
Company	**Unit #**	**Nameplate**	**Unit**	**Primary Energy**	**In Service**	**Year**	**Age**	**Status**
Plant		**Rating MW**	**Type**	**Source**	**Date**	**Retired**		
Dallas	3	78.8	ST	Nat Gas	1954	1998	45	
	9	75	ST	Nat Gas	1951	1998	47	
Trinidad	5	69	ST	Nat Gas	1949	1994	45	
Wisconsin								
Wisconsin Elec. Pwr. Co.								
Lakeside	9	60	ST	Nat Gas	1928	1983	55	dismantled
	11	60	ST	Nat Gas	1930	1983	53	dismantled
Northern States Power								
Wheaton	1	54	ST	FO2	1973	1983	10	
North Oak Creek	3	130	ST	BIT	1955	1988	33	retired in place
	4	130	ST	BIT	1957	1988	31	retired in place
	1	120	ST	BIT	1953	1989	36	retired in place
	2	120	ST	BIT	1954	1989	35	retired in place
Port Washington	5	80	ST	BIT	1950	1991	41	retired in place

Total number of units studied **145**
Units Dismantled or Greenfielded **40**

Updated August 14, 2005

Attorney General First Set Data Requests
Duke Energy Kentucky Case No. 2006-00172
Date Received: July 12, 2006
Response Due Date: July 26, 2006

AG-DR-01-139

REQUEST:

139. Provide all information obtained by Mr. Spanos and Gannett Fleming from Company operating personnel, and separately, financial management personnel relative to current operations and future expectations in the preparation of the study.

RESPONSE:

Attachment AG-DR-01-139 contains the documents in Mr. Spanos' possession that he obtained during the course of his depreciation study from operating or financial management personnel, in addition to documents provided in response to AG-DR-01-138.

WITNESS RESPONSIBLE: John J. Spanos

Spanos, John J.

From: Melendez, Brenda [Brenda.Melendez@Cinergy.COM]
Sent: Monday, January 09, 2006 4:31 PM
To: Spanos, John J.
Cc: Storck, Don
Subject: RE: ULH&P Electric Rate Case

John,

The test year is December 31, 2005. We will get the retirements and transfers for the years 1999 - 2004 for Woodsdale, East Bend, and the Miami Fort #6 assets being transferred to ULH&P. You are right, we will get those from the CG&E records. Just to clarify, for PIS Report 1047 and 1033, are you indicating that you need them for all of ULH&P T&D electric and common or just for electric production? It looks like we ran the reports for T&D electric and common at the time we sent the earlier data; so, I can send those right away if you didn't recieve on the CD. We have them both in a .txt and .xls format. Do you want both or have a preference?

As for the December 31, 2005 information, I just want to confirm that we should send you exactly what we did for 1999-2004. I think this is a summary of the files:

- Report 1033 Monthly Depr Reserve Activity for ULH&P Electric T&D, Common, and Electric Production (from CG&E)
- Report 1047 Account Summary by Function for ULH&P Electric T&D, Common, and Electric Production (from CG&E)
- 200512 Balances for Electric Production (from CG&E)
- 200512 Balances for ULH&P Electric T&D and Common
- Retirements 2005 for ULH&P Electric T&D, Common, and Electric Production (from CG&E)
- Transfers 2005 for ULH&P Electric T&D, Common, and Electric Production (from CG&E)

Is there anything else we need to provide?

John, also, the ULH&P electric production is going to be regulated so we will be able to incorporate a COR component unlike the CG&E assets that are deregulated. So, we will need the rates developed with the COR separated.
Don and I are both new to depreciation studies, so let us know whatever it is you need and we'll work to get it to you as quickly as possible. Thanks.

From: Spanos, John J. [mailto:jspanos@GFNET.com]
Sent: Tuesday, December 20, 2005 8:33 AM
To: Melendez, Brenda
Cc: Storck, Don
Subject: RE: ULH&P Electric Rate Case

Brenda:

The time table is a little short but since we have already started our work we should not have any trouble meeting the deadline as long as you are able to get us the updated data in early January. Is the test year December 31, 2005 or September 30, 2005?

Also, a few items from the 2004 data and prior that seem to be missing. We do not have the retirements and transfers fro the years 1999 through 2004 for the production accounts. I would assume you need to get those from the CGE records. We need PIS Report 1047 for the years 2000-2004. We need Report 1033 for 2000-2004.

Thanks

John

-----Original Message-----
From: Melendez, Brenda [mailto:Brenda.Melendez@Cinergy.COM]
Sent: Monday, December 19, 2005 3:28 PM
To: Spanos, John J.

Attorney General Second Set Data Requests
Duke Energy Kentucky Case No. 2006-00172
Date Received: August 09, 2006
Response Due Date: August 23, 2006

AG-DR-02-027

REQUEST:

27. Refer to page 38 of 95 of Attachment AG-DR-01-139.

a. Explain in detail the following statement from Brenda Martinez *(sic)* to John Spanos, "John, also, the UHL&P electric production is going to be regulated so we will be able to incorporate a COR component unlike the CG&E assets that are deregulated. So, we will need the rates developed with the COR separated."

b. Specifically identify the UHL&P and CG&E assets to which Ms. Martinez *(sic)* refers, and explain where they can be specifically found in Mr. Spanos' depreciation study.

c. Explain why deregulated assets do not incorporate a COR component?

d. Does this statement relate in any way to SFAS No. 143, FIN 47, FERC Order No. 631?

RESPONSE:

a. The basis of this statement from Brenda Melendez relates to the production assets that were transferred from The Cincinnati Gas & Electric Company to The Union Light, Heat and Power Company (now Duke Energy Kentucky). In Ohio, these assets were deregulated and the depreciation rate was not identified with components such as we proposed in this traditional study for regulated assets. Therefore, the rates are developed with a life parameter, probable retirement date and net salvage component.

b. The specific assets are identified as the Miami Fort, East Bend and Woodsdale generating plants, which are all assets in Accounts 311-346. These assets can be found on pages III-4, III-5, III-11 through III-35, III-140 through III-144 and III-172 through III-190.

c. Deregulation does not require the rate to be determined in the same fashion with a detailed calculation, and life and net salvage parameters.

d. No, it does not.

WITNESS RESPONSIBLE: John J. Spanos

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT	)	
OF ELECTRIC RATES OF THE UNION	)	
LIGHT, HEAT AND POWER COMPANY	)	CASE NO. 2006-00172
D/B/A DUKE ENERGY KENTUCKY	)	

DIRECT TESTIMONY OF

STEVEN W. RUBACK

ON BEHALF OF

THE OFFICE OF ATTORNEY GENERAL

SEPTEMBER 13, 2006

INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Steven W. Ruback, and my business address is 785 Washington Street, Canton, Massachusetts 02021.

Q. WHAT IS YOUR OCCUPATION?

A. I am the founder and a principal of The Columbia Group, Inc., which is a public interest consulting firm specializing in public utility issues solely on behalf of state agencies, local government agencies, municipal utilities, offices of attorneys general, staffs of public utility commissions and citizens utility boards.

My practice consists of providing expert testimony before state public utilities commissions, providing technical assistance to attorneys negotiating settlements or contracting for utility services, providing services to municipal utilities and other rate related services.

Q. PLEASE STATE YOUR QUALIFICATIONS.

A. I am a lawyer and engineer. For more than 25 years I have worked as a rate consultant to state agencies, local governments, municipal utilities, and offices of attorneys general, citizens utility boards and the staff's of public utility commissions. My principal areas of concentration have been the electric and natural gas utility industries.

I have provided expert testimony in numerous natural gas and electricity cases before regulatory commissions in Connecticut, Pennsylvania, Georgia, New Mexico, Virginia, and other jurisdictions. I have undertaken more than 350 utility assignments, and I have provided expert testimony in over 150 proceedings.[1] I have specialized in gas and electric class allocated cost of service studies, rate design, regulatory policy, class revenue requirements and gas supply issues.

I have provided expert testimony before the Georgia Public Service Commission on numerous occasions involving class allocated cost of service studies, class revenue allocations and rate design and tariff issues. I have provided expert rate design testimony in many of Georgia Power Company's and Savannah Electric and Power's previous rate cases and I recently finished an electric rate design case for the Ohio Office of Consumers' Counsel regarding Cincinnati Gas & Electric Company.

Since 1979 I have provided class allocated cost of service and rate design services to the Virginia Municipal League and the Virginia Association of Counties in connection with contract negotiations with Virginia Power. The value of the Virginia Power contract exceeds $200,000,000 annually. I have also provided these services to associations of local governments in Virginia involving the Northern Virginia Electric Cooperative and Appalachian Power Company.

[1] A list of testimonies is provided as an attachment.

With respect to my municipal utility work I have completed numerous allocated cost of service studies and rate design assignments for the City of Richmond, Virginia Department of Public Utilities and the Danvers Massachusetts Municipal Electric Utility. I also completed an allocated service and rate design assignment for the Burlington Municipal Electric Utility in Vermont.

I graduated from Clarkson College of Technology in 1968 with a degree in Interdisciplinary Engineering & Management, and from the State University of New York at Buffalo, School of Law, in 1973. I have not, however, practiced law since 1976, and my current practice consists solely of providing utility consulting services.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I am presenting this testimony on behalf of the Rate Intervention Department of the Office of Attorney General. I was asked to review and evaluate Duke Energy Kentucky's (Duke or the Company) proposed rate design and to provide comments and alternative recommendations, if appropriate to do so.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. Section I is a summary of my findings, conclusions and recommendations. Section II addresses the allocation methodology that should be used in a class allocated service study for the fixed costs of production and transmission. Section III addresses the classification of distribution Accounts 364 to 368 in the cost of service study. Section IV provides my proposed distribution of the increase among the classes of service. Section V addresses the proposed Green Power Rider.

SECTION I

FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR FINDINGS, CONCLUSIONS AND RECOMMENDATIONS?

A. My findings, conclusions and recommendations are as follows:

Allocation of Fixed Production and Transmission Costs

1. The Company recommends using the Twelve Month Coincident Peak (12-CP) methodology, without any recognition of capitalized energy. I propose a modification to the 12-CP methodology that would recognize both class contributions to the 12 monthly peaks as well as capitalized energy.

2. Since the results of a class allocated service study are the starting point for determining class revenue requirements, the allocation factor used to allocate the fixed costs of production and transmission should include annual utilization of the system along with contributions to coincident demands as a matter of fairness.

3. In addition to fairness, there are sound engineering and economic reasons why the allocation of the fixed costs of production and transmission should include annual utilization of the system along with contributions to coincident demands.

4. The goal of power supply planning is not to minimize capital costs at the expense of higher fuel costs or visa versa. The proper goal is to balance the advantages of peaking, intermediate and base load facilities against each other to produce the lowest annual revenue requirement, consistent with reliability.

Classification of Distribution Accounts 364 to 368

5. The classification of distribution Accounts 364 to 368 is controversial because the classification controls the allocation of distribution costs among the classes.

6. The classification of distribution Accounts 364 to 368 is important because small customers comprise about 90% of total customers while the small customers' non-coincident demand allocation factor is usually about 50%.

7. For Duke the RS customer allocation factor about 90 % and the non-coincident demand factors range between 45% to 66%.

8. The theoretical basis for a dual customer/demand classification is the minimum system or zero load theory. The underlying assumption is that a utility is required to serve customers regardless of load requirements.

9. Distribution systems are not designed for zero or minimum loads. Even minimum size facilities include load carrying capacity and a zero load distribution system is theoretical and does not exist in fact.

10. The purpose of poles, overhead conductors and underground conduits is to deliver power for customers that want power.

11. Non-coincident distribution demands are the primary design criteria for distribution systems because distribution systems are designed for local areas, not the service area as a whole.

<u>Class Revenue Requirements</u>

12. The distribution of an increase among classes of service is traditionally based on cost of service and non-cost criteria.

13. Regulatory commissions which set retail rates regularly include non-cost considerations such as gradualism or rate continuity, public acceptability, revenue stability, fairness and equity and value of service. Moreover, regulatory commissions have been unwilling to assign a specific weight to either the cost or non-cost criteria.

14. The Commission should set class revenue requirements using informed judgment applied to both cost and non-cost considerations.

15. The 12-CP and Average method, not the 12 CP method, includes annual utilization of production and transmission facilities better satisfying cost of service criteria for rate design.

16. Rate RS, rate DS, DT-SEC and DT-PRI are the four major classes representing about 95% of total rate base, with the remaining dozen or so other rate schedules representing just 5% of rate base.

17. For these four major classes the cost of service criteria was met by moving the index rates of return (IRR) at proposed rates closer to the system average. The amount of movement for each major class incorporated a more tolerant use of the non-cost criteria of gradualism.

18. If gradualism is employed, customers have a better chance to adjust their consumption to higher rates as the indexed rate of returns move closer to cost over measured steps.

19. I recommend that the revenue requirements increase proposed by the Company for the Residential class be decreased by $10,234,829 and that the DT_SEC class be decreased by $2,100,000.

20. For the DS and DT_PRI classes, I agree with the Company's proposed revenue increase when the 12-CP & Average methodology is applied to the cost of service study.

21. I recommend that any decrease from that proposed by the Company awarded to the Residential and DT_SEC classes be distributed to the other classes in an across-the-board manner.

<u>Green Power</u>

22. In the proposed tariff, GP revenues will not necessarily be used to purchase or develop environmentally friendly resources. Instead, the revenues will be used to purchase Renewable Energy Certificates (REC) and carbon credits.

23. Renewable Portfolio Standards (RPS) legislation generally requires power generators to meet part of their requirements from renewable resources. RPS legislation may allow a power supplier to fulfill its Green Power portfolio requirements by purchasing RECs. Kentucky does not have RPS legislation at this time.

24. Absent legislation, the capital necessary to purchase RECs or carbon credits is provided by customers, not investors. For that reason, the revenues from sales of RECs or carbon credits should be credited to the customers that provided the capital for purchases.

25. If insufficient funds are collected to purchase REC or carbon credits, the money voluntarily collected should be returned to participating customers with 6% interest.

SECTION II

ALLOCATION METHODOLOGY FOR FIXED COSTS OF PRODUCTION AND TRANSMISSION

Q. HOW MANY CLASS ALLOCATED CLASS COST OF SERVICE STUDIES HAS THE COMPANY FILED TO JUSTIFY ITS PROPOSED RATE DESIGN?

A. The Company has filed 3 class cost of service studies which contain the same data but use different methodologies to allocate the demand component of production and transmission plant. As described in detail in the testimony of Paul F. Ochsner, the three methods used are (1) the average of the twelve coincident monthly peaks (12-CP) method, (2) the Average and Excess (A&E) method and (3) the Summer/Non-Summer (S/NS) method.

Q. WHAT METHOD DOES THE COMPANY PROPOSE AND WHAT DO YOU RECOMMEND?

A. The Company recommends using the Twelve Month Coincident Peak (12-CP) methodology, without any recognition of capitalized energy. I propose a modification to the 12-CP methodology that would recognize both class contributions to the 12 monthly peaks as well as capitalized energy; the 12-CP and Average Demand Methodology (12-CP & Average). It is the exclusion of average demand or annual energy usage from Company's preferred cost of service methodology that causes me to conclude that the 12-CP & Average approach is superior.

Q. IS THERE ANY ACADEMIC SUPPORT FOR RECOGNIZING ANNUAL UTILIZATION OF FACILITIES IN THE CALCULATION OF THE PRODUCTION AND TRANSMISSION ALLOCATOR FOR FIXED COST?

A. According to Professor Bonbright fairness is one attributes of a sound rate structure. He says, "the burden of meeting total revenue requirements must be distributed fairly and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service [rate schedules or classes]…. Bonbright, Principles of Public Utility Rates, Second Edition, page 385. (Emphasis added).

I agree. Since the results of a class allocated service study are the starting point for determining class revenue requirements, the allocation factor used to allocate the fixed costs of production and transmission should include annual utilization of the system along with contributions to coincident demands.

Consider two customer classes or rate schedules. The customers in rate schedule A and B have the same coincident peaks. Schedule A's kilowatt-hour sales are three times the kilowatt-hours sales of schedule B customers. If annual utilization of facilities is not recognized, both schedule A and B will have the same cost allocation despite a significantly greater benefit to customers with a higher annual utilization of production and transmission costs.

Q. PLEASE DESCRIBE THE ENGINEERING AND ECONOMIC REASONS WHY ANNUAL UTILIZATION OF FACILITIES SHOULD BE RECOGNIZED?

A. In addition to fairness, there are sound engineering and economic reasons why the allocation of the fixed costs of production and transmission should include annual utilization of the system along with contributions to coincident demands.

Monthly coincident peak requirements can be met with peaking facilities. Peaking facilities are characterized as having lower capital costs than base load or intermediate units. On the other hand, peaking facilities have higher unit fuel costs than base load or intermediate units. The goal of power supply planning is not to minimize capital costs at the expense of higher fuel costs or visa versa. The proper goal is to balance the advantages of peaking, intermediate and base load facilities against each other to produce the lowest annual revenue requirement, consistent with reliability.

A preponderance of peaking facilities is appropriate if the utility has a needle peak, but not if a utility has a reasonable load factor. Load factor is calculated by dividing average demand (Kwh/hour) by annual peak demand. The higher the load factor, the greater the need for intermediate and base load facilities.

Although base load and intermediate units have higher capital costs than peaking facilities, they have lower fuel costs on a unit basis. Base load and intermediate units, as opposed to only low capital cost peakers, are needed to fulfill the power supply planning goal to produce the lowest annual revenue requirement, consistent with reliability.

Q. WHAT IS THE COMPANY'S LOAD FACTOR?

A. The Company's annual load factor is a reasonable 56.66% (see Exhibit SWR-1). This load factor is evidence that lower fuel costs from base load and intermediate units, as opposed to only peaking facilities, are necessary to produce the lowest power supply revenue requirement.

Q. DOES THE 12-CP & AVERAGE APPROACH RECOGNIZE ALL THE ELEMENTS OF COST CAUSATION?

A. Yes. The problem with the Company's proposed 12 month CP method is that it fails to allocate the fixed costs of base load and intermediate facilities in a manner that reflects cost causation.

The 12-CP & Average methodology recognizes the significant *extra* investment (per KW of demand) utilities make for non-peaking generating facilities. These extra dollars of investment represent capitalized energy. The reason electric utilities invest these extra dollars is because the fuel costs of non-peaking facilities are low enough to economically justify the extra investment.

For the reasons discussed above it is my recommendation that the Commission reject the Company proposed 12-CP method and choose instead to allocate non-fuel generating costs on a 12-CP and Average Demand basis. In addition, I recommend that the Average component be weighted by the Company's load factor and the 12 CP portion be weighted by 1 minus the load factor.

Q. DO YOU AGREE WITH THE COMPANY'S DECISION NOT TO PROPOSE AN AVERAGE & EXCESS (A&E) METHOD FOR THE ALLOCATION OF GENERATION COSTS?

A. Yes. The A&E method is not a reasonable methodology to use because of the use of non-coincident peaks. In the A&E method average demand is weighted by load factor and the excess demand is calculated on non-coincident peaks. The problem is that the sum of non-coincident demands and each classes' contribution to total non-coincident demand are never used for power supply planning purposes. Class contributions to the sum of the non-coincident demands are used to allocate distribution costs because distribution facilities are built to meet local demands while generating facilities are built not to meet local demands, but total system requirements.

Q. DO YOU AGREE WITH THE COMPANY'S DECISION NOT TO PROPOSE A SUMMER/WINTER (S/NS) METHOD?

A. Yes. Similar to the 12-CP method, the S/NS method does not recognize capitalized energy.

Q. IS THE PEAK AND AVERAGE APPROACH USED TO ALLOCATE FIXED COSTS IN RETAIL GAS ALLOCATED COST OF SERVICE STUDIES?

A. Yes. Some retail gas distribution companies allocate fixed costs using a peak and average approach. Distribution mains typically represent the largest plant in service account. The reason for the peak and average approach is that mains are installed to meet coincident peak requirements and daily delivery requirements.

For bundled electric utilities, investment in generation represents the largest plant in service account. Like gas utilities, electric utilities build or acquire generation not only to meet system coincident peaks, but also to meet daily requirements (with the lowest revenue requirement). The peak and average approach for retail gas utilities serves to allocate part of total fixed costs based on the annual utilization of facilities. The peak and average approach is equally applicable for fixed electric generation allocation in order to spread part of the fixed costs on average daily usage.

Q. HAS UNION LIGHT, HEAT AND POWER COMPANY (UHL&P) PROPOSED TO ALLOCATE GAS PRODUCTION COSTS ON A PEAK AND AVERAGE BASIS IN THE PAST?

A. Yes, in Case No. 2005-00042 UHL&P allocated production related costs on a Peak and Average Demand (P&A) basis. Similar to the 12-CP and Average method, a portion of gas production demand cost were allocated based upon UHL&P's average daily deliveries of gas. With respect to the demand component of distribution mains, UHL&P also used a peak and average approach (See the Direct Testimony of Paul Ochesner, Case No. 2005-00042, at page 8 line 11 to page 9 line 4).

In this case, Duke proposes a 12 month CP method without any recognition of load factor (annual utilization of facilities). My 12 CP and Average Demand method does, however, recognize load factor by allocating some of the non-fuel power supply costs on the basis on annual utilization of the system (Sales/365 days per year). Recognition of annual utilization in the allocation of fixed costs for an electric utility is just as valid and important as it is for retail gas utilities

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE 12-CP AND AVERAGE ALLOCATION FACTOR.

A. I calculated the 12-CP & Average factors by weighting the energy factor (Total KWH K301) by the Company's load factor and weighting the 12CP Factor by 1 minus the load factor. I then added the results of the energy factor and the 12CP factor (see Exhibit SWR-2). For example, for the Residential Class the 12-CP & Average factor is calculated as follows:

(.3783 * .5666) + (.4471 * (1 - .5666)) = .4081; where

.3783 is the energy factor

.5666 is the load factor and

.4471 is the 12 CP factor

Q. HAVE YOU COMPARED THE CLASS RATES OF RETURN USING THE 12 CP AND 12-CP & AVERAGE METHODS.

A. Yes. In Exhibit SWR-3, which compares the Company's rates of return using the 12-CP method and the rates of return using my recommended 12-CP & Average methodology, the change in the rates of return for the classes resulting from the two methods is shown.

SECTION III

DISTRIBUTION PLANT

Q. HOW HAS THE COMPANY CLASSIFIED DISRTIBUTION PLANT ACCOUNTS 364 TO 368 IN ITS CLASS COST OF SERVICE STUDY?

A. The Company has classified Account 364-Poles, Account 365-Overhead Conductors, Account 366-Underground Conduits, Account 367-Underground Conduits and Devices and Account 368-Line Transformers as distribution demand. These accounts have no customer component. Distribution costs, such as meters and services are classified as customer related.

Q. DO YOU AGREE WITH DEK'S CLASSIFICATION OF PART OF THE DISTRIBUTION SYSTEM?

A. Yes, I do.

Q. IS THE CLASSIFICATION OF THE DISTRIBUTION SYSTEM (ACCOUNTS 364 TO 368) CONTROVERSIAL?

A. Yes. The classification of Accounts 364 to 368 is one of the main factors that drive cost of service results and is controversial. The controversy concerns the choice is between a demand only classification or a dual demand/customer classification. The classification is controversial because the classification of distribution costs controls the allocation of distribution costs among the classes.

When a demand only classification is used, distribution demand costs are allocated on class contributions to the sum of non-coincident demands. The allocation of distribution demand costs on non-coincident peaks is appropriate because distribution plant is installed to meet localized demands, not system demands. If costs are classified as customer related, the costs are allocated based on the number of customers.

Q. DO YOU AGREE WITH THE COMPANY'S CLASSIFICATION OF THE DISTRIBUTION SYSTEM?

A. Yes, I do. It is important because small customers comprise about 90% of total customers while the small customers' non-coincident demand allocation factor is usually about 50%. For each dollar of costs classified as customer related, 90% is allocated to small customers and 10% to larger customers. For each dollar of costs classified as demand related, about 50% is allocated to small customers and 50% to larger customers.

For Duke, the RS customer allocation factor is about 90 % and the non-coincident demand factors range between 45% to 66%.

Q. WHAT IS THE IMPACT OF THAT CLASSIFICATION RATHER THAN A DUAL DEMAND AND CUSTOMER CLASSIFICATION?

A. Because small customer contribution to the sum of non-coincident demands is much less than the number of small customers, the rates of return for small customers will be higher than it would otherwise be with a dual classification. Conversely, the rates of return for larger customers will be lower. For that reason, I would expect that larger customer classes will propose a minimum distribution system that includes a dual non-coincident demand and customer classification.

Q. WHAT IS THE THEORETICAL BASIS FOR A DUAL CLASSIFICATION?

A. The theoretical basis for a dual classification for the accounts previously mentioned is the minimum system or zero load theory. The underlying assumption is that a utility is required to serve customers regardless of load requirements and that a minimum or no load distribution system is required to provide customer access.

Q. DO YOU AGREE WITH THAT THEORETICAL BASIS?

A. Absolutely not. Distribution systems are not designed for zero or minimum loads. Even minimum size facilities include load carrying capacity and a zero load distribution system is theoretical and does not exist in fact. Distribution engineers do not design distribution systems to meet zero loads. Customers with zero loads should be served with a battery, not distribution assets.

Instead, non-coincident distribution demands are the primary design criteria for distribution systems. A distribution engineer would have a very difficult time conceptualizing the appearance and the purpose of a distribution system with no load. The zero or minimum distribution theory is simply a theory, not a reality.

Moreover, if a customer component of the distribution system is necessary because of the simple existence of customers, there should also be a customer component of the generating system as well as the transmission system. To date, neither generating facilities nor transmission facilities have been seriously considered as partially customer related.

The purpose of poles, overhead conductors and underground conduits is to deliver power for customers that want power. Transformers regulate voltage. The equipment is sized based to step down the power delivered to the high voltage side of the transformer to the voltage necessary for the customer to use the power.

Q. IS THERE AN INDUSTRY CONSENSUS REGARDING THE CLASSIFICATION OF ACCOUNTS 364 TO 368?

A. No. The National Association of Regulatory Commissioners (NARUC) 1992 <u>Electric Utility Cost Allocation Manual</u> recognizes a dual classification that includes a customer component of the distribution system. Some jurisdictions have followed the NARUC <u>Electric Utility Cost Allocation Manual</u>, but other jurisdictions have not. In 1991 when a draft of the NARUC <u>Electric Utility Cost Allocation Manual</u> was reviewed by the Washington Utilities and Transportation Commission, the Secretary of that Commission responded by letter that:

> "Our Commission has been extremely clear about one thing in this area: that the "minimum-distribution" and "minimum-intercept method" are not acceptable and the only costs that should be considered as customer related are the cost of meters, services, meter reading and billing. Our staff believes that this is the most common approach taken by Commissions around the country. For example, in Iowa the administrative rules of the Commission set forth this explicitly, while in Arizona and Illinois have explicitly rejected the minimum-distribution and minimum-intercept methods in favor of the basic customer approach." (See Exhibit SWR-4)

I have worked on rate design dockets before the Kansas Commission involving Kansas Power & Light and Western Resources, doing business as Kansas Gas & Electric. In both these cases, the accounts have been classified as 100% demand related by those companies (see Exhibit SWR-5; pages 1 & 2). Moreover, Cincinnati Gas & Electric Company (Electric Case Nos: 05-59-EL-AIR and 05-06-EL-60) in its most recent rate case classified Accounts 364 to 368 as solely demand related and Commonwealth Edison, in Illinois, did so also.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that Duke's classification of Accounts 364 to 368 be accepted. The classification of these Accounts is far from settled. Sharp differences of opinion exist among cost of service analysts. Should larger customers propose a minimum distribution system, this Commission should reject the same as a theoretical system, which does not actually exist in practice.

SECTION IV

CLASS REVENUE REQUIREMENTS

Q. WHAT IS THE ACCEPTED METHOD FOR ALLOCATING OVERALL REVENUE REQUIREMENTS AMONG THE CLASSES?

A. The distribution of an increase among classes of service is traditionally based on cost of service and non-cost criteria.

Q. IS COST OF SERVICE AN IMPORTANT CONSIDERATION IN ESTABLISHING CLASS REVENUE REQUIREMENTS?

A. Yes. Cost of service is a basic consideration in arriving at an appropriate allocation of a utility's total revenue requirements among the customer classes. It is not however, the sole criterion. Because of cost of service study limitations it is generally agreed that the results of cost of service study should be used as a guide for the establishment of class revenue requirements, along with non-cost considerations. The Commission should set class revenue requirements using informed judgment applied to both cost and non-cost considerations.

Q. WHAT ARE THE NON-COST CRITERIA GENERALLY USED BY COMMISSIONS TO SET CLASS REVENUE REQUIREMENTS?

A. Most regulatory commissions follow a long standing policy of considering numerous factors other than cost. The limited exception to this policy is wholesale and jurisdictional cost of service studies. Regulatory commissions which set retail rates, however, include other considerations such as gradualism or rate continuity, public acceptability, revenue stability, fairness and equity and value of service. Moreover, regulatory commissions have been unwilling to assign a specific weight to either the cost or non-cost criteria. Such a weighting has been found to be impractical because cost of service is not an exact science and because commission's have wide rate discretion to consider criteria other than cost.

Q. WHAT WAS THE STARTING POINT FOR YOU CLASS REVENUE ALLOCATION RECOMMENDATION?

A. My starting point was the class rates of return using my recommended 12-CP and Average method. I elected this method for two reasons.

First, the 12-CP and Average method includes annual utilization of production and transmission facilities better satisfying cost of service considerations by including capitalized energy in the allocation factor. The allocation of capitalized energy based on annual usage should be part of the allocation method because power supply planners select units to provide the lowest total revenue requirement, which includes demand and energy costs.

Second, the 12CP & Avergage method satisfies the fairness and equity criteria of ratemaking because customers with higher kilowatt-hour requirements benefit more than customers with lower higher kilowatt-hour requirements.

Q. WHAT RATE SHEDULES WERE OF PRIMARY CONCERN?

A. Rates RS, DS, DT-SEC and customers receiving service from primary voltages DT-PRI were of primary concern. These four major classes represent about 95% of total rate base, with the remaining dozen or so other rate schedules representing just 5% of rate base.

For these four major classes I sought to satisfy the cost of service criteria by moving the index rates of return (IRR) at proposed rates closer to the system average. The amount of movement for each major class incorporated a more tolerant use of the non-cost criteria of gradualism. If gradualism is employed customers have a better chance to adjust their consumption to higher rates..

Q. HOW DOES THE COMPANY PROPOSE TO ALLOCATE ANY INCREASE AMONG THE RATE SCHEDULES?

A. The Company proposes to reduce the difference between class rates of return at present rates and the system average rate of return by 25%. After that calculation, the Company allocates the increase to each of the classes based on class contributions to total rate base. Using this approach, the Company has allocated $32.6 million to the Residential Class (RS), $15.7 million to DS, $10.7 million to DT-SEC and $5.3 million to DT-PRI. These increases total 95% of the total proposed increase.

.

Q. WHAT IS THE DIFFERENCE BETWEEN YOUR METHOD AND THE COMPANY'S METHOD?

A. The difference is that my proposal moves the class rates of return more gradually toward the system average return.

Using the Company's 12-CP methodology, the RS IRR at present rates is .04. The Company has proposed an IRR of .88 at proposed rates, which is a movement of 84 points (see Exhibit SWR-6). Using my recommended methodology, 12CP & Average method, the RS IRR, at present rates to proposed rates go from .48 to 1.00 in a single swoop of 53 points. Both violate the principle of gradualism. Consequently, I recommend moving the RS IRR from.48 to .74, one half of the difference between .48 and a system IRR of 1.00 using a 12 CP & Average Methodology without a minimum distribution system. This recommendation is consistent with the principle of gradualism.

With the Company's proposed revenue increase and my recommended 12 CP& Average method the DS IRR, at present rates to proposed rates go from 2.85 to 1.24 for a reduction of 1.61 points (see Exhibit SWR-7). I agree with the Company's target IRR at proposed rates because this class of service has an IRR at present rates over 2.5 times the system rate of return. My recommendation is based a 12 CP & Average Methodology without a minimum distribution system. This recommendation is consistent with the principle of gradualism.

With the Company's proposed revenue increase and my recommended 12 CP& Average method the DT-SEC IRR, at present rates to proposed rates goes from .47 to .89 for an increase of 42 points (see Exhibit SWR-7). This violates the principle of gradualism. Instead, I recommend moving the DT-SEC IRR from .47 to .74, about one half of the difference between .47 IRR and a system IRR of 1.00 using a 12 CP & Average Methodology without a minimum distribution system. This recommendation is consistent with my RS recommendation.

With the Company's proposed revenue increase and my recommended 12 CP& Average method, the DT-PRI IRR at present rates to proposed rates goes from -1.71 to .49 for an increase of 2.20 points (see Exhibit SWR-7). I agree with the Company's target IRR at proposed rates because this class of service has such a low IRR at present rates.

Q. PLEASE COMPARE YOUR RECOMMENDED INCREASES WITH THE COMPANY'S PROPOSED INCREASES FOR THE 4 MAJOR CLASSES OF SERVICE?

A. I recommend that the revenue requirements increase proposed by the Company for the Residential class be decreased by $9,434,829. This decrease moves the IRR one half of the difference between .48 and a system IRR of 1.00 using a 12 CP & Average Methodology without a minimum distribution system (see Exhibit

SWR-8). As stated above, this recommendation is consistent with the principle of gradualism.

For the DT_SEC class, I recommend a decrease of $1,700,000, which moves this class about one half of the difference between .47 IRR and a system IRR of 1.00 using a 12 CP & Average Methodology without a minimum distribution system. This recommendation is consistent with my RS recommendation. (see Exhibit SWR-9).

For the DS and DT_PRI classes, I agree with the Company's proposed revenue increase and target IRR when the 12-CP & Average methodology is applied to the cost of service study.

Q. WHAT IS YOUR RECOMMENDATION FOR THE OTHER CLASSES OF SERVICE?

A. I recommend that any decrease from that proposed by the Company awarded to the RS and DT_SEC classes be distributed to the other classes as an across-the-board increase.

Q. WHAT IS YOUR SCALE BACK PROPOSAL?

A. I am not endorsing the Company's proposed revenue requirement. My recommendations are based on the Company's proposed revenue requirements so that the Commission can compare the two recommendations using consistent data. In the event the Commission sets the overall revenue requirement at a lower amount, my recommendations should be scaled back proportionately.

SECTION V

GREEN POWER RIDER

Q. PLEASE COMMENT ON THE GREEN POWER RIDER RATE DESIGN.

A. Duke's tariff includes a Green Power (GP) Rider. The existing program allows customers to voluntarily contribute to the GP fund for power purchases from environmentally friendly resources or for the development of environmentally friendly generation. The proposed GP, for small customers, shifts from a voluntary sum certain to a voluntary per kilowatt-hour contribution of $0.025 in increments of 100 kilowatt-hours.

Q. WILL THE REVENUES FROM CUSTOMERS BE USED IN A DIFFERENT MANNER?

A. Yes. In the proposed tariff GP revenues will not be used to purchase or develop environmentally friendly resources. Instead, the revenues will be used to purchase Renewable Energy Certificates (REC) and carbon credits and cover the costs of education, marketing and advertising. Large customer participation will be governed by contract negotiations.

Q. WHAT DO RECS AND CARBON CREDITS REPRESENT?

A. RECs represent the environmental attributes of one megawatt-hour from a renewable generation source. A carbon credit represents one ton of carbon dioxide reduction. Both REC and carbon credits are a tradable commodities.

Q. DOES KENTUCKY HAVE MANDATORY RENEWABLE PORTFOLIO STANDARDS?

A. No. Kentucky does not have RPS legislation. Renewable Portfolio Standards (RPS) legislation generally requires power generators to meet part of their requirements from renewable resources. RPS legislation may allow a power supplier to fulfill its Green Power portfolio requirements by purchasing RECs. Without RPS legislation the GP program is purely voluntary.

Q. IF THE PROPOSED GP IS APPROVED, WILL DUKE PURCHASE RECS?

A. Yes. Duke will purchase RECs to "match the Green Power commitments made by retail customers". (See the pre-filed testimony of J. Bailey, page 22, lines 7 to 10).

Q. IF THE VOLUNTARY FUNDS ARE INSUFFICIENT TO PURCHASE RECS WILL THE FUNDS BE RETURNED TO RATEPAYERS?

A. Pursuant to the existing GP tariff, if insufficient funds are collected to purchase REC or carbon credits, the money voluntarily provided are returned to participating customers with 6% interest. The proposed GP tariff includes no such provision, but should include such a provision.

Q. DOES THE PROPOSED TARIFF ADDRESS THE RATEMAKING TREATMENT OF REVENUES FROM THE SALE OF RECS OR CARBON CREDITS?

A. No. The proposed GP tariff also provides that the Company may transfer RECs or carbon credits at prevailing wholesale prices to and from third parties and affiliates. In the proposed tariff, carbon credits can be obtained from purchased power, Company owned generation or from carbon credit purchases.

The proposed tariff does not include a provision governing the treatment of revenues from RECs or carbon credit sales. In response to AG-DR-01-228, the Company states that all costs and proceeds of the program, including the revenue from any sale of RECs or carbon credits will be treated "below the line." Absent legislation, since the capital necessary to purchase RECs or carbon credits is provided by customers, not investors, the revenues from sales should be credited to the customers that provided the capital for purchases. If the Company invests in new equipment to reduce carbon dioxide emissions, carbon credits will be issued to the Company. If the Company intends to include the cost of the new investment in rate base, sale proceeds should also be credited to ratepayers

Q. WHAT ARE YOUR RECOMMENDATIONS?

A. I recommend that the proposed GP tariff be approved after modification to provide that (1) if insufficient funds are collected to purchase REC or carbon credits, the money voluntarily collected be returned to customers with 6%

interest, and (2) revenues from sales of RECs or carbon credits should be credited to customers.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION

In the Matter of:

AN ADJUSTMENT OF THE ELECTRIC RATES OF	)	
THE UNION LIGHT, HEAT AND POWER COMPANY	)	**CASE NO. 2006-00172**
D/B/A DUKE ENERGY KENTUCKY, INC.	)	

AFFIDAVIT

I, Steven W. Ruback, hereby swear and affirm that the foregoing testimony and all supporting appendices and schedules were prepared by me or under my direct supervision and are, to the best of my information and belief, true and accurate.

COMMONWEALTH/STATE OF MA
COUNTY OF Norfolk

Subscribed and sworn to before me by Steven W. Ruback this the 11th day of September, 2006.

My Commission Expires: 4/26/13

DUSTIN E. ARMITAGE
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
April 26, 2013

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. | **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
Vermont Gas Systems, Inc.	Vermont	7109 7160	05/10/06	Implement Alternative Regulation Plan/ Tariff Filing	Public Service Board
Georgia Power	Georgia	22403-U	05/05/06	Review & Evaluate Proposed Fuel Cost Recovery	Consumers' Utility Counsel
Commonwealth Edison Company	Illinois	05-0597	12/22/05	Proposed General Increase in Electric Rates for Delivery Service Direct and Rebuttal	Citizen's Utility Board & Cook County Attorney's Office
CNG, SCG and Yankee Gas Services	Connecticut	05-05-10	10/21/05	Complete LDC's Unbundling of Natural Gas Service	Office of Consumer Counsel
Cincinnati Gas & Electric Company	Ohio	05-0059-EL-AIR	10/11/05	Electric Rate Design	Office of the Ohio Consumers' Counsel
Atmos Energy Corporation	Georgia	20298-U	09/29/05	Gas Rate Design	Consumers' Utility Counsel
SCG	Connecticut	05-03-17	07/01/05	Gas Supply Direct and Supplemental	Office of Consumer Counsel
CNG, SCG and Yankee Gas Services	Connecticut	97-07-11RE02	05/02/05	Unbundling Natural Gas-Supplemental & Rebuttal Testimony	Office of Consumer Counsel
Savannah Electric and Power Company	Georgia	19758-U	3/18/05	Rate Design	Consumers' Utility Counsel
Atlanta Gas Light Company	Georgia	18638-U	02/25/05	Rate Design	Consumers' Utility Counsel
Georgia Power Company	Georgia	18300-U	10/8/04	Rate Design	Consumers' Utility Counsel
CNG, SCG and Yankee Gas Services	Connecticut	04-05-11	9/3/04	DPUC Generic Review of the Southern Methodology	Office of Consumer Counsel
CNG, SCG and Yankee Gas Services	Connecticut	97-07-11RE02	6/25/04	Unbundling Natural Gas –	Office of Consumer

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
				Rebuttal Testimony	Counsel
Aquarion Water Company	Connecticut	04-02-14	6/24/04	Rate Design – Single Tariff Priciing	Office of Consumer Counsel
Connecticut Local Distribution Companies	Connecticut	04-04-16	8/16/04	Hedging	Office of Consumer Counsel
CNG, SCG and Yankee Gas Services	Connecticut	97-07-11RE02	5/28/04	Unbundling Natural Gas	Office of Consumer Counsel
South Jersey Gas Company	New Jersey	GR03050413	01/9/04	Natural Gas Procurement Practices	New Jersey's Rate Payer Advocates
Kansas Atmos	Kansas	Docket No. 03-ATMG-1036-RTS	11/3/03	Review and evaluate Rate design proposal and Consollidation of division	Kansas Corporation Commission
Sierra Power Pacific Power Company	Nevada	Docket No. 03-5021	8/19/03	Review Sierra's PGA application and its gas supply report.	Office of Nevada Attorney General Bureau of Consumer Protection (BCP)
Kansas Gas Service, a Division of Oneok, Inc.	Kansas	Docket No. 03-KGSG-602-RTS	7/11/03	Adjustment of Gas Rates	Kansas Corporation Commission
SCG and CNG	Connecticut	Docket No. 97-07-11PH02	7/11/03	Unbundling of Natural Gas Services	Office of Consumer Counsel
Washington Gas Light Company	District of Columbia	Formal Case No. 1016	6/26/03	Rate Increase	The Office of the People's Counsel
Public Service Company of New Mexico (PNM)	New Mexico	Case No. 03-000-17 UT	5/23/03	Rate Modifications	Attorney General
CNG, SCG and Yankee Gas Services	Connecticut	02-10-01	1/27/03	Appropriateness of class specific Purchased Gas Adjustments (PGA)	The Office of Consumer Counsel
Arkla	Oklahoma	200200166	10/30/02	General Change or Modification in Arkla's rates,	The Oklahoma Corporation Commission

List of Testimonies of Steven W. Ruback

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
				charges and tarrifs	
Yankee Gas	Connecticut	01-05-19PH02	11/20/02	Rate Increase Rate Design	Office of Consumers Council
Sierra Pacific Power Company	Nevada	02-7003	11/14/02	Gas Supply Prudence Review	Office of Nevada Attorney General Bureau of Consumer Protection (BCP)
Atlanta Gas & Light Company	Georgia	15527-U	8/7/02	Lost and Unaccounted for Gas	Consumers' Utility Counsel
Western Resources, Inc. and Kansas Gas and Electric Company	Kansas	02-WSRE-301-RTS	4/22/02	Rate Design	State Corporation Commission
Savannah Electric and Power Company	Georgia	14618-U	3/15/02	Automatic Adjustment Clauses, Class Revenue Requirements, Cost of Service Studies	Consumer Utilities Counsel
DPUC Generic Investigation of Connecticut Local Distribution Companies	Connecticut	97-07-11 PH02	2/1/02	Capacity Release	Office of Consume Counsel
Beaumont Power & Light Company	Texas	SOA 473-98-2251, PUC 20125	11/1/01	Pro Forma	Beaumont Power & Light Company
Georgia Power Company	Georgia	14000-U	10/12/01	Rate Design	Consumers' Utility Counsel Division
Yankee Gas Services Company	Connecticut	01-05-19PH1	9/25/01	Interruptible Margin	Office of Consumer Counsel
United Cities Gas Company	Georgia	14105-U	8/24/01	Gas Supply Plan	Consumers' Utility Counsel Division
Navopache Electric Cooperative, Inc.	Arizona	E-01787A-01-0063	8/15/01	Rate Design	White Mountain Apache Tribe
Piedmont Natural Gas Company	South Carolina	2001-004-G	7/31/01	Gas Purchasing Policies	Department of Consumer Affairs

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
Southern Connecticut Gas Company and Connecticut Natural Gas Corporation	Connecticut	99-04-18, PH III and 99-09-03, PH II	7/13/01	Merger-Enabled Gas-Supply Savings	Office of Consumer Counsel
Southern Connecticut Gas Company	Connecticut	99-04-18, Ph IV	7/2/01	Rate Design	Office of Consumer Counsel
Southern Connecticut Gas Company and Connecticut Natural Gas Corporation	Connecticut	99-04-18, PH III and 99-09-03, PH II	6/25/01	Merger-Enabled Gas-Supply Savings	Office of Consumer Counsel
Oklahoma Natural Gas Corporation	Oklahoma	PUD 200100097	5/18/01	Gas Hedging	Oklahoma Corporation Commission
Entergy New Orleans, Inc. (2)	Louisiana	UD-99-2	3/14/01	Period Costs in Fuel Adjustment Charge	Reverend C.S. Gordon, Jr., et al
Southwest Gas Corporation	Nevada	00-10070	3/14/01	Prudence Review	Bureau of Consumer Protection
Sierra Pacific Power Company	Nevada	00-11002	2/20/01	Prudence Review	Bureau of Consumer Protection
EnergyNorth Natural Gas, Inc.	New Hampshire	DG 00-063	11/27/00	Rate Design	Office of Consumer Advocate
Northern Utilities, Inc.	New Hampshire	DG 00-046	11/16/00	Rate Design	Office of Consumer Advocate
Beaumont Power & Light Company	Texas	SOAH 473-98-2251, PUC 20125	11/6/00	Pro Forma	Beaumont Power & Light, L.C.
Connecticut Natural Gas Corporation	Connecticut	99-09-03	9/25/00	Incentive Rate Plan	Office of Consumer Counsel
EnergyNorth Natural Gas, Inc.	New Hampshire	DG 00-063	9/1/00	Rate Design	Office of Consumer Advocate
United Cities Gas Company	Georgia	12498-U	8/25/00	2000-2001 Gas Supply Plan	Consumer's Utility Counsel Division
Northern Utilities, Inc.	New Hampshire	DG 00-046	8/18/00	Rate Design	Office of

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
					Consumer Advocate
Southern Connecticut Gas Company, Connecticut Natural Gas Corporation, Yankee Gas Services	Connecticut	99-03-28	2/4/00	Cost of Service Study Methodologies	Office of Consumer Counsel
Oklahoma Natural Gas Company	Oklahoma	PUD980000683P UD980000570 PUD990000166	1/24/00	Cushion Gas	Corporation Commission
Oklahoma Natural Gas Company	Oklahoma	PUD980000683 PUD980000570 PUD990000166	2/1/00	Cost of Service and Rate Design	Corporation Commission
Connecticut Natural Gas Corporation	Connecticut	99-09-03	1/2000	Interruptible Margin	Office of Consumer Counsel
United Cities Gas Company	Georgia	10939-U	11/5/99	1999/2000 Gas Supply Plan	Consumers' Utility Counsel Division
Southern Connecticut Gas Company	Connecticut	99-04-18	9/22/99	Interruptible Margin	Office of Consumer Counsel
United Cities Gas Company	Georgia	10939-U	8/24/99	1999/2000 Gas Supply Plan	Consumers' Utility Counsel Division
United Illuminating Company	Connecticut	99-03-35	7/2/99	Standard Offer	Office of Consumer Counsel
Connecticut Light & Power Company	Connecticut	99-03-36	7/7/99	Standard Offer	Office of Consumer Counsel
Western Resources, Inc. and Kansas City Power & Light Company	Kansas	98-WSRE-676-MER	2/18/99	Market Power	Citizens' Utility Ratepayer Board
Western Resources, Inc. and Kansas City Power & Light Company	Kansas	98-WSRE-676-MER	2/99	Rate Design	Citizens' Utility Ratepayer Board
Kansas Gas Service Company, a Division of Oneok, Inc.	Kansas	98-KGSG-822-TAR	11/98	Gas Unbundling	Citizens' Utility Ratepayer Board
Residential Electric, Incorporated	New Mexico	2867 & 2868	11/9/98	Electric Retail Competition	Office of Attorney General
United Cities Gas Company	Georgia	9306-U	8/24/98	1998-1999 Gas Supply Plan	Consumers' Utility Counsel

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. — **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
Atlanta Gas Light Company	Georgia	9305-U	8/24/98	1998-99 Gas Supply Plan	Consumers' Utility Counsel
Atlanta Gas Light Company	Georgia	9305-U	8/25/98	Addendum - 1998-99 Gas Supply Plan	Consumers Utility Counsel
Kansas Gas Service Company a Division of Oneok, Inc.	Kansas	98-KGSG-611-TAR	7/31/98	Optional Services	Citizens' Utility Ratepayer Board
Eastern Enterprises/Essex County Gas Company	Massachusetts	D.T.E. 98-27	6/9/98	Performance Based Ratemaking	Local 12086, United Steelworkers of America, AFL-CIO and the Alliance of Utility Workers' Unions
Southern Connecticut Gas Company	Connecticut	97-12-21	5/22/98	Request to Exit Merchant Function	Connecticut Office of Consumer Counsel
Atlanta Gas Light Company	Georgia	8390-U	3/31/98	SFV Rate Design	Consumers' Utility Counsel Division
Western Resources, Inc. Kansas Gas & Electric Company	Kansas	193,306-U;96-KG&E-100-RTS, 193,307-U;96-WSRE-101-DRS	2/98	Rate Design	Citizens' Utility Ratepayer Board
PNM Gas Services	New Mexico	2762	2/98	Class Revenue Allocation, Cost of Service Study, Discounted Rates, Transportation Balancing	New Mexico Attorney General
Western Resources, Inc. ONEOK, Inc.	Kansas	97-WSRG-486-MER	9/97	Line Extensions	Citizens' Utility Ratepayer Board
Atlanta Gas Light Company	Georgia	7710-U	8/97	Gas Supply Plan	Consumers' Utility Counsel Division
United Cities Gas Company	Georgia	7711-U	8/97	Gas Supply Plan	Consumers' Utility Counsel Division
DPUC Review of Electric Companies	Connecticut	97-01-15	8/97	Cost of Service and Unbundled	Connecticut Office of Consumer

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
				Tariffs	Counsel
Columbia Gulf Transmission Company	Pennsylvania	RP97-52-000	7/97	Rate Design	Pennsylvania Office of Consumer Advocate
PNM Gas Services	New Mexico	2760	7/97	Small Customer Transportation Program	New Mexico Attorney General
Consumers Pennsylvania Water Company	Pennsylvania	R-00973869	5/97	Competitive Pricing	Pennsylvania Office of Consumer Advocate
T.W. Phillips Gas & Oil Company	Pennsylvania	R-00963812	3/97	Purchased Gas Adjustment Clause Rate Design	Pennsylvania Office of Consumer Advocate
Sierra Pacific Power Company	Nevada	96-6013 96-6014	1/97	Competitive Tariffs Power Supply Contract	Office of Advocate for Customers of Public Utilities
United Cities Gas Company	Georgia	6753-U	11/96	Application for Performance Based Ratemaking	Consumers Utility Counsel Division
Application of Virginia Power	Virginia	PUE	10/96	Competitive Practices	City of Richmond
Atlanta Gas Light Company	Georgia	6660-U	8/96	Gas Supply Plan	Consumers Utility Counsel Division
United Cities Gas Company	Georgia	6661-U	8/96	Cost of Gas Purchased Gas Adjustment Clause	Consumers Utility Counsel Division
Chesapeake Utilities Corporation	Delaware	95-73, Phase II	8/96	Cost of Service Rate Design	Office of Public Advocate
Generic PGA Proceedings	Connecticut	96-01-28	6/96	PGA Rate Design	Connecticut Office of Consumer Counsel
PFG Gas and North Penn Gas Company	Pennsylvania	R-00953524	5/96	Cost of Gas	Pennsylvania Office of Consumer Advocate

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
Equitable Gas Company	Pennsylvania	R-00963576	5/96	Anti Competitive Practices	Pennsylvania Office of Consumer Advocate
Equitable Gas Company	Pennsylvania	P-00940886	5/96	Anti Competitive Practices	Pennsylvania Office of Consumer Advocate
Western Resources, Inc.	Kansas	193,306-U 193,307-U	5/96	Rate Design Cost of Service	Citizen's Utility Ratepayers Board
Connecticut American Water Company	Connecticut	95-12-15	3/96	Rate Design Cost of Service	Connecticut Office of Consumer Advocate
Carnegie Natural Gas Company	Pennsylvania	M-0095069 & M-00950698	2/96	Gas Cost Issues Merger Issues	Pennsylvania Office of Consumer Advocate
Western Resources, Inc.	Kansas	193,305-U	1/96	Cost of Service Rate Design	Citizens Utility Ratepayer Board
Public Service Company of New Mexico Gas Services	New Mexico	Case No. 2662	1/96	Cost of Service Rate Design	New Mexico Office of Attorney General
Delmarva Power & Light Company	Delaware	95-137	11/95	Economic Development and Negotiated Rates	Delaware Office of Public Advocate
Yankee Gas Services Company	Connecticut	92-09-19 Reopened	11/17/95	Cost of Service	Connecticut Office of Consumer Counsel
Public Service Company of New Mexico Gas Services	New Mexico	Case No. 2655	11/95	Optional Services	New Mexico Office of Attorney General
Connecticut Natural Gas Company	Connecticut	95-02-07 (Phase II)	9/95	Cost of Service Rate Design	Connecticut Office of Consumer Counsel
Citizens Water Company	Pennsylvania	R-00953300	9/95	Cost of Service	Pennsylvania Office of

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. — **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
				Rate Design	Consumer Advocate
Apollo Gas Company and Carnegie Natural Gas Company	Pennsylvania	R-00953378 R-00953379	8/95	Merger Application	Pennsylvania Office of Consumer Advocate
Philadelphia Suburban Water Company	Pennsylvania	R-00953343	8/95	Cost of Service Rate Design	Pennsylvania Office of Consumer Advocate
Delaware Power & Light Company	Delaware	95-44	8/95	Order 636 Issues	Delaware Office of Consumer Advocate
PECO Energy Company	Pennsylvania	R-00953376	7/95	Cost of Gas	Pennsylvania Office of Consumer Advocate
Connecticut Natural Gas Company	Connecticut	95-02-07	7/95	Rate Design	Connecticut Office of Consumer Counsel
Hope Gas Company	West Virginia	95-0003-G-42T	6/95	Cost of Service	WV PSC Consumer Advocate Division
Mountaineer Gas Company	West Virginia	95-0011-G-42T	6/95	Cost of Service	WV PSC Consumer Advocate Division
North Penn Gas Company	Pennsylvania	R-943245	5/95	Cost of Service Rate Design	Pennsylvania Office of Consumer Advocate
Equitable Gas Company	Pennsylvania	R-953320	5/95	Purchased Gas Costs	Pennsylvania Office of Consumer Advocate
North Shore Gas Company	Illinois	95-0031	4/95	Cost of Service Rate Design	Illinois Citizens Utility Board
The Peoples Gas Light & Coke Co.	Illinois	95-0032	4/95	Cost of Service Rate Design	Illinois Citizens Utility Board
Equitable Gas Company	Pennsylvania	R-00943272	4/95	Transportation Balancing	Pennsylvania Office of

Company	State	Docket	Date	Topic	On Behalf Of:
					Consumer Advocate
T.W. Phillips Gas & Oil Co.	Pennsylvania	R-00943256	3/95	Cost of Gas	Pennsylvania Office of Consumer Advocate
Virginia Power	Virginia	PUE940067	3/95	IRP	City of Richmond
Generic Order 636 Proceeding	Connecticut	94-11-12	3/95	Order 636 Issues/ Cost Allocation Transportation Issues	Connecticut Office of Consumer Counsel
Roaring Creek Water Company	Pennsylvania	R-00943177	1/95	Cost of Service Rate Design	Pennsylvania Office of Consumer Advocate
Generic Proceeding	Illinois	94-0403	1/95	Purchased Gas Adjustment Charge	Illinois Citizens Utility Board
Gas Company of New Mexico	New Mexico	Case No. 2587	12/94	Cost of Service Gas Prudency	New Mexico Office of Attorney General
Associated Natural Gas Company	Missouri	GR90-106-GR91-208	11/94	Gas Prudency	Missouri Public Service Commission
Empire District Electric Company	Kansas	190,360-U	8/94	Rate Design	Citizens' Utility Ratepayer Board
PECO Energy Company	Pennsylvania	R-00943070	7/94	Gas Supply Order 636	Pennsylvania Office of Consumer Advocate
National Fuel Gas Distribution Corp.	Pennsylvania	R-00942991	6/94	Rate Design	Pennsylvania Office of Consumer Advocate
Equitable Gas Company	Pennsylvania	R-00943022	5/94	Rate Design	Pennsylvania Office of Consumer Advocate
Bay State Gas Company	Massachusetts	DPU 94-16	3/94	Gas Supply Order 636	Massachusetts Office

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	State	Docket	Date	Topic	On Behalf Of:
					of Attorney General
Gas Company of New Mexico	New Mexico	Case No. 2508	3/94	Rate Design	New Mexico Office of Attorney General
Boston Gas Company	Massachusetts	DPU 93-212	2/94	Gas Supply Order 636	Massachusetts Office of Attorney General
Commonwealth Gas Company	Massachusetts	DPU 93-222	2/94	Gas Supply Order 636	Massachusetts Office of Attorney General
Philadelphia Electric Company Gas Division	Pennsylvania	R-00932935	2/94	Rate Design	Pennsylvania Office of Consumer Advocate
UGI Utilities- Electric Division	Pennsylvania	R-00932862	2/94	Rate Design Cost of Service	Pennsylvania Office of Consumer Advocate
Delmarva Power & Light Company	Delaware	93-80F	2/94	Order 636 Rate Design	Delaware Office of Public Advocate
Burlington Electric Department (Municipal Utility)	Vermont	5694	1/94	Rate Design Cost of Service	Burlington Electric Dept. (Municipal Utility)
Mansfield Consortium Essex Gas Company Fitchburg Gas & Electric Colonial Gas Company Berkshire Gas Company	Massachusetts	DPU 93-189 DPU 93-190 DPU 93-188 DPU 93-187	1/94	Order 636 Gas Supply	Massachusetts Office of Attorney General
Gas Company of New Mexico	New Mexico	Case No. 2508	12/93	Approve Continued use of purchased gas adjustment clause	The New Mexico Attorney General's office
Roaring Creek Water Company	Pennsylvania	R-00932665	9/93	Rate Design	Pennsylvania Office of Consumer Advocate
Allied Gas Company	Pennsylvania	R-00932627	8/93	Order 636	Pennsylvania

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
				Capacity Release	Office of Consumer Advocate
Southern CT Gas Company	Connecticut	93-03-09	8/93	Rate Design & Gas Supply	Office of Consumers' Counsel
Pennsylvania Gas & Water Company (Spring Brook)	Pennsylvania	R-00932667	8/93	Rate Design & Cost of Service	Pennsylvania Office of Consumer Advocate
National Fuel Gas Distribution Corp.	Pennsylvania	R-00932548	7/93	Gas Supply Planning; Transition Costs; Capacity Release	Pennsylvania Office of Consumer Advocate
Philadelphia Electric Company Gas Division	Pennsylvania	R-00932669	7/93	Excess Capacity Transition Costs Commodity Costs Balancing	Pennsylvania Office of Consumer Advocate
Equitable Gas Company	Pennsylvania	R-00932599	5/93	Excess Capacity Transition Costs Commodity Costs	Pennsylvania Office of Consumer Advocate
Pennsylvania Gas & Water Co. (Scranton)	Pennsylvania	R-00922482	1/93	Rate Design Cost of Service	Pennsylvania Office of Consumer Advocate
Burlington Electric Dept.	Massachusetts		1/93	Rate Design	Burlington Electric Department
Pennsylvania American Water Co.	Pennsylvania	R-00922428	10/92	Rate Design	Pennsylvania Office of Consumer Advocate
United Illuminating Company	Connecticut	92-06-05	10/92	Rate Design	Office of CT Consumer Counsel
Pennsylvania Gas & Water Co. (Crystal Lake)	Pennsylvania	R-00922404	10/92	Rate Design Cost of Service	Pennsylvania Office of Consumer Advocate
Yankee Gas Company	Connecticut	92-02-19	6/92	Rate Design	Office of CT Consumer

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. — **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
					Counsel
Atlanta Gas & Light Company	Georgia	4011-U	10/91	Rate Design	Georgia Consumer Counsel
Consolidated Edison of New York	New York	91-E-0462	9/91	Rate Design	New York City
Texas Eastern Transmission Corporation	Pennsylvania	RP88-67-000 RP88-81-000 RP-88-221-000 RP90-119-000 RP91-4-000 RP91-119-000	7/91	Rate Design	Pennsylvania Office of Consumer Advocate
Philadelphia Suburban Water Co.	Pennsylvania	R-911892	6/91	Rate Design	Pennsylvania Office of Consumer Advocate
Equitable Gas Company	Pennsylvania	R-911925	4/91	Rate Design	Pennsylvania Office of Consumer Advocate
Virginia Electric and Power Companmy	Virginia	PUE870093	2/91	Petition to construct, own and operate a pipeline	City of Richmond, Virginia
Middlesex Water Company	New Jersey	WR90080884	2/91	Rate Design	New Jersey Rate Counsel
Hackensac Water Company	New Jersey	WR90080792J	1/91	Rate Design	New Jersey Rate Counsel
Pennsylvania Gas & Water Company	Pennsylvania	R-901726	10/90	Rate Design	Pennsylvania Office of Consumer Advocate
Artesian Water Company	Delaware	90-10	8/90	Rate Design	Delaware Public Service Commission
Atlanta Gas & Light Company	Georgia	3923-U	7/90	Rate Design	Georgia Consumer Counsel
Pennsylvania American Water Company	Pennsylvania	R-901652	6/90	Rate Design	Pennsylvania Office of Consumer Advocate

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
Kent County Water Authority	Rhode Island	1952	6/90	Rate Design	RI Public Utilities Commission
Gas Company of New Mexico	New Mexico	2307	4/90	Rate Design	NM Attorney General
Columbia Gas of Pennsylvania	Pennsylvania	R-891468	4/90	Rate Design	Pennsylvania Office of Consumer Advocate
National Fuel Gas Company	Pennsylvania	R891218	6/89	Rate Design	Pennsylvania Office of Consumer Advocate
Philiadelphia Electric Company	Pennsylvania	R-881089	12/88	Rate Design	Pennsylvania Public Utility Commision & Pennsylvania Natural Gas Associates
Commonwealth Gas Pipeline	Virginia	PUE880048	9/88	Rate Design Gas Supply	City of Richmond
Jamaica Water Supply Co.	New York	88-W-080	8/88	Rate Design	Town of Hempstead Service Commission
Equitable Gas Company	Pennsylvania	R-880971	6/88	Rate Design	Pennsylvania Office of Consumer Advocate
Pennsylvania American Water Company	Pennsylvania	R880916	5/88	Rate Design	Pennsylvania Office of Consumer Advocate
National Fuel Gas Co.	Pennsylvania	87-719	12/87	Rate Design	Pennsylvania Office of Consumer Advocate
Pennsylvania-American Water Co.	Pennsylvania	R-870732	11/87	Rate Design	Pennsylvania Office of Consumer Advocate
Valley Gas Co.	Rhode Island		9/87	Cogeneration Rate	RI Division of Public Utilities

List of Testimonies of Steven W. Ruback

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
					and Carriers
Philadelphia Electric Company	Pennsylvania	R-870629	8/87	Rate Design	Pennsylvania Office of Consumer Advocate
Delmarva Power & Light Company	Delaware	86-22	8/87	Rate Design	Delaware Public Commission
UGI-Corporation-Gas	Pennsylvania	R870602	6/87	Gas Supply	Pennsylvania Office of Consumer Advocate
East Ohio Gas Company	Ohio	86-297-GA-AIR	11/86	Rate Design	Office of Consumer Counsel
Delmarva Power and Light	Delaware	86-22,86-32	10/86	Gas Supply Rate Design	Public Service Commission
Commonwealth Gas Services	Virginia	PUE860031	10/86	Gas Supply	VA Office of Attorney General
Metropolitan Edison Co.	Pennsylvania	R-860384	10/86	Rate Design	Office of Consumer Counsel
Pennsylvania Electric Co.	Pennsylvania	R-860413	10/86	Rate Design	Pennsylvania Office of Consumer Advocate
Providence Gas Company	Rhode Island	1844	7/86	Cogeneration Rates	RI Division of Public Utilities and Carriers
National Fuel Gas	Pennsylvania	R-850287	7/86	Rate Design	Pennsylvania Office of Consumer Advocate
In the Matter of Adopting Commission Policy Regarding Natural Gas Industrial Rates and Transportation Policies	Virginia	PUE860024	6/86	Transportation Policy	Rates & Transportation Policy
Connecticut Light and Power Company	Connecticut	85-10-22	3/86	Street Lighting	CT Municipal League & Schools
Boston Edison Company	Massachusetts	DPU85-271	3/86	Street Lighting	City of Boston

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
West Penn. Power Co.	Pennsylvania	R-850220	2/86	Rate Design	Pennsylvania Office of Consumer Advocate
Public Service Comm. of Maryland	Maryland	7871	7/85	Cogen Unit Perf. Prog.	People's Counsel Performance Program
Valley Gas Company	Rhode Island	1806	7/85	Rate Design	RI Division of Public Utilities and Carriers
Public Service Co. Of New Mexico	New Mexico	1916	7/85	Jurisdiction-al Cost of Service Study	NM Attorney General's Office
Pennsylvania Electric Co.	Pennsylvania	R-842771	5/85	Rate Design	Pennsylvania Office of Consumer Advocate
Metropolitan Edison Co.	Pennsylvania	R-842770	5/85	Rate Design	Pennsylvania Office of Consumer Advocate
Equitable Gas Company	Pennsylvania	R-842769	5/85	Rate Design	Pennsylvania Office of Consumer Advocate
Providence Gas Company	Rhode Island	1741	9/84	Rate Design	RI Division of Public Utilities and Carriers
Public Service Co. Of New Mexico	New Mexico	1891-1892	7/84	Excess Capacity	NM Attorney General's Office
South Jersey Gas Company	New Jersey	834-184	7/84	Rate Design	Department of Public Advocate
Florida Power Corporation	Florida	830470-EI	4/84	Rate Design	Department of Navy and Federal Executive Agencies
Virginia Electric Power Co.	Virginia	830067	3/84	Small Power Production Rates	City of Richmond
National Fuel Gas Corporation	Pennsylvania	R-832469	2/84	Rate Design	Pennsylvania Office of

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
					Consumer Advocate
Philadelphia Electric Company	Pennsylvania	R-832410	12/83	Rate Design	Pennsylvania Office of Consumer Advocate
Narragansett Electric Co.	Rhode Island	1719	12/83	Rate Design	RI Division of Public Utilities and Carriers
Pennsylvania Power Company	Pennsylvania	R-832409	12/83	Rate Design	Public Corporate Commission
Appalachian Power Company	Virginia	PUE830037	9/83	Power Supply; Off-System	Attorney General's Office
People's Natural Gas	Pennsylvania	R-832315	8/83	Rate Design	Pennsylvania Office of Consumer Advocate
Atlanta Gas & Light Company	Georgia	3402-U	8/83	Rate Design	Georgia Consumers Counsel
New Jersey Natural Gas Company	New Jersey	831-46	7/83	Gas Supply Planning	NJ Department of Public Advocate
East Ohio Gas Company	Ohio	89-901-GA-AIR	5/83	Rate Design	City of Cleveland Consumers Counsel
South Jersey Gas Company	New Jersey	831-107	5/83	Rate Design	NJ Department of Public Advocate
Gas Cost Rate No. 5 Investigation	Pennsylvania	M-78050055	4/83	Gas Supply	PA Public Utility Commission
Western Massachusetts Electric Company	Massachusetts		4/83	Generating Performance Standards	Massachusetts Departments of Attorney General
Narragansett Electric Co.	Rhode Island	1606,1692	3/83	Rate Design	RI Division of Public Utilities and Carriers
National Fuel Gas Co.	Pennsylvania	R-822145	2/83	Rate Design	Pennsylvania Office of Consumer

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
					Advocate
Columbia Gas of West Virginia	West Virginia	82-379-G-30C	12/82	Rate Design	Office of Consumer Advocate
Narragansett Electric Company	Rhode Island	1659	11/82	Rate Design	RI Division of Public Utilities and Carriers
Cleveland Electric Illuminating Co.	Ohio	81-1378-EL-AIR	9/82	Rate Design	Ohio Office of Consumers' Counsel
Potomac Electric and Power Co.	District of Columbia	FC785	7/82	Rate Design	DC Office of People's Counsel
UGI-Gas	Pennsylvania	R-821899	8/82	Rate Design	Pennsylvania Office of Consumer Advocate
Virginia Electric and Power Co.	Virginia	PUE 820018	7/82	Power Supply	Attorney General
Potomac Electric and Power Co.	District of Columbia	FC759	6/82	Rate Design	DC Office of People's Counsel
Pike County Light and Power Company	Pennsylvania	R-821857	6/82	Power Supply	Pennsylvania Office of Consumer Advocate
Potomac Electric and Power Co.	District of Columbia	FC 757	1/82	Cogen.	DC Office of People's Counsel
Philadelphia Electric Company-Gas	Pennsylvania	R-811719	2/82	Rate Design	Pennsylvania Office of Consumer Advocate
Narragansett Electric Co.	Rhode Island	1591	12/81	Rate Design	RI Division of Public Utilities and Carriers
National Fuel Gas Co.	Pennsylvania	R-811600	12/81	Rate Design	Pennsylvania Office of Consumer Advocate
UGI Gas	Pennsylvania	R-811488	8/81	Rate Design	Pennsylvania Office of Consumer

List of Testimonies of Steven W. Ruback

The Columbia Group, Inc. **Gas Supply, Cost of Service and Rate Design Testimonies**

Company	*State*	*Docket*	*Date*	*Topic*	*On Behalf Of:*
					Advocate
Appalachian Power Company	Virginia	PUE810033	8/81	Power Supply	VA Attorney General
Pennsylvania Power Company	Pennsylvania	R-8001510	8/81	Rate Design	Pennsylvania Office of Consumer Advocate
Old Dominion Power Company	Virginia	PUE800116	1/81	Cogen.	Office of Attorney General
Appalachian Power Company	Virginia	PUE800112	1/81	Cogen.	VA Attorney General
Virginia Electric Cooperatives	Virginia	PUE800117	1/81	Cogen.	VA Attorney General
Virginia Electric and Power Co.	Virginia	PUE800102	1/81	Cogen.	VA Attorney General
National Fuel Gas Co.	Pennsylvania	R-79090956	4/80	Rate Design	PA Office of Consumer Advocate
Potomac Electric and Power Co.	District of Columbia	FC 725	1/80	Fuel Adjustment Coal Supply	DC Office of People's Counsel

DUKE ENERGY KENTUCKY
CALCULATION OF COMPANY LOAD FACTOR
ELECTRIC CASE NO: 2006-00172

	Total Company	Comments
Total KWH (K301)	4,318,019,707	Provided from Company allocation factor
Total Average Demand	492,925	Total KWH divided by 8760 (number of hours in a year)
System Peak	870,000	Provided from Company COS work papers WPFR-9v pa(
Load Factor	56.66%	Total Average Demand divided by System Peak

Source:

Total KWH is provided from Company's cost of service study FR-9V-1; 12 months ending December 31, 2007; page 1 of allocation factor:

DUKE ENERGY KENTUCKY
DEVELOPMENT OF PEAK (12-CP) AND AVERAGE FACTORS
TWELVE MONTHS ENDING DECEMBER 31, 2007
ELECTRIC CASE NO: 2006-00172

LINE NO.	LINE ALLOCATORS	TOTAL	RS	DS	DS_RTP	GSFL	EH	SP	DT_SEC	DT_SEC_RTP	DT_PRI	DT_PRI_RTP	DP	TT	TT_RTP	LT	OTHER
1	TOTAL KWH (K301)	4,318,019,707	1,633,623,871	1,118,383,192	1,085,288	6,714,746	15,149,755	434,115	782,930,553	8,700,822	467,034,883	21,489,618	36,757,242	186,542,548	11,905,892	26,919,458	347,724
2	Ratio to Total Electric	1.0000	0.3783	0.2590	0.0003	0.0016	0.0035	0.0001	0.1813	0.0020	0.1082	0.0050	0.0085	0.0432	0.0028	0.0062	0.0001
3	Load Factor	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666	0.5666
4	Energy Weighted by Load Factor	0.5666	0.2144	0.1467	0.0001	0.0009	0.0020	0.0001	0.1027	0.0011	0.0613	0.0028	0.0048	0.0245	0.0016	0.0035	0.0000
5	12CP Factor	717,083	320,629	190,669	156	841	2,430	76	106,156	1,170	59,508	2,747	5,771	23,135	1,465	2,276	54
6	Ratio to Total Electric	1.0000	0.4471	0.2659	0.0002	0.0012	0.0034	0.0001	0.1480	0.0016	0.0830	0.0038	0.0080	0.0323	0.0020	0.0032	0.0001
7	12 CP Weighted by 1 minus LF	0.4334	0.1938	0.1152	0.0001	0.0005	0.0015	0.0000	0.0642	0.0007	0.0360	0.0017	0.0035	0.0140	0.0009	0.0014	0.0000
8	12 CP and Average Allocator	1.0000	0.4081	0.2620	0.0002	0.0014	0.0035	0.0001	0.1669	0.0018	0.0972	0.0045	0.0083	0.0385	0.0024	0.0049	0.0001

Footnotes:

(1) Energy at generation is provided from the Company's Cost of Service Study Test Year Ending December 31,2007

(2) Energy Allocation Factor equals for each class; class divided by total system

(3) Load Factor equals Total Average Demand divided by System Peak

(4) Energy Weighted by Load Factor = 2 * 3

(5) 12CP data provided from the Company's Cost of Service Study Test Year December 31,2007

(6) 12CP Factor equals for each class; 12CP divided by total system

(7) 12 CP Weighted by 1 minus LF = 6 * (1 - LF); where LF = Load factor row #3

(8) 12 CP and Average Allocator = 4 + 7

DUKE ENERGY KENTUCKY
RATES of RETURN COMPARISON
TWELVE MONTHS ENDING DECEMBER 31, 2007
ELECTRIC CASE NO: 2006-00172

	COMPANY				12-CP & AVERAGE			
Class	Present ROR	Present IRR	Proposed ROR	Proposed IRR	Present ROR	Present IRR	Proposed ROR	Proposed IRR
TOTAL	1.44%	1.00	8.76%	1.00	1.44%	1.00	8.76%	1.00
RS	0.05%	0.04	7.72%	0.88	0.69%	0.48	8.79%	1.00
DS	3.97%	2.75	10.66%	1.22	4.12%	2.85	10.87%	1.24
DS_RTP	20.07%	13.90	21.31%	2.43	18.42%	12.75	19.59%	2.24
GSFL	16.39%	11.35	19.97%	2.28	13.32%	9.22	16.50%	1.88
EH	-2.04%	-1.41	6.15%	0.70	-2.15%	-1.49	5.94%	0.68
SP	10.95%	7.58	15.89%	1.81	11.35%	7.86	16.38%	1.87
DT_SEC	1.67%	1.16	9.36%	1.07	0.68%	0.47	7.78%	0.89
DT_SEC_RTP	8.30%	5.75	9.05%	1.03	6.76%	4.68	7.45%	0.85
DT_PRI	-1.43%	-0.99	6.13%	0.70	-2.48%	-1.71	4.29%	0.49
DT_PRI_RTP	8.37%	5.80	8.98%	1.02	6.30%	4.36	6.84%	0.78
DP	0.16%	0.11	7.80%	0.89	-0.10%	-0.07	7.36%	0.84
TT	3.55%	2.46	10.61%	1.21	1.36%	0.94	7.37%	0.84
TT_RTP	11.90%	8.24	12.33%	1.41	8.36%	5.79	8.72%	1.00
LT	11.26%	7.80	16.12%	1.84	8.76%	6.06	13.08%	1.49
OTHER	-7.61%	-5.27	1.97%	0.23	-7.69%	-5.32	1.68%	0.19

Exhibit SWR-4

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Idaho Public Utilities Commission
Office of the Secretary
RECEIVED
FEB 20 2004
Boise, Idaho

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AUTHORITY TO INCREASE ITS INTERIM AND BASE RATES AND CHARGES FOR ELECTRIC SERVICE	)	CASE NO. IPC-E-03-13

DIRECT TESTIMONY OF NANCY HIRSH

ON BEHALF OF NW ENERGY COALITION

Exhibit SWR-4

Sharon L. Nelson, Chairman
Richard D. Casad, Commissioner
A. J. "Bud" Pardini, Commissioner

STATE OF WASHINGTON

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

P.O. Box 9022 • 1300 S. Evergreen Park Dr. S.W. • Olympia, Washington 98504-9022 • (206) 753-6423 • (SCAN) 234-6423

REF:6-1132

June 11, 1992

Mr. Julian Ajello
California PUC
505 Van Ness Avenue
San Francisco, California 94102

Dear Mr. Ajello:

Please accept this belated response to your request for review of the February, 1991 draft of the new NARUC Electric Utility Cost Allocation Manual. Our staff recognizes that the final has now been printed. However, the inconsistent treatment of customer related costs in the manual is of concern. In three areas, three different approaches are presented. The first is an energy weighted approach, the second the so-called "minimum-system" or "zero-intercept" method, and the last is the "basic customer" method.

At page 39 of the draft, distribution plant is identified as being customer, demand, and energy-related. That is consistent with the treatment of gas distribution plant by this Commission, where it has ordered that 50% of distribution mains be treated as commodity-related. Our Commission has not made specific findings on electric distribution plant, except as set forth below.

At pages 91-100 of the draft, the minimum-system and zero intercept methods are presented. These methods do not conform to the matrix on page 39, which incorporates an energy component of distribution plant. Unfortunately, these two methods are the only methods presented. These are the two methods our Commission has explicitly rejected.

Finally, at page 148, in the section on marginal cost determination, the "basic customer" method, counting as customer related costs only meters, services, meter reading, and billing, is identified and defended.

Previous drafts included additional methods which are missing from the final version. For example, the 10/31/88 draft discussed at the fall meeting in San Francisco contained a section explicitly setting forth the basic customer method in the embedded cost section. In November of 1988, a section discussing the energy-weighted method was distributed to the Committee.

EXHIBIT
605

Our Commission has been extremely clear about one thing in this area: that the "minimum-distribution" and "minimum-intercept" methods are not acceptable, and that the only costs which should be considered customer-related are the costs of meters, services, meter reading and billing. Our staff believes that is the most common approach taken by Commissions around the country. For example, in Iowa, the administrative rules of the Commission set this forth explicitly, while in Arizona and Illinois, the Commissions have explicitly rejected the minimum-system or minimum-intercept methods in favor of the basic customer approach.

In gas cost of service, our Commission has explicitly found that distribution plant (including service connections) is partially demand-related and partially commodity related, consistent with the matrix on page 39. The corresponding plant on the electric side -- poles, conductors and transformers -- has not been positively resolved in any cases to date. A recently filed electric cost of service case will provide an opportunity for advocates of the demand-only allocation approach and those favoring an energy weighing approach to make their cases before the Commission.

We hope that it is possible to either correct future editions of the Manual to reflect the variety of approaches to determining customer-related costs, or to even issue a correction to this edition.

Please feel free to contact Bruce Folsom at (206) 586-1132 with any questions you may have.

Sincerely,

Paul Curl

Paul Curl
Secretary

DUKE ENERGY KENTUCKY
ELECTRIC CASE NO: 2006-00172

KANSAS GAS & ELECTRIC COMPANY
AS ORDERED, BEFORE CHANGE IN RATES
TEST YEAR ENDING 9/30/2000

CLASSIFICATION OF GROSS PLANT IN SERVICE

		Test Year $	Classif. Basis	Demand %	Energy %	Customer %	Demand $	Energy $	Customer $
1	Intangible Plant	11,986,239	Func. Plt.	95.96%	0.00%	4.04%	11,501,506	0	484,733
2									
3	Production								
4									
5	Steam	577,244,276	Input	100.00%	0.00%	0.00%	577,244,276	0	0
6	Nuclear	1,365,742,982	Input	100.00%	0.00%	0.00%	1,365,742,982	0	0
7	Other	586,300	Input	100.00%	0.00%	0.00%	586,300	0	0
8									
9	Total Production	1,943,573,558					1,943,573,558	0	0
10									
11	Transmission	203,605,710	Input	100.00%	0.00%	0.00%	203,605,710	0	0
12									
13	Distribution:								
14									
15	Land & Land Rights	1,388,683	Dist. Plt.	79.31%	0.00%	20.69%	1,101,395	0	287,288
16	Structure & Improv.	2,898,421	Input	100.00%	0.00%	0.00%	2,898,421	0	0
17	Station Equip.	46,069,070	Input	100.00%	0.00%	0.00%	46,069,070	0	0
18	Poles, Towers & Fix.	84,742,576	Input	100.00%	0.00%	0.00%	84,742,576	0	0
19	Overhead Cond.	71,859,871	Input	100.00%	0.00%	0.00%	71,859,871	0	0
20	Undrground Conduit	29,023,111	Input	100.00%	0.00%	0.00%	29,023,111	0	0
21	Under. Conductor	51,143,261	Input	100.00%	0.00%	0.00%	51,143,261	0	0
22	Transformers	122,728,743	Input	100.00%	0.00%	0.00%	122,728,743	0	0
23	Services	53,960,598	Input	0.00%	0.00%	100.00%	0	0	53,960,598
24	Meters	31,702,202	Input	0.00%	0.00%	100.00%	0	0	31,702,202
25	Install. Cust. Premises	1,776,650	Input	0.00%	0.00%	100.00%	0	0	1,776,650
26	Leased Prop.	5,322,306	Dist. Plt.	79.31%	0.00%	20.69%	4,221,238	0	1,101,068
27	Street Light. & Signal	19,104,586	Input	0.00%	0.00%	100.00%	0	0	19,104,586
28									
29	Total Distribution	521,720,078					413,787,686	0	107,932,392
30									
31	General Plant:								
32									
33	Land, Office & Fixtures	40,916,468	Tot. Payrol	64.01%	23.35%	12.64%	26,190,446	9,552,350	5,173,672
34	Transportation	3,178,722	Tot. Payrol	64.01%	23.35%	12.64%	2,034,686	742,104	401,933
35	Tool, Shop, Lab & Stores	5,908,634	Func. Plt.	95.96%	0.00%	4.04%	5,669,684	0	238,950
36	Power Equipment	455,494	Tot. Payrol	64.01%	23.35%	12.64%	291,560	106,340	57,595
37	Communications	36,073,631	Tot. Payrol	64.01%	23.35%	12.64%	23,090,568	8,421,742	4,561,321
38	Other	184,970	Tot. Payrol	64.01%	23.35%	12.64%	118,398	43,183	23,388
39									
40	Total General	86,717,919					57,395,342	18,865,719	10,456,859
41									
42	TOTAL PLANT IN SERVICE	2,767,603,504					2,629,863,802	18,865,719	118,873,983

Footnote:
Lines 18 thru 22 are classified as 100% demand related

KANSAS POWER & LIGHT COMPANY
AS ORDERED, BEFORE CHANGE IN RATES
TEST YEAR ENDING 9/30/2000

CLASSIFICATION OF GROSS PLANT IN SERVICE

		Test Year $	Classif. Basis	Demand %	Energy %	Customer %	Demand $	Energy $	Customer $
1	Intangible Plant	5,415,664	Func. Plt.	95.21%	0.00%	4.79%	5,156,318	0	259,346
2									
3	Production								
4									
5	Steam	996,815,316	Input	100.00%	0.00%	0.00%	996,815,316	0	0
6	Nuclear	0	Input	100.00%	0.00%	0.00%	0	0	0
7	Other	154,184,314	Input	100.00%	0.00%	0.00%	154,184,314	0	0
8									
9	Total Production	1,150,999,630					1,150,999,630	0	0
10									
11	Transmission	251,412,860	Input	100.00%	0.00%	0.00%	251,412,860	0	0
12									
13	Distribution:								
14									
15	Land & Land Rights	2,961,111	Dist. Plt.	84.42%	0.00%	15.58%	2,499,769	0	461,342
16	Structure & Improv.	6,464,363	Input	100.00%	0.00%	0.00%	6,464,363	0	0
17	Station Equip.	82,015,879	Input	100.00%	0.00%	0.00%	82,015,879	0	0
18	Poles, Towers & Fix.	148,516,109	Input	100.00%	0.00%	0.00%	148,516,109	0	0
19	Overhead Cond.	84,988,245	Input	100.00%	0.00%	0.00%	84,988,245	0	0
20	Undrground Conduit	15,355,331	Input	100.00%	0.00%	0.00%	15,355,331	0	0
21	Under. Conductor	35,987,237	Input	100.00%	0.00%	0.00%	35,987,237	0	0
22	Transformers	141,659,704	Input	100.00%	0.00%	0.00%	141,659,704	0	0
23	Services	39,469,520	Input	0.00%	0.00%	100.00%	0	0	39,469,520
24	Meters	32,142,340	Input	0.00%	0.00%	100.00%	0	0	32,142,340
25	Install. Cust. Premises	3,147,124	Input	0.00%	0.00%	100.00%	0	0	3,147,124
26	Leased Prop.	9,358,603	Dist. Plt.	84.42%	0.00%	15.58%	7,900,530	0	1,458,073
27	Street Light. & Signal	20,283,778	Input	0.00%	0.00%	100.00%	0	0	20,283,778
28									
29	Total Distribution	622,349,344					525,387,168	0	96,962,176
30									
31	General Plant:								
32									
33	Land, Office & Fixtures	58,560,736	Tot. Payrol	53.61%	22.51%	23.88%	31,395,306	13,181,021	13,984,409
34	Transportation	1,641,238	Tot. Payrol	53.61%	22.51%	23.88%	879,893	369,415	391,931
35	Tool, Shop, Lab & Stores	9,982,590	Func. Plt.	95.21%	0.00%	4.79%	9,504,542	0	478,048
36	Power Equipment	1,420,524	Tot. Payrol	53.61%	22.51%	23.88%	761,565	319,736	339,224
37	Communications	30,474,620	Tot. Payrol	53.61%	22.51%	23.88%	16,337,910	6,859,316	7,277,394
38	Other	232,033	Tot. Payrol	53.61%	22.51%	23.88%	124,396	52,227	55,410
39									
40	Total General	102,311,741					59,003,611	20,781,714	22,526,416
41									
42	TOTAL PLANT IN SERVICE	2,132,489,239					1,991,959,587	20,781,714	119,747,938

Footnote:
Lines 18 thru 22 are classified as 100% demand related

DUKE ENERGY KENTUCKY
RESIDENTIAL RATES of RETURN COMPARISON
AT PRESENT AND PROPOSED RATES
TWELVE MONTHS ENDING DECEMBER 31, 2007
ELECTRIC CASE NO: 2006-00172

		COMPANY	12-CP & AVE
PRESENT RATES	**TOTAL**	**RS**	
Net Income	8,045,600	135,024	1,701,824
Rate Base	557,080,702	260,738,880	246,821,369
ROR	1.44%	0.05%	0.69%
IRR	1.00	0.04	0.48
PROPOSED RATES			
Proposed Rev. Increase	66,560,173	32,634,829	32,634,829
Estimated Tax %	38.76%	38.76%	38.76%
Rev Increase less taxes	40,760,046	19,984,881	19,984,881
Proposed Net Income	48,805,646	20,119,905	21,686,705
Rate Base	557,080,702	260,738,880	246,821,369
ROR	8.76%	7.72%	8.79%
IRR	1.00	0.88	1.00
IRR MOVEMENT		0.84	0.53

SOURCE:

Net Income: At present rates; calculated equals Proposed Net Income minus Revenue Increase less taxes
Rate Base: Company cost of service study excel line # 17
Proposed Rev. Increase: Company cost of service study excel line # 45
Estimated Tax %: Company Exhibit PFO-4
Increase less taxes: Proposed Rev Increase minus taxes
Proposed Net Income: Company's cost of service study excel line # 36

DUKE ENERGY KENTUCKY
RATES of RETURN WITH 12-CP AND AVERAGE
TWELVE MONTHS ENDING DECEMBER 31, 2007
ELECTRIC CASE NO: 2006-00172

PRESENT RATES	TOTAL	RS	DS	DT_SEC	DT_PRI
Net Income	8,045,600	1,701,824	5,887,809	597,110	(1,188,371)
Rate Base	557,080,702	246,821,369	142,837,236	87,819,258	47,991,498
ROR	1.44%	0.69%	4.12%	0.68%	-2.48%
IRR	1.00	0.48	2.85	0.47	-1.71

PROPOSED RATES	TOTAL	RS	DS	DT_SEC	DT_PRI
Proposed Rev. Increase	66,560,173	32,634,829	15,746,630	10,176,341	5,298,878
Estimated Tax %	38.76%	38.76%	38.76%	38.76%	38.76%
Rev Increase less taxes	40,760,046	19,984,881	9,642,904	6,231,777	3,244,921
Proposed Net Income	48,805,646	21,686,705	15,530,713	6,828,887	2,056,550
Rate Base	557,080,702	246,821,369	142,837,236	87,819,258	47,991,498
ROR	8.76%	8.79%	10.87%	7.78%	4.29%
IRR	1.00	1.00	1.24	0.89	0.49
IRR MOVEMENT		0.53	-1.61	0.42	2.20

SOURCE:

Net Income: At present rates; calculated equals Proposed Net Income minus Revenue Increase less taxes
Rate Base: Company cost of service study excel line # 17
Proposed Rev. Increase: Company cost of service study excel line # 45
Estimated Tax %: Company Exhibit PFO-4
Increase less taxes: Proposed Rev Increase minus taxes
Proposed Net Income: Company's cost of service study excel line # 36

DUKE ENERGY KENTUCKY
RS REVENUE REQUIREMENTS USING GRADULISM
TWELVE MONTHS ENDING DECEM
ELECTRIC CASE NO: 2006-00172

		12-CP & AVE w/ Company Rev Increase	12-CP & AVE w/ Revised Rev. Increase
PRESENT RATES	**TOTAL**	**RS**	**RS**
Net Income	8,045,600	1,701,824	1,701,824
Rate Base	557,080,702	246,821,369	246,821,369
ROR	1.44%	0.69%	0.69%
IRR	1.00	0.48	0.48
PROPOSED RATES			
Proposed Rev. Increase	66,560,173	32,634,829	23,200,000
Estimated Tax %	38.76%	38.76%	38.76%
Rev Increase less taxes	40,760,046	19,984,881	14,207,190
Proposed Net Income	48,805,646	21,686,705	15,909,015
Rate Base	557,080,702	246,821,369	246,821,369
ROR	8.76%	8.79%	6.45%
IRR	1.00	1.00	0.74
Proposed Residential Revenue Increa		32,634,829	23,200,000
Difference from Company			(9,434,829)

DUKE ENERGY KENTUCKY
DT_SEC REVENUE REQUIREMENTS USING GRADULISM
TWELVE MONTHS ENDING DECEMBER 31, 2007
ELECTRIC CASE NO: 2006-00172

		12-CP & AVE w/ Company Rev Increase	12-CP & AVE w/ Revised Rev. Increase
PRESENT RATES	**TOTAL**	**DT_SEC**	**DT_SEC**
Net Income	8,045,600	597,110	597,110
Rate Base	557,080,702	87,819,258	87,819,258
ROR	1.44%	0.68%	0.68%
IRR	1.00	0.47	0.47
PROPOSED RATES			
Proposed Rev. Increase	66,560,173	10,176,341	8,476,341
Estimated Tax %	38.76%	38.76%	38.76%
Rev Increase less taxes	40,760,046	6,231,777	5,190,732
Proposed Net Income	48,805,646	6,828,887	5,787,843
Rate Base	557,080,702	87,819,258	89,586,077
ROR	8.76%	7.78%	6.46%
IRR	1.00	0.89	0.74
Proposed Residential Revenue Increa		10,176,341	8,476,341
Difference from Company			(1,700,000)