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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

RESPONSES TO THE FIRST DATA REQUEST OF COMMISSION STAFF TO THE KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

1. Refer to the Direct Testimony of Lane Kollen ("Kollen Testimony"), page 6. To the extent not already supplied, provide all calculations, workpapers, and assumptions used by Mr. Kollen to determine his revenue requirement effects shown on page 6.

RESPONSE:

Please refer to Kollen Workpapers folder on attached CD.

2. Refer to the Kollen Testimony, pages 6 and 41 through 49.

a. The first item listed under "Operating Income Issues" on page 6 is "Correct Error in Off-System Sales Margin Roll-in" in the amount of $(2.035) million. Is this item intended to correspond to the jurisdictional amount of $2.036 million on lines 18 and 19 of page 41, which is identified as an error that incorrectly increased O & M expense? If no, explain the response.

b. The second item listed under "Operating Income Issues" on page 6 is "Increase Off-System Sales Margins to 2006 Projection" in the amount of $(5.102) million. Does this item represent the jurisdictional portion of the $5.145 million (Total Company) on line 19 of page 44? If no, explain the response.

c. Page 48 identifies an adjustment of $3.603 million to increase off-system sales margins due to a reallocation of such margins between American Electric Power Company ("AEP") East and AEP West companies. In the question and answer starting on line 9 of page 48, Mr. Kollen states that the Commission should reflect this increase in off-system sales margins in Kentucky Power Company's ("Kentucky Power") base revenue requirement. However, this amount is not in the summary of revenue requirement recommendations on page 6 of the testimony. Should this amount have been included on page 6? Explain the response.

RESPONSE:

a. Yes. The amount on page 41 lines 18-19 is $2.026 million, which is the equivalent of $2.035 million in the revenue requirement once the expense amount is grossed-up for uncollectible accounts.

b. Yes. Mr. Kollen applied a jurisdictional allocation factor of 98.7% (from Section V Workpaper S-4 page 26 line 14) to the $5.145 million and then grossed it up for the uncollectible accounts expense.

c. Yes. Mr. Kollen inadvertently failed to include this amount on his summary table and also in the total dollar amount of reductions to the Company's claimed request in the preceding textual narrative on page 5 line 13. Revised pages 5 and 6 correcting these two errors are attached.

3. Refer to the Kollen Testimony, pages 7 through 15, which includes the recommendation that the Commission accept the proposed Net Congestion Recovery Rider ("NCR") subject to "several" modifications.

a. The first modification, which is identified on page 8, is to include off-system sales margins in the NCR and terminate Kentucky Power's existing System Sales Clause Rider ("SSC"). The second modification, identified on pages 8 and 9, is to change the amounts rolled-in to base rates for financial transmission rights and auction revenue rights revenues, congestion costs, and system sales margins, based on KIUC's proposed amounts for these items. These appear to be the only two modifications to the proposed NCR identified in the Kollen Testimony. Are there only two modifications rather than "several" modifications? Explain the response.

b. Starting at line 11 on page 8 and continuing through line 12 of page 15, Mr. Kollen discusses KIUC's proposed treatment of off-system sales margins versus the current treatment under the SSC. However, there is no discussion of the merits of the NCR or why he recommends that it be accepted by the Commission, aside from his discussion of capturing greater off-system sales margins for the benefit of ratepayers. State all other reasons, if any, for why Mr. Kollen favors the NCR. Explain the response.

RESPONSE:

a. Mr. Kollen identified the following modifications to the Company's proposed NCR: 1) include off-system sales margins in excess of amount included in base rates, 2) eliminate any sharing of off-system sales margins currently reflected in the SSC, 3) revise the off-system sales margins included in base rates from the amounts proposed by the Company, 4) revise the net congestion costs included in base rates from the amounts proposed by the Company (this adjustment was addressed by KIUC witness Mr. Baron).

c. Mr. Kollen believes the NCR should be adopted, with the modifications proposed by KIUC, because the implicit congestion costs and FTR and ARR revenues in the rate effective period are inherently volatile and there is little experience with these costs and revenues at this time. Thus, the NCR is an equitable means of minimizing risk to both the Company and the ratepayers of changes in these costs and revenues compared to the amounts included in base rates. In addition, Mr. Kollen's proposal is an improvement over the Company's proposal because it consolidates the SSC and NCR, thus eliminating the SSC rider in exchange for implementing the NCR rider. The elimination of the SSC also improves administrative efficiencies for the Company and Staff because the SSC filings are made monthly and the NCR filings will be made annually.

4. Refer to the Kollen Testimony, pages 15 through 20.

a. Does Mr. Kollen agree that Kentucky Power's proposed roll-in of its environmental surcharge into base rates is consistent with the surcharge formula "CRR – BRR," where the two revenue requirements are netted before the surcharge factor is determined? Explain the response.

b. Provide the calculations used to determine the $6.7 million amount Mr. Kollen references on page 19.

c. Provide the base period jurisdictional environmental surcharge factor Mr. Kollen would propose for Kentucky Power's environmental surcharge roll-in. Include all calculations, workpapers, and assumptions used to determine the factor.

RESPONSE:

a. Yes, although this formula and the BRR term have never reflected an ECR roll-in. This formula was established by the Commission to subtract the amount of environmental costs included in base rates prior to the implementation of the surcharge. However, it is essential that this formula be modified now if the Commission implements a roll-in in conjunction with this base rate proceeding to reflect the jurisdictional revenue recovered through base rates. Given that there has been no prior ECR roll-in to base rates, the BRR term reflects only the environmental revenue requirement included in the Case No. 91-089 base rates. The BRR term is fixed at the amount included in the Case No. 91-089 base rates, but does not reflect the amount of base rate recovery because sales have grown significantly from the sales used to set rates in Case No. 91-089.

In addition, the BRR term is used to reduce the total Company ECR revenue requirement, before the application of the jurisdictional allocation factor. This has the effect of overstating the jurisdictional ECR factor.

To illustrate the problems with the CRR-BRR formula even as it currently exists, which are magnified if there is an ECR roll-in, consider the following example. The ECR total Company revenue requirement (CRR) is $100. The BRR is $10. Since Case No. 91-089, sales have increased by a factor of 2. As such, the environmental recovery through base rates really is $20, not $10. Assume further that the base rate retail jurisdictional factor in Case No. 91-089 was 99% and the ECR jurisdictional factor currently is 65%. Under the CRR-BRR formula, the retail jurisdictional ECR revenue requirement used to develop the ECR factor would be $58.50 (($100 – $10) * .65)). However, the proper ECR recovery should be $45.20 (($100 * .65) – ($20 *.99)), not $58.50.

These problems in the current ECR methodology have not had a significant dollar impact to date. However, with the Company's proposed ECR roll-in, the existing insignificant problem will be magnified into a multi-million dollar problem, which Mr. Kollen estimated at approximately $6.7 million on an annual basis currently and which will continue to grow each year as sales and revenues continue to grow.

Mr. Kollen proposes that if the Commission approves the proposed ECR roll-in that it also modify the existing ECR methodology to reflect the roll-in the same manner that it uses to reflect the roll-ins for LG&E and KU. This methodology originated with the Staff and is based on the concept of revenue neutrality, i.e., the total amount recovered from ratepayers should be the same regardless of whether it is recovered through base rates or through the ECR. Mr. Kollen has attached a copy of the Staff's white paper dated June 1, 2001 wherein it describes the methodology ultimately adopted by the Commission for LG&E and KU roll-ins. This methodology specifically addresses and resolves both problems identified by Mr. Kollen with respect to the Company's proposed ECR roll-in methodology. It does so by first computing a jurisdictional ECR factor, which is based on the total Company ECR revenue requirement before roll-ins, and then subtracts a jurisdictional ECR roll-in factor, which is based on the ECR revenue requirement rolled-in to base rates divided by the retail revenues at the time of the roll-in.

Finally, if the Commission does not modify the Company's proposed ECR roll-in methodology so that it is revenue neutral and does not result in a "back-door" rate ECR rate increase, then it should defer the issue, reject the ECR roll-in at this time and in this proceeding, and subsequently address it in conjunction with the next ECR 2 year review.

b. The computation is described on page 19 lines 1-4 of Mr. Kollen's Testimony.

c. The factor will be a function of the retail revenues including the final base revenue increase adopted by the Commission. The formula would be the jurisdictional ECR revenue requirement rolled-in to base rates divided by the per books retail revenues for the test year, excluding ECR revenues and all other revenues not included in the computation of the ECR factor, increased by the base revenue increase adopted by the Commission. Mr. Kollen cannot compute the factor until the Commission determines the base revenue increase.

5. Refer to the Kollen Testimony, pages 23 and 24. Mr. Kollen proposes to adjust both Kentucky Power's rate base and capitalization to reflect the use of 13-month average balances for non-fuel materials and supplies. Was Mr. Kollen aware that the Commission typically uses 13-month average balances for these accounts in the determination of the rate base, but does not make a corresponding adjustment to capitalization? Explain the response.

RESPONSE:

No. Mr. Kollen was not aware that the Commission made such a distinction based on his review of prior Commission Orders for Kentucky Power Co. Regardless of whether the Commission has made such a distinction in the past, such an adjustment should be made to both capitalization and rate base. The capitalization at June 30, 2005 necessarily reflects the Company's investment in M&S or any other rate base component at June 30, 2005. If it makes sense to adjust the M&S in rate base to reflect a 13 month average, then it makes sense for the same reasons to adjust capitalization by the same amount. The reason is that capitalization represents the amount of investment in rate base and would be equivalent in a perfect ratemaking world. If a portion of that investment varies significantly from month to month, then that should be reflected in the capitalization upon which the Company is entitled to earn a rate of return.

Normally, changes in M&S, prepayments, and other working capital items vary throughout the test year and the effect of these variations is captured in one of two places for ratemaking purposes. The first place is in the amount of short term debt included in capitalization, for which the Commission does use a 13 month average (see Section V Workpaper S-3 page 2 of the Company's filing). The second place is in the amount of interest income from short term investments included in revenues, which inherently reflects a 365 day average because short term interest income is earned on a daily basis. Mr. Kollen made his proposed adjustment to M&S as a reduction to short term debt, which is consistent with the Commission's use of a 13 month average for that component of capitalization.

6. Refer to the Kollen Testimony, pages 31, 32, and 52.

a. In Mr. Kollen's opinion does Kentucky Power's proposed vegetation management program adjustment constitute a known and measurable adjustment? Explain the response.

b. In Mr. Kollen's opinion does Kentucky Power's proposed vegetation management program adjustment reflect the correct application of the matching principle for rate-making purposes? Explain the response.

RESPONSE:

a. If the Commission allows a certain dollar amount of additional expense and capitalization with the requirement that the Company expend these amounts, then by definition, the amount is known and measurable.

b. No. There are two problems. First, the amounts proposed will not be incurred fully until nearly four years after the end of the Company's test year by virtue of the fact that the Company's request is based on three years of projected expenditures, all of which will be incurred after the effective date of the Order in this proceeding. Most other costs reflected in the proposed revenue requirement are tied to the historic test year ending June 30, 2005, albeit with certain adjustments to reflect costs and revenues projected in the rate effective period. Second, the Commission's normal practice is that costs first must be incurred and then they are subject to recovery through base rates.

7. Refer to the Kollen Testimony, page 34. Mr. Kollen states that because Kentucky Power's minimum pension funding liability does not reflect additional pension contributions made prior to June 30, 2005, it is necessary to reduce all capitalization proportionately by the amount of the additional pension funding. Would Mr. Kollen's approach produce the same effect as having the minimum pension funding liability recalculated as of June 30, 2005? Explain the response.

RESPONSE:

No. If the minimum pension funding liability was recalculated as of June 30, 2005, it would affect only common equity. Mr. Kollen's adjustment affects all capitalization components because the additional funding was not provided only by common equity, but presumably was provided proportionately by all capitalization components.

8. Refer to the Kollen Testimony, pages 35 through 40, 50, and 51.

a. Explain how Mr. Kollen determined that Kentucky Power has included the regional transmission organization formation costs ("RTO formation costs") in its proposed capitalization?

b. Would Mr. Kollen agree that the recognition of the RTO formation costs as a regulatory asset results in a rate base item rather than a capitalization item? Explain the response.

c. In previous Commission decisions, the amortization of a regulatory asset has been included for rate-making purposes, but the unamortized balance of the regulatory asset has not been included in the determination of the utility's rate base. If the Commission concludes that the amortization of the RTO formation costs should be included for rate-making purposes, would Mr. Kollen recommend the unamortized balance of the regulatory asset be included or excluded from the determination of Kentucky Power's rate base? Explain the response.

RESPONSE:

a. If the Company had not deferred the RTO formation costs, it would have expensed them. This would have resulted in lower income, lower retained earnings, lower common equity, and lower capitalization. Mr. Kollen reduced common equity by the after tax effect of the amounts that would have been expensed absent deferral.

b. No. It is not an either or proposition. The deferral of these costs certainly resulted in an increase in capitalization compared to expensing them. Thus, the RTO formation costs necessarily are both a rate base item and a capitalization item.

c. Mr. Kollen disagrees with the premise of the question. If any costs were deferred, then those costs are reflected in capitalization. No explicit ratemaking adjustment is necessary to include them in capitalization; they are inherently included in the per books capitalization amounts. If the Commission excludes a cost from rate base, it also should exclude the cost from capitalization as a matter of consistency, particularly since capitalization, not rate base, is the basis for the return component of the Company's revenue requirement.

9. Refer to the Kollen Testimony, pages 49 and 50.

a. Provide the basis for the statement at line 1 of page 50 that short-term interest rates have risen significantly since the beginning of the test year.

b. Does Mr. Kollen agree with the interest rates proposed by Kentucky Power for long-term debt, short-term debt, and accounts receivable financing? Explain the response.

RESPONSE:

a. Please refer to short term interest rates in the following table.

Historical Short Term Interest Rates
From July 2004 to Most Recently Available
Source: Federal Reserve Board Website

	Prime Rate	Federal Funds Effective Rate	Non-Financial Commercial Paper	1 Year Interest Rate Swaps	6-Month T-Bills Secondary Market
Jul-04	4.25%	1.26%	1.50%	2.34%	1.66%
Aug-04	4.43%	1.43%	1.62%	2.28%	1.72%
Sep-04	4.58%	1.61%	1.75%	2.38%	1.87%
Oct-04	4.75%	1.76%	1.95%	2.48%	2.00%
Nov-04	4.93%	1.93%	2.18%	2.82%	2.27%
Dec-04	5.15%	2.16%	2.34%	3.02%	2.43%
Jan-05	5.25%	2.28%	2.53%	3.22%	2.61%
Feb-05	5.49%	2.50%	ND	3.39%	2.77%
Mar-05	5.58%	2.63%	2.82%	3.70%	3.00%
Apr-05	5.75%	2.79%	2.97%	3.74%	3.05%
May-05	5.98%	3.00%	3.09%	3.76%	3.08%
Jun-05	6.01%	3.04%	3.27%	3.82%	3.13%
Jul-05	6.25%	3.26%	3.47%	4.08%	3.42%
Aug-05	6.44%	3.50%	3.64%	4.27%	3.66%
Sep-05	6.59%	3.62%	3.72%	4.23%	3.67%
Oct-05	6.75%	3.78%	4.01%	4.58%	3.99%
Nov-05	7.00%	4.00%	4.23%	4.79%	4.15%
Dec-05	7.15%	4.16%		4.84%	4.18%

All rates above represent the average monthly rates incurred for each month.

b. Mr. Kollen has no stated disagreement with those interest rates. However, Mr. Kollen has stated that if the Commission allows the Company to update its costs of these capitalization components, then it also should require the Company to update and annualize the interest income on short term investments included in revenues. Conceptually, the alternative is for the Commission to remove short term interest from revenues and include short term investments as a negative capitalization component and amount using the updated interest rates as the cost of this capitalization component.

10. Refer to the Kollen Testimony, pages 52 through 55.

a. Was Mr. Kollen aware that Kentucky Power's parent, AEP, announced on January 4, 2006 that it had fully funded its pension liabilities for 2005?

b. Explain the impact, if any, AEP's decision to fully fund its pension program has upon Mr. Kollen's proposed pension adjustments.

RESPONSE:

a. Yes.

b. None. Mr. Kollen's adjustment reflects the funding situation at June 30, 2005, which is the date at which capitalization is determined, not December 31, 2005.

11. Refer to the Kollen Testimony, pages 57 through 69.

a. Concerning the inclusion of demolition costs for the Big Sandy plant, was Mr. Kollen aware that Kentucky Power had included such costs in its previous depreciation study? Explain the response.

b. Identify which set of his proposed depreciation rates Mr. Kollen is recommending the Commission use to determine the revenue requirements in this case.

c. Concerning the retirement of Big Sandy Unit 1 in 2015, would Mr. Kollen agree that the environmental requirements of the Clean Air Interstate Rule could make the continued operation of Big Sandy Unit 1 uneconomical? Explain the response.

d. Explain how Mr. Kollen determined that 5 years was an appropriate extension of the retirement date for Big Sandy Unit 1.

e. On page 66, Mr. Kollen recommends using all salvage and removal data in the determination of the appropriate level of net negative salvage to include in Kentucky Power's proposed depreciation rates. The Attorney General's ("AG") witness, Michael J. Majoros, Jr., proposes that the cost of removal factors should be based on the most recent 5-year average of actual cost of removal experience. What is Mr. Kollen's opinion of Mr. Majoros's recommendation?

RESPONSE:

a. Yes. The demolition cost estimate was based on a Sargent and Lundy study.

b. The depreciation rates appearing on the KIUC Schedule I attached as page two of Exhibit___(LK-14) represents Mr. Kollen's proposed functional depreciation rates.

c. Any environmental requirements have the potential to make the continued operation of a unit uneconomic. However, the Company's plans currently are to retrofit Big Sandy 1 and to continue operating the unit unless and until continued operation is uneconomic.

d. Mr. Kollen believes that 5 years is the minimum reasonable based on the Company's planned environmental retrofits and apparent intention to continue operating the unit unless and until it is uneconomic to do so.

f. Mr. Kollen agrees with Mr. Majoros' recommendation from the perspective of "capping" the amount of net negative salvage to be recovered prospectively through the depreciation rates. The basis for Mr. Kollen's and Mr. Majoros' recommendations are different and are not inconsistent. Mr. Kollen proposed that all available data be used as the basis for projecting future net negative salvage and he did not review or consider the substantial over-recovery to date of the net negative salvage. Mr. Majoros proposed a top down adjustment to limit the net negative salvage to an average of the most recent five years compared to the Company's request given the substantial over-recovery to date of the net negative salvage. He then reflected this top-down adjustment in his proposed depreciation rates.

12. Refer to the Kollen Testimony, pages 74 through 76.

a. Mr. Kollen proposes to reflect the reduction in the Kentucky corporate income tax rate effective January 1, 2007. Will the Internal Revenue Code Section 199 ("Section 199") deduction percentage for 2007 be 3 percent? Explain the response.

b. If the Section 199 deduction percentage changes in 2007, would Mr. Kollen agree the change in this deduction percentage should be recognized? If yes, what would be the impact of this change on Mr. Kollen's recommendations?

RESPONSE:

a. Yes. This is a matter of federal tax law. The 6% deduction will be in effect from January 1, 2007 through December 31, 2009. On January 1, 2010, the deduction will increase to 9%.

b. Yes. The revenue requirement effect due to the change in federal and state income taxes will be a reduction of $0.368 million. Please refer to the attached schedule.

13. To recognize that the Section 199 deduction applies only to production taxable income, Mr. Kollen proposes to allocate the common equity portion of Kentucky Power's capitalization between production and non-production components.

a. While it is the return on the common equity portion of capitalization that is grossed up for income taxes in determining revenue requirements, would Mr. Kollen agree that his allocation approach, shown in Exhibit LK-4, in effect assumes that production activity is financed solely by common equity? Explain the response.

b. Explain why the allocation percentage should be based on rate base.

c. Would using an allocation percentage based on the ratio of production plant to total utility plant be a reasonable approach? Explain the response.

d. In order to reflect the Section 199 deduction for production activity, would an allocation of the total revenue deficiency between production and non-production and the application of the appropriate gross revenue conversion factor produce the same effect as that proposed by Mr. Kollen? Would such an approach be reasonable? Explain the responses.

RESPONSE:

a. No. All production activity is financed proportionately by all capitalization components. Mr. Kollen could have allocated all capitalization components between production and non-production, but that would not affect the amount of the §199 deduction because the GRCR would not have changed for non-equity capitalization components. Instead, Mr. Kollen took the common equity portion of the capitalization supporting the production investment and then computed the reduction in the gross revenue conversion factor on that limited portion of the Company's capitalization investment. In essence, the result of this approach is to multiply the common equity ratio times the production ratio times the difference between the GRCF before the §199 deduction and the GRCR after the §199 deduction.

b. Rate base is the best measure of the investment components underlying the capitalization used to finance that investment and upon which the Commission allows the Company to earn a rate of return.

c. It would be another approach, but one which is unnecessarily less precise than that proposed by Mr. Kollen.

d. No. The only source for taxable income, and thus, the §199 deduction, is from the equity return. Taxable income is not created from recovery of expenses. For example, $100 in expenses results in $100 of revenues. Thus, there is no taxable income from the recovery of expenses. As such, for ratemaking purposes, all components of the ratemaking formula drop out of the taxable income computation except for the return on common equity. The approach suggested in the question would not be reasonable because there is no tie to the underlying basis for the §199 deduction.

14. Refer to the Kollen Testimony, Exhibits LK-10 through LK-14.

a. Explain why the amounts shown on the first page of each exhibit under the column "KIUC Adjusted Annualized Depreciation" do not agree with the "Recommended Annual Amount" shown on Schedule I of each exhibit. If necessary, provide revisions to the exhibits reflecting the correct depreciation expense.

b. Prepare a revised first page and Schedule I for each exhibit reflecting the inclusion of the $32,000,000 in demolition costs associated with the Big Sandy plant.

RESPONSE:

a. The Schedule Is for each exhibit are based on the worksheet used in Mr. Henderson's depreciation study that determined depreciation rates and applied them against 12/31/04 balances to determine the "Recommended Annual Amount." These Schedule Is were utilized to determine the depreciation rates that in turn should be applied to test year plant balances to compute the test year depreciation expense. The "KIUC Adjusted Annualized Depreciation" reflects the depreciation expense computed using the depreciation rates from the Schedule Is applied to the test year plant balances provided in the Company's filing, not the 12/31/04 balances used to derive the depreciation rates.

b. See attached revised exhibit pages in the attached Excel file entitled "Revised Exhibits with Demolition Costs Included."

15. Refer to the Kollen Testimony, Exhibits LK-15 and LK-16.

a. Would Mr. Kollen agree that in previous rate cases, the Commission has included the PSC Assessment in the gross revenue conversion factor? Explain the response.

b. Would Mr. Kollen agree that the PSC Assessment should be recognized in the gross revenue conversion factor? Explain the response.

c. Provide revised Exhibits LK-15 and LK-16 that include the PSC Assessment in the determination of the gross revenue conversion factor.

RESPONSE:

a. No. Mr. Kollen is not aware that the Commission has included the PSC assessment in the gross revenue conversion factor based on his review of prior Commission Orders for Kentucky Power Co.

b. No. The PSC assessment is not a direct function of the Company's revenues which should be included in the GRCF. In addition, the Company already has included the annualized PSC assessment amount for the July 2005 through June 2006 period in its filing. Mr. Kollen's understanding is that this is a fixed amount for this period and will not vary based on the Commission's decision on the revenue requirement in this proceeding.

c. Mr. Kollen is not able to provide the requested revised exhibits. See the response to part (b) of this Item.

16. Refer to the Kollen Testimony, Exhibit LK-17. Provide the calculations used to determine the "Production Only %" figures shown in this exhibit. Include all supporting workpapers and assumptions used in the calculations.

RESPONSE:

Please refer to the electronic workpapers provided in response to Item 1.

17. Refer to the Direct Testimony of Stephen J. Baron ("Baron Testimony"), pages 10 through 13, and the Testimony of David H. Brown Kinloch ("Kinloch Testimony"), pages 3 through 10, filed on behalf of the AG.

a. Mr. Baron states that Kentucky Power filed a 12 Coincident Peak ("12 CP") cost of service study ("COSS") in this case. He also states that he independently developed a 12 CP COSS, using inputs provided by Kentucky Power, which produced results identical to Kentucky Power's COSS. Mr. Kinloch contends that because of the "black box" nature of the TACOS Gold software used by Kentucky Power to produce its COSS, he was unable to verify, produce, or replicate the calculations performed in Kentucky Power's COSS. Does Mr. Baron share any of Mr. Kinloch's concerns about Kentucky Power's COSS and the Commission's reliance on it in this case? Explain the response.

b. On page 9 of his testimony, Mr. Kinloch cites the requirement for a COSS contained in 807 KAR 5:001, Section 10(6)(u), which requires "a cost of service study based on a methodology generally accepted within the industry." In Mr. Baron's opinion is the 12 CP method a method that is generally accepted within the electric industry? Explain the response.

RESPONSE

a. As discussed in Mr. Baron's direct testimony, he completely replicated Kentucky Power's 12 CP cost of service study, using the data provided by the Company (which was made available to all parties in this case). Based on Mr. Baron's analysis, he believes that the Company's 12 CP cost of service study was developed in a reasonable manner and follows standard methodologies used in the electric utility industry. These methodologies are generally accepted by state regulatory commissions. As such, Mr. Baron does not agree with any of the concerns raised by Mr. Kinloch about the Kentucky Power cost of service study and further recommends that the Commission relies on this study, as well as the other studies developed by Mr. Baron in support of KIUC's recommendations in this case on the allocation of the Commission approved revenue increase to rate classes.

b. Yes. See response to part (a) of this question. The 12 CP cost of service study filed in this case by Kentucky Power and replicated by Mr. Baron utilizes generally accepted allocation methodologies that are presented in the NARUC Electric Utility Cost Allocation Manual. The 12 CP study is a very common electric utility cost allocation methodology, based on Mr. Baron's 31 years in the electric utility industry.

18. Refer to the Baron Testimony, pages 12 and 13. Mr. Baron states that Kentucky Power's COSS "is a reasonable basis to inform the Commission regarding the relationship between current rates and cost of service for each of the Company's rate schedules." On pages 10 through 12 of his testimony, Mr. Kinloch recommends that the Commission adopt the class allocation percentages included in the settlement agreement it approved in Kentucky Power's last rate case.[1] What is Mr. Baron's opinion on this recommendation? Explain the response.

RESPONSE

Mr. Baron strongly disagrees with Mr. Kinloch's recommendation in this case to allocate the approved revenue increase using allocation percentages that were adopted in a settlement agreement, <u>in a case that is 25 years old</u>. There is absolutely no basis to support Mr. Kinloch's recommendation. First it is generally inappropriate to rely on the results of a settlement agreement as a litigation basis. Mr. Kinloch has presented no evidence that his allocation recommendation is just and reasonable in this case. It is clear that with the passage of 25 years, the allocation factors can no longer be deemed just and reasonable. More significantly, since there is reasonable evidence available to the Commission in this case on the cost responsibility of providing service to each rate class, there is no reason to give any recognition to Mr. Kinloch's out of date allocation percentages. His recommended percentage rate increase for the residential class is $20,787,865, assuming, for illustration, that the Company's full revenue increase of $64.8 million is approved. This produces a 15.98% rate increase, compared to the system average increase of 19.21%. Mr. Kinloch's recommendation is entirely unreasonable, in light of the cost of service study results showing that the residential class is producing a negative rate of return on rate base.

19. Refer to the Direct Testimony of Richard A. Baudino ("Baudino Testimony"), page 18.

a. For each company in the comparison group, provide the percentage of total revenues derived from regulated electric operations, regulated natural gas operations, if any, and non-regulated operations.

b. Kentucky Power does not operate any nuclear generation facilities. For each company in the comparison group, provide the percentage of generation capacity derived from nuclear operations.

RESPONSE

a. According to the December 2005 issue of the AUS Monthly Utility Report, the percentage of regulated electric revenues for the companies in the comparison group are as follows:

1. Avista Corporation 53%

[1] Case No. 1991-00066, Application of Electric Rates of Kentucky Power Company, Order dated October 28, 1991.

2.	Cleco Corporation	99%
3.	DPL, Inc.	99%
4.	Duquesne Light Holdings	84%
5.	Empire District Electric	93%
6.	Energy East Corp.	59%
7.	First Energy Corporation	73%
8.	Green Mountain Power	100%
9.	Hawaiian Electric Industries	82%
10.	Northeast Utilities	63%
11.	Pinnacle West Capital Corp.	71%
12.	PNM Resources	74%
13.	PPL Corporation	68%
14.	Progress Energy	77%
15.	Puget Energy	61%
16.	UniSource Energy Corp.	87%

Mr. Baudino does not have information on the percentages of revenues from regulated natural gas operations and non-regulated operations.

b. According to the Value Line Investment Survey reports that Mr. Baudino used in preparing his analysis, the percentage of nuclear generation for each company in the comparison group is as follows:

1.	Avista Corporation	0%
2.	Cleco Corporation	0%
3.	DPL, Inc.	0%
4.	Duquesne Light Holdings	No generation
5.	Empire District Electric	0%
6.	Energy East Corp.	Not listed
7.	First Energy Corporation	Not listed
8.	Green Mountain Power	36.9%
9.	Hawaiian Electric Industries	0%
10.	Northeast Utilities	0%
11.	Pinnacle West Capital Corp.	14%
12.	PNM Resources	28%
13.	PPL Corporation	Not listed
14.	Progress Energy	43%
15.	Puget Energy	0%
16.	UniSource Energy Corp.	0%

20. Refer to the Baudino Testimony, page 21. Provide a copy of the material referenced in Footnote 5.

RESPONSE

Please refer to the attached documents.

21. Refer to the Baudino Testimony, page 30. Mr. Baudino discusses his use of both the 20-year Treasury bond and the 5-year Treasury note in developing his risk free rate for the Capital Asset Pricing Model ("CAPM"). While the 20-year bond does carry interest rate risk, would Mr. Baudino agree that its use better matches the long-term horizon of a stock?

RESPONSE

Yes.

22. Refer to the Baudino Testimony, page 33. Mr. Baudino states that he did not take his CAPM results into consideration when developing his recommendation because he believes that the CAPM results are overstated. Provide an estimate of the amount of overstatement Mr. Baudino believes is in the CAPM results.

RESPONSE

Mr. Baudino's statement on page 33, lines 16 – 17, was based on the results of his DCF analysis. The CAPM results fell within a range of 8.98% - 12.56%. Thus, based on my Baudino's recommendation of 9.35%, the potential overstatement from the CAPM could be as great as 3.21%, or 321 basis points.

23. Refer to the Baudino Testimony, page 34. Provide a copy of the study referenced in Footnote 9.

RESPONSE

Please refer to the attached document.

24. Refer to the Baudino Testimony, Exhibit RAB-4, page 2 of 3. Explain why Mr. Baudino uses a 3-year average Earnings per Share ("EPS") in the calculation rather than the EPS for the most current year.

RESPONSE

Mr. Baudino used a 3-year historical average of EPS as the starting point of his compound growth calculation because historical EPS numbers tend to fluctuate from year to year. The averaging process smoothes out these yearly fluctuations and provides a more reasonable starting point for the compound growth calculation than the most current year.

ATTACHMENT TO RESPONSE NO. 1
(DEPRECIATION WORKPAPERS)

Kentucky Power Company
Summary - KIUC Depreciation Expense Adjustments
For the Test Year Ended 6/30/05

	Total
1 - Remove $32,000,000 million demolition costs from computation of net salvage costs.	(1,409,132)
2 - Correct Account #312 Interim Retirements by removing additional retirements in 2007 and 2009.	(272,735)
3 - Use full history of additions and retirements to determine interim retirement rate for Big Sandy Assets instead of last 30 years.	(909,118)
4 - Use of Net Salvage percentages on overall functional account basis instead of judgement percentages based on retirements.	(1,352,141)
5 - Use full history for all Net Salvage percentages instead of just the 15 year period of 1990-2004.	(2,694,468)
6 - Delay retirement of Big Sandy Unit I five years from 2015 until 2020.	(90,912)
Total Adjustments	(6,728,507)

Kentucky Power Company
Depreciation Expense Adjustments
For the Test Year Ended 6/30/05

	Electric Plant In Service as of 6/30/2005	New Annual Rate Per KPCO Filing	Annualized Depreciation Per KPCO Filing	New Annual Rate With Adjustments Listed	KIUC Adjusted Annualized Depreciation	KIUC Depreciation Adjustment
Production Steam	459,150,369	0.0357	16,391,668	0.0326	14,968,302	(1,423,366)
Transmission	385,378,899	0.0271	10,443,768	0.0271	10,443,768	-
Distribution	445,002,421	0.0364	16,198,088	0.0364	16,198,088	-
General Plant	29,575,208	0.0531	1,570,444	0.0531	1,570,444	-
	1,319,106,897		44,603,968		43,180,602	(1,423,366)

Allocation Factor - GP-TOT	0.990
Total Depreciation Expense Reduction	(1,409,132)
Total of Prior Depreciation Adjustments	0
Total of Depreciation Adjustment 1	(1,409,132)

Adustments Included:
1 - Remove $32,000,000 demolition costs from computation of net salvage costs.

Kentucky Power Company
Depreciation Expense Adjustments
For the Test Year Ended 6/30/05

	Electric Plant In Service as of 6/30/2005	New Annual Rate Per KPCO Filing	Annualized Depreciation Per KPCO Filing	New Annual Rate With Adjustments Listed	KIUC Adjusted Annualized Depreciation	KIUC Depreciation Adjustment
Production Steam	459,150,369	0.0357	16,391,668	0.0320	14,692,812	(1,698,856)
Transmission	385,378,899	0.0271	10,443,768	0.0271	10,443,768	-
Distribution	445,002,421	0.0364	16,198,088	0.0364	16,198,088	-
General Plant	29,575,208	0.0531	1,570,444	0.0531	1,570,444	-
	1,319,106,897		44,603,968		42,905,112	(1,698,856)
			Allocation Factor - GP-TOT			0.990
			Total Depreciation Expense Reduction			(1,681,868)
			Total of Prior Depreciation Adjustments			(1,409,132)
			Total of Depreciation Adjustment 2			(272,735)

Adustments Included:
1 - Remove $32,000,000 million demolition costs from computation of net salvage costs.
2 - Correct Account #312 Interim Retirements by removing additional retirements in 2007 and 2009.

Kentucky Power Company
Depreciation Expense Adjustments
For the Test Year Ended 6/30/05

	Electric Plant In Service as of 6/30/2005	New Annual Rate Per KPCO Filing	Annualized Depreciation Per KPCO Filing	New Annual Rate With Adjustments Listed	KIUC Adjusted Annualized Depreciation	KIUC Depreciation Adjustment
Production Steam	459,150,369	0.0357	16,391,668	0.0300	13,774,511	(2,617,157)
Transmission	385,378,899	0.0271	10,443,768	0.0271	10,443,768	-
Distribution	445,002,421	0.0364	16,198,088	0.0364	16,198,088	-
General Plant	29,575,208	0.0531	1,570,444	0.0531	1,570,444	-
	1,319,106,897		44,603,968		41,986,811	(2,617,157)
			Allocation Factor - GP-TOT			0.990
			Total Depreciation Expense Reduction			(2,590,986)
			Total of Prior Depreciation Adjustments			(1,681,868)
			Total of Depreciation Adjustment 3			(909,118)

Adustments Included:
1 - Remove $32,000,000 million demolition costs from computation of net salvage costs.
2 - Correct Account #312 Interim Retirements by removing additional retirements in 2007 and 2009.
3 - Use full history of additions and retirements to determine interim retirement rate for Big Sandy Assets instead of last 30 years.

Kentucky Power Company
Depreciation Expense Adjustments
For the Test Year Ended 6/30/05

	Electric Plant In Service as of 6/30/2005	New Annual Rate Per KPCO Filing	Annualized Depreciation Per KPCO Filing	New Annual Rate With Adjustments Listed	KIUC Adjusted Annualized Depreciation	KIUC Depreciation Adjustment
Production Steam	459,150,369	0.0357	16,391,668	0.0299	13,728,596	(2,663,072)
Transmission	385,378,899	0.0271	10,443,768	0.0261	10,058,389	(385,379)
Distribution	445,002,421	0.0364	16,198,088	0.0343	15,263,583	(934,505)
General Plant	29,575,208	0.0531	1,570,444	0.0531	1,570,444	-
	1,319,106,897		44,603,968		40,621,012	(3,982,956)

Allocation Factor - GP-TOT	0.990
Total Depreciation Expense Reduction	(3,943,127)
Total of Prior Depreciation Adjustments	(2,590,986)
Total of Depreciation Adjustment 4	(1,352,141)

Adustments Included:
1 - Remove $32,000,000 million demolition costs from computation of net salvage costs.
2 - Correct Account #312 Interim Retirements by removing additional retirements in 2007 and 2009.
3 - Use full history of additions and retirements to determine interim retirement rate for Big Sandy Assets instead of last 30 years.
4 - Use of Net Salvage percentages on overall functional account basis instead of judgement percentages based on retirements.

Kentucky Power Company
Depreciation Expense Adjustments
For the Test Year Ended 6/30/05

	Electric Plant In Service as of 6/30/2005	New Annual Rate Per KPCO Filing	Annualized Depreciation Per KPCO Filing	New Annual Rate With Adjustments Listed	KIUC Adjusted Annualized Depreciation	KIUC Depreciation Adjustment
Production Steam	459,150,369	0.0357	16,391,668	0.0295	13,544,936	(2,846,732)
Transmission	385,378,899	0.0271	10,443,768	0.0213	8,208,571	(2,235,198)
Distribution	445,002,421	0.0364	16,198,088	0.0328	14,596,079	(1,602,009)
General Plant	29,575,208	0.0531	1,570,444	0.0524	1,549,741	(20,703)
	1,319,106,897		44,603,968		37,899,327	(6,704,641)
			Allocation Factor - GP-TOT			0.990
			Total Depreciation Expense Reduction			(6,637,595)
			Total of Prior Depreciation Adjustments			(3,943,127)
			Total of Depreciation Adjustment 5			(2,694,468)

Adustments Included:
1 - Remove $32,000,000 million demolition costs from computation of net salvage costs.
2 - Correct Account #312 Interim Retirements by removing additional retirements in 2007 and 2009.
3 - Use full history of additions and retirements to determine interim retirement rate for Big Sandy Assets instead of last 30 years.
4 - Use of Net Salvage percentages on overall functional account basis instead of judgement percentages based on retirements.
5 - Use full history for all Net Salvage percentages instead of just the 15 year period of 1990-2004.

Kentucky Power Company
Depreciation Expense Adjustments
For the Test Year Ended 6/30/05

	Electric Plant In Service as of 6/30/2005	New Annual Rate Per KPCO Filing	Annualized Depreciation Per KPCO Filing	New Annual Rate With Adjustments Listed	KIUC Adjusted Annualized Depreciation	KIUC Depreciation Adjustment
Production Steam	459,150,369	0.0357	16,391,668	0.0293	13,453,106	(2,938,562)
Transmission	385,378,899	0.0271	10,443,768	0.0213	8,208,571	(2,235,198)
Distribution	445,002,421	0.0364	16,198,088	0.0328	14,596,079	(1,602,009)
General Plant	29,575,208	0.0531	1,570,444	0.0524	1,549,741	(20,703)
	1,319,106,897		44,603,968		37,807,497	(6,796,471)
			Allocation Factor - GP-TOT			0.990
			Total Depreciation Expense Reduction			(6,728,507)
			Total of Prior Depreciation Adjustments			(6,637,595)
			Total of Depreciation Adjustment 6			(90,912)

Adustments Included:
1 - Remove $32,000,000 million demolition costs from computation of net salvage costs.
2 - Correct Account #312 Interim Retirements by removing additional retirements in 2007 and 2009.
3 - Use full history of additions and retirements to determine interim retirement rate for Big Sandy Assets instead of last 30 years.
4 - Use of Net Salvage percentages on overall functional account basis instead of judgement percentages based on retirements.
5 - Use full history for all Net Salvage percentages instead of just the 15 year period of 1990-2004.
6 - Delay retirement of Big Sandy Unit I five years from 2015 until 2020.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
STEAM PRODUCTION PLANT												
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.08	39,041,739	19,558,366	17,003,960	22,037,779	25.98	848,259	2.35%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.19	386,201,047	120,063,125	105,248,658 (a)	280,952,389	22.10	12,712,778	3.92%
314.0	Turbogenerator Units	73,038,983	FCST.		1.16	84,725,220	40,553,738	35,257,246	49,467,974	22.71	2,178,246	2.98%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.10	15,116,861	8,374,746	7,280,968	7,835,893	25.81	303,599	2.21%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.11	7,236,039	3,408,827	2,963,620	4,272,419	24.79	172,344	2.64%
	Total Steam Production Plant	453,988,991				532,320,906	191,958,802	167,754,452	364,566,454		16,215,226	3.57%
TRANSMISSION PLANT												
350.1	Land Rights	23,258,047	75 R4.0	N.A.	1.00	23,258,047	6,496,508	5,181,575	18,076,472	54.05	334,440	1.44%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	1.00	6,387,065	2,174,176	1,734,110	4,652,955	36.28	128,251	2.01%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	1.00	123,153,116	30,208,886	24,094,424	99,058,692	30.19	3,281,176	2.66%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	1.35	124,691,881	44,490,496	35,485,349	89,206,532	35.38	2,521,383	2.73%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	1.50	56,259,312	18,200,586	14,516,677	41,742,635	23.68	1,762,780	4.70%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	1.05	105,373,255	39,881,156	31,808,967	73,564,288	31.08	2,366,933	2.36%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	1.00	11,590	5,713	4,557	7,033	18.76	375	3.23%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	1.00	106,066	37,616	30,002	76,064	28.40	2,678	2.53%
	Total Transmission Plant	383,141,929				439,240,332	141,495,137	112,855,660	326,384,672		10,398,016	2.71%
DISTRIBUTION PLANT												
360.1	Land Rights	3,691,802	75 R4.0	N.A.	1.00	3,691,802	1,464,290	1,521,740	2,170,062	45.25	47,957	1.30%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	1.00	4,231,065	801,496	832,942	3,398,123	56.74	59,889	1.42%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	1.00	42,017,840	11,888,206	12,354,632	29,663,208	21.51	1,379,043	3.28%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	1.40	174,541,140	48,873,736	50,791,264	123,749,876	20.16	6,138,387	4.92%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.80	79,541,249	19,903,904	20,684,820	58,856,429	22.49	2,617,004	2.63%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	1.00	2,959,899	483,560	502,532	2,457,367	41.83	58,747	1.98%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.85	4,659,758	603,991	627,688	4,032,070	46.13	87,407	1.59%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.75	63,139,067	18,278,290	18,995,426	44,143,640	20.60	2,142,895	2.55%
369.0	Services	31,239,944	22 R0.5	N.A.	0.85	26,553,952	6,927,939	7,199,752	19,354,200	16.26	1,190,295	3.81%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.75	15,803,845	7,761,512	8,066,030	7,737,815	10.18	760,100	3.61%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	1.00	15,598,882	3,614,093	3,755,890	11,842,992	9.22	1,284,489	8.23%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	1.05	2,878,296	844,368	877,496	2,000,799	14.13	141,599	5.17%
	Total Distribution Plant	437,318,753				435,616,794	121,445,385	126,210,213	309,406,581		15,907,812	3.64%
GENERAL PLANT												
389.2	Land Rights	84,011	75 R4.0	N.A.	1.00	84,011	10,301	5,029	78,982	65.80	1,200	1.43%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.90	17,366,397	8,266,103	4,035,838	13,330,560	13.10	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	1.00	1,737,579	386,452	188,681	1,548,898	27.22	56,903	3.27%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	1.00	5,819	3,136	1,531	4,288	13.83	310	5.33%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	1.00	189,262	47,037	22,965	166,297	22.54	7,378	3.90%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	1.00	1,711,318	262,618	128,220	1,583,098	27.09	58,438	3.41%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	1.00	394,394	258,983	126,446	267,948	10.99	24,381	6.18%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	1.00	5,931	1,853	905	5,026	5.50	914	15.41%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.90	4,200,092	1,960,549	957,217	3,242,875	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	1.00	584,684	134,604	65,719	518,965	14.63	35,473	6.07%
	Total General Plant	28,675,764				26,279,487	11,331,636	5,532,552	20,746,935		1,522,723	5.31%
	Total Depreciable Plant	1,303,125,437				1,433,457,519	466,230,960	412,352,877 (a)	1,021,104,642		44,043,777	3.38%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Adjustment 1

SCHEDULE I

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
STEAM PRODUCTION PLANT												
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.01	36,511,256	18,290,694	16,917,594	19,593,661	25.98	754,183	2.09%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.12	363,483,338	113,000,588	105,383,816 (a)	258,099,523	22.10	11,678,711	3.60%
314.0	Turbogenerator Units	73,038,983	FCST.		1.09	79,612,491	38,106,530	35,245,836	44,366,656	22.71	1,953,618	2.67%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.03	14,154,879	7,841,808	7,253,116	6,901,763	25.81	267,407	1.95%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.04	6,779,712	3,193,856	2,954,090	3,825,622	24.79	154,321	2.37%
	Total Steam Production Plant	453,988,991				500,541,677	180,433,477	167,754,452	332,787,225		14,808,238	3.26%
TRANSMISSION PLANT												
350.1	Land Rights	23,258,047	75 R4.0	N.A.	1.00	23,258,047	6,496,508	5,181,575	18,076,472	54.05	334,440	1.44%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	1.00	6,387,065	2,174,176	1,734,110	4,652,955	36.28	128,251	2.01%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	1.00	123,153,116	30,208,886	24,094,424	99,058,692	30.19	3,281,176	2.66%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	1.35	124,691,881	44,490,496	35,485,349	89,206,532	35.38	2,521,383	2.73%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	1.50	56,259,312	18,200,586	14,516,677	41,742,635	23.68	1,762,780	4.70%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	1.05	105,373,255	39,881,156	31,808,967	73,564,288	31.08	2,366,933	2.36%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	1.00	11,590	5,713	4,557	7,033	18.76	375	3.23%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	1.00	106,066	37,616	30,002	76,064	28.40	2,678	2.53%
	Total Transmission Plant	383,141,929				439,240,332	141,495,137	112,855,660	326,384,672		10,398,016	2.71%
DISTRIBUTION PLANT												
360.1	Land Rights	3,691,802	75 R4.0	N.A.	1.00	3,691,802	1,464,290	1,521,740	2,170,062	45.25	47,957	1.30%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	1.00	4,231,065	801,496	832,942	3,398,123	56.74	59,889	1.42%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	1.00	42,017,840	11,888,206	12,354,632	29,663,208	21.51	1,379,043	3.28%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	1.40	174,541,140	48,873,736	50,791,264	123,749,876	20.16	6,138,387	4.92%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.80	79,541,249	19,903,904	20,684,820	58,856,429	22.49	2,617,004	2.63%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	1.00	2,959,899	483,560	502,532	2,457,367	41.83	58,747	1.98%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.85	4,659,758	603,991	627,688	4,032,070	46.13	87,407	1.59%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.75	63,139,067	18,278,290	18,995,426	44,143,640	20.60	2,142,895	2.55%
369.0	Services	31,239,944	22 R0.5	N.A.	0.85	26,553,952	6,927,939	7,199,752	19,354,200	16.26	1,190,295	3.81%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.75	15,803,845	7,761,512	8,066,030	7,737,815	10.18	760,100	3.61%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	1.00	15,598,882	3,614,093	3,755,890	11,842,992	9.22	1,284,489	8.23%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	1.05	2,878,296	844,368	877,496	2,000,799	14.13	141,599	5.17%
	Total Distribution Plant	437,318,753				435,616,794	121,445,385	126,210,213	309,406,581		15,907,812	3.64%
GENERAL PLANT												
389.2	Land Rights	84,011	75 R4.0	N.A.	1.00	84,011	10,301	5,029	78,982	65.80	1,200	1.43%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.90	17,366,397	8,266,103	4,035,838	13,330,560	13.10	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	1.00	1,737,579	386,452	188,681	1,548,898	27.22	56,903	3.27%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	1.00	5,819	3,136	1,531	4,288	13.83	310	5.33%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	1.00	189,262	47,037	22,965	166,297	22.54	7,378	3.90%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	1.00	1,711,318	262,618	128,220	1,583,098	27.09	58,438	3.41%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	1.00	394,394	258,983	126,446	267,948	10.99	24,381	6.18%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	1.00	5,931	1,853	905	5,026	5.50	914	15.41%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.90	4,200,092	1,960,549	957,217	3,242,875	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	1.00	584,684	134,604	65,719	518,965	14.63	35,473	6.07%
	Total General Plant	28,675,764				26,279,487	11,331,636	5,532,552	20,746,935		1,522,723	5.31%
	Total Depreciable Plant	1,303,125,437				1,401,678,290	454,705,635	412,352,877 (a)	989,325,413		42,636,789	3.27%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Adjustments 1 and 2

SCHEDULE I

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
STEAM PRODUCTION PLANT												
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.01	36,511,256	18,290,694	17,091,616	19,419,639	25.98	747,484	2.07%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.12	363,483,338	111,163,462	104,742,242 (a)	258,741,096	22.63	11,433,544	3.52%
314.0	Turbogenerator Units	73,038,983	FCST.		1.09	79,612,491	38,106,530	35,608,391	44,004,100	22.71	1,937,653	2.65%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.03	14,154,879	7,841,808	7,327,725	6,827,154	25.81	264,516	1.92%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.04	6,779,712	3,193,856	2,984,478	3,795,235	24.79	153,095	2.35%
	Total Steam Production Plant	453,988,991				500,541,677	178,596,351	167,754,452	332,787,225		14,536,291	3.20%
TRANSMISSION PLANT												
350.1	Land Rights	23,258,047	75 R4.0	N.A.	1.00	23,258,047	6,496,508	5,181,575	18,076,472	54.05	334,440	1.44%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	1.00	6,387,065	2,174,176	1,734,110	4,652,955	36.28	128,251	2.01%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	1.00	123,153,116	30,208,886	24,094,424	99,058,692	30.19	3,281,176	2.66%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	1.35	124,691,881	44,490,496	35,485,349	89,206,532	35.38	2,521,383	2.73%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	1.50	56,259,312	18,200,586	14,516,677	41,742,635	23.68	1,762,780	4.70%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	1.05	105,373,255	39,881,156	31,808,967	73,564,288	31.08	2,366,933	2.36%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	1.00	11,590	5,713	4,557	7,033	18.76	375	3.23%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	1.00	106,066	37,616	30,002	76,064	28.40	2,678	2.53%
	Total Transmission Plant	383,141,929				439,240,332	141,495,137	112,855,660	326,384,672		10,398,016	2.71%
DISTRIBUTION PLANT												
360.1	Land Rights	3,691,802	75 R4.0	N.A.	1.00	3,691,802	1,464,290	1,521,740	2,170,062	45.25	47,957	1.30%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	1.00	4,231,065	801,496	832,942	3,398,123	56.74	59,889	1.42%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	1.00	42,017,840	11,888,206	12,354,632	29,663,208	21.51	1,379,043	3.28%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	1.40	174,541,140	48,873,736	50,791,264	123,749,876	20.16	6,138,387	4.92%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.80	79,541,249	19,903,904	20,684,820	58,856,429	22.49	2,617,004	2.63%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	1.00	2,959,899	483,560	502,532	2,457,367	41.83	58,747	1.98%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.85	4,659,758	603,991	627,688	4,032,070	46.13	87,407	1.59%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.75	63,139,067	18,278,290	18,995,426	44,143,640	20.60	2,142,895	2.55%
369.0	Services	31,239,944	22 R0.5	N.A.	0.85	26,553,952	6,927,939	7,199,752	19,354,200	16.26	1,190,295	3.81%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.75	15,803,845	7,761,512	8,066,030	7,737,815	10.18	760,100	3.61%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	1.00	15,598,882	3,614,093	3,755,890	11,842,992	9.22	1,284,489	8.23%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	1.05	2,878,296	844,368	877,496	2,000,799	14.13	141,599	5.17%
	Total Distribution Plant	437,318,753				435,616,794	121,445,385	126,210,213	309,406,581		15,907,812	3.64%
GENERAL PLANT												
389.2	Land Rights	84,011	75 R4.0	N.A.	1.00	84,011	10,301	5,029	78,982	65.80	1,200	1.43%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.90	17,366,397	8,266,103	4,035,838	13,330,560	13.10	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	1.00	1,737,579	386,452	188,681	1,548,898	27.22	56,903	3.27%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	1.00	5,819	3,136	1,531	4,288	13.83	310	5.33%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	1.00	189,262	47,037	22,965	166,297	22.54	7,378	3.90%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	1.00	1,711,318	262,618	128,220	1,583,098	27.09	58,438	3.41%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	1.00	394,394	258,983	126,446	267,948	10.99	24,381	6.18%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	1.00	5,931	1,853	905	5,026	5.50	914	15.41%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.90	4,200,092	1,960,549	957,217	3,242,875	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	1.00	584,684	134,604	65,719	518,965	14.63	35,473	6.07%
	Total General Plant	28,675,764				26,279,487	11,331,636	5,532,552	20,746,935		1,522,723	5.31%
	Total Depreciable Plant	1,303,125,437				1,401,678,290	452,868,509	412,352,877 (a)	989,325,413		42,364,842	3.25%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Adjustments 1,2 and 3

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
STEAM PRODUCTION PLANT												
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.01	36,511,256	18,290,694	17,754,918	18,756,337	25.98	721,953	2.00%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.12	363,483,338	105,839,044	103,605,070 (a)	259,878,269	24.27	10,707,798	3.30%
314.0	Turbogenerator Units	73,038,983	FCST.		1.09	79,612,491	36,854,362	35,774,814	43,837,678	24.19	1,812,223	2.48%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.03	14,154,879	7,779,966	7,552,073	6,602,806	26.27	251,344	1.83%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.04	6,779,712	3,160,144	3,067,577	3,712,135	25.29	146,783	2.25%
	Total Steam Production Plant	453,988,991				500,541,677	171,924,211	167,754,452	332,787,225		13,640,100	3.00%
TRANSMISSION PLANT												
350.1	Land Rights	23,258,047	75 R4.0	N.A.	1.00	23,258,047	6,496,508	5,181,575	18,076,472	54.05	334,440	1.44%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	1.00	6,387,065	2,174,176	1,734,110	4,652,955	36.28	128,251	2.01%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	1.00	123,153,116	30,208,886	24,094,424	99,058,692	30.19	3,281,176	2.66%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	1.35	124,691,881	44,490,496	35,485,349	89,206,532	35.38	2,521,383	2.73%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	1.50	56,259,312	18,200,586	14,516,677	41,742,635	23.68	1,762,780	4.70%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	1.05	105,373,255	39,881,156	31,808,967	73,564,288	31.08	2,366,933	2.36%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	1.00	11,590	5,713	4,557	7,033	18.76	375	3.23%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	1.00	106,066	37,616	30,002	76,064	28.40	2,678	2.53%
	Total Transmission Plant	383,141,929				439,240,332	141,495,137	112,855,660	326,384,672		10,398,016	2.71%
DISTRIBUTION PLANT												
360.1	Land Rights	3,691,802	75 R4.0	N.A.	1.00	3,691,802	1,464,290	1,521,740	2,170,062	45.25	47,957	1.30%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	1.00	4,231,065	801,496	832,942	3,398,123	56.74	59,889	1.42%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	1.00	42,017,840	11,888,206	12,354,632	29,663,208	21.51	1,379,043	3.28%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	1.40	174,541,140	48,873,736	50,791,264	123,749,876	20.16	6,138,387	4.92%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.80	79,541,249	19,903,904	20,684,820	58,856,429	22.49	2,617,004	2.63%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	1.00	2,959,899	483,560	502,532	2,457,367	41.83	58,747	1.98%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.85	4,659,758	603,991	627,688	4,032,070	46.13	87,407	1.59%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.75	63,139,067	18,278,290	18,995,426	44,143,640	20.60	2,142,895	2.55%
369.0	Services	31,239,944	22 R0.5	N.A.	0.85	26,553,952	6,927,939	7,199,752	19,354,200	16.26	1,190,295	3.81%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.75	15,803,845	7,761,512	8,066,030	7,737,815	10.18	760,100	3.61%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	1.00	15,598,882	3,614,093	3,755,890	11,842,992	9.22	1,284,489	8.23%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	1.05	2,878,296	844,368	877,496	2,000,799	14.13	141,599	5.17%
	Total Distribution Plant	437,318,753				435,616,794	121,445,385	126,210,213	309,406,581		15,907,812	3.64%
GENERAL PLANT												
389.2	Land Rights	84,011	75 R4.0	N.A.	1.00	84,011	10,301	5,029	78,982	65.80	1,200	1.43%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.90	17,366,397	8,266,103	4,035,838	13,330,560	13.10	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	1.00	1,737,579	386,452	188,681	1,548,898	27.22	56,903	3.27%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	1.00	5,819	3,136	1,531	4,288	13.83	310	5.33%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	1.00	189,262	47,037	22,965	166,297	22.54	7,378	3.90%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	1.00	1,711,318	262,618	128,220	1,583,098	27.09	58,438	3.41%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	1.00	394,394	258,983	126,446	267,948	10.99	24,381	6.18%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	1.00	5,931	1,853	905	5,026	5.50	914	15.41%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.90	4,200,092	1,960,549	957,217	3,242,875	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	1.00	584,684	134,604	65,719	518,965	14.63	35,473	6.07%
	Total General Plant	28,675,764				26,279,487	11,331,636	5,532,552	20,746,935		1,522,723	5.31%
	Total Depreciable Plant	1,303,125,437				1,401,678,290	446,196,369	412,352,877 (a)	989,325,413		41,468,651	3.18%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Adjustments 1,2,3 and 4

SCHEDULE I

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
STEAM PRODUCTION PLANT												
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.10	39,764,734	18,290,694	17,754,918	22,009,815	25.98	847,183	2.34%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.10	356,992,565	105,839,044	103,605,070 (a)	253,387,495	24.27	10,440,358	3.22%
314.0	Turbogenerator Units	73,038,983	FCST.		1.10	80,342,881	36,854,362	35,774,814	44,568,067	24.19	1,842,417	2.52%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.10	15,116,861	7,779,966	7,552,073	7,564,788	26.27	287,963	2.10%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.10	7,170,849	3,160,144	3,067,577	4,103,273	25.29	162,249	2.49%
	Total Steam Production Plant	453,988,991				499,387,890	171,924,211	167,754,452	331,633,438		13,580,169	2.99%
TRANSMISSION PLANT												
350.1	Land Rights	23,258,047	75 R4.0	N.A.	1.12	26,049,013	6,496,508	5,181,575	20,867,437	54.05	386,077	1.66%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	1.12	7,153,513	2,174,176	1,734,110	5,419,403	36.28	149,377	2.34%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	1.12	137,931,490	30,208,886	24,094,424	113,837,066	30.19	3,770,688	3.06%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	1.12	103,448,079	44,490,496	35,485,349	67,962,730	35.38	1,920,936	2.08%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	1.12	42,006,953	18,200,586	14,516,677	27,490,276	23.68	1,160,907	3.10%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	1.12	112,398,139	39,881,156	31,808,967	80,589,171	31.08	2,592,959	2.58%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	1.12	12,981	5,713	4,557	8,424	18.76	449	3.87%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	1.12	118,794	37,616	30,002	88,792	28.40	3,126	2.95%
	Total Transmission Plant	383,141,929				429,118,960	141,495,137	112,855,660	316,263,300		9,984,520	2.61%
DISTRIBUTION PLANT												
360.1	Land Rights	3,691,802	75 R4.0	N.A.	0.95	3,507,212	1,464,290	1,521,740	1,985,471	45.25	43,878	1.19%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	0.95	4,019,512	801,496	832,942	3,186,570	56.74	56,161	1.33%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	0.95	39,916,948	11,888,206	12,354,632	27,562,316	21.51	1,281,372	3.05%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	0.95	118,438,631	48,873,736	50,791,264	67,647,367	20.16	3,355,524	2.69%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.95	94,455,233	19,903,904	20,684,820	73,770,413	22.49	3,280,143	3.30%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	0.95	2,811,904	483,560	502,532	2,309,372	41.83	55,209	1.87%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.95	5,207,965	603,991	627,688	4,580,276	46.13	99,291	1.81%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.95	79,976,151	18,278,290	18,995,426	60,980,724	20.60	2,960,229	3.52%
369.0	Services	31,239,944	22 R0.5	N.A.	0.95	29,677,947	6,927,939	7,199,752	22,478,195	16.26	1,382,423	4.43%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.95	20,018,203	7,761,512	8,066,030	11,952,174	10.18	1,174,084	5.57%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	0.95	14,818,938	3,614,093	3,755,890	11,063,048	9.22	1,199,897	7.69%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	0.95	2,604,172	844,368	877,496	1,726,676	14.13	122,199	4.46%
	Total Distribution Plant	437,318,753				415,452,815	121,445,385	126,210,213	289,242,602		15,010,409	3.43%
GENERAL PLANT												
389.2	Land Rights	84,011	75 R4.0	N.A.	0.91	76,450	10,301	5,029	71,421	65.80	1,085	1.29%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.91	17,559,357	8,266,103	4,035,838	13,523,519	13.10	1,032,330	5.35%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	0.91	1,581,197	386,452	188,681	1,392,516	27.22	51,158	2.94%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	0.91	5,295	3,136	1,531	3,764	13.83	272	4.68%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	0.91	172,228	47,037	22,965	149,263	22.54	6,622	3.50%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	0.91	1,557,299	262,618	128,220	1,429,079	27.09	52,753	3.08%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	0.91	358,899	258,983	126,446	232,453	10.99	21,151	5.36%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	0.91	5,397	1,853	905	4,493	5.50	817	13.77%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.91	4,246,760	1,960,549	957,217	3,289,542	10.13	324,733	6.96%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	0.91	532,062	134,604	65,719	466,343	14.63	31,876	5.45%
	Total General Plant	28,675,764				26,094,945	11,331,636	5,532,552	20,562,393		1,522,797	5.31%
	Total Depreciable Plant	1,303,125,437				1,370,054,611	446,196,369	412,352,877 (a)	957,701,734		40,097,894	3.08%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Adjustments 1,2,3,4 and 5

SCHEDULE I

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
STEAM PRODUCTION PLANT												
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.09	39,403,236	18,290,694	17,754,918	21,648,318	25.98	833,269	2.31%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.09	353,747,178	105,839,044	103,605,070 (a)	250,142,108	24.27	10,306,638	3.18%
314.0	Turbogenerator Units	73,038,983	FCST.		1.09	79,612,491	36,854,362	35,774,814	43,837,678	24.19	1,812,223	2.48%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.09	14,979,435	7,779,966	7,552,073	7,427,362	26.27	282,732	2.06%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.09	7,105,660	3,160,144	3,067,577	4,038,083	25.29	159,671	2.45%
	Total Steam Production Plant	453,988,991				494,848,000	171,924,211	167,754,452	327,093,548		13,394,532	2.95%
TRANSMISSION PLANT												
350.1	Land Rights	23,258,047	75 R4.0	N.A.	0.97	22,560,306	6,496,508	5,181,575	17,378,730	54.05	321,531	1.38%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	0.97	6,195,453	2,174,176	1,734,110	4,461,344	36.28	122,970	1.93%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	0.97	119,458,523	30,208,886	24,094,424	95,364,099	30.19	3,158,798	2.56%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	0.97	89,593,425	44,490,496	35,485,349	54,108,077	35.38	1,529,341	1.66%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	0.97	36,381,022	18,200,586	14,516,677	21,864,345	23.68	923,325	2.46%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	0.97	97,344,817	39,881,156	31,808,967	65,535,849	31.08	2,108,618	2.10%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	0.97	11,242	5,713	4,557	6,686	18.76	356	3.07%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	0.97	102,884	37,616	30,002	72,882	28.40	2,566	2.42%
	Total Transmission Plant	383,141,929				371,647,671	141,495,137	112,855,660	258,792,011		8,167,505	2.13%
DISTRIBUTION PLANT												
360.1	Land Rights	3,691,802	75 R4.0	N.A.	0.92	3,396,458	1,464,290	1,521,740	1,874,717	45.25	41,430	1.12%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	0.92	3,892,580	801,496	832,942	3,059,638	56.74	53,924	1.27%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	0.92	38,656,413	11,888,206	12,354,632	26,301,781	21.51	1,222,770	2.91%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	0.92	114,698,464	48,873,736	50,791,264	63,907,199	20.16	3,170,000	2.54%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.92	91,472,436	19,903,904	20,684,820	70,787,616	22.49	3,147,515	3.17%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	0.92	2,723,107	483,560	502,532	2,220,575	41.83	53,086	1.79%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.92	5,043,503	603,991	627,688	4,415,814	46.13	95,725	1.75%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.92	77,450,588	18,278,290	18,995,426	58,455,162	20.60	2,837,629	3.37%
369.0	Services	31,239,944	22 R0.5	N.A.	0.92	28,740,748	6,927,939	7,199,752	21,540,996	16.26	1,324,785	4.24%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.92	19,386,050	7,761,512	8,066,030	11,320,020	10.18	1,111,986	5.28%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	0.92	14,350,971	3,614,093	3,755,890	10,595,082	9.22	1,149,141	7.37%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	0.92	2,521,935	844,368	877,496	1,644,439	14.13	116,379	4.25%
	Total Distribution Plant	437,318,753				402,333,253	121,445,385	126,210,213	276,123,040		14,324,371	3.28%
GENERAL PLANT												
389.2	Land Rights	84,011	75 R4.0	N.A.	0.90	75,610	10,301	5,029	70,581	65.80	1,073	1.28%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.90	17,366,397	8,266,103	4,035,838	13,330,560	13.10	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	0.90	1,563,821	386,452	188,681	1,375,140	27.22	50,519	2.91%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	0.90	5,237	3,136	1,531	3,706	13.83	268	4.61%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	0.90	170,336	47,037	22,965	147,370	22.54	6,538	3.45%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	0.90	1,540,186	262,618	128,220	1,411,966	27.09	52,121	3.05%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	0.90	354,955	258,983	126,446	228,509	10.99	20,792	5.27%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	0.90	5,338	1,853	905	4,433	5.50	806	13.59%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.90	4,200,092	1,960,549	957,217	3,242,875	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	0.90	526,216	134,604	65,719	460,497	14.63	31,476	5.38%
	Total General Plant	28,675,764				25,808,188	11,331,636	5,532,552	20,275,636		1,501,320	5.24%
	Total Depreciable Plant	1,303,125,437				1,294,637,112	446,196,369	412,352,877 (a)	882,284,235		37,387,726	2.87%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
ANNUAL DEPRECIATION RATES AND ACCRUALS BY THE REMAINING LIFE METHOD
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AVERAGE LIFE GROUP (ALG) METHOD ACCRUAL RATES

Adjustments 1,2,3,4,5 and 6

SCHEDULE I

ACCOUNT NO. (I)	ACCOUNT TITLE (II)	ORIGINAL COST AT 12/31/04 (III)	AVERAGE LIFE AND CURVE TYPE (IV)	TERMINAL RETIREMENT DATE (V)	NET SALVAGE RATIO (VI)	TOTAL TO BE RECOVERED (VII)	CALCULATED DEPRECIATION REQUIREMENT (VIII)	ALLOCATED ACCUMULATED DEPRECIATION (IX)	REMAINING TO BE RECOVERED (X)	AVERAGE REMAINING LIFE (XI)	RECOMMENDED ANNUAL AMOUNT (XII)	RECOMMENDED ACCRUAL PERCENT (XIII)
STEAM PRODUCTION PLANT												
	BIG SANDY PLANT			2015/2034								
311.0	Structures & Improvements	36,149,758	FCST.		1.09	39,403,236	18,013,877	17,576,849	21,826,387	26.78	815,026	2.25%
312.0	Boiler Plant Equipment	324,538,695	FCST.		1.09	353,747,178	105,592,333	103,896,887 (a)	249,850,290	24.35	10,260,792	3.16%
314.0	Turbogenerator Units	73,038,983	FCST.		1.09	79,612,491	36,594,366	35,706,564	43,905,928	24.51	1,791,348	2.45%
315.0	Accessory Electrical Equipment	13,742,601	FCST.		1.09	14,979,435	7,713,844	7,526,701	7,452,734	26.77	278,399	2.03%
316.0	Misc. Power Plant Equip.	6,518,954	FCST.		1.09	7,105,660	3,123,222	3,047,451	4,058,209	25.85	156,991	2.41%
	Total Steam Production Plant	453,988,991				494,848,000	171,037,642	167,754,452	327,093,548		13,302,554	2.93%
TRANSMISSION PLANT												
350.1	Land Rights	23,258,047	75 R4.0	N.A.	0.97	22,560,306	6,496,508	5,181,575	17,378,730	54.05	321,531	1.38%
352.0	Structures & Improvements	6,387,065	55 S3.0	N.A.	0.97	6,195,453	2,174,176	1,734,110	4,461,344	36.28	122,970	1.93%
353.0	Station Equipment	123,153,116	40 R1.5	N.A.	0.97	119,458,523	30,208,886	24,094,424	95,364,099	30.19	3,158,798	2.56%
354.0	Towers & Fixtures	92,364,356	55 R4.0	N.A.	0.97	89,593,425	44,490,496	35,485,349	54,108,077	35.38	1,529,341	1.66%
355.0	Poles & Fixtures	37,506,208	35 S6.0	N.A.	0.97	36,381,022	18,200,586	14,516,677	21,864,345	23.68	923,325	2.46%
356.0	OH Conductor & Devices	100,355,481	50 S6.0	N.A.	0.97	97,344,817	39,881,156	31,808,967	65,535,849	31.08	2,108,618	2.10%
356.0	Underground Conduit	11,590	37 R2.0	N.A.	0.97	11,242	5,713	4,557	6,686	18.76	356	3.07%
358.0	Underground Conductor	106,066	44 R1.0	N.A.	0.97	102,884	37,616	30,002	72,882	28.40	2,566	2.42%
	Total Transmission Plant	383,141,929				371,647,671	141,495,137	112,855,660	258,792,011		8,167,505	2.13%
DISTRIBUTION PLANT												
360.1	Land Rights	3,691,802	75 R4.0	N.A.	0.92	3,396,458	1,464,290	1,521,740	1,874,717	45.25	41,430	1.12%
361.0	Structures & Improvements	4,231,065	70 L1.5	N.A.	0.92	3,892,580	801,496	832,942	3,059,638	56.74	53,924	1.27%
362.0	Station Equipment	42,017,840	30 R0.5	N.A.	0.92	38,656,413	11,888,206	12,354,632	26,301,781	21.51	1,222,770	2.91%
364.0	Poles, Towers, & Fixtures	124,672,243	28 R0.5	N.A.	0.92	114,698,464	48,873,736	50,791,264	63,907,199	20.16	3,170,000	2.54%
365.0	Overhead Conductor & Devices	99,426,561	30 R0.5	N.A.	0.92	91,472,436	19,903,904	20,684,820	70,787,616	22.49	3,147,515	3.17%
366.0	Underground Conduit	2,959,899	50 R1.0	N.A.	0.92	2,723,107	483,560	502,532	2,220,575	41.83	53,086	1.79%
367.0	Underground Conductor	5,482,068	53 R0.5	N.A.	0.92	5,043,503	603,991	627,688	4,415,814	46.13	95,725	1.75%
368.0	Line Transformers	84,185,422	29 R0.5	N.A.	0.92	77,450,588	18,278,290	18,995,426	58,455,162	20.60	2,837,629	3.37%
369.0	Services	31,239,944	22 R0.5	N.A.	0.92	28,740,748	6,927,939	7,199,752	21,540,996	16.26	1,324,785	4.24%
370.0	Meters	21,071,793	20 R3.0	N.A.	0.92	19,386,050	7,761,512	8,066,030	11,320,020	10.18	1,111,986	5.28%
371.0	Installations on Custs. Prem.	15,598,882	12 L0.0	N.A.	0.92	14,350,971	3,614,093	3,755,890	10,595,082	9.22	1,149,141	7.37%
373.0	Street Lighting & Signal Sys.	2,741,234	20 L0.0	N.A.	0.92	2,521,935	844,368	877,496	1,644,439	14.13	116,379	4.25%
	Total Distribution Plant	437,318,753				402,333,253	121,445,385	126,210,213	276,123,040		14,324,371	3.28%
GENERAL PLANT												
389.2	Land Rights	84,011	75 R4.0	N.A.	0.90	75,610	10,301	5,029	70,581	65.80	1,073	1.28%
390.0	Structures & Improvements	19,295,997	25 L2.0	N.A.	0.90	17,366,397	8,266,103	4,035,838	13,330,560	13.10	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	35 R0.5	N.A.	0.90	1,563,821	386,452	188,681	1,375,140	27.22	50,519	2.91%
392.0	Transportation Equipment	5,819	30 R3.0	N.A.	0.90	5,237	3,136	1,531	3,706	13.83	268	4.61%
393.0	Stores Equipment	189,262	30 L0.0	N.A.	0.90	170,336	47,037	22,965	147,370	22.54	6,538	3.45%
394.0	Tools Shop & Garage Equipment	1,711,318	32 L0.0	N.A.	0.90	1,540,186	262,618	128,220	1,411,966	27.09	52,121	3.05%
395.0	Laboratory Equipment	394,394	32 S5.0	N.A.	0.90	354,955	258,983	126,446	228,509	10.99	20,792	5.27%
396.0	Power Operated Equipment	5,931	8 SQ	N.A.	0.90	5,338	1,853	905	4,433	5.50	806	13.59%
397.0	Communication Equipment	4,666,769	19 S6.0	N.A.	0.90	4,200,092	1,960,549	957,217	3,242,875	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	19 L2.0	N.A.	0.90	526,216	134,604	65,719	460,497	14.63	31,476	5.38%
	Total General Plant	28,675,764				25,808,188	11,331,636	5,532,552	20,275,636		1,501,320	5.24%
	Total Depreciable Plant	1,303,125,437				1,294,637,112	445,309,800	412,352,877 (a)	882,284,235		37,295,748	2.86%

(a) Includes allocated reserve of $105,161,967 plus $866,291 of accumulated amortization applicable to SCR Catalysts.

KENTUCKY POWER COMPANY
Depreciation Study as of December 31, 2004
Production Plant

This investment consists of two generating units located on the Big Sandy River near Louisa, Kentucky. Unit 1 is rated at 260 MW and was placed in service in 1963. Unit 2 is rated at 800MW and was placed in service in 1969. The estimated final retirement dates for the units were provided by the Asset and Outage Planning Section of AEP's Generating Division.

AEP recently announced plans to install flue gas desulfurization (FGD) equipment to reduce sulfur dioxide emmissions on Unit 2 at Big Sandy Plant. This additional investment in pollution control equipment is expected to result in operating Unit 2 to year 2034. There are currently no plans to install FGD equipment on Unit 1. Due to enviromnental constraints, the current plans are to retire Unit 1 in year 2015.

Life Analysis

Interim retirements for the Big Sandy Plant were determined by analyzing past history for each of the accounts in the production plant function. Interim retirement ratio's were developed based on the period 1975 through 2004. Interim retirements are not usually considered representative of the future until the generating units have experienced a few years of actual operation. Since Unit 2 was placed in-service in 1969, the period beginning in 1975 provided for five years of operational experience.

In addition to the interim retirements experienced to date, the Selective Catalytic Reduction (SCR) system that is installed at Big Sandy Plant will have the SCR Catalysts replaced at future intervals. The AEP Engineering group provided the following details for replacement of the SCR Catalysts:

Layers 1 and 2 will be replaced in year 2009.
Layer 3 will be replaced in 2007.

The original cost of the catalysts are as follows:

Layer 1	$3,259,048
Layer 2	$3,259,049
Layer 3	$1,629,524

After determining the interim retirments and the retirement of the SCR catalysts, a remaining life was calculated for each of the primary production plant accounts. The surviving plant balances by primary plant account at 12/31/04 were also aged. The age of the surviving balances plus the remaining life were summed to determine the total life of the investments.

Salvage and Cost of Removal

Kentucky Power Company engaged the firm of Brandenburg Industrial Service Company to perform a conceptual demolition cost estimate for the Big Sandy Plant. The demolition cost is estimated to be $32,000,000 in current (2004) dollars. It is appropriate to include the final retirement costs for the Big Sandy plant in depreciation rates in order to ensure that the generation of customers that are receiving service from the plant also share in the final removal costs of the plant.

There are also gross salvage and removal costs associated with the removal/replacement of equipment during the operating life of the plant. An analysis of interim retirements was made for the production plant function and the fifteen year period of 1990-2004 was used as the basis to determing a gross salvage percentage and a gross removal percentage. The estimates of salvage and removal for both the final plant retirement and the interim retirements were combined to calculate a net salvage for each plant account. That calculation is as follows:

KENTUCKY POWER COMPANY
Depreciation Study as of December 31, 2004
Production Plant

Calculation of Removal and Salvage:

Interim Retirements:

Account	Interim Retirements (From Remaining Life Workpaper)	Gross Removal Percent	Gross Salvage Percent	Interim Retirement Net Salvage Percent
311	1,037,633	35.3%	8.8%	-27%
312	144,478,211	35.3%	8.8%	-27%
314	25,648,705	35.3%	8.8%	-27%
315	1,488,647	35.3%	8.8%	-27%
316	1,013,890	35.3%	8.8%	-27%
Total	173,667,086			

Account	Plant In-Service at 12/31/04	Net Salvage on Interim Retirement	Final Demolition Cost (a)	Total Net Salvage Costs	Net Salvage as Percent of Plant
311	36,149,758	-275,088	0	-275,088	-1%
312	324,538,695	-38,302,841	0	-38,302,841	-12%
314	73,038,983	-6,799,768	0	-6,799,768	-9%
315	13,742,601	-394,657	0	-394,657	-3%
316	6,518,954	-268,794	0	-268,794	-4%
Total	453,988,991	-46,041,149	0	-46,041,149	-10%

Notes: (a) Costs allocated to plant accounts based on Plant-In-Service Balances at 12/31/04

Calculation of Theoretical Reserve and Depreciation Rates

A theoretical reserve was determined based on the above calculations of average age, remaining life and net salvage. The theoretical reserve was used to allocate the actual book reserve to the individual plant accounts.

Based on plant balances at 12/31/04 and the allocated book reserve, remaining life depreciation rates were calculated for each primary plant account.

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATED DEPRECIATION RESERVE
STEAM PRODUCTION PLANT

ACCOUNT	PLANT BALANCE AT 12-31-04	AVERAGE AGE	AVERAGE REM. LIFE	AVERAGE LIFE	NET SALVAGE	% REM. LIFE TO AVG. LIFE	CALCULATED RESERVE %	CALCULATED RESERVE W/O NET SALVAGE	CALCULATED RESERVE WITH NET SALVAGE
BIG SANDY									
311	36,149,758	26.08	25.98	52.06	-1%	49.90%	50.10%	18,109,598	18,290,694
312	324,538,694	9.97	22.10	32.07	-12%	68.91%	31.09%	100,893,383	113,000,588
314	73,038,983	20.85	22.71	43.56	-9%	52.13%	47.87%	34,960,119	38,106,530
315	13,742,601	32.06	25.81	57.87	-3%	44.60%	55.40%	7,613,406	7,841,808
316	6,518,954	22.08	24.79	46.87	-4%	52.89%	47.11%	3,071,016	3,193,856
Total	453,988,990							164,647,522	180,433,477

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT ACCOUNT 312
RETIREMENT YEARS - UNIT 1 2015; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0150

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	4,868,080	0.5	2,434,040	
2006	4,868,080	1.5	7,302,121	
2007	4,868,080	2.5	12,170,201	
2008	4,868,080	3.5	17,038,281	
2009	4,868,080	4.5	21,906,362	
2010	4,868,080	5.5	26,774,442	
2011	4,868,080	6.5	31,642,523	
2012	4,868,080	7.5	36,510,603	
2013	4,868,080	8.5	41,378,684	
2014	4,868,080	9.5	46,246,764	
2015	11,763,314	10.5	123,514,801	
2016	4,764,652	11.5	54,793,497	
2017	4,764,652	12.5	59,558,149	
2018	4,764,652	13.5	64,322,801	
2019	4,764,652	14.5	69,087,453	
2020	4,764,652	15.5	73,852,105	
2021	4,764,652	16.5	78,616,757	
2022	4,764,652	17.5	83,381,409	
2023	4,764,652	18.5	88,146,060	
2024	4,764,652	19.5	92,910,712	
2025	4,764,652	20.5	97,675,364	
2026	4,764,652	21.5	102,440,016	
2027	4,764,652	22.5	107,204,668	
2028	4,764,652	23.5	111,969,320	
2029	4,764,652	24.5	116,733,972	
2030	4,764,652	25.5	121,498,624	
2031	4,764,652	26.5	126,263,276	
2032	4,764,652	27.5	131,027,928	
2033	4,764,652	28.5	135,792,580	
2034	178,330,842	29.5	5,260,759,835	
TOTALS	324,538,695		7,342,953,347	22.63

INTERIM RETIREMENTS:	
Total Plant at 12/31/04	324,538,695
Less Retirement of Unit 1 in 2015	-6,895,234
Less Final Retirement in year 2034	-178,330,842
Total Interim Retirements	139,312,619

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATED DEPRECIATION RESERVE
STEAM PRODUCTION PLANT

ACCOUNT	PLANT BALANCE AT 12-31-04	AVERAGE AGE	AVERAGE REM. LIFE	AVERAGE LIFE	NET SALVAGE	% REM. LIFE TO AVG. LIFE	CALCULATED RESERVE %	CALCULATED RESERVE W/O NET SALVAGE	CALCULATED RESERVE WITH NET SALVAGE
BIG SANDY									
311	36,149,758	26.08	25.98	52.06	-1%	49.90%	50.10%	18,109,598	18,290,694
312	324,538,694	9.97	22.63	32.60	-12%	69.42%	30.58%	99,253,091	111,163,462
314	73,038,983	20.85	22.71	43.56	-9%	52.13%	47.87%	34,960,119	38,106,530
315	13,742,601	32.06	25.81	57.87	-3%	44.60%	55.40%	7,613,406	7,841,808
316	6,518,954	22.08	24.79	46.87	-4%	52.89%	47.11%	3,071,016	3,193,856
Total	453,988,990							163,007,230	178,596,351

KENTUCKY POWER COMPANY
CALCULATION OF INTERIM RETIREMENT RATIOS
STEAM PRODUCTION PLANT
ACCOUNT 311.0 STRUCTURES & IMPROVEMENTS

YEAR	ADDITIONS	RETIREMENTS	BALANCE	AVERAGE BALANCE	RETIREMENT RATIO
1963	6,127,706	0	6,127,706	N. A.	N. A.
1964	13,194	0	6,140,900	6,134,303	0.0000
1965	18,607	255	6,159,252	6,150,076	0.0000
1966	4,255	7,338	6,156,169	6,157,711	0.0012
1967	575	69,333	6,087,411	6,121,790	0.0113
1968	21,282	0	6,108,693	6,098,052	0.0000
1969	15,770,374	0	21,879,067	13,993,880	0.0000
1970	803,526	7,182	22,675,411	22,277,239	0.0003
1971	163,043	37,002	22,801,452	22,738,432	0.0016
1972	56,860	0	22,858,312	22,829,882	0.0000
1973	2,605	0	22,860,917	22,859,615	0.0000
1974	66,090	1,665	22,925,342	22,893,130	0.0001
1975	29,219	0	22,954,561	22,939,952	0.0000
1976	65,662	0	23,020,223	22,987,392	0.0000
1977	87,499	0	23,107,722	23,063,973	0.0000
1978	297,729	24,379	23,381,072	23,244,397	0.0010
1979	214,311	5,000	23,590,383	23,485,728	0.0002
1980	27,547	6,618	23,611,312	23,600,848	0.0003
1981	212,801	358	23,823,755	23,717,534	0.0000
1982	716,535	44,396	24,495,894	24,159,825	0.0018
1983	389,851	307,808	24,577,937	24,536,916	0.0125
1984	81,115	469	24,658,583	24,618,260	0.0000
1985	64,741	1,605	24,721,719	24,690,151	0.0001
1986	0	0	24,721,719	24,721,719	0.0000
1987	34,955	966	24,755,708	24,738,714	0.0000
1988	171,684	718	24,926,674	24,841,191	0.0000
1989	28,362	2,856	24,952,180	24,939,427	0.0001
1990	484,041	3,690	25,432,531	25,192,356	0.0001
1991	18,357	35,387	25,415,501	25,424,016	0.0014
1992	22,217	13,640	25,424,078	25,419,790	0.0005
1993	168,711	56,800	25,535,989	25,480,034	0.0022
1994	1,254,912	4,050	26,786,851	26,161,420	0.0002
1995	45,725	9,070	26,823,506	26,805,179	0.0003
1996	113,294	94,931	26,841,869	26,832,688	0.0035
1997	0	101,804	26,740,065	26,790,967	0.0038
1998	2,448,051	54,548	29,133,568	27,936,817	0.0020
1999	220,173	4,000	29,349,741	29,241,655	0.0001
2000	46,629	17,282	29,379,088	29,364,415	0.0006
2001	20,444	8,355	29,391,177	29,385,133	0.0003
2002	431	1,168	29,390,440	29,390,809	0.0000
2003	6,265,695	5,061	35,651,074	32,520,757	0.0002
2004	630,676	74,097	36,207,653	35,929,364	0.0021
TOTAL 1975-2004	14,161,367	879,056	788,802,573	782,161,418	0.0336

Used 1975 through 2004 interim retirements. Based on retirements five years after in-service date of Unit 2.

AVERAGE INTERIM RATE $\frac{0.0336}{30}$ 0.0011

KIUC Adjustment

Total All Years	37,209,484	1,001,831	961,583,205	940,415,526	0.0481

AVERAGE INTERIM RATE $\frac{0.0481}{42}$ ***0.0011 No Change***

KENTUCKY POWER COMPANY
CALCULATION OF INTERIM RETIREMENT RATIOS
STEAM PRODUCTION PLANT
ACCOUNT 312.0 BOILER PLANT EQUIPMENT

YEAR	ADDITIONS	RETIREMENTS	BALANCE	AVERAGE BALANCE	RETIREMENT RATIO
1963	16,508,970	0	16,508,970	N. A.	N. A.
1964	119,842	8,093	16,620,719	16,564,845	0.0005
1965	33,135	7,505	16,646,349	16,633,534	0.0005
1966	176,256	19,803	16,802,802	16,724,576	0.0012
1967	7,026	3,196	16,806,632	16,804,717	0.0002
1968	39,011	127,966	16,717,677	16,762,155	0.0076
1969	57,241,411	5,000	73,954,088	45,335,883	0.0001
1970	2,611,299	569,493	75,995,894	74,974,991	0.0076
1971	1,703,522	87,366	77,612,050	76,803,972	0.0011
1972	773,998	23,261	78,362,787	77,987,419	0.0003
1973	124,697	24,700	78,462,784	78,412,786	0.0003
1974	795,833	128,171	79,130,446	78,796,615	0.0016
1975	1,177,739	43,910	80,264,275	79,697,361	0.0006
1976	4,699,081	1,136,240	83,827,116	82,045,696	0.0138
1977	1,500,565	738,415	84,589,266	84,208,191	0.0088
1978	3,596,304	210,933	87,974,637	86,281,952	0.0024
1979	3,702,290	690,851	90,986,076	89,480,357	0.0077
1980	1,574,173	1,302,708	91,257,541	91,121,809	0.0143
1981	2,710,157	1,947,465	92,020,233	91,638,887	0.0213
1982	4,780,741	1,372,184	95,428,790	93,724,512	0.0146
1983	2,053,897	244,647	97,238,040	96,333,415	0.0025
1984	1,928,226	583,176	98,583,090	97,910,565	0.0060
1985	1,775,366	79,270	100,279,186	99,431,138	0.0008
1986	1,302,549	1,199,650	100,382,085	100,330,636	0.0120
1987	2,870,827	941,836	102,311,076	101,346,581	0.0093
1988	2,769,412	757,438	104,323,050	103,317,063	0.0073
1989	1,780,224	543,698	105,559,576	104,941,313	0.0052
1990	2,114,057	841,371	106,832,262	106,195,919	0.0079
1991	1,503,783	964,562	107,371,483	107,101,873	0.0090
1992	3,022,972	929,688	109,464,767	108,418,125	0.0086
1993	6,037,402	2,619,487	112,882,682	111,173,725	0.0236
1994	11,992,454	1,471,709	123,403,427	118,143,055	0.0125
1995	10,399,357	5,694,627	128,108,157	125,755,792	0.0453
1996	12,608,246	12,608,246	128,108,157	128,108,157	0.0984
1997	0	3,024,973	125,083,184	126,595,671	0.0239
1998	10,554,688	901,600	134,736,272	129,909,728	0.0069
1999	1,940,785	263,258	136,413,799	135,575,036	0.0019
2000	2,930,632	704,876	138,639,555	137,526,677	0.0051
2001	925,934	356,729	139,208,760	138,924,158	0.0026
2002	3,329,584	560,581	141,977,763	140,593,262	0.0040
2003	183,221,112	15,170,924	310,027,951	226,002,857	0.0671
2004	6,041,203	2,293,276	313,775,878	311,901,915	0.0074
TOTAL 1975-2004	294,843,760	60,198,328	3,671,058,134	3,553,735,418	0.4507

Used 1975 through 2004 interim retirements. Based on retirements five years after in-service date of Unit 2.

AVERAGE INTERIM RATE $\frac{0.4507}{30}$ **0.0150**

KIUC Adjustment

Total All Years	374,978,760	61,202,882	4,234,679,332	4,069,536,908	0.4718

AVERAGE INTERIM RATE $\frac{0.4718}{42}$ **0.0112**

KENTUCKY POWER COMPANY
CALCULATION OF INTERIM RETIREMENT RATIOS
STEAM PRODUCTION PLANT
ACCOUNT 314.0 TURBO-GENERATOR UNITS

YEAR	ADDITIONS	RETIREMENTS	BALANCE	AVERAGE BALANCE	RETIREMENT RATIO
1963	11,821,004	0	11,821,004	N. A.	N. A.
1964	19,361	0	11,840,365	11,830,685	0.0000
1965	12,601	755	11,852,211	11,846,288	0.0001
1966	7,592	872	11,858,931	11,855,571	0.0001
1967	7,158	0	11,866,089	11,862,510	0.0000
1968	52,378	0	11,918,467	11,892,278	0.0000
1969	26,377,737	0	38,296,204	25,107,336	0.0000
1970	1,024,372	180,383	39,140,193	38,718,199	0.0047
1971	713,082	0	39,853,275	39,496,734	0.0000
1972	272,380	0	40,125,655	39,989,465	0.0000
1973	63,768	0	40,189,423	40,157,539	0.0000
1974	63,140	0	40,252,563	40,220,993	0.0000
1975	336,271	80,578	40,508,256	40,380,410	0.0020
1976	74,777	2,746	40,580,287	40,544,272	0.0001
1977	33,676	1,548	40,612,415	40,596,351	0.0000
1978	45,149	6,818	40,650,746	40,631,581	0.0002
1979	1,007,454	398,443	41,259,757	40,955,252	0.0097
1980	66,913	214,355	41,112,315	41,186,036	0.0052
1981	1,916,304	618,632	42,409,987	41,761,151	0.0148
1982	1,006,642	82,616	43,334,013	42,872,000	0.0019
1983	1,067,481	549,626	43,851,868	43,592,941	0.0126
1984	237,266	2,944	44,086,190	43,969,029	0.0001
1985	528,415	7,819	44,606,786	44,346,488	0.0002
1986	634,657	709,776	44,531,667	44,569,227	0.0159
1987	229,683	307,098	44,454,252	44,492,960	0.0069
1988	5,606,623	58,088	50,002,787	47,228,520	0.0012
1989	3,103,073	2,768,504	50,337,356	50,170,072	0.0552
1990	2,320,315	1,094,464	51,563,207	50,950,282	0.0215
1991	2,065,521	138,353	53,490,375	52,526,791	0.0026
1992	836,989	1,593,641	52,733,723	53,112,049	0.0300
1993	2,739,309	550,206	54,922,826	53,828,275	0.0102
1994	2,265,960	2,354,678	54,834,108	54,878,467	0.0429
1995	1,186,873	444,477	55,576,504	55,205,306	0.0081
1996	126,815	477,746	55,225,573	55,401,039	0.0086
1997	13,047,841	4,684,964	63,588,450	59,407,012	0.0789
1998	0	695,946	62,892,504	63,240,477	0.0110
1999	0	205,238	62,687,266	62,789,885	0.0033
2000	227,801	52,538	62,862,529	62,774,898	0.0008
2001	47,682	141,367	62,768,844	62,815,687	0.0023
2002	1,505,312	257,582	64,016,574	63,392,709	0.0041
2003	9,648,825	1,427,668	72,237,731	68,127,153	0.0210
2004	1,394,539	692,983	72,939,287	72,588,509	0.0095
TOTAL 1975-2004	53,308,166	20,621,442	1,554,678,183	1,538,334,821	0.3807

Used 1975 through 2004 interim retirements. Based on retirements five years after in-service date of Unit 2.

AVERAGE INTERIM RATE	0.3807 / 30	0.0127

KIUC Adjustment

Total All Years	93,742,739	20,803,452	1,863,692,563	1,821,312,418	0.3855

AVERAGE INTERIM RATE	0.3855 / 42	**0.0092**

KENTUCKY POWER COMPANY
CALCULATION OF INTERIM RETIREMENT RATIOS
STEAM PRODUCTION PLANT
ACCOUNT 315.0 ACCESSORY ELECTRICAL EQUIPMENT

YEAR	ADDITIONS	RETIREMENTS	BALANCE	AVERAGE BALANCE	RETIREMENT RATIO
1963	2,090,616	0	2,090,616	N. A.	N. A.
1964	9,817	2,835	2,097,598	2,094,107	0.0014
1965	2,265	0	2,099,863	2,098,731	0.0000
1966	20,284	0	2,120,147	2,110,005	0.0000
1967	4,595	0	2,124,742	2,122,445	0.0000
1968	947	0	2,125,689	2,125,216	0.0000
1969	6,451,294	0	8,576,983	5,351,336	0.0000
1970	555,696	0	9,132,679	8,854,831	0.0000
1971	356,319	0	9,488,998	9,310,839	0.0000
1972	13,318	2,910	9,499,406	9,494,202	0.0003
1973	114,131	12,654	9,600,883	9,550,145	0.0013
1974	1,489	4,680	9,597,692	9,599,288	0.0005
1975	0	0	9,597,692	9,597,692	0.0000
1976	425,620	0	10,023,312	9,810,502	0.0000
1977	113,934	0	10,137,246	10,080,279	0.0000
1978	226,909	0	10,364,155	10,250,701	0.0000
1979	40,978	0	10,405,133	10,384,644	0.0000
1980	81,148	0	10,486,281	10,445,707	0.0000
1981	607,835	49,582	11,044,534	10,765,408	0.0046
1982	369,121	120,858	11,292,797	11,168,666	0.0108
1983	92,707	10,516	11,374,988	11,333,893	0.0009
1984	88,302	5,454	11,457,836	11,416,412	0.0005
1985	108,963	11,203	11,555,596	11,506,716	0.0010
1986	38,938	19,802	11,574,732	11,565,164	0.0017
1987	119,792	27,283	11,667,241	11,620,987	0.0023
1988	187,376	71,442	11,783,175	11,725,208	0.0061
1989	100,224	0	11,883,399	11,833,287	0.0000
1990	286,615	24,236	12,145,778	12,014,589	0.0020
1991	106,173	12,852	12,239,099	12,192,439	0.0011
1992	38,842	10,027	12,267,914	12,253,507	0.0008
1993	115,632	9,068	12,374,478	12,321,196	0.0007
1994	79,021	1,052	12,452,447	12,413,463	0.0001
1995	35,386	91,239	12,396,594	12,424,521	0.0073
1996	12,996	0	12,409,590	12,403,092	0.0000
1997	1,139,691	324,810	13,224,471	12,817,031	0.0253
1998	363,986	24,960	13,563,497	13,393,984	0.0019
1999	8,929	1,372	13,571,054	13,567,276	0.0001
2000	368,049	80,920	13,858,183	13,714,619	0.0059
2001	46,339	32,876	13,871,646	13,864,915	0.0024
2002	7,426	2,009	13,877,063	13,874,355	0.0001
2003	244,780	587,860	13,533,983	13,705,523	0.0429
2004	4,907	4,041	13,534,849	13,534,416	0.0003
TOTAL 1975-2004	5,460,619	1,523,462	359,968,763	358,000,185	0.1189

Used 1975 through 2004 interim retirements. Based on retirements five years after in-service date of Unit 2.

AVERAGE INTERIM RATE $\frac{0.1189}{30}$ 0.0040

KIUC Adjustment

Total All Years	15,081,390	1,546,541	428,524,059	420,711,327	0.1224

AVERAGE INTERIM RATE $\frac{0.1224}{42}$ **0.0029**

KENTUCKY POWER COMPANY
CALCULATION OF INTERIM RETIREMENT RATIOS
STEAM PRODUCTION PLANT
ACCOUNT 316.0 MISCELLANEOUS POWER PLANT EQUIPMENT

YEAR	ADDITIONS	RETIREMENTS	BALANCE	AVERAGE BALANCE	RETIREMENT RATIO
1963	1,013,821	0	1,013,821	N. A.	N. A.
1964	5,839	1,922	1,017,738	1,015,780	0.0019
1965	5,676	0	1,023,414	1,020,576	0.0000
1966	15,702	292	1,038,824	1,031,119	0.0003
1967	2,344	394	1,040,774	1,039,799	0.0004
1968	8,129	150	1,048,753	1,044,764	0.0001
1969	1,686,335	1,226	2,733,862	1,891,308	0.0006
1970	204,242	8,507	2,929,597	2,831,730	0.0030
1971	88,954	1,728	3,016,823	2,973,210	0.0006
1972	58,425	83	3,075,165	3,045,994	0.0000
1973	93,582	1,700	3,167,047	3,121,106	0.0005
1974	555	37,702	3,129,900	3,148,474	0.0120
1975	132,129	1,473	3,260,556	3,195,228	0.0005
1976	20,739	6,251	3,275,044	3,267,800	0.0019
1977	66,965	13,849	3,328,160	3,301,602	0.0042
1978	37,660	27,895	3,337,925	3,333,043	0.0084
1979	25,265	5,173	3,358,017	3,347,971	0.0015
1980	17,868	15,971	3,359,914	3,358,966	0.0048
1981	117,316	3,482	3,473,748	3,416,831	0.0010
1982	122,076	54,567	3,541,257	3,507,503	0.0156
1983	6,160	14,806	3,532,611	3,536,934	0.0042
1984	78,342	5,857	3,605,096	3,568,854	0.0016
1985	101,194	2,086	3,704,204	3,654,650	0.0006
1986	108,695	11,296	3,801,603	3,752,904	0.0030
1987	32,012	12,552	3,821,063	3,811,333	0.0033
1988	29,324	12,736	3,837,651	3,829,357	0.0033
1989	169,870	5,926	4,001,595	3,919,623	0.0015
1990	34,137	10,400	4,025,332	4,013,464	0.0026
1991	41,416	3,814	4,062,934	4,044,133	0.0009
1992	127,431	70,529	4,119,836	4,091,385	0.0172
1993	21,290	623	4,140,503	4,130,170	0.0002
1994	803,660	136,159	4,808,004	4,474,254	0.0304
1995	91,614	104,801	4,794,817	4,801,411	0.0218
1996	39,964	9,510	4,825,271	4,810,044	0.0020
1997	865,744	31,903	5,659,112	5,242,192	0.0061
1998	6,545	51,000	5,614,657	5,636,885	0.0090
1999	31,382	805	5,645,234	5,629,946	0.0001
2000	64,253	0	5,709,487	5,677,361	0.0000
2001	59,062	4,330	5,764,219	5,736,853	0.0008
2002	67,283	38,540	5,792,962	5,778,591	0.0067
2003	442,131	62,105	6,172,988	5,982,975	0.0104
2004	698,136	64,449	6,806,675	6,489,832	0.0099
TOTAL 1975-2004	4,459,663	782,888	131,180,475	129,342,088	0.1735

Used 1975 through 2004 interim retirements. Based on retirements five years after in-service date of Unit 2.

AVERAGE INTERIM RATE $\frac{0.1735}{30}$ 0.0058

KIUC Adjustment

Total All Years	7,643,267	836,592	155,416,193	151,505,945	0.1930

AVERAGE INTERIM RATE $\frac{0.1930}{42}$ **0.0046**

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT ACCOUNT 311
RETIREMENT YEARS - UNIT 1 2015; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0011 **No Change**

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	39,765	0.5	19,882	
2006	39,765	1.5	59,647	
2007	39,765	2.5	99,412	
2008	39,765	3.5	139,177	
2009	39,765	4.5	178,941	
2010	39,765	5.5	218,706	
2011	39,765	6.5	258,471	
2012	39,765	7.5	298,236	
2013	39,765	8.5	338,000	
2014	39,765	9.5	377,765	
2015	5,875,352	10.5	61,691,193	
2016	33,346	11.5	383,474	
2017	33,346	12.5	416,820	
2018	33,346	13.5	450,165	
2019	33,346	14.5	483,511	
2020	33,346	15.5	516,857	
2021	33,346	16.5	550,202	
2022	33,346	17.5	583,548	
2023	33,346	18.5	616,893	
2024	33,346	19.5	650,239	
2025	33,346	20.5	683,585	
2026	33,346	21.5	716,930	
2027	33,346	22.5	750,276	
2028	33,346	23.5	783,621	
2029	33,346	24.5	816,967	
2030	33,346	25.5	850,312	
2031	33,346	26.5	883,658	
2032	33,346	27.5	917,004	
2033	33,346	28.5	950,349	
2034	29,276,538	29.5	863,657,881	
TOTALS	36,149,758		939,341,723	25.98 **No change**

INTERIM RETIREMENTS:

Total Plant at 12/31/04	36,149,758
Less Retirement of Unit 1 in 2015	-5,835,587
Less Final Retirement in year 2034	-29,276,538
Total Interim Retirements	1,037,633

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT ACCOUNT 312
RETIREMENT YEARS - UNIT 1 2015; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0112

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	3,634,833	0.5	1,817,417	
2006	3,634,833	1.5	5,452,250	
2007	3,634,833	2.5	9,087,083	
2008	3,634,833	3.5	12,721,917	
2009	3,634,833	4.5	16,356,750	
2010	3,634,833	5.5	19,991,584	
2011	3,634,833	6.5	23,626,417	
2012	3,634,833	7.5	27,261,250	
2013	3,634,833	8.5	30,896,084	
2014	3,634,833	9.5	34,530,917	
2015	10,530,067	10.5	110,565,708	
2016	3,557,607	11.5	40,912,478	
2017	3,557,607	12.5	44,470,085	
2018	3,557,607	13.5	48,027,691	
2019	3,557,607	14.5	51,585,298	
2020	3,557,607	15.5	55,142,905	
2021	3,557,607	16.5	58,700,512	
2022	3,557,607	17.5	62,258,118	
2023	3,557,607	18.5	65,815,725	
2024	3,557,607	19.5	69,373,332	
2025	3,557,607	20.5	72,930,939	
2026	3,557,607	21.5	76,488,545	
2027	3,557,607	22.5	80,046,152	
2028	3,557,607	23.5	83,603,759	
2029	3,557,607	24.5	87,161,366	
2030	3,557,607	25.5	90,718,972	
2031	3,557,607	26.5	94,276,579	
2032	3,557,607	27.5	97,834,186	
2033	3,557,607	28.5	101,391,793	
2034	213,623,372	29.5	6,301,889,475	
TOTALS	324,538,695		7,874,935,287	24.27

INTERIM RETIREMENTS:

Total Plant at 12/31/04	324,538,695
Less Retirement of Unit 1 in 2015	-6,895,234
Less Final Retirement in year 2034	-213,623,372
Total Interim Retirements	104,020,089

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT ACCOUNT 314
RETIREMENT YEARS - UNIT 1 2015; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0092

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	671,959	0.5	335,979	
2006	671,959	1.5	1,007,938	
2007	671,959	2.5	1,679,897	
2008	671,959	3.5	2,351,855	
2009	671,959	4.5	3,023,814	
2010	671,959	5.5	3,695,773	
2011	671,959	6.5	4,367,731	
2012	671,959	7.5	5,039,690	
2013	671,959	8.5	5,711,648	
2014	671,959	9.5	6,383,607	
2015	6,146,815	10.5	64,541,554	
2016	621,590	11.5	7,148,285	
2017	621,590	12.5	7,769,875	
2018	621,590	13.5	8,391,465	
2019	621,590	14.5	9,013,055	
2020	621,590	15.5	9,634,645	
2021	621,590	16.5	10,256,234	
2022	621,590	17.5	10,877,824	
2023	621,590	18.5	11,499,414	
2024	621,590	19.5	12,121,004	
2025	621,590	20.5	12,742,594	
2026	621,590	21.5	13,364,184	
2027	621,590	22.5	13,985,774	
2028	621,590	23.5	14,607,364	
2029	621,590	24.5	15,228,954	
2030	621,590	25.5	15,850,544	
2031	621,590	26.5	16,472,134	
2032	621,590	27.5	17,093,724	
2033	621,590	28.5	17,715,314	
2034	48,983,962	29.5	1,445,026,893	
TOTALS	73,038,983		1,766,938,768	24.19

INTERIM RETIREMENTS:	
Total Plant at 12/31/04	73,038,983
Less Retirement of Unit 1 in 2015	-5,474,856
Less Final Retirement in year 2034	-48,983,962
Total Interim Retirements	18,580,165

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT ACCOUNT 315
RETIREMENT YEARS - UNIT 1 2015; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0029

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	39,854	0.5	19,927	
2006	39,854	1.5	59,780	
2007	39,854	2.5	99,634	
2008	39,854	3.5	139,487	
2009	39,854	4.5	179,341	
2010	39,854	5.5	219,194	
2011	39,854	6.5	259,048	
2012	39,854	7.5	298,902	
2013	39,854	8.5	338,755	
2014	39,854	9.5	378,609	
2015	1,505,064	10.5	15,803,167	
2016	35,604	11.5	409,451	
2017	35,604	12.5	445,055	
2018	35,604	13.5	480,660	
2019	35,604	14.5	516,264	
2020	35,604	15.5	551,869	
2021	35,604	16.5	587,473	
2022	35,604	17.5	623,078	
2023	35,604	18.5	658,682	
2024	35,604	19.5	694,286	
2025	35,604	20.5	729,891	
2026	35,604	21.5	765,495	
2027	35,604	22.5	801,100	
2028	35,604	23.5	836,704	
2029	35,604	24.5	872,309	
2030	35,604	25.5	907,913	
2031	35,604	26.5	943,517	
2032	35,604	27.5	979,122	
2033	35,604	28.5	1,014,726	
2034	11,198,122	29.5	330,344,605	
TOTALS	13,742,601		360,958,046	26.27

INTERIM RETIREMENTS:

Total Plant at 12/31/04	13,742,601
Less Retirement of Unit 1 in 2015	-1,465,210
Less Final Retirement in year 2034	-11,198,122
Total Interim Retirements	1,079,269