COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

GENERAL ADJUSTMENTS IN	)	
ELECTRIC RATES OF	)	**CASE NO. 2005-00341**
KENTUCKY POWER COMPANY	)	

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

Date: January 9, 2005

Direct Testimony
Of
Michael J. Majoros, Jr.

Introduction

Q. State your name, position, and business address.

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

Q. Describe Snavely King.

A. Snavely King is an economic consulting firm founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. Snavely King represents the interests of government agencies, businesses, and individuals who are consumers of telecom, public utility, and transportation services.

We have a professional staff of 12 individuals with backgrounds in economics, accounting, engineering and cost analysis. Most of our work involves the development, preparation and presentation of expert witness testimony before Federal and state regulatory agencies. Over the course of our 35-year history, members of the firm have participated in more than 1,000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

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

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

Q. For whom are you appearing in this proceeding?

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

<u>Subject and Purpose of Testimony</u>

Q. What is the subject of your testimony?

A. My testimony addresses depreciation.

Q. What is the purpose of your testimony?

A. The AG asked me to review Kentucky Power Company's ("Kentucky Power" or "the Company") depreciation proposals, express an opinion regarding their reasonableness, and make alternative recommendations if warranted.

<u>Prior Experience</u>

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

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

Q. Does your experience specifically include electric company depreciation?

A. Yes, I have appeared as an expert on the subject of electric company depreciation in over thirty proceedings. Depreciation was a settled issue in several other electric proceedings in which I prepared testimony.

Q. Have you ever appeared before the Kentucky Public Service Commission ("KPSC")?

A. Yes, I have appeared before the KPSC on several occasions. Recently, I submitted testimony in Case No. 2005-00042, regarding the depreciation rates of Union Light, Heat and Power Company. The decision of the Commission in that case was issued by order dated December 22, 2005.

Kentucky Power's Present Depreciation Rates

Q. When were Kentucky Power's present depreciation rates approved?

A. The present depreciation rates were established as part of the settlement in Case No. 91-066. According to the Order in that case, "...Kentucky Power's depreciation study and revised depreciation rates shall be [were] approved as filed..."[1]

Q. How were the present depreciation rates calculated?

A. They are straight-line remaining life depreciation rates.[2]

[1] Case No. 91-066, *In the Matter of: Application for Adjustment of Electric Rates of Kentcuky Power Company*, Order, Issued October 28, 1991, page 2.

[2] Direct Testimony of James E. Henderson ("Henderson Direct"), page 6.

Kentucky Power's Proposed Depreciation Rates

Q. Summarize Kentucky Power's depreciation rate proposals in this proceeding.

A. Mr. James E. Henderson sponsors Kentucky Power's depreciation study. Mr. Henderson's proposals would increase annual depreciation expense by $3.7 million, relative to current depreciation rates based on December 31, 2004 plant balances.[3] The table below summarizes Mr. Henderson's proposals and compares them to the present rates.

Table 1

Comparison of Kentucky Power's Present and Proposed Accruals Based on Plant as of December 31, 2004[4]
($000)

		Proposed Rates			
	Present Rates Total Accrual	Capital Recovery Accrual	Cost of Removal Accrual	Total Accrual	Difference
Steam Production	$ 17,713	$ 13,262	$ 2,952	$ 16,215	($ 1,498)
Transmission	6,552	6,440	3,958	10,398	3,846
Distribution	15,394	9,060	6,848	15,908	514
General	728	1,493	29	1,523	794
Total	$ 40,387	$ 30,255	$13,788	$ 44,044	$ 3,657

Q. Is Mr. Henderson making any new proposals?

A. Yes, Mr. Henderson has three new proposals. First, Kentucky Power's current generating plant depreciation rates incorporate future cost of removal (decommissioning) estimates based on a 1990 study by Sargent & Lundy. The Company had a new study conducted by Brandenburg Industrial Service

[3] Henderson Direct, page 4.
[4] Henderson Direct, page 4.

Company which demonstrates that the old $43.2 million estimate was vastly overstated. Mr. Henderson incorporated the new estimate in his proposed generating plant depreciation rates.

Second, Kentucky Power's <u>current</u> depreciation rates for Transmission, Distribution and General plant <u>do not</u> incorporate any future cost of removal estimates. Mr. Henderson's new proposals, however, incorporate a substantial amount of estimated future cost of removal.

Third, although Mr. Henderson proposes a longer life span for Big Sandy Unit 2, he did not extend the life span for Big Sandy Unit 1.

<u>Unbundled Depreciation Rates</u>

Q. Have you included any additional versions of Mr. Henderson's proposed depreciation rates in your exhibits?

A. Yes, Exhibit___(MJM-1) shows Mr. Henderson's proposed depreciation rates unbundled into two rates which sum to his proposed depreciation rate for each account. I have shown Mr. Henderson's capital recovery rate and his future cost of removal rate for each account. I am providing these specifically identified depreciation rates in order to facilitate external reporting and for regulatory analysis and rate setting purposes. Unbundled depreciation rates provide new and better information and do not require any change to current accounting rules. It will provide the Commission and ratepayers with the ability to know how much they are paying for capital recovery versus future cost of removal.

Q. If they are unbundled, would you agree with all of Mr. Henderson's proposed depreciation rates?

A. No. I also disagree with certain other aspects of Mr. Henderson's specific rate proposals. Regardless of that, Mr. Henderson's rates should be unbundled into two components as discussed above.

<u>**Conclusions**</u>

Q. What are your conclusions?

A. I conclude that even on an unbundled basis, Mr. Henderson's proposals result in *excessive depreciation* expense and charges to ratepayers. The excessive depreciation is caused by an understated life span for Big Sandy Unit 1 and overstated cost of removal factors. I base my conclusions on my depreciation study, my analysis, the new information brought to light by recent accounting pronouncements, and this Company's prior actions as a result of those recent accounting pronouncements. My recommended depreciation rates are set-forth in Exhibit___(MJM-2) and summarized in the table below. My recommendations result in a $7.2 million decrease in depreciation expense, based on December 31, 2004 plant balances.

Table 2

Comparison of Present and Snavely King Recommended Accruals
Based on Plant as of December 31, 2004[5]
($000)

		SK Recommended Rates			
	Present Rates Total Accrual	Capital Recovery Accrual	Cost of Removal Accrual	Total Accrual	Difference
Steam Production	$ 17,713	$ 13,023	$ 1,224	$ 14,247	($ 3,466)
Transmission	6,552	6,485	421	6,905	354
Distribution	15,394	8,929	1,542	10,470	(4,923)
General	728	1,493	24	1,517	789
Total	$ 40,387	$ 29,930	$ 3,210	$ 33,140	($ 7,247)

My proposal results a $10.9 million downward swing from Mr. Henderson's $3.7 million increase proposal.

Q. What is the foundation of your conclusions and recommendations?

A. I submitted data requests and reviewed the Company's responses thereto. I also reviewed Kentucky Power's responses to relevant Staff and other intervenor data requests. I referred to the most recent update to my firm's national study of electric production plant lives. This is included as Exhibit___(MJM-3). I conducted an independent detailed service life study, which addresses lives and survivor curves. Due to its volume, I have extracted certain relevant pages from the study to provide the results. These pages are attached as Exhibit___(MJM-4). The complete study is 620 pages and will be provided as workpapers. I also conducted a net salvage study which is attached as Exhibit___(MJM-5).

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[5] Exhibit___(MJM-2)

Excessive Depreciation

Q. You have used the phrase "*excessive depreciation.*" Have you provided any background information on the concept of *excessive depreciation*?

A. Yes, an *excessive depreciation rate* is one that produces more depreciation expense than necessary to return the cost of a company's capital asset over the life of the asset. Exhibit___(MJM-6) is a brief summary of a landmark U.S. Supreme Court decision on depreciation. I am not an attorney and I do not present this as a legal argument or conclusion. I merely present this to demonstrate that the concept of *excessive depreciation* is not a new one.

I have also included in Exhibit___(MJM-6) a discussion of, and quotations from, the Financial Accounting Standard Board's ("FASB") Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") demonstrating that the public accounting profession is also cognizant of and concerned about excessive depreciation.

Q. Mr. Majoros, does the fact that accumulated depreciation reduces rate base render the concept of excessive depreciation moot?

A. No, this is a straw-man argument put forth by many utility witnesses. If ratepayers are required to pay too much for depreciation expense, they will have paid too much. In the case of excessive depreciation, the Company has taken more of the ratepayer's money than it should have. The fact that ratepayers are not required to pay a return on prior excessive charges does not mean that those charges were not excessive.

Depreciation Concepts

Q. Does your testimony include a discussion of the depreciation concepts relevant to your testimony?

A. Yes, Exhibit___(MJM-7) is a brief discussion of depreciation concepts relevant to my testimony. I am submitting this discussion as a separate exhibit to minimize the technical aspects of my direct testimony. The depreciation concepts discussion may be helpful to understanding my testimony as well as Mr. Henderson's.

New Accounting Rules

Q. Are there any new depreciation-related accounting rules been since the Company's last depreciation study?

A. Yes, the Financial Accounting Standards Board's ("FASB") Statement of Financial Accounting Standard No. 143 ("SFAS No. 143") addresses asset retirement obligations ("AROs") associated with long-lived plant. If a utility has previously collected money in the form of future cost of removal embedded in depreciation rates, such as the Company's prior collections for its generating plant, but does not have a legal obligation to incur those costs, SFAS No. 143 requires reporting of that excess as a regulatory liability.[6]

The Federal Energy Regulatory Commission's ("FERC") Order No. 631 is that agency's implementation of SFAS No. 143 for regulatory purposes. FERC identified the excess amounts discussed above as "non-legal" asset

[6] SFAS No. 143, paragraph B.73.

retirement obligations, meaning that utilities do not have actual legal obligations and liabilities to incur these costs in the future. FERC requires separate identification of these amounts in sub-accounts of accumulated depreciation and depreciation expense.

Q. Has Kentucky Power recognized any regulatory liabilities as a result of SFAS No. 143?

A. Yes, Kentucky Power's 2004 SEC Form 10K reports a $28.2 million cost of removal regulatory liability in compliance with SFAS No. 143.[7]

Q. Explain the amount and the issue in non-technical language.

A. Kentucky Power has collected $28.2 million more from ratepayers than it has incurred for cost of removal. Current GAAP accounting rules require the $28.2 million excess collections be reported as amounts owed to ratepayers (regulatory liabilities) until they are spent on their intended purpose. Unfortunately, FERC Order No. 631 does not have a similar requirement. Therefore, for regulatory purposes, the $28.2 million excess is currently recorded as a separate sub-component of account 108 – Accumulated Depreciation.

Q. What caused this regulatory liability?

A. The $28.2 million regulatory liability is the result of including estimated decommissioning costs for generating plants in current depreciation rates.

Q. Will Mr. Henderson's proposals increase the $28.2 million regulatory liability?

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[7] Kentucky Power Company 2004 10K Report, page H-12.

A. Yes, although Mr. Henderson recognizes as a result of the new 2004 study that prior decommissioning costs were overstated, his proposed future cost of removal factors for the generating plant interim retirements, and the transmission, distribution and general plant functions will increase the $28 million regulatory liability by an exorbitant increment each year. Luckily, SFAS No. 143 and FERC Order No. 631 have recognized and highlighted the excess collections, and SFAS No. 143 requires reporting them as a regulatory liability for GAAP purposes.

Q. Do any new issues emanate from the new accounting rules?

A. The most important new issue is the need for the Kentucky Public Service Commission to hold the Company accountable for these excess advance collections by <u>officially recognizing a regulatory liability.</u> In my opinion, it should be reclassified from account 108-accumulated depreciation to account 254-other regulatory liabilities, and from there, the Commission should <u>require separate identification and reporting</u> of these amounts.

<u>The KPSC Should Specifically Recognize the SFAS No. 143 Regulatory Liability</u>

Q. How does GAAP define a regulatory liability?

A. SFAS No. 71 – Accounting for the Effects of Certain Types of Regulation defines regulatory liabilities from a GAAP perspective. Paragraph 11 (summarized below) defines a regulatory liability. Please pay particular attention to paragraphs 11 and 11 b.

SFAS No. 71 – Regulatory Liabilities[8]

> 11. Rate actions of a regulator can impose a liability on a regulated enterprise. Such liabilities are usually obligations to the enterprise's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:
>
> a. A regulator may require refunds to customers. ...
>
> b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be recognized as liabilities and taken to income only when associated costs are incurred.
>
> c. A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. ...

Q. Does Kentucky Power agree that its collections for non-legal AROs result in a regulatory liability?

A. Yes, for GAAP and SEC reporting Kentucky Power agrees that its non-legal ARO collections represent an amount owed to ratepayers.

Q. Have you made similar recommendations to the KPSC regarding cost of removal collections?

[8] SFAS No. 71, paragraph 11. Only the first sentence of each subparagraph is included.

A. Yes, I made the same recommendations in Union Light, Heat and Power Company's recent gas rate case (No. 2005-00042). The Commission's December 22, 2005 order specifically addressed my recommendation.

Q. Did the Commission adopt your recommendation in that case?

A. No, it did not. The Commission stated the following:

> The Commission is not persuaded by the AG's arguments. The AG *has not demonstrated the need for this "transparent and enhanced reporting"* and *why it is necessary to establish a regulatory liability for the portion of accumulated depreciation related to net salvage.* The AG presumes that excessive depreciation expense accruals exist because of his belief that the estimated cost of removal far exceeds the actual cost of removal. However, *the AG has provided no analysis of plant retirements or removals that compare the estimated and actual costs.* The AG also appears to have *overlooked how the remaining life approach adjusts depreciation rates when there have been over-accruals.* As defined in the Uniform System of Accounts, prescribed by FERC and adopted by this Commission, depreciation means the loss of service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Service value means the difference between original cost and net salvage value of gas plant. The definition of depreciation is not the recovery of capital investment.[9]
>
> Therefore, the Commission finds that the AG's request to establish a regulatory liability should be denied.[10]

Q. Mr. Majoros, please address the Commission's concerns as expressed in that order regarding your recommendation in this case.

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[9] Order, Case No. 2005-00042, *In the Matter of: An Adjustment of the Gas Rates of the Union Light, Heat and Power Company* Issued December 22, 2005, pages 36-37.

[10] Order, Case No. 2005-00042, Issued December 22, 2005, page 37.

A. Exhibit___(MJM-1) shows that Mr. Henderson is proposing to charge ratepayers $13.8 million per year for cost of removal. My Exhibit___(MJM-5) is my net salvage study which was, in turn, drawn from Mr. Henderson's study and responses to data requests. It provides, among other things, a historical analysis of the Company's actual cost of removal. The average from the most recent five years is $3.2 million. It also demonstrates that the Company's net salvage has actually been positive $8 thousand.

These data constitute the analysis the Commission said was missing from the Union Heat Light and Power case. This demonstrates directly that the Company proposes to charge ratepayers at least $13.8 million each year for an expenditure that is only $3.2 million on average. Given this, the Company must show why the excess collections should be allowed in rates. This Company has not done that. Furthermore, if a refundable regulatory liability is not recognized, the Company is not even held accountable for the excess collections.

Q. Is there a need for transparent and enhanced reporting?

A. The need for transparency and enhanced reporting has been addressed by the FERC as well as the Financial Accounting Standards Board and the Securities and Exchange Commission. Both SFAS No. 143 and FERC Order No. 631 provide transparency and enhanced reporting.

Q. If the KPSC requires transparency and enhanced reporting, should it also specifically recognize a regulatory liability?

A. Even though Kentucky Power reports these collections as amounts owed to ratepayers for GAAP purposes, and separates the reserve for FERC accounting, it maintains that it does not owe the money back to ratepayers even if it does not incur the cost of removal it has collected. Kentucky Power maintains that all collections, even excess collections, belong to its shareholders simply because they are reported in accumulated depreciation. Kentucky Power considers accumulated depreciation to represent capital recovery and therefore to be its shareholders' property.

Therefore, the KPSC should specifically recognize a refundable regulatory liability because Kentucky Power intends to keep the money, even if it does not spend the money for cost of removal. Only <u>this</u> Commission can <u>protect</u> these amounts on behalf of Kentucky ratepayers.

Even though SFAS No. 143 and the SEC require recognition of these amounts as regulatory liabilities, the FERC left such recognition up to the states for regulatory purposes. Without such protection, Kentucky Power could absorb the unspent funds into its corporate income account, even if they will never be spent on cost of removal.

Q. On what basis do you maintain that Kentucky Power intends to keep the money even if it does not spend it for cost of removal?

A. The AG asked the Company this specific question in AG-1-168, attached as Exhibit___(MJM-8). Below is a portion of the Company's response.

> <u>AG Request No. 168:</u> With respect to the Regulatory Liability relating to asset cost of removal which you reclassified out of accumulated depreciation:

b. Do you agree that this amount is a refundable obligation to ratepayers until it is spent on its intended purpose (cost of removal)? If not, why not?

h. Does Kentucky Power believe that amounts recorded in accumulated depreciation represent capital recovery? If not, why not?

i. Whose capital is reflected in accumulated depreciation – shareholders' or ratepayers'?

Response:

b. No. The Company does not believe the approved collection of removal costs through depreciation rates creates a refundable obligation. The definition of depreciation provides that net salvage is to be considered in depreciation.

h. Yes.

i. The shareholder's.

Q. From this response, what do you conclude?

A. Kentucky Power considers the excess collections to belong to shareholders and would transfer them into its income if the opportunity arises.

Q. Do you have any indication that Kentucky Power would transfer these excess cost of removal amounts into income if the opportunity arises?

A. Yes, I do. Kentucky Power's parent company, American Electric Power Company, Inc. ("AEP") did just that when several of its production plants were deregulated. AEP immediately transferred $473 million relating to those deregulated plants from accumulated depreciation into its own income.[11]

[11] AEP 2003 Annual Report to Shareholders, page 69.

Q. Have other electric utilities treated amounts recorded as accumulated depreciation as their own money and taken past collections for future cost of removal into their own income?

A. Yes, that is exactly what other electric utilities did when their production plants were deregulated. For example, Tucson Electric Power Company ("TEP") stated that:

> TEP had accrued $113 million for final decommissioning of its generating facilities.. ... this amount was reversed for 2002 and included as part of the cumulative effect adjustment of accounting adjustment when FAS 143 was adopted on January 1, 2003.[12]

This means that TEP transferred non-legal AROs into its own income.

Q. If the opportunity arises, would TEP transfer even more non-legal AROs into its own income?

A. Yes, TEP applies SFAS No. 71 - Accounting for the Effects of Certain Types of Regulation - to its <u>regulated</u> operations, which include the transmission and distribution portions of its business. As a result TEP recorded the cost of removal collected for regulated non-legal AROs as a regulatory liability. According to TEP's December 31, 2004 10K Report:

> As of December 31, 2004, TEP had accrued $67 million for the net cost of removal of the interim retirements from its transmission, distribution and general plant. As of December 31, 2003, TEP had accrued $60 million for these removal costs. The amount is recorded as a regulatory liability.[13]

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[12] Tucson Electric Power Company December 31, 2004 10 K Report, page K-59.
[13] Id., page K-60.

However, also according to TEP's December 31, 2004 10K Report:

> If TEP stopped applying FAS 71 to its remaining regulated operations, it would write off the related balances of its regulatory assets as an expense and its regulatory liabilities as income on its income statement.[14]

Q. Why is that language significant?

A. It provides TEP with an "out." If it can find a way to discontinue accounting under SFAS No. 71, TEP will transfer the rest of its excess collections into its corporate income.

Q. Does AEP have a similar statement in its 10K Report?

A. Yes, page A-76 of AEP's 2004 Form 10K states:

> For cost-based rate-regulated operations, the composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation. Actual removal costs incurred are debited to accumulated depreciation. *Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from accumulated depreciation and reflected as a regulatory liability.* For nonregulated operations, non-ARO removal costs are expensed as incurred.[15] (Emphasis added.)

Page L-2 of AEP's 2004 Form 10K also states:

> ***Accounting for the Effects of Cost-Based Regulation***
> As cost-based rate-regulated electric public utility companies, the Registrant Subsidiaries' financial statements reflect the actions of regulators that result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets (deferred expenses) and

[14] Id.
[15] AEP 2004 10K Report, page A-76.

> regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. The following Registrant Subsidiaries discontinued the application of SFAS 71 for the generation portion of their business as follows: in Ohio by OPCo and CSPCo in September 2000, in Virginia and West Virginia by APCo in June 2000, in Texas by TCC, TNC, and SWEPCo in September 1999, in Arkansas by SWEPCo in September 1999 and in the FERC jurisdiction for TNC in December 2003. During 2003, APCo reapplied SFAS 71 for its West Virginia generation operations and SWEPCo reapplied SFAS 71 for its Arkansas generation operations. SFAS 101, "Regulated Enterprises – Accounting for the Discontinuance of Application of FASB Statement No. 71" requires the recognition of an impairment of a regulatory asset arising from the discontinuance of SFAS 71 be classified as an extraordinary item.[16]

Q. What does all of this mean?

A. It means that the public accounting profession is aware that AEP has collected more than it needs for future cost of removal, and as long as it is regulated on a cost basis, the excess is a refundable liability to ratepayers. But, should the industry be deregulated, or even move to price regulation, the money drops to AEP's bottom line.

Q. Have any other industries taken non-legal ARO amounts into income?

A. Yes, while regulated, the telephone industry collected substantial amounts of future cost of removal through depreciation, just as Kentucky Power is proposing here. Upon deregulation and the adoption of SFAS No. 143, the

[16] AEP 2004 10K Report, page L-2.

major telephone companies took $11.5 billion from accumulated depreciation into net income.[17]

Q. All of these examples appear to involve deregulation or partial deregulation. Is there any reason to be concerned about that for Kentucky Power as a regulated utility in a state that plans to continue to regulate its utilities?

A. Yes, there are reasons to be concerned. First, Kentucky Power is a subsidiary of AEP. The generation portion of AEP's business has already been deregulated in many state jurisdictions as well as at the Federal level. Furthermore, Congress just passed the Energy Policy Act of 2005, which not only gutted, but overturned the protections provided by the Public Utility Holding Company Act of 1935. Then too, telephone companies are considering broadband over power lines and might consider purchases of electric distribution grids for that purpose. Were this to occur, suddenly regulated electric assets become deregulated telephone assets. One cannot continue to assume that regulated utilities will avoid the impact of other unregulated enterprises. Therefore, there are reasons to be concerned.

Notwithstanding these concerns, nothing holds Kentucky Power directly accountable for these excess collections from a regulatory standpoint. Kentucky Power's actual experience demonstrates it is not likely that it will incur cost of removal at the levels collected; but even if did, it is still fair and

[17] Pre-tax gains of SBC ($5.9 billion), Verizon ($3.5 billion), Qwest ($0.4 billion), BellSouth ($1.3 billion) and Sprint ($0.4 billion). See Companies' 2003 10K Reports and 2003 Annual Reports to Shareholders.

reasonable for the KPSC to recognize the ratepayers' interest in these monies until actually spent on their intended purpose. Unless they are explicitly identified as "subject to refund," they are merely hidden potential income to Kentucky Power.

Q. Does the remaining life depreciation technique solve the problem?

A. No. The remaining life technique assumes perpetual cost-based regulation ad infinitum, but that assumption is no longer valid. Only recognition as a regulatory liability will protect the excess depreciation collections.

Q. Would this change were the Company to need the excess collections for construction?

A. In those circumstances, the excess collections should be specifically identified and charged and recorded in account 252-Customers advances for construction. They will also be subject to refund in that account.

Q. Do you recommend that the KPSC require that Kentucky Power separately identify this regulatory liability in filings before it?

A. Yes, the KPSC should require that Kentucky Power explicitly identify and report this regulatory liability and all related activity in all future reports, rate cases, and depreciation studies that it files with the KPSC. Furthermore, the KPSC's explicit recognition of this amount as a regulatory liability should be prominently disclosed in Kentucky Power's Form 1 reports.

Q. Would it be sufficient to report the item as a "deferred credit?"

A. No, treatment as a deferred credit would defeat the purpose. Kentucky Power could easily assert that ratepayers have no claim to a deferred credit.

Kentucky Power could claim that a deferred credit is its money, not ratepayers' money. In order to protect ratepayers, the KPSC must officially recognize the item and Kentucky Power must report a regulatory liability for regulatory and ratemaking purposes.

Q. What are your conclusions?

A. My recommendations for specific recognition by the Commission of a regulatory liability for non-legal cost of removal and dismantlement amounts and the continued identification and reporting of such regulatory liability by Kentucky Power in its regulated reports does not harm the Company in any way. It does provide a level of protection for ratepayers that they are not currently receiving. This is a true win-win situation.

<u>Going-Forward Treatment of Future Cost of Removal</u>

Q. Given the Commission's decision in the Union Heat Light and Power case, what is the appropriate going-forward treatment of cost of removal?

A. If the Company is not to be held accountable for excess collections going-forward, the only reasonable solution is to keep the annual charges to ratepayers as close as possible to the Company's actual expenditures.

Q. How would that be done?

A. The cost of removal factors should be based on the most recent five-year average of actual cost of removal experience. This approach, combined with the remaining-life technique keeps the Company whole on a current basis, and reduces the amount excess collections charged to ratepayers.

Q. Have you calculated depreciation rates based on this approach?

A. Yes, these calculations are included in Exhibit___(MJM-5), and carried forward to my overall recommendations in Exhibit___(MJM-2). As you can see, this approach still provides the unbundling I discussed earlier, but does not provide such an exorbitant advance payment to the Company each year. At the same time, the Company is kept more than whole on a going-forward basis.

<u>Production Plant Life Span Depreciation Rate Calculations</u>

Q. How did Mr. Henderson estimate his service life for Production Plant?

A. Mr. Henderson used the life span method for Production plant.

Q. Please explain the life span method in more detail.

A. The life span method is actually a procedure to estimate an average service life and average remaining life for a property group. It is based on the assumption that a property group is comprised of a small number of large units subject to concurrent terminal (final) retirement. The period between the original installation and the terminal retirement date is the life span. The period between the study date and the terminal retirement date is the remaining life span. The life span method also recognizes "interim" additions and retirements prior to the terminal date. Importantly, however, future interim additions <u>are not</u> considered in the depreciation base or depreciation rate until they occur.[18] Given the ease of visualizing a concurrent final retirement of major structures, the life span method has obvious intuitive appeal. The method also has limitations and strenuous rules for its application.

[18] NARUC Public Utility Depreciation Practices Manual, 1996, p. 142.

Q. Is the fundamental life span assumption of a concurrent terminal retirement always valid?

A. Not necessarily. I have discovered problems with the life span method. For example, in the early 1990's I visited a major water treatment plant where the structures and treatment process were being upgraded. A few years later I revisited the same plant and discovered that a majority of the original structures were still in service. They had merely been modernized and expanded. A final retirement assumption was inappropriate because the treatment plant is fundamental and critical to the operation of that Company. The most reasonable depreciation assumption was that the plant will be well maintained and upgraded as long as the water it treats continues to flow.

I have also visited electric plants that have had partial final retirements of structures only to find that the space would be reused as offices or training centers. A specific terminal retirement year estimate was specious in those circumstances. A supportable average service life assumption based on the flow of dollars in and out of the accounts was much more reasonable.

Q. What terminal retirement years is Mr. Henderson proposing for his production plant investment?

A. Mr. Henderson has proposed retirement dates of 2015 for Big Sandy Plant Unit 1 and 2034 for Unit 2. These retirement years result in life spans of 52 years for Unit 1 and 65 years for Unit 2. According to Mr. Henderson, AEP provided the retirement dates.[19]

Q. Are these terminal retirement years and remaining life spans realistic?

A. Mr. Henderson's life span of 65 years for Unit 2 is realistic for a steam production plant. In making this determination, I relied on a National Study of U.S. Steam Generating Unit Lives – 50 MW and Greater ("National Study") conducted by my firm. This study, included as Exhibit___(MJM-3), uses analytical techniques generally accepted in the utility industry and a database maintained by the U.S. Department of Energy.[20] The study concludes that U.S. Steam Generating Units 50 MW or greater are experiencing average life spans of approximately 60 years and that these spans are lengthening almost on a year-to-year basis.

Q. What about Unit 1?

A. I do not agree with the proposed retirement date and resulting life span for Unit 1.

Q. How did the Company select the retirement dates for Big Sandy?

A. The proposed retirement dates appear to have been selected based on environmental reasons. Page 2 of Mr. Henderson's workpapers states, "AEP recently announced plans to install flue gas desulfurization (FGD) equipment to reduce sulfur dioxide emissions on Unit 2 at Big Sandy Plant. This

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[19] Exhibit JEH-1, pages 2-3.

[20] The study is an actuarial retirement rate analysis, using the Energy Information Agency's Form 860 data base of aged generating unit retirements and exposures. A full band (1900-2000) and both rolling band and shrinking band analyses were conducted.

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 environmental constraints, the current plans are to retire Unit 1 in year 2015."[21]

Q. Did Kentucky Power provide a reason for not installing the FGD equipment on Unit 1?

A. No. I have attached the responses to several data requests concerning this issue as Exhibit___(MJM-9). Kentucky Power has offered no support for its decision. In particular, the Company notes, "At this time, there are no analyses or other documents addressing the replacement of Big Sandy 1 capacity in 2015."[22]

Q. What do you conclude?

A. I conclude that the terminal retirement date for Unit 1 should be extended to 2028. This conclusion is based on a 65-year life span from the installation date of 1963, which is the same life span Kentucky Power is assuming for Unit 2. This conclusion is also supported by my national study. In fact, based on my experience and my study, I believe that Big Sandy Unit 1 may very well last more than 65 years. Mr. Henderson has failed to prove that Big Sandy will retire early. A lack of plans to install FGD equipment is not a good reason to move a retirement date forward.

[21] Henderson Depreciation Study workpapers, page 2 of 443.
[22] Response to KIUC Data Request No. 2-4. See Exhibit___(MJM-9).

Q. Have you calculated new remaining lives for Big Sandy Unit 1 based on your recommended retirement date?

A. Yes, my remaining life calculations are included in Exhibit___(MJM-4).

Snavely King Life Analysis Approach For Mass Property

Q. What was your approach to analyzing Kentucky Power's lives and curves in the Transmission, Distribution and General functions?

A. I began by reviewing Mr. Henderson's study. I analyzed each account using the retirement rate and/or simulated plant record ("SPR"), and geometric mean turnover ("GMT") methods. I also reviewed the Company's responses to data requests to obtain any additional information that would impact my analysis.

Q. What was the result of your analyses?

A. Based on my analyses, I conclude that the lives proposed by Mr. Henderson are reasonable. As such, I do not recommend any changes to his lives for Transmission, Distribution and General plant.

Reserves

Q. How does Kentucky Power maintain its book reserves?

A. Kentucky Power currently applies its depreciation rates, and maintains its book reserves at the functional level.

Q. Has Mr. Henderson put forth any recommendations regarding this policy?

A. Yes. Mr. Henderson recommends that the Company begin applying depreciation rates at the plant account level. He also recommends maintaining the book reserves at that level.

Q. How has Mr. Henderson calculated the book reserve by plant account for use in his rate calculations?

A. Mr. Henderson allocated the functional book reserve based on the theoretical reserve for each account.

Q. Have you reallocated the reserves using theoretical reserves based on your recommended parameters?

A. Yes. The depreciation rates I have calculated reflect the allocation of book reserves based on my capital recovery theoretical reserves.

<u>Recommended Depreciation Rates</u>

Q. Have you provided your recommended depreciation rates?

A. Yes, my recommended depreciation rates are included in Exhibit___(MJM-2). I am recommending two rates for each account: capital recovery and cost of removal. The two rates sum to the single rate which I have included for ease of calculating revenue requirement effects. But, as I explained throughout this testimony, it is imperative that the Commission require the separate rate for cost of removal.

<u>Summary of Recommendations</u>

Q. Mr. Majoros, please summarize your recommendations.

A. I recommend that the KPSC specifically recognize the refundable regulatory liability resulting from Kentucky Power's collection of excessive non-legal ARO charges. The KPSC should recognize this as a regulatory liability for regulatory reporting, regulatory analysis, and ratemaking purposes in Kentucky. It should require separate capital recovery versus cost of removal depreciation rates. I recommend extending the terminal retirement date for Big Sandy Unit 1 to 2028. I have accepted Mr. Henderson's proposed retirement date of 2034 for Unit 2, as well as all of Mr. Henderson's proposed lives for Transmission, Distribution and General plant.

Q. Does this conclude your testimony?

A. Yes, it does.

Washington,)
: ss.
District of Columbia)

AFFIDAVIT

I, Michael J. Majoros, Jr., hereby swear and affirm that the foregoing testimony and any accompanying exhibits were prepared by me or under my direction and that the information contained therein is, to the best of my information and belief, true and correct.

Michael J. Majoros, Jr.

Washington,
District of Columbia

Subscribed and sworn to before me this 9th day of January, 2006, by Michael J. Majoros, Jr.

Notary Public

My Commission Expires: 3-14-06

ANSEL L. FINCH NOTARY PUBLIC DISTRICT OF COLUMBIA

Exhibit___(MJM-1)

Split of Company Proposed Rates

Into

Capital Recovery and Cost of Removal Rates

KENTUCKY POWER COMPANY
SEPARATION OF COMPANY PROPOSED RATES INTO CAPITAL RECOVERY AND COST OF REMOVAL
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

ACCOUNT		ORIGINAL	CAPITAL RECOVERY		COST OF REMOVAL		COMBINED	
		COST AT	ANNUAL	ACCRUAL	ANNUAL	ACCRUAL	ANNUAL	ACCRUAL
NO.	TITLE	12/31/2004	ACCRUAL	RATE	ACCRUAL	RATE	ACCRUAL	RATE
(1)	(2)	(3)	(4)	(5)=(4)*(3)	(6)	(7)=(6)*(3)	(8)=(4)+(6)	(9)=(5)+(7)
STEAM PRODUCTION PLANT								
	BIG SANDY PLANT							
311.0	Structures & Improvements	$ 36,149,758	$ 843,613	2.33%	$ 1,168	0.00%	$ 844,781	2.34%
312.0	Boiler Plant Equipment	324,538,695	10,136,700	3.12%	2,576,077	0.79%	12,712,778	3.92%
314.0	Turbogenerator Units	73,038,983	1,828,450	2.50%	349,796	0.48%	2,178,246	2.98%
315.0	Accessory Electrical Equipment	13,742,601	292,504	2.13%	11,095	0.08%	303,599	2.21%
316.0	Misc. Power Plant Equip.	6,518,954	160,908	2.47%	14,066	0.22%	174,974	2.68%
	Total Steam Production Plant	453,988,991	13,262,175	2.92%	2,952,202	0.65%	16,214,378	3.57%
TRANSMISSION PLANT								
350.1	Land Rights	23,258,047	334,440	1.44%	-	0.00%	334,440	1.44%
352.0	Structures & Improvements	6,387,065	110,646	1.73%	17,605	0.28%	128,251	2.01%
353.0	Station Equipment	123,153,116	1,853,432	1.50%	1,427,744	1.16%	3,281,176	2.66%
354.0	Towers & Fixtures	92,364,356	1,607,660	1.74%	913,723	0.99%	2,521,383	2.73%
355.0	Poles & Fixtures	37,506,208	970,842	2.59%	791,939	2.11%	1,762,780	4.70%
356.0	OH Conductor & Devices	100,355,481	1,559,698	1.55%	807,235	0.80%	2,366,933	2.36%
356.0	Underground Conduit	11,590	375	3.23%	-	0.00%	375	3.23%
358.0	Underground Conductor	106,066	2,678	2.53%	-	0.00%	2,678	2.53%
	Total Transmission Plant	383,141,929	6,439,771	1.68%	3,958,246	1.03%	10,398,016	2.71%
DISTRIBUTION PLANT								
360.1	Land Rights	3,691,802	47,957	1.30%	-	0.00%	47,957	1.30%
361.0	Structures & Improvements	4,231,065	52,432	1.24%	7,457	0.18%	59,889	1.42%
362.0	Station Equipment	42,017,840	695,349	1.65%	683,693	1.63%	1,379,043	3.28%
364.0	Poles, Towers, & Fixtures	124,672,243	2,118,696	1.70%	4,019,690	3.22%	6,138,387	4.92%
365.0	Overhead Conductor & Devices	99,426,561	1,732,820	1.74%	884,185	0.89%	2,617,004	2.63%
366.0	Underground Conduit	2,959,899	58,747	1.98%	-	0.00%	58,747	1.98%
367.0	Underground Conductor	5,482,068	87,407	1.59%	-	0.00%	87,407	1.59%
368.0	Line Transformers	84,185,422	1,529,895	1.82%	613,001	0.73%	2,142,895	2.55%
369.0	Services	31,239,944	1,190,295	3.81%	-	0.00%	1,190,295	3.81%
370.0	Meters	21,071,793	656,604	3.12%	103,496	0.49%	760,100	3.61%
371.0	Installations on Custs. Prem.	15,598,882	776,934	4.98%	507,556	3.25%	1,284,489	8.23%
373.0	Street Lighting & Signal Sys.	2,741,234	112,499	4.10%	29,100	1.06%	141,599	5.17%
	Total Distribution Plant	437,318,753	9,059,634	2.07%	6,848,178	1.57%	15,907,812	3.64%
GENERAL PLANT								
389.2	Land Rights	84,011	1,200	1.43%	-	0.00%	1,200	1.43%
390.0	Structures & Improvements	19,295,997	988,140	5.12%	29,460	0.15%	1,017,600	5.27%
391.0	Office Furniture & Equipment	1,737,579	56,903	3.27%	-	0.00%	56,903	3.27%
392.0	Transportation Equipment	5,819	310	5.33%	-	0.00%	310	5.33%
393.0	Stores Equipment	189,262	7,378	3.90%	-	0.00%	7,378	3.90%
394.0	Tools Shop & Garage Equipment	1,711,318	58,438	3.41%	-	0.00%	58,438	3.41%
395.0	Laboratory Equipment	394,394	24,381	6.18%	-	0.00%	24,381	6.18%
396.0	Power Operated Equipment	5,931	914	15.41%	-	0.00%	914	15.41%
397.0	Communication Equipment	4,666,769	320,126	6.86%	-	0.00%	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	35,473	6.07%	-	0.00%	35,473	6.07%
	Total General Plant	28,675,764	1,493,263	5.21%	29,460	0.10%	1,522,723	5.31%
	Total Depreciable Plant	$ 1,303,125,437	$ 30,254,843	2.32%	$ 13,788,084	1.06%	$ 44,042,929	3.38%

Sources:
Col. (3) from Exhibit JEH-1, Schedule 1.
Col. (4) from page 2.
Col. (6) from page 3.

KENTUCKY POWER COMPANY
CALCULATION OF COMPANY PROPOSED CAPITAL RECOVERY RATE
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/2004 (3)	BOOK RESERVE LESS COR (4)	GROSS SALVAGE RATIO (5)	FUTURE ACCRUALS (6)=((3)*(5))-(4)	AVERAGE LIFE AND CURVE TYPE (7)	AVERAGE REMAINING LIFE (8)	CAPITAL RECOVERY ANNUAL ACCRUAL (9)=(6)/(8)	CAPITAL RECOVERY ACCRUAL RATE (10)=(9)*(3)
STEAM PRODUCTION PLANT									
	BIG SANDY PLANT								
311.0	Structures & Improvements	$ 36,149,758	$ 14,142,316	1.00	$ 21,917,068	FCST.	25.98	$ 843,613	2.33%
312.0	Boiler Plant Equipment	324,538,695	87,536,069	0.96	224,021,079	FCST.	22.10	10,136,700	3.12%
314.0	Turbogenerator Units	73,038,983	29,323,706	0.97	41,524,107	FCST.	22.71	1,828,450	2.50%
315.0	Accessory Electrical Equipment	13,742,601	6,055,634	0.99	7,549,541	FCST.	25.81	292,504	2.13%
316.0	Misc. Power Plant Equip.	6,518,954	2,464,864	0.99	3,988,901	FCST.	24.79	160,908	2.47%
	Total Steam Production Plant	453,988,991	139,522,588		299,000,695			13,262,175	2.92%
TRANSMISSION PLANT									
350.1	Land Rights	23,258,047	5,181,575	1.00	18,076,472	75 R4.0	54.05	334,440	1.44%
352.0	Structures & Improvements	6,387,065	1,734,110	0.90	4,014,249	55 S3.0	36.28	110,646	1.73%
353.0	Station Equipment	123,153,116	24,094,424	0.65	55,955,102	40 R1.5	30.19	1,853,432	1.50%
354.0	Towers & Fixtures	92,364,356	35,485,349	1.00	56,879,007	55 R4.0	35.38	1,607,660	1.74%
355.0	Poles & Fixtures	37,506,208	14,516,677	1.00	22,989,531	35 S6.0	23.68	970,842	2.59%
356.0	OH Conductor & Devices	100,355,481	31,808,967	0.80	48,475,418	50 S6.0	31.08	1,559,698	1.55%
356.0	Underground Conduit	11,590	4,557	1.00	7,033	37 R2.0	18.76	375	3.23%
358.0	Underground Conductor	106,066	30,002	1.00	76,064	44 R1.0	28.40	2,678	2.53%
	Total Transmission Plant	383,141,929	112,855,660		206,472,876			6,439,771	1.68%
DISTRIBUTION PLANT									
360.1	Land Rights	3,691,802	1,521,740	1.00	2,170,062	75 R4.0	45.25	47,957	1.30%
361.0	Structures & Improvements	4,231,065	832,942	0.90	2,975,016	70 L1.5	56.74	52,432	1.24%
362.0	Station Equipment	42,017,840	12,354,632	0.65	14,956,964	30 R0.5	21.51	695,349	1.65%
364.0	Poles, Towers, & Fixtures	124,672,243	50,791,264	0.75	42,712,918	28 R0.5	20.16	2,118,696	1.70%
365.0	Overhead Conductor & Devices	99,426,561	20,684,820	0.60	38,971,116	30 R0.5	22.49	1,732,820	1.74%
366.0	Underground Conduit	2,959,899	502,532	1.00	2,457,367	50 R1.0	41.83	58,747	1.98%
367.0	Underground Conductor	5,482,068	627,688	0.85	4,032,070	53 R0.5	46.13	87,407	1.59%
368.0	Line Transformers	84,185,422	18,995,426	0.60	31,515,827	29 R0.5	20.60	1,529,895	1.82%
369.0	Services	31,239,944	7,199,752	0.85	19,354,200	22 R0.5	16.26	1,190,295	3.81%
370.0	Meters	21,071,793	8,066,030	0.70	6,684,225	20 R3.0	10.18	656,604	3.12%
371.0	Installations on Custs. Prem.	15,598,882	3,755,890	0.70	7,163,328	12 L0.0	9.22	776,934	4.98%
373.0	Street Lighting & Signal Sys.	2,741,234	877,496	0.90	1,589,614	20 L0.0	14.13	112,499	4.10%
	Total Distribution Plant	437,318,753	126,210,213		174,582,708			9,059,634	2.07%
GENERAL PLANT									
389.2	Land Rights	84,011	5,029	1.00	78,982	75 R4.0	65.80	1,200	1.43%
390.0	Structures & Improvements	19,295,997	4,035,838	0.88	12,944,640	25 L2.0	13.10	988,140	5.12%
391.0	Office Furniture & Equipment	1,737,579	188,681	1.00	1,548,898	35 R0.5	27.22	56,903	3.27%
392.0	Transportation Equipment	5,819	1,531	1.00	4,288	30 R3.0	13.83	310	5.33%
393.0	Stores Equipment	189,262	22,965	1.00	166,297	30 L0.0	22.54	7,378	3.90%
394.0	Tools Shop & Garage Equipment	1,711,318	128,220	1.00	1,583,098	32 L0.0	27.09	58,438	3.41%
395.0	Laboratory Equipment	394,394	126,446	1.00	267,948	32 S5.0	10.99	24,381	6.18%
396.0	Power Operated Equipment	5,931	905	1.00	5,026	8 SQ	5.50	914	15.41%
397.0	Communication Equipment	4,666,769	957,217	0.90	3,242,875	19 S6.0	10.13	320,126	6.86%
398.0	Miscellaneous Equipment	584,684	65,719	1.00	518,965	19 L2.0	14.63	35,473	6.07%
	Total General Plant	28,675,764	5,532,552		20,361,015			1,493,263	5.21%
	Total Depreciable Plant	$ 1,303,125,437	$ 384,121,013		$ 700,417,294			$ 30,254,843	2.32%

Sources:
Cols. (3), (7) & (8) from Exhibit JEH-1, Schedule 1.
Col. (4) from page 4.
Col. (5) for Production from ProductionAnalysis.xls (response to AG 1-105, SK split of gross salvage and COR). T, D & G from Exhibit JEH-1, Schedule III.

KENTUCKY POWER COMPANY
CALCULATION OF COMPANY PROPOSED COST OF REMOVAL RATE
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/2004 (3)	HENDERSON INFLATED FUTURE COR % (4)	HENDERSON INFLATED FUTURE COR $ (5)=(3)*((4)-1)	TOTAL COR IN RESERVE (6)	FUTURE ACCRUALS (7)=(5)-(6)	AVERAGE REMAINING LIFE (8)	COST OF REMOVAL ANNUAL ACCRUAL (9)=(6)/(8)	COST OF REMOVAL ACCRUAL RATE (10)=(9)*(3)
STEAM PRODUCTION PLANT									
	BIG SANDY PLANT								
311.0	Structures & Improvements	$ 36,149,758	1.08	$ 2,891,981	$ 2,861,644	$ 30,337	25.98	$ 1,168	0.00%
312.0	Boiler Plant Equipment	324,538,695	1.23	74,643,900	17,712,590	56,931,310	22.10	2,576,077	0.79%
314.0	Turbogenerator Units	73,038,983	1.19	13,877,407	5,933,540	7,943,867	22.71	349,796	0.48%
315.0	Accessory Electrical Equipment	13,742,601	1.11	1,511,686	1,225,334	286,352	25.81	11,095	0.08%
316.0	Misc. Power Plant Equip.	6,518,954	1.13	847,464	498,756	348,708	24.79	14,066	0.22%
	Total Steam Production Plant	453,988,991		93,772,437	28,231,864	65,540,574		2,952,202	0.65%
TRANSMISSION PLANT									
350.1	Land Rights	23,258,047	1.00	-	-	-	54.05	-	0.00%
352.0	Structures & Improvements	6,387,065	1.10	638,707	-	638,707	36.28	17,605	0.28%
353.0	Station Equipment	123,153,116	1.35	43,103,591	-	43,103,591	30.19	1,427,744	1.16%
354.0	Towers & Fixtures	92,364,356	1.35	32,327,525	-	32,327,525	35.38	913,723	0.99%
355.0	Poles & Fixtures	37,506,208	1.50	18,753,104	-	18,753,104	23.68	791,939	2.11%
356.0	OH Conductor & Devices	100,355,481	1.25	25,088,870	-	25,088,870	31.08	807,235	0.80%
356.0	Underground Conduit	11,590	1.00	-	-	-	18.76	-	0.00%
358.0	Underground Conductor	106,066	1.00	-	-	-	28.40	-	0.00%
	Total Transmission Plant	383,141,929		119,911,796	-	119,911,796		3,958,246	1.03%
DISTRIBUTION PLANT									
360.1	Land Rights	3,691,802	1.00	-	-	-	45.25	-	0.00%
361.0	Structures & Improvements	4,231,065	1.10	423,107	-	423,107	56.74	7,457	0.18%
362.0	Station Equipment	42,017,840	1.35	14,706,244	-	14,706,244	21.51	683,693	1.63%
364.0	Poles, Towers, & Fixtures	124,672,243	1.65	81,036,958	-	81,036,958	20.16	4,019,690	3.22%
365.0	Overhead Conductor & Devices	99,426,561	1.20	19,885,312	-	19,885,312	22.49	884,185	0.89%
366.0	Underground Conduit	2,959,899	1.00	-	-	-	41.83	-	0.00%
367.0	Underground Conductor	5,482,068	1.00	-	-	-	46.13	-	0.00%
368.0	Line Transformers	84,185,422	1.15	12,627,813	-	12,627,813	20.60	613,001	0.73%
369.0	Services	31,239,944	1.00	-	-	-	16.26	-	0.00%
370.0	Meters	21,071,793	1.05	1,053,590	-	1,053,590	10.18	103,496	0.49%
371.0	Installations on Custs. Prem.	15,598,882	1.30	4,679,665	-	4,679,665	9.22	507,556	3.25%
373.0	Street Lighting & Signal Sys.	2,741,234	1.15	411,185	-	411,185	14.13	29,100	1.06%
	Total Distribution Plant	437,318,753		134,823,873	-	134,823,873		6,848,178	1.57%
GENERAL PLANT									
389.2	Land Rights	84,011	1.00	-	-	-	65.80	-	0.00%
390.0	Structures & Improvements	19,295,997	1.02	385,920	-	385,920	13.10	29,460	0.15%
391.0	Office Furniture & Equipment	1,737,579	1.00	-	-	-	27.22	-	0.00%
392.0	Transportation Equipment	5,819	1.00	-	-	-	13.83	-	0.00%
393.0	Stores Equipment	189,262	1.00	-	-	-	22.54	-	0.00%
394.0	Tools Shop & Garage Equipment	1,711,318	1.00	-	-	-	27.09	-	0.00%
395.0	Laboratory Equipment	394,394	1.00	-	-	-	10.99	-	0.00%
396.0	Power Operated Equipment	5,931	1.00	-	-	-	5.50	-	0.00%
397.0	Communication Equipment	4,666,769	1.00	-	-	-	10.13	-	0.00%
398.0	Miscellaneous Equipment	584,684	1.00	-	-	-	14.63	-	0.00%
	Total General Plant	28,675,764		385,920	-	385,920		29,460	0.10%
	Total Depreciable Plant	$ 1,303,125,437		$ 348,894,027	$ 28,231,864	$ 320,662,163		$ 13,788,085	1.06%

Sources:
Cols. (3) & (8) from Exhibit JEH-1, Schedule 1.
Col. (4) for Production from ProductionAnalysis.xls (response to AG 1-105, SK split of gross salvage and COR). T, D & G from Exhibit JEH-1, Schedule III.
Col. (6) from page 4.

KENTUCKY POWER COMPANY
REMOVAL OF ACCRUED COST OF REMOVAL FROM BOOK RESERVE
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/2004 (3)	ALLOCATED ACCUMULATED DEPRECIATION (4)	ALLOCATED COR IN RESERVE (5)	BOOK RESERVE LESS COR (6)=(4)-(5)
STEAM PRODUCTION PLANT					
	BIG SANDY PLANT				
311.0	Structures & Improvements	$ 36,149,758	$ 17,003,960	$ 2,861,644	$ 14,142,316
312.0	Boiler Plant Equipment	324,538,695	105,248,658	17,712,590	87,536,069
314.0	Turbogenerator Units	73,038,983	35,257,246	5,933,540	29,323,706
315.0	Accessory Electrical Equipment	13,742,601	7,280,968	1,225,334	6,055,634
316.0	Misc. Power Plant Equip.	6,518,954	2,963,620	498,756	2,464,864
	Total Steam Production Plant	453,988,991	167,754,452	28,231,864	139,522,588
TRANSMISSION PLANT					
350.1	Land Rights	23,258,047	5,181,575	-	5,181,575
352.0	Structures & Improvements	6,387,065	1,734,110	-	1,734,110
353.0	Station Equipment	123,153,116	24,094,424	-	24,094,424
354.0	Towers & Fixtures	92,364,356	35,485,349	-	35,485,349
355.0	Poles & Fixtures	37,506,208	14,516,677	-	14,516,677
356.0	OH Conductor & Devices	100,355,481	31,808,967	-	31,808,967
356.0	Underground Conduit	11,590	4,557	-	4,557
358.0	Underground Conductor	106,066	30,002	-	30,002
	Total Transmission Plant	383,141,929	112,855,660	-	112,855,660
DISTRIBUTION PLANT					
360.1	Land Rights	3,691,802	1,521,740	-	1,521,740
361.0	Structures & Improvements	4,231,065	832,942	-	832,942
362.0	Station Equipment	42,017,840	12,354,632	-	12,354,632
364.0	Poles, Towers, & Fixtures	124,672,243	50,791,264	-	50,791,264
365.0	Overhead Conductor & Devices	99,426,561	20,684,820	-	20,684,820
366.0	Underground Conduit	2,959,899	502,532	-	502,532
367.0	Underground Conductor	5,482,068	627,688	-	627,688
368.0	Line Transformers	84,185,422	18,995,426	-	18,995,426
369.0	Services	31,239,944	7,199,752	-	7,199,752
370.0	Meters	21,071,793	8,066,030	-	8,066,030
371.0	Installations on Custs. Prem.	15,598,882	3,755,890	-	3,755,890
373.0	Street Lighting & Signal Sys.	2,741,234	877,496	-	877,496
	Total Distribution Plant	437,318,753	126,210,213	-	126,210,213
GENERAL PLANT					
389.2	Land Rights	84,011	5,029	-	5,029
390.0	Structures & Improvements	19,295,997	4,035,838	-	4,035,838
391.0	Office Furniture & Equipment	1,737,579	188,681	-	188,681
392.0	Transportation Equipment	5,819	1,531	-	1,531
393.0	Stores Equipment	189,262	22,965	-	22,965
394.0	Tools Shop & Garage Equipment	1,711,318	128,220	-	128,220
395.0	Laboratory Equipment	394,394	126,446	-	126,446
396.0	Power Operated Equipment	5,931	905	-	905
397.0	Communication Equipment	4,666,769	957,217	-	957,217
398.0	Miscellaneous Equipment	584,684	65,719	-	65,719
	Total General Plant	28,675,764	5,532,552	-	5,532,552
	Total Depreciable Plant	$ 1,303,125,437	$ 412,352,877	$ 28,231,864	$ 384,121,013

Sources:
Cols. (3) and (4) from Exhibit JEH-1, Schedule 1. Note that reserves were allocated based on theoretical reserve.
Col. (5) total COR in reserve from response to AG 1-166 and AG 2-49, allocated to production accounts
based on allocated reserves.

Exhibit___(MJM-2)

Snavely King Majoros O'Connor & Lee, Inc.

Recommended Depreciation Rates

KENTUCKY POWER COMPANY
SEPARATION OF SNAVELY KING RECOMMENDED RATES INTO CAPITAL RECOVERY AND COST OF REMOVAL
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

ACCOUNT		ORIGINAL	CAPITAL RECOVERY		COST OF REMOVAL		COMBINED	
NO.	TITLE	COST AT 12/31/2004	ANNUAL ACCRUAL	ACCRUAL RATE	ANNUAL ACCRUAL	ACCRUAL RATE	ANNUAL ACCRUAL	ACCRUAL RATE
(1)	(2)	(3)	(4)	(5)=(4)*(3)	(6)	(7)=(6)*(3)	(8)=(4)+(6)	(9)=(5)+(7)
STEAM PRODUCTION PLANT								
	BIG SANDY PLANT							
311.0	Structures & Improvements	$ 36,149,758	$ 738,255	2.04%	$ 484	0.00%	$ 738,739	2.04%
312.0	Boiler Plant Equipment	324,538,695	10,115,865	3.12%	1,067,863	0.33%	11,183,728	3.45%
314.0	Turbogenerator Units	73,038,983	1,760,941	2.41%	145,001	0.20%	1,905,942	2.61%
315.0	Accessory Electrical Equipment	13,742,601	261,543	1.90%	4,599	0.03%	266,142	1.94%
316.0	Misc. Power Plant Equip.	6,518,954	146,603	2.25%	5,831	0.09%	152,434	2.34%
	Total Steam Production Plant	453,988,991	13,023,206	2.87%	1,223,778	0.27%	14,246,985	3.14%
TRANSMISSION PLANT								
350.1	Land Rights	23,258,047	299,353	1.29%	-	0.00%	299,353	1.29%
352.0	Structures & Improvements	6,387,065	99,691	1.56%	1,870	0.03%	101,561	1.59%
353.0	Station Equipment	123,153,116	1,943,058	1.58%	151,688	0.12%	2,094,746	1.70%
354.0	Towers & Fixtures	92,364,356	1,596,031	1.73%	97,077	0.11%	1,693,108	1.83%
355.0	Poles & Fixtures	37,506,208	1,025,774	2.73%	84,138	0.22%	1,109,912	2.96%
356.0	OH Conductor & Devices	100,355,481	1,518,235	1.51%	85,763	0.09%	1,603,999	1.60%
356.0	Underground Conduit	11,590	286	2.47%	-	0.00%	286	2.47%
358.0	Underground Conductor	106,066	2,292	2.16%	-	0.00%	2,292	2.16%
	Total Transmission Plant	383,141,929	6,484,721	1.69%	420,537	0.11%	6,905,258	1.80%
DISTRIBUTION PLANT								
360.1	Land Rights	3,691,802	33,061	0.90%	-	0.00%	33,061	0.90%
361.0	Structures & Improvements	4,231,065	48,050	1.14%	1,679	0.04%	49,729	1.18%
362.0	Station Equipment	42,017,840	730,930	1.74%	153,899	0.37%	884,829	2.11%
364.0	Poles, Towers, & Fixtures	124,672,243	2,690,855	2.16%	904,829	0.73%	3,595,683	2.88%
365.0	Overhead Conductor & Devices	99,426,561	1,656,906	1.67%	199,029	0.20%	1,855,935	1.87%
366.0	Underground Conduit	2,959,899	53,424	1.80%	-	0.00%	53,424	1.80%
367.0	Underground Conductor	5,482,068	81,381	1.48%	-	0.00%	81,381	1.48%
368.0	Line Transformers	84,185,422	1,387,062	1.65%	137,986	0.16%	1,525,048	1.81%
369.0	Services	31,239,944	994,202	3.18%	-	0.00%	994,202	3.18%
370.0	Meters	21,071,793	382,210	1.81%	23,297	0.11%	405,507	1.92%
371.0	Installations on Custs. Prem.	15,598,882	772,913	4.95%	114,250	0.73%	887,163	5.69%
373.0	Street Lighting & Signal Sys.	2,741,234	97,763	3.57%	6,550	0.24%	104,313	3.81%
	Total Distribution Plant	437,318,753	8,928,757	2.04%	1,541,519	0.35%	10,470,275	2.39%
GENERAL PLANT								
389.2	Land Rights	84,011	1,199	1.43%	-	0.00%	1,199	1.43%
390.0	Structures & Improvements	19,295,997	990,016	5.13%	24,006	0.12%	1,014,022	5.26%
391.0	Office Furniture & Equipment	1,737,579	56,793	3.27%	-	0.00%	56,793	3.27%
392.0	Transportation Equipment	5,819	308	5.30%	-	0.00%	308	5.30%
393.0	Stores Equipment	189,262	7,360	3.89%	-	0.00%	7,360	3.89%
394.0	Tools Shop & Garage Equipment	1,711,318	58,361	3.41%	-	0.00%	58,361	3.41%
395.0	Laboratory Equipment	394,394	24,193	6.13%	-	0.00%	24,193	6.13%
396.0	Power Operated Equipment	5,931	911	15.36%	-	0.00%	911	15.36%
397.0	Communication Equipment	4,666,769	318,559	6.83%	-	0.00%	318,559	6.83%
398.0	Miscellaneous Equipment	584,684	35,403	6.06%	-	0.00%	35,403	6.06%
	Total General Plant	28,675,764	1,493,104	5.21%	24,006	0.08%	1,517,110	5.29%
	Total Depreciable Plant	$ 1,303,125,437	$ 29,929,786	2.30%	$ 3,209,839	0.25%	$ 33,139,627	2.54%

Sources:
Col. (3) from Exhibit JEH-1, Schedule 1.
Col. (4) from page 2.
Col. (6) from page 3.

KENTUCKY POWER COMPANY
CALCULATION OF SNAVELY KING RECOMMENDED CAPITAL RECOVERY RATE
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

ACCOUNT NO.	TITLE	ORIGINAL COST AT 12/31/2004	BOOK RESERVE LESS COR	GROSS SALVAGE RATIO	FUTURE ACCRUALS	AVERAGE LIFE AND CURVE TYPE	AVERAGE REMAINING LIFE	CAPITAL RECOVERY ANNUAL ACCRUAL	CAPITAL RECOVERY ACCRUAL RATE
(1)	(2)	(3)	(4)	(5)	(6)=((3)*(5))-(4)	(7)	(8)	(9)=(6)/(8)	(10)=(9)*(3)
STEAM PRODUCTION PLANT									
	BIG SANDY PLANT								
311.0	Structures & Improvements	$ 36,149,758	$ 15,343,962	1.00	$ 20,715,422	FCST.	28.06	$ 738,255	2.04%
312.0	Boiler Plant Equipment	324,538,695	85,669,882	0.96	225,887,265	FCST.	22.33	10,115,865	3.12%
314.0	Turbogenerator Units	73,038,983	29,395,255	0.97	41,452,558	FCST.	23.54	1,760,941	2.41%
315.0	Accessory Electrical Equipment	13,742,601	6,509,523	0.99	7,095,652	FCST.	27.13	261,543	1.90%
316.0	Misc. Power Plant Equip.	6,518,954	2,603,967	0.99	3,849,798	FCST.	26.26	146,603	2.25%
	Total Steam Production Plant	453,988,991	139,522,588		299,000,695			13,023,206	2.87%
TRANSMISSION PLANT									
350.1	Land Rights	23,258,047	7,078,002	1.00	16,180,045	75 R4.0	54.05	299,353	1.29%
352.0	Structures & Improvements	6,387,065	2,131,580	0.90	3,616,778	55 S3.0	36.28	99,691	1.56%
353.0	Station Equipment	123,153,116	21,388,603	0.65	58,660,922	40 R1.5	30.19	1,943,058	1.58%
354.0	Towers & Fixtures	92,364,356	35,896,770	1.00	56,467,586	55 R4.0	35.38	1,596,031	1.73%
355.0	Poles & Fixtures	37,506,208	13,215,883	1.00	24,290,325	35 S6.0	23.68	1,025,774	2.73%
356.0	OH Conductor & Devices	100,355,481	33,097,627	0.80	47,186,757	50 S6.0	31.08	1,518,235	1.51%
356.0	Underground Conduit	11,590	6,225	1.00	5,365	37 R2.0	18.76	286	2.47%
358.0	Underground Conductor	106,066	40,970	1.00	65,096	44 R1.0	28.40	2,292	2.16%
	Total Transmission Plant	383,141,929	112,855,660		206,472,876			6,484,721	1.69%
DISTRIBUTION PLANT									
360.1	Land Rights	3,691,802	2,195,772	1.00	1,496,030	75 R4.0	45.25	33,061	0.90%
361.0	Structures & Improvements	4,231,065	1,081,585	0.90	2,726,373	70 L1.5	56.74	48,050	1.14%
362.0	Station Equipment	42,017,840	11,589,283	0.65	15,722,313	30 R0.5	21.51	730,930	1.74%
364.0	Poles, Towers, & Fixtures	124,672,243	39,256,550	0.75	54,247,632	28 R0.5	20.16	2,690,855	2.16%
365.0	Overhead Conductor & Devices	99,426,561	22,392,130	0.60	37,263,806	30 R0.5	22.49	1,656,906	1.67%
366.0	Underground Conduit	2,959,899	725,190	1.00	2,234,709	50 R1.0	41.83	53,424	1.80%
367.0	Underground Conductor	5,482,068	905,664	0.85	3,754,093	53 R0.5	46.13	81,381	1.48%
368.0	Line Transformers	84,185,422	21,937,771	0.60	28,573,482	29 R0.5	20.60	1,387,062	1.65%
369.0	Services	31,239,944	10,388,227	0.85	16,165,725	22 R0.5	16.26	994,202	3.18%
370.0	Meters	21,071,793	10,859,356	0.70	3,890,899	20 R3.0	10.18	382,210	1.81%
371.0	Installations on Custs. Prem.	15,598,882	3,792,959	0.70	7,126,259	12 L0.0	9.22	772,913	4.95%
373.0	Street Lighting & Signal Sys.	2,741,234	1,085,725	0.90	1,381,386	20 L0.0	14.13	97,763	3.57%
	Total Distribution Plant	437,318,753	126,210,213		174,582,708			8,928,757	2.04%
GENERAL PLANT									
389.2	Land Rights	84,011	5,114	1.00	78,897	75 R4.0	65.80	1,199	1.43%
390.0	Structures & Improvements	19,295,997	4,011,271	0.88	12,969,206	25 L2.0	13.10	990,016	5.13%
391.0	Office Furniture & Equipment	1,737,579	191,682	1.00	1,545,897	35 R0.5	27.22	56,793	3.27%
392.0	Transportation Equipment	5,819	1,557	1.00	4,262	30 R3.0	13.83	308	5.30%
393.0	Stores Equipment	189,262	23,356	1.00	165,906	30 L0.0	22.54	7,360	3.89%
394.0	Tools Shop & Garage Equipment	1,711,318	130,313	1.00	1,581,005	32 L0.0	27.09	58,361	3.41%
395.0	Laboratory Equipment	394,394	128,508	1.00	265,886	32 S5.0	10.99	24,193	6.13%
396.0	Power Operated Equipment	5,931	920	1.00	5,011	8 SQ	5.50	911	15.36%
397.0	Communication Equipment	4,666,769	973,092	0.90	3,227,000	19 S6.0	10.13	318,559	6.83%
398.0	Miscellaneous Equipment	584,684	66,738	1.00	517,946	19 L2.0	14.63	35,403	6.06%
	Total General Plant	28,675,764	5,532,552		20,361,015			1,493,104	5.21%
	Total Depreciable Plant	$ 1,303,125,437	$ 384,121,013		$ 700,417,294			$ 29,929,786	2.30%

Sources:
Cols. (3) & (7) from Exhibit JEH-1, Schedule 1.
Col. (4) from page 5.
Col. (5) for Production from Exhibit___(MJM-5). T, D & G from Exhibit JEH-1, Schedule III.

KENTUCKY POWER COMPANY
CALCULATION OF SNAVELY KING RECOMMENDED COST OF REMOVAL RATE
USING 5-YEAR AVERAGE ALLOWANCE APPROACH
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/2004 (3)	HENDERSON COR ANNUAL ACCRUAL (4)	SNAVELY KING ALLOCATED COR ANNUAL ACCRUAL (5)	SNAVELY KING COR ANNUAL RATE (6)=(5)/(3)
STEAM PRODUCTION PLANT					
	BIG SANDY PLANT				
311.0	Structures & Improvements	$ 36,149,758	$ 1,168	$ 484	0.00%
312.0	Boiler Plant Equipment	324,538,695	2,576,077	1,067,863	0.33%
314.0	Turbogenerator Units	73,038,983	349,796	145,001	0.20%
315.0	Accessory Electrical Equipment	13,742,601	11,095	4,599	0.03%
316.0	Misc. Power Plant Equip.	6,518,954	14,066	5,831	0.09%
	Total Steam Production Plant	453,988,991	2,952,202	1,223,778	0.27%
TRANSMISSION PLANT					
350.1	Land Rights	23,258,047	-	-	0.00%
352.0	Structures & Improvements	6,387,065	17,605	1,870	0.03%
353.0	Station Equipment	123,153,116	1,427,744	151,688	0.12%
354.0	Towers & Fixtures	92,364,356	913,723	97,077	0.11%
355.0	Poles & Fixtures	37,506,208	791,939	84,138	0.22%
356.0	OH Conductor & Devices	100,355,481	807,235	85,763	0.09%
356.0	Underground Conduit	11,590	-	-	0.00%
358.0	Underground Conductor	106,066	-	-	0.00%
	Total Transmission Plant	383,141,929	3,958,246	420,537	0.11%
DISTRIBUTION PLANT					
360.1	Land Rights	3,691,802	-	-	0.00%
361.0	Structures & Improvements	4,231,065	7,457	1,679	0.04%
362.0	Station Equipment	42,017,840	683,693	153,899	0.37%
364.0	Poles, Towers, & Fixtures	124,672,243	4,019,690	904,829	0.73%
365.0	Overhead Conductor & Devices	99,426,561	884,185	199,029	0.20%
366.0	Underground Conduit	2,959,899	-	-	0.00%
367.0	Underground Conductor	5,482,068	-	-	0.00%
368.0	Line Transformers	84,185,422	613,001	137,986	0.16%
369.0	Services	31,239,944	-	-	0.00%
370.0	Meters	21,071,793	103,496	23,297	0.11%
371.0	Installations on Custs. Prem.	15,598,882	507,556	114,250	0.73%
373.0	Street Lighting & Signal Sys.	2,741,234	29,100	6,550	0.24%
	Total Distribution Plant	437,318,753	6,848,178	1,541,519	0.35%
GENERAL PLANT					
389.2	Land Rights	84,011	-	-	0.00%
390.0	Structures & Improvements	19,295,997	29,460	24,006	0.12%
391.0	Office Furniture & Equipment	1,737,579	-	-	0.00%
392.0	Transportation Equipment	5,819	-	-	0.00%
393.0	Stores Equipment	189,262	-	-	0.00%
394.0	Tools Shop & Garage Equipment	1,711,318	-	-	0.00%
395.0	Laboratory Equipment	394,394	-	-	0.00%
396.0	Power Operated Equipment	5,931	-	-	0.00%
397.0	Communication Equipment	4,666,769	-	-	0.00%
398.0	Miscellaneous Equipment	584,684	-	-	0.00%
	Total General Plant	28,675,764	29,460	24,006	0.08%
	Total Depreciable Plant	$ 1,303,125,437	$ 13,788,085	$ 3,209,840	0.25%

Sources:
Col. (3) from Exhibit JEH-1, Schedule 1.
Col. (4) from Exhibit___(MJM-1).
Col. (5) by function from Exhibit___(MJM-5), allocated to account based on Col. (4).

KENTUCKY POWER COMPANY
THEORETICAL RESERVE AND ALLOCATION OF BOOK RESERVE
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AND SNAVELY KING RECOMMENDED PARAMETERS

ACCOUNT NO. (1)	ACCOUNT TITLE (2)	ORIGINAL COST AT 12/31/2004 (3)	AVG. LIFE AND CURVE TYPE (4)		GROSS SALVAGE RATIO (5)	AVERAGE REMAINING LIFE (6)	CALCULATED DEPRECIATION REQUIREMENT (7)	ALLOCATED ACCUMULATED DEPRECIATION (8)	
STEAM PRODUCTION PLANT									
	BIG SANDY PLANT								
311.0	Structures & Improvements	$ 36,149,758	54.14	FCST.	1.00	28.06	$ 17,370,313	$ 18,448,754	
312.0	Boiler Plant Equipment	324,538,695	32.30	FCST.	0.96	22.33	96,167,949	103,004,856	(a)
314.0	Turbogenerator Units	73,038,983	44.39	FCST.	0.97	23.54	33,277,245	35,343,273	
315.0	Accessory Electrical Equipment	13,742,601	59.19	FCST.	0.99	27.13	7,369,182	7,826,700	
316.0	Misc. Power Plant Equip.	6,518,954	48.34	FCST.	0.99	26.26	2,947,851	3,130,869	
	Total Steam Production Plant	453,988,991					157,132,540	167,754,452	
TRANSMISSION PLANT									
350.1	Land Rights	23,258,047	75	R4.0	1.00	54.05	6,496,748	7,078,002	
352.0	Structures & Improvements	6,387,065	55	S3.0	0.90	36.28	1,956,532	2,131,580	
353.0	Station Equipment	123,153,116	40	R1.5	0.65	30.19	19,632,146	21,388,603	
354.0	Towers & Fixtures	92,364,356	55	R4.0	1.00	35.38	32,948,885	35,896,770	
355.0	Poles & Fixtures	37,506,208	35	S6.0	1.00	23.68	12,130,579	13,215,883	
356.0	OH Conductor & Devices	100,355,481	50	S6.0	0.80	31.08	30,379,611	33,097,627	
356.0	Underground Conduit	11,590	37	R2.0	1.00	18.76	5,714	6,225	
358.0	Underground Conductor	106,066	44	R1.0	1.00	28.40	37,605	40,970	
	Total Transmission Plant	383,141,929					103,587,820	112,855,660	
DISTRIBUTION PLANT									
360.1	Land Rights	3,691,802	75	R4.0	1.00	45.25	1,464,415	2,195,772	
361.0	Structures & Improvements	4,231,065	70	L1.5	0.90	56.74	721,336	1,081,585	
362.0	Station Equipment	42,017,840	30	R0.5	0.65	21.51	7,729,182	11,589,283	
364.0	Poles, Towers, & Fixtures	124,672,243	28	R0.5	0.75	20.16	26,181,171	39,256,550	
365.0	Overhead Conductor & Devices	99,426,561	30	R0.5	0.60	22.49	14,933,869	22,392,130	
366.0	Underground Conduit	2,959,899	50	R1.0	1.00	41.83	483,647	725,190	
367.0	Underground Conductor	5,482,068	53	R0.5	0.85	46.13	604,010	905,664	
368.0	Line Transformers	84,185,422	29	R0.5	0.60	20.60	14,630,846	21,937,771	
369.0	Services	31,239,944	22	R0.5	0.85	16.26	6,928,168	10,388,227	
370.0	Meters	21,071,793	20	R3.0	0.70	10.18	7,242,375	10,859,356	
371.0	Installations on Custs. Prem.	15,598,882	12	L0.0	0.70	9.22	2,529,619	3,792,959	
373.0	Street Lighting & Signal Sys.	2,741,234	20	L0.0	0.90	14.13	724,097	1,085,725	
	Total Distribution Plant	437,318,753					84,172,735	126,210,213	
GENERAL PLANT									
389.2	Land Rights	84,011	75	R4.0	1.00	65.80	10,305	5,114	
390.0	Structures & Improvements	19,295,997	25	L2.0	0.88	13.10	8,082,707	4,011,271	
391.0	Office Furniture & Equipment	1,737,579	35	R0.5	1.00	27.22	386,239	191,682	
392.0	Transportation Equipment	5,819	30	R3.0	1.00	13.83	3,136	1,557	
393.0	Stores Equipment	189,262	30	L0.0	1.00	22.54	47,063	23,356	
394.0	Tools Shop & Garage Equipment	1,711,318	32	L0.0	1.00	27.09	262,580	130,313	
395.0	Laboratory Equipment	394,394	32	S5.0	1.00	10.99	258,944	128,508	
396.0	Power Operated Equipment	5,931	8	SQ	1.00	5.50	1,853	920	
397.0	Communication Equipment	4,666,769	19	S6.0	0.90	10.13	1,960,780	973,092	
398.0	Miscellaneous Equipment	584,684	19	L2.0	1.00	14.63	134,477	66,738	
	Total General Plant	28,675,764					11,148,086	5,532,552	
	Total Depreciable Plant	$ 1,303,125,437					$ 356,041,182	$ 412,352,877	(a)

(a) Per Company calculation, includes $866,291 of accumulated amortization applicable to SCR Catalysts.

Sources:
Col. (3) from Exhibit JEH-1, Schedule 1.
Cols. (4) and (6) for Production from Exhibit___(MJM-4). T, D & G from Exhibit JEH-1, Schedule 1.
Col. (5) for Production from Exhibit___(MJM-5). T, D & G from Exhibit JEH-1, Schedule III.
Col. (7) calculated using standard theoretical reserve formula.
Col. (8) allocated based on col. (7) as per Company formula.

KENTUCKY POWER COMPANY
REMOVAL OF ACCRUED COST OF REMOVAL FROM BOOK RESERVE
BASED ON PLANT IN SERVICE AT DECEMBER 31, 2004
AND SNAVELY KING ALLOCATED RESERVE

ACCOUNT NO. (1)	TITLE (2)	ORIGINAL COST AT 12/31/2004 (3)	ALLOCATED ACCUMULATED DEPRECIATION (4)	ALLOCATED COR IN RESERVE (5)	BOOK RESERVE LESS COR (6)=(4)-(5)
STEAM PRODUCTION PLANT					
	BIG SANDY PLANT				
311.0	Structures & Improvements	$ 36,149,758	$ 18,448,754	$ 3,104,792	$ 15,343,962
312.0	Boiler Plant Equipment	324,538,695	103,004,856	17,334,974	85,669,882
314.0	Turbogenerator Units	73,038,983	35,343,273	5,948,018	29,395,255
315.0	Accessory Electrical Equipment	13,742,601	7,826,700	1,317,177	6,509,523
316.0	Misc. Power Plant Equip.	6,518,954	3,130,869	526,903	2,603,967
	Total Steam Production Plant	453,988,991	167,754,452	28,231,864	139,522,588
TRANSMISSION PLANT					
350.1	Land Rights	23,258,047	7,078,002	-	7,078,002
352.0	Structures & Improvements	6,387,065	2,131,580	-	2,131,580
353.0	Station Equipment	123,153,116	21,388,603	-	21,388,603
354.0	Towers & Fixtures	92,364,356	35,896,770	-	35,896,770
355.0	Poles & Fixtures	37,506,208	13,215,883	-	13,215,883
356.0	OH Conductor & Devices	100,355,481	33,097,627	-	33,097,627
356.0	Underground Conduit	11,590	6,225	-	6,225
358.0	Underground Conductor	106,066	40,970	-	40,970
	Total Transmission Plant	383,141,929	112,855,660	-	112,855,660
DISTRIBUTION PLANT					
360.1	Land Rights	3,691,802	2,195,772	-	2,195,772
361.0	Structures & Improvements	4,231,065	1,081,585	-	1,081,585
362.0	Station Equipment	42,017,840	11,589,283	-	11,589,283
364.0	Poles, Towers, & Fixtures	124,672,243	39,256,550	-	39,256,550
365.0	Overhead Conductor & Devices	99,426,561	22,392,130	-	22,392,130
366.0	Underground Conduit	2,959,899	725,190	-	725,190
367.0	Underground Conductor	5,482,068	905,664	-	905,664
368.0	Line Transformers	84,185,422	21,937,771	-	21,937,771
369.0	Services	31,239,944	10,388,227	-	10,388,227
370.0	Meters	21,071,793	10,859,356	-	10,859,356
371.0	Installations on Custs. Prem.	15,598,882	3,792,959	-	3,792,959
373.0	Street Lighting & Signal Sys.	2,741,234	1,085,725	-	1,085,725
	Total Distribution Plant	437,318,753	126,210,213	-	126,210,213
GENERAL PLANT					
389.2	Land Rights	84,011	5,114	-	5,114
390.0	Structures & Improvements	19,295,997	4,011,271	-	4,011,271
391.0	Office Furniture & Equipment	1,737,579	191,682	-	191,682
392.0	Transportation Equipment	5,819	1,557	-	1,557
393.0	Stores Equipment	189,262	23,356	-	23,356
394.0	Tools Shop & Garage Equipment	1,711,318	130,313	-	130,313
395.0	Laboratory Equipment	394,394	128,508	-	128,508
396.0	Power Operated Equipment	5,931	920	-	920
397.0	Communication Equipment	4,666,769	973,092	-	973,092
398.0	Miscellaneous Equipment	584,684	66,738	-	66,738
	Total General Plant	28,675,764	5,532,552	-	5,532,552
	Total Depreciable Plant	$ 1,303,125,437	$ 412,352,877	$ 28,231,864	$ 384,121,013

Sources:
Col. (3) from Exhibit JEH-1, Schedule 1.
Col. (4) from page 4. Book reserve allocated based on SK theoretical reserve.
Col. (5) total COR in reserve from response to AG 1-166 and AG 2-49, allocated to production accounts based on allocated reserves.

Exhibit___(MJM-3)

Snavely King Majoros O'Connor & Lee, Inc.

National Study
Steam Generating Unit Lives

Snavely King Majoros O'Connor & Lee, Inc.
National Study of U.S. Steam Generating Unit Lives
50 MW and Greater
(Update)

Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King") performed a study of U.S. Steam Generating Units Lives, 50 MW and Greater using analytical techniques generally accepted in the utility industry and a database maintained by the U.S. Department of Energy ("DOE"). Snavely King concludes that the lives of the U.S. Steam Generating Units (50 MW and Greater) are experiencing average life spans of approximately 60 years and these spans are lengthening almost on a year-to-year basis.

Database

The DOE's Energy Information Administration ("EIA") requires every owner of an electric utility generating plant to file a Form 860 describing the status of its generating facilities. From these reports, EIA maintains data on the installation and retirements of generating units around the country.

The data utilized in this study is available on the EIA's web site. The primary data used in Snavely King's study is located in the Form 860-A database files. The Form 860-B data is also used to check the current status of units that have been sold to Non-Utility Generators ("NUG's"). The data was downloaded in several steps into a single Microsoft Access file and developed into inputs for Snavely King's actuarial analysis program.

Various sorts were made to refine the data and to remove bad data. For instance, some units listed as retired had no retirement dates indicated, etc.

Analysis

Snavely King initially conducted a full band (1918-1999) resulting in a 54 L4 life and Iowa curve indication. Snavely King's initial ten-year band resulted in a 59 L4 indication and its initial rolling and shrinking band analysis showed trends toward longer lives – as long as 70 years.

Snavely King's update consisted of an analysis of the full band (1900-2000) and the most recent ten-year band (1991-2000) of data. The full band analysis had a best fit result of 60.5 L3, which indicates a 60 year life. The ten-year band best fit was a 59.5 R4, which indicates a 59 year life. Additional analyses were performed: an expanded full band analysis, rolling band analysis and a shrinking band analysis. The results are discussed and set forth in tabular form below.

Expanded Full Band Analysis

The expanded full band analysis held the initial year constant but used cut-off dates of 1999, 1998, 1997 and 1996. The actuarial analyses yielded the following results.

Expanded Full Band Analysis		
Band	Life	Curve Type
1900-00	60.5	L3
1900-99	58.5	L3
1900-98	58	L3
1900-97	57	L3
1900-96	56	L3

The results indicate that large generating units are being kept operational longer.

Rolling Band Analysis

The ten-year band analyses for these data sets provided a "rolling band" analysis. The results are summarized in the table below.

Band	Life	Curve Type
1991-2000	59.5	R4
1990-1999	56	R4
1989-1998	57.5	L4
1988-1997	54	S4
1987-1996	54.5	L4

This indicates an increase in lives of generating units probably coincident with the wide spread introduction of life extension programs and the reduction in investment by utilities in new base load generating units.

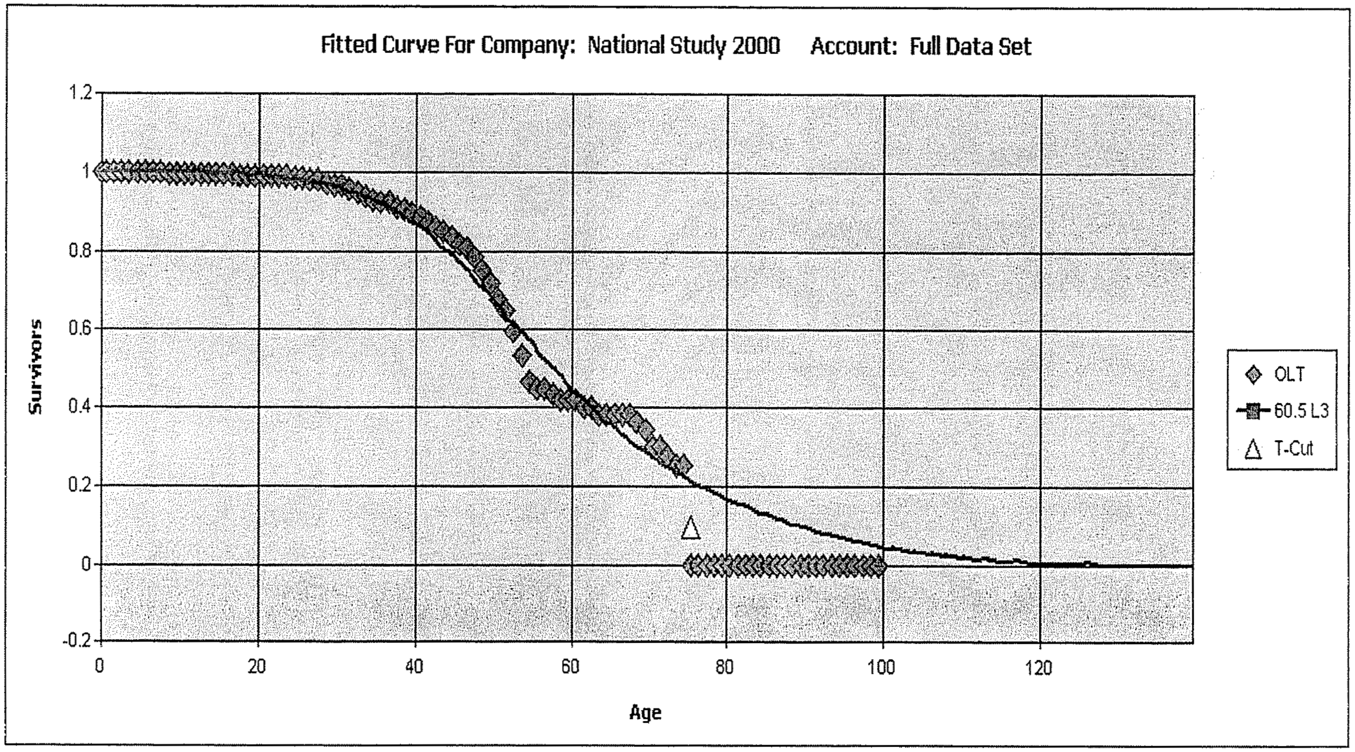
Shrinking Band Analysis

Finally, Snavely King did a "shrinking band" analysis, in which the final 2000 year was held constant and the bands were continually shrunk.

Band	Width	Life	Curve Type
1996-99	5 years	77.5	R2
1995-00	6 years	74.5	R2.5
1994-00	7 years	66.5	R3
1993-00	8 years	69.5	L3
1992-00	9 years	67.5	L3
1991-00	10 years	59.5	R4
1986-00	15 years	58	R4
1981-00	20 years	56	L4
1976-00	25 years	55	L4

The shrinking band analysis corroborated earlier results and conclusions. The average life span of steam units 50 MW and Greater is currently in the 60-year range and is getting longer.

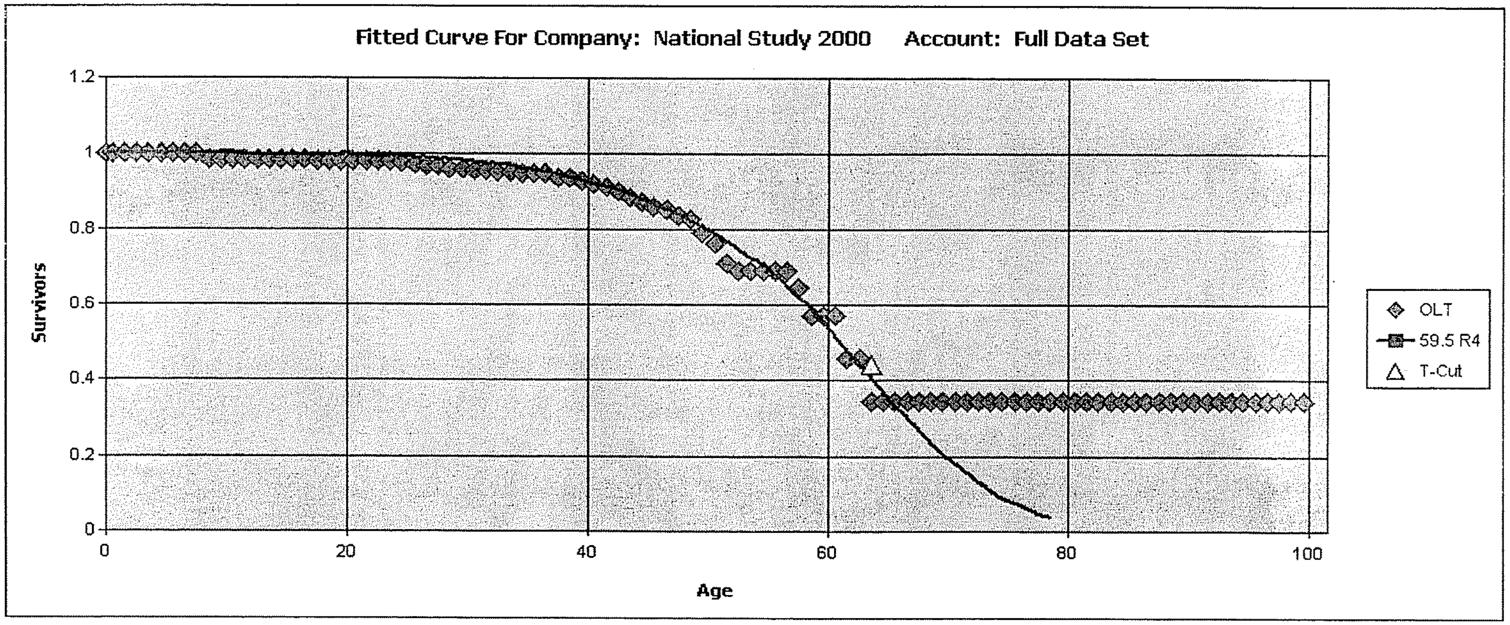
Best Fit Curve for 1900-2000



Analytical Parameters

OLT Placement Band:	1900 -2000
OLT Experience Band:	1900 - 2000
Minimum Life Parameter:	10
Maximum Life Parameter:	150
Life Increment Parameter:	0.5
Maximum Observations (T-Cut):	77 (75.5)

Best Fit Curve Results for 1991-2000



Analytical Parameters

OLT Placement Band:	1900 -2000
OLT Experience Band:	1991 - 2000
Minimum Life Parameter:	10
Maximum Life Parameter:	150
Life Increment Parameter:	0.5
Maximum Observations (T-Cut):	65 (63.5)

Exhibit___(MJM-4)

Snavely King Majoros O'Connor & Lee, Inc.

Depreciation Study

Lives

Note: Due to its volume, only selected pages of the Study are included here. The entire study will be provided as workpapers.

Kentucky Power Company

Snavely King Life Study

Production, Transmission, Distribution, and General Plant

Kentucky Power Company
Snavely King Life Study
Production, Transmission, Distribution, and General Plant

Description of Analysis Method

The SK actuarial model relies on the vintage date, activity date and the dollar value of plant transactions (i.e., additions, retirements, transfers, sales, and adjustments, etc.). The SPR model relies on the annual addition and retirement activity of the plant transactions. The information is determined from the data submitted in the Kentucky Power Company 12/31/2004 Depreciation Study and from its supporting documents.

Actuarial Analysis Program

The retirement rate method of actuarial analysis is a means to evaluate past experience for the purpose of determining life indications. It relies upon a compilation of plant mortality data arranged so that the plant dollars (or units) and retired dollars (or units) can be identified by ages. The plant dollars exposed at the start of each age year are termed exposures, the plant dollars at the end of that age year are the survivors, and the difference between the two is the plant dollars retired, or the retirements. These data are used to construct an observed life table (OLT) which is smoothed and extended by comparison to Iowa curves.

Iowa curves are standard curves empirically developed to describe the life characteristics of most industrial and utility property. They are used throughout the utility industry as well as other applications where life characteristics are sought.

There are 31 Iowa curves classified into L, R, S or O families, depending upon whether the highest point (mode) of the retirement frequency was left of , right of, or symmetrical to the curves average life. The mode of the O curves is at the origins. These curves are combined with varying average life assumptions and statistically compared to the OLT to obtain a "best fit" life for each curve, and then these results are ranked to obtain the best of the best fits.

Chapter VIII of the 1996 edition of the NARUC Public Utility Depreciation Practices manual provides an example of a retirement rate actuarial analysis stating with raw data and continuing through the best fit curve result. The NARUC example used aged mortality data as described above. Snavely King's retirement rate actuarial program was tailored upon the NARUC example. Snavely King's approach and program replicates the model contained in NARUC's 1996 Public Utility Depreciation Practices manual.

The actuarial program requires the analyst to determine the average service life upper and lower limits for the accounts being studied.
Industry statistics were taken from the source: AGA/EEI "A Survey of Depreciation Statistics," 1998-1999

Simulated Plant Record Analysis

The Simulated Plant Record (SPR) model requires determining the surviving balances for each vintage of plant equipment. This data was retrieved from studies and data submitted by the Company.

The SPR data was calculated by determining the plant balance, or survivors, from vintage additions and non-vintage retirements. This plant balance was used with each Iowa curve to simulate retirements and corresponding aged balances. The properties of the simulated balances for each curve were ranked according to their ability to simulate the survivors for the account over the period selected. The algorithm for this method is as follows:

The annual additions and retirements determine the plant balances that are compared against the the theoretical balances calculated from the 31 Iowa curves. Each curve is rated and ranked according to how close it matches the actual plant balance. The lower the conformance index, the better the match between the theoretical and actual balance.

The SPR programs requires the analyst to determine the average service life upper and lower limits for the accounts being studied.
Industry statistics were taken from the source: AGA/EEI "A Survey of Depreciation Statistics," 1998-1999

Results

The actuarial model results provide a historical plant service life and curve that most closely represents the average of plant survivors for each account. The first step of the model provides the Observed Life Table or OLT. This shows exposures, retirements, retirement ratio, survival ratio and cumulative survivors. This OLT is a summary of historical plant mortality that shows experience bands of the plant data considered in the study. The cumulative survivor data may be truncated for aged data when the aged data shows discontinuity of small values as compared to the more recent plant activity. These cumulative survivors are fitted against the 31 Iowa curves to determine the best curve and life of the plant data. The curve results, cumulative survivors, Company proposed and Company Current are plotted to provide a visual reference of the fitted curves.

The results of the SPR provide a statistical matching of actual plant balances to the balances of the best fitted life and curves. The life and curves are ranked from best to worse.

All results are analyzed and compared with the results submitted by Kentucky Power Company .
If the result of Kentucky Power Company is in question (due to various factors including data responses, company study, actuarial data, industry statistics and related information), then Generation Arrangement calculations are performed to determine the average remaining life. The remaining life calculation for Kentucky Power Company uses the BG/VG (broad group/vintage group) methodology.

The average remaining life is then used as a factor in calculating the depreciation rate for the account.

Kentucky Power Company
SK Analysis of Proposed Lives and Survivor Curves
Production, Transmission, Distribution, and General Plant Summary 4/

ACCOUNT NO.	TITLE	ORIGINAL COST AT 12/31/04	Company Current Life - Curve 2/	Company Proposed Life - Curve 3/	SK Modeling Data Best Fit Life - Curve 4/		SK Selection Life - Curve 5/	ARL 6/	Notes
STEAM PRODUCTION PLANT									
	BIG SANDY PLANT								
311.0	Structures & Improvements	36,149,758	FCST.	FCST.	100 - R2.5				
312.0	Boiler Plant Equipment	324,538,695	FCST.	FCST.	32 - R2.5				
314.0	Turbogenerator Units	73,038,983	FCST.	FCST.	39 - L2				
315.0	Accessory Electrical Equipment	13,742,601	FCST.	FCST.	67 - L2				
316.0	Misc. Power Plant Equip.	6,518,954	FCST.	FCST.	66 - L1				
	Total Steam Production Plant	453,988,991							
TRANSMISSION PLANT									
350.1	Land Rights	23,258,047	75 - R4.0	75 - R4.0	NA		75 - R4.0		
352.0	Structures & Improvements	6,387,065	55 - S1.5	55 - S3.0	55 - L4		55 - S3.0		
353.0	Station Equipment	123,153,116	50 - RO.5	40 - R1.5	41 - R2		40 - R1.5		
354.0	Towers & Fixtures	92,364,356	55 - R4.0	55 - R4.0	52 - R5		55 - R4.0		
355.0	Poles & Fixtures	37,506,208	45 - R3.0	35 - S6.0	39 - R3	*	39 - R3	28.0	accept due to lack of other disagreements
356.0	OH Conductor & Devices	100,355,481	50 - R3.0	50 - S6.0	51 - S6		50 - S6.0		
357.0	Underground Conduit	11,590	37 - R2.0	37 - R2.0	NA		37 - R2.0		lack of data
358.0	Underground Conductor	106,066	44 - R1.0	44 - R1.0	NA		44 - R1.0		lack of data
	Total Transmission Plant	383,141,929							
DISTRIBUTION PLANT									
360.1	Land Rights	3,691,802	75 - R4.0	75 - R4.0	NA		75 - R4.0		lack of data
361.0	Structures & Improvements	4,231,065	65 - LO.5	70 - L1.5	67 - S0.5		70 - L1.5		
362.0	Station Equipment	42,017,840	25 - LO.O	30 - R0.5	30 - R1		30 - R0.5		
364.0	Poles, Towers, & Fixtures	124,672,243	28 - LO.O	28 - R0.5	45 - O3		28 - R0.5		
365.0	Overhead Conductor & Devices	99,426,561	26 - R1.5	30 - R0.5	48 - O3		30 - R0.5		
366.0	Underground Conduit	2,959,899	37 - R2.0	50 - R1.0	96 - R1	*	74 - R1.5	64.5	Company moving from 37 to 50 ASL
367.0	Underground Conductor	5,482,068	44 - R1.0	53 - R0.5	64 - O1		53 - R0.5		
368.0	Line Transformers	84,185,422	25 - R1.5	29 - R0.5	47 - O3		29 - R0.5		
369.0	Services	31,239,944	18 - R2.0	22 - R0.5	43 - O4		22 - R0.5		

Kentucky Power Company
SK Analysis of Proposed Lives and Survivor Curves
Production, Transmission, Distribution, and General Plant Summary 4/

ACCOUNT NO.	TITLE	ORIGINAL COST AT 12/31/04	Company Current Life	Company Current Curve 2/	Company Proposed Life	Company Proposed Curve 3/	SK Modeling Data Best Fit Life	SK Modeling Data Best Fit Curve 4/	SK Selection Life	SK Selection Curve 5/	ARL 6/	Notes
370.0	Meters	21,071,793	27 -	R0.5	20 -	R3.0	22 -	L1.5	20 -	R3.0		
371.0	Installations on Custs. Prem.	15,598,882	11 -	LO.O	12 -	L0.0	22 -	O4	12 -	L0.0		
373.0	Street Lighting & Signal Sys.	2,741,234	15 -	LO.O	20 -	L0.0	35 -	O4	20 -	L0.0		
	Total Distribution Plant	437,318,753										
GENERAL PLANT												
389.2	Land Rights	84,011	75 -	R4.0	75 -	R4.0	NA		75 -	R4.0		lack of data
390.0	Structures & Improvements	19,295,997	45 -	L3.0	25 -	L2.0	22 -	R3	25 -	L2.0		
391.0	Office Furniture & Equipment	1,737,579	35 -	R0.5	35 -	R0.5	41 -	O2	35 -	R0.5		
392.0	Transportation Equipment	5,819	30 -	R3.0	30 -	R3.0	17 -	SQ	30 -	R3.0		- only a 2001 investment left in account
393.0	Stores Equipment	189,262	30 -	R1.0	30 -	L0.0	29 -	L0	30 -	L0.0		
394.0	Tools Shop & Garage Equipment	1,711,318	30 -	RO.5	32 -	L0.0	39 -	O2	32 -	L0.0		
395.0	Laboratory Equipment	394,394	30 -	L5.0	32 -	S5.0	36 -	R3	32 -	S5.0		
396.0	Power Operated Equipment	5,931	-		8 -	8 SQ	NA		8 -	8 SQ		lack of data
397.0	Communication Equipment	4,666,769	22 -	L3.0	19 -	S6.0	20 -	R4	19 -	S6.0		
398.0	Miscellaneous Equipment	584,684	20 -	S5.0	19 -	L2.0	16 -	L2	19 -	L2.0		
	Total General Plant	28,675,764										
	Total Depreciable Plant	1,303,125,437										

1/ Excel file --> Other Depreciation Schedules/Schedule1 KPNewRates.xls
2/ Excel file --> Other Depreciation Schedules/Schedule III KPMortalitiy Compare.xls
3/ Excel file --> Other Depreciation Schedules/Schedule1 KPNewRates.xls
4/ SK Statistical Modeling - Company Data from 2004 Company Depreciation Study [Account].dat files
5/ SK Analysis - Based on observations of Company depreciation data, Company depreciation study(ies), Company responses to questions, and Snavely King analyses
6/ Broad Group/Vintage Group (BG/VG) calculations based on SK selection.

* Snavely King Analysis shows a different Life and Curve then the Company Proposal. Snavely King's selection in its testimony may be different then this analysis based on other factors that may not be included in this life analysis.

KENTUCKY POWER COMPANY
CALCULATED AVERAGE LIFE
STEAM PRODUCTION PLANT - SNAVELY KING RECOMMENDATIONS

ACCOUNT	PLANT BALANCE AT 12-31-04	AVERAGE AGE	AVERAGE REM. LIFE	AVERAGE LIFE
(1)	(2)	(3)	(4)	(5)=(3)+(4)
BIG SANDY				
311	36,149,758	26.08	28.06	54.14
312	324,538,694	9.97	22.33	32.30
314	73,038,983	20.85	23.54	44.39
315	13,742,601	32.06	27.13	59.19
316	6,518,954	22.08	26.26	48.34
Total	453,988,990			

Sources:
Cols. (2) and (3) from "Big Sandy Theo Res.xls", provided in response to AG-1-105.
Col. (4) from Exhibit___(MJM-4).

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT, ACCOUNT 311
RETIREMENT YEARS - UNIT 1 2028; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0011

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	39,765	10.5	417,530	
2016	39,765	11.5	457,294	
2017	39,765	12.5	497,059	
2018	39,765	13.5	536,824	
2019	39,765	14.5	576,589	
2020	39,765	15.5	616,353	
2021	39,765	16.5	656,118	
2022	39,765	17.5	695,883	
2023	39,765	18.5	735,648	
2024	39,765	19.5	775,412	
2025	39,765	20.5	815,177	
2026	39,765	21.5	854,942	
2027	39,765	22.5	894,707	
2028	5,875,352	23.5	138,070,766	
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	29,193,089	29.5	861,196,139	
TOTALS	36,149,758		1,014,202,967	28.06

INTERIM RETIREMENTS:	
Total Plant at 12/31/04	36,149,758
Less Retirement of Unit 1 in 2028	-5,835,587
Less Final Retirement in year 2034	-29,193,089
Total Interim Retirements	1,121,082

Note:
Unit 1 Retirement at 2028 based on 65 year life span from 1963.

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT, ACCOUNT 312
RETIREMENT YEARS - UNIT 1 2028; 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	6,497,604	2.5	16,244,011	
2008	4,843,638	3.5	16,952,731	
2009	11,361,735	4.5	51,127,806	
2010	4,745,866	5.5	26,102,264	
2011	4,745,866	6.5	30,848,130	
2012	4,745,866	7.5	35,593,996	
2013	4,745,866	8.5	40,339,862	
2014	4,745,866	9.5	45,085,728	
2015	4,745,866	10.5	49,831,594	
2016	4,745,866	11.5	54,577,460	
2017	4,745,866	12.5	59,323,326	
2018	4,745,866	13.5	64,069,192	
2019	4,745,866	14.5	68,815,059	
2020	4,745,866	15.5	73,560,925	
2021	4,745,866	16.5	78,306,791	
2022	4,745,866	17.5	83,052,657	
2023	4,745,866	18.5	87,798,523	
2024	4,745,866	19.5	92,544,389	
2025	4,745,866	20.5	97,290,255	
2026	4,745,866	21.5	102,036,121	
2027	4,745,866	22.5	106,781,987	
2028	11,641,100	23.5	273,565,853	
2029	4,642,438	24.5	113,739,721	
2030	4,642,438	25.5	118,382,159	
2031	4,642,438	26.5	123,024,596	
2032	4,642,438	27.5	127,667,034	
2033	4,642,438	28.5	132,309,472	
2034	171,820,680	29.5	5,068,710,045	
TOTALS	324,538,695		7,247,417,849	22.33

INTERIM RETIREMENTS:

Total Plant at 12/31/04	324,538,695
Less Retirement of Unit 1 in 2028	-6,895,234
Less Final Retirement in year 2034	-171,820,680
Total Interim Retirements	145,822,781

Note:
Unit 1 Retirement at 2028 based on 65 year life span from 1963.

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT, ACCOUNT 314
RETIREMENT YEARS - UNIT 1 2028; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0127

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	927,595	0.5	463,798	
2006	927,595	1.5	1,391,393	
2007	927,595	2.5	2,318,988	
2008	927,595	3.5	3,246,583	
2009	927,595	4.5	4,174,178	
2010	927,595	5.5	5,101,773	
2011	927,595	6.5	6,029,368	
2012	927,595	7.5	6,956,963	
2013	927,595	8.5	7,884,558	
2014	927,595	9.5	8,812,153	
2015	927,595	10.5	9,739,748	
2016	927,595	11.5	10,667,343	
2017	927,595	12.5	11,594,939	
2018	927,595	13.5	12,522,534	
2019	927,595	14.5	13,450,129	
2020	927,595	15.5	14,377,724	
2021	927,595	16.5	15,305,319	
2022	927,595	17.5	16,232,914	
2023	927,595	18.5	17,160,509	
2024	927,595	19.5	18,088,104	
2025	927,595	20.5	19,015,699	
2026	927,595	21.5	19,943,294	
2027	927,595	22.5	20,870,889	
2028	6,402,451	23.5	150,457,600	
2029	858,064	24.5	21,022,578	
2030	858,064	25.5	21,880,643	
2031	858,064	26.5	22,738,707	
2032	858,064	27.5	23,596,771	
2033	858,064	28.5	24,454,836	
2034	41,011,523	29.5	1,209,839,926	
TOTALS	73,038,983		1,719,339,961	23.54

INTERIM RETIREMENTS:	
Total Plant at 12/31/04	73,038,983
Less Retirement of Unit 1 in 2028	-5,474,856
Less Final Retirement in year 2034	-41,011,523
Total Interim Retirements	26,552,604

Note:
Unit 1 Retirement at 2028 based on 65 year life span from 1963.

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT, ACCOUNT 315
RETIREMENT YEARS - UNIT 1 2028; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0040

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	54,970	0.5	27,485	
2006	54,970	1.5	82,456	
2007	54,970	2.5	137,426	
2008	54,970	3.5	192,396	
2009	54,970	4.5	247,367	
2010	54,970	5.5	302,337	
2011	54,970	6.5	357,308	
2012	54,970	7.5	412,278	
2013	54,970	8.5	467,248	
2014	54,970	9.5	522,219	
2015	54,970	10.5	577,189	
2016	54,970	11.5	632,160	
2017	54,970	12.5	687,130	
2018	54,970	13.5	742,100	
2019	54,970	14.5	797,071	
2020	54,970	15.5	852,041	
2021	54,970	16.5	907,012	
2022	54,970	17.5	961,982	
2023	54,970	18.5	1,016,952	
2024	54,970	19.5	1,071,923	
2025	54,970	20.5	1,126,893	
2026	54,970	21.5	1,181,864	
2027	54,970	22.5	1,236,834	
2028	1,520,180	23.5	35,724,239	
2029	49,110	24.5	1,203,184	
2030	49,110	25.5	1,252,294	
2031	49,110	26.5	1,301,403	
2032	49,110	27.5	1,350,513	
2033	49,110	28.5	1,399,623	
2034	10,712,553	29.5	316,020,328	
TOTALS	13,742,601		372,791,256	27.13

INTERIM RETIREMENTS:

Total Plant at 12/31/04	13,742,601
Less Retirement of Unit 1 in 2028	-1,465,210
Less Final Retirement in year 2034	-10,712,553
Total Interim Retirements	1,564,838

Note:
Unit 1 Retirement at 2028 based on 65 year life span from 1963.

KENTUCKY POWER COMPANY
DEPRECIATION STUDY AS OF DECEMBER 31, 2004
CALCULATION OF AVERAGE REMAINING LIFE
BIG SANDY PLANT, ACCOUNT 316
RETIREMENT YEARS - UNIT 1 2028; UNIT 2 2034

ANNUAL INTERIM RETIREMENT RATE 0.0058

YEAR	AMOUNT RETIRED	REM. LIFE (YEARS)	DOLLAR YEARS	AVERAGE REM. LIFE
2005	37,810	0.5	18,905	
2006	37,810	1.5	56,715	
2007	37,810	2.5	94,525	
2008	37,810	3.5	132,335	
2009	37,810	4.5	170,145	
2010	37,810	5.5	207,955	
2011	37,810	6.5	245,765	
2012	37,810	7.5	283,574	
2013	37,810	8.5	321,384	
2014	37,810	9.5	359,194	
2015	37,810	10.5	397,004	
2016	37,810	11.5	434,814	
2017	37,810	12.5	472,624	
2018	37,810	13.5	510,434	
2019	37,810	14.5	548,244	
2020	37,810	15.5	586,054	
2021	37,810	16.5	623,864	
2022	37,810	17.5	661,674	
2023	37,810	18.5	699,484	
2024	37,810	19.5	737,294	
2025	37,810	20.5	775,104	
2026	37,810	21.5	812,914	
2027	37,810	22.5	850,723	
2028	828,981	23.5	19,481,052	
2029	33,221	24.5	813,918	
2030	33,221	25.5	847,139	
2031	33,221	26.5	880,360	
2032	33,221	27.5	913,581	
2033	33,221	28.5	946,803	
2034	4,654,239	29.5	137,300,047	
TOTALS	6,518,954		171,183,628	26.26

INTERIM RETIREMENTS:	
Total Plant at 12/31/04	6,518,954
Less Retirement of Unit 1 in 2028	-791,171
Less Final Retirement in year 2034	-4,654,239
Total Interim Retirements	1,073,544

Note:
Unit 1 Retirement at 2028 based on 65 year life span from 1963.

Exhibit___(MJM-5)

Snavely King Majoros O'Connor & Lee, Inc.

Depreciation Study

Net Salvage

Kentucky Power Company
Case No. 2005-00341

Five-Year Average Net Salvage Experience
2000-2004

Year	Gross Salvage	COR	Net Salvage
Production Plant			
2000	1,711	203,653	(201,942)
2001	172,103	(80,513)	252,616
2002	30,879	55,395	(24,516)
2003	(28,698)	1,578,174	(1,606,872)
2004	39,639	4,362,183	(4,322,544)
5-Year Total	**215,634**	**6,118,892**	**(5,903,258)**
5-Year Avg.	**43,127**	**1,223,778**	**(1,180,652)**
Transmission Plant			
2000	23,740	53,562	(29,822)
2001	101,608	823,970	(722,362)
2002	(31,282)	(54,593)	23,311
2003	305,945	1,074,786	(768,841)
2004	365,788	204,960	160,828
5-Year Total	**765,799**	**2,102,685**	**(1,336,886)**
5-Year Avg.	**153,160**	**420,537**	**(267,377)**
Distribution Plant			
2000	1,501,740	213,654	1,288,086
2001	2,190,111	2,918,529	(728,418)
2002	5,075,585	1,403,071	3,672,514
2003	1,560,605	1,192,686	367,919
2004	2,946,107	1,979,653	966,454
5-Year Total	**13,274,148**	**7,707,593**	**5,566,555**
5-Year Avg.	**2,654,830**	**1,541,519**	**1,113,311**
General Plant			
2000	-	(35,438)	35,438
2001	-	8,861	(8,861)
2002	-	-	-
2003	(100,160)	146,609	(246,769)
2004	1,932,476	-	1,932,476
5-Year Total	**1,832,316**	**120,032**	**1,712,284**
5-Year Avg.	**366,463**	**24,006**	**342,457**
Total Plant			
2000	1,527,191	435,431	1,091,760
2001	2,463,822	3,670,847	(1,207,025)
2002	5,075,182	1,403,873	3,671,309
2003	1,737,692	3,992,255	(2,254,563)
2004	5,284,010	6,546,796	(1,262,786)
5-Year Total	**16,087,897**	**16,049,202**	**38,695**
5-Year Avg.	**3,217,579**	**3,209,840**	**7,739**

Source: "PSALV.dat", "TSALV.dat", "DSALV.dat" and "GSALV.dat", matched to hardcopy of files provided in Henderson Workpapers (included as pages 4-14 of this exhibit).

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

Account (1)	Interim Retirements (2)	Interim Gross Salvage Percent (3)	Salvage on Interim Ret. (4)=(2)*(3)	Plant In-Service at 12/31/04 (5)	Salvage as % of Plant (6)=(4)/(5)
311	$ 1,121,082	8.8%	$ 99,086	$ 36,149,758	0%
312	145,822,781	8.8%	12,888,502	324,538,695	4%
314	26,552,604	8.8%	2,346,844	73,038,983	3%
315	1,564,838	8.8%	138,308	13,742,601	1%
316	1,073,544	8.8%	94,885	6,518,954	1%
Total	$ 176,134,849		$ 15,567,625	$ 453,988,991	

Sources:
Col. (2) from Exhibit___(MJM-4).
Cols. (3) and (5) from ProductionAnalysis.xls (provided in response to AG 1-105 and Henderson Wkprs, p. 3.

KENTUCKY POWER COMPANY
GROSS SALVAGE FACTORS
TRANSMISSION, DISTRIBUTION AND GENERAL PLANT

		Salvage Factor
TRANSMISSION PLANT		
350.1	Rights of Way	0%
352.0	Structures & Improvements	10%
353.0	Station Equipment	35%
354.0	Towers & Fixtures	0%
355.0	Poles & Fixtures	0%
356.0	OH Cond. & Devices	20%
357.0	Underground Conduit	0%
358.0	Underground Conductor and Devices	0%
DISTRIBUTION PLANT		
360.1	Rights of Way	0%
361.0	Structures & Improvements	10%
362.0	Station Equipment	35%
364.0	Poles, Towers, & Fixtures	25%
365.0	Overhead Conductor & Devices	40%
366.0	Underground Conduit	0%
367.0	Underground Conductor	15%
368.0	Line Transformers	40%
369.0	Services	15%
370.0	Meters	30%
371.0	Installations on Custs. Prem.	30%
373.0	Street Lighting & Signal Sys.	10%
GENERAL PLANT		
389.2	Rights of Way	0%
390.0	Structures & Improvements	12%
391.0	Office Furniture & Equipment	0%
392.0	Transportation Equipment	0%
393.0	Stores Equipment	0%
394.0	Tools Shop & Garage Equipment	0%
395.0	Laboratory Equipment	0%
396.0	Power Operated Equipment	0%
397.0	Communication Equipment	10%
398.0	Miscellaneous Equipment	0%

Source:
Exhibit JEH-1, Schedule III.

DELOITTE HASKINS & SELLS — DEPRECIATION SYSTEM - DSALVG01 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2004 —

KENTUCKY POWER COMPANY — 7-16-2005

ACCOUNT NO.: 10810000

PRODUCTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1960	0.	0.	0.	0.%	450.	0.%	3141.	0.%	0.%	0.%
1961	0.	0.	0.	0.%	365.	0.%	250.	0.%	0.%	0.%
1964	0.	12972.	0.	0.%	2350.	18.%	559.	4.%	14.%	14.%
1965	0.	8393.	0.	0.%	63.	1.%	1353.	16.%	-15.%	-15.%
1966	0.	28356.	0.	0.%	1639.	6.%	1309.	5.%	1.%	1.%
1967	0.	72923.	0.	0.%	50088.	69.%	207.	0.%	68.%	68.%
1968	0.	128116.	0.	0.%	3717.	3.%	11276.	9.%	-6.%	-6.%
1969	0.	6226.	0.	0.%	0.	0.%	0.	0.%	0.%	0.%
1970	0.	765565.	0.	0.%	38983.	5.%	20261.	3.%	2.%	2.%
1971	0.	126096.	0.	0.%	2831.	2.%	42474.	34.%	-31.%	-31.%
1972	0.	26254.	0.	0.%	8641.	33.%	3092.	12.%	21.%	21.%
1973	0.	40145.	0.	0.%	3905.	10.%	76655.	191.%	-181.%	-181.%
1974	0.	172218.	0.	0.%	661.	0.%	756.	0.%	0.%	0.%
1975	0.	123712.	0.	0.%	8539.	7.%	28002.	23.%	-16.%	-16.%
1976	0.	1145237.	0.	0.%	9669.	1.%	56912.	5.%	-4.%	-4.%
1977	0.	753812.	0.	0.%	78585.	10.%	111093.	15.%	-4.%	-4.%
1978	0.	280923.	0.	0.%	1491.	1.%	20757.	7.%	-7.%	-7.%
1979	0.	1978089.	0.	0.%	83069.	4.%	278953.	14.%	-10.%	-10.%
1980	0.	1539921.	0.	0.%	5630.	0.%	126933.	8.%	-8.%	-8.%
1981	0.	1729730.	0.	0.%	3569.	0.%	573164.	33.%	-33.%	-33.%
1982	0.	1674621.	0.	0.%	55571.	3.%	704047.	42.%	-39.%	-39.%
1983	0.	1127403.	0.	0.%	12461.	1.%	49042.	4.%	-3.%	-3.%
1984	0.	597900.	0.	0.%	724.	0.%	112419.	19.%	-19.%	-19.%
1985	0.	101983.	0.	0.%	69625.	68.%	537959.	527.%	-459.%	-459.%
1986	0.	1341809.	0.	0.%	69408.	5.%	10759.	1.%	4.%	4.%
1987	0.	1296541.	0.	0.%	671733.	52.%	386860.	30.%	22.%	22.%
1988	0.	1239413.	0.	0.%	146691.	12.%	1881634.	152.%	-140.%	-140.%
1989	0.	3675101.	0.	0.%	1495274.	41.%	264645.	7.%	33.%	33.%
1990	0.	1974433.	0.	0.%	435816.	22.%	814536.	41.%	-19.%	-19.%
1991	0.	1154968.	0.	0.%	25400.	2.%	311112.	27.%	-25.%	-25.%
1992	0.	2617525.	0.	0.%	866774.	33.%	427592.	16.%	17.%	17.%
1993	0.	3236184.	0.	0.%	-34358.	-1.%	1578355.	49.%	-50.%	-50.%
1994	0.	3969598.	0.	0.%	60472.	2.%	2038522.	51.%	-50.%	-50.%
1995	0.	6338609.	0.	0.%	1919772.	30.%	2274820.	36.%	-6.%	-6.%
1996	0.	2883635.	0.	0.%	-108297.	-4.%	2268116.	79.%	-82.%	-82.%
1997	0.	8213501.	0	0.%	1622235.	20.%	1652784.	20.%	0.%	0.%
1998	0.	1885004.	0.	0.%	-109746.	-6.%	2094579.	111.%	-117.%	-117.%
1999	0.	474672.	0.	0.%	3780.	1.%	8266.	2.%	-1.%	-1.%
2000	0.	855616.	0.	0.%	1711.	0.%	203653.	24.%	-24.%	-24.%
2001	0.	543659.	0.	0.%	172103.	32.%	-80513.	-15.%	46.%	46.%
2002	0	875114.	0.	0.%	30879.	4.%	55395.	6.%	-3.%	-3.%
2003	0.	17253619.	0.	0.%	-28698.	0.%	1578174.	9.%	-9.%	-9.%

KENTUCKY POWER COMPANY 7-16-2005

ACCOUNT NO.: 10810000

PRODUCTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
2004	0.	3134846.	0.	0.%	39640.	1.%	4362183.	139.%	-138.%	-138.%
	0.	75404442.	0.	0.%	7723215.	10.%	24892086.	33.%	-23.%	-23.%

ROLLING BAND

1960-1974	0.	1387264.	0.	0.%	113693.	8.%	161333.	12.%	-3.%	-3.%
1961-1975	0.	1510976.	0.	0.%	121782.	8.%	186194.	12.%	-4.%	-4.%
1962-1976	0.	2656213.	0.	0.%	131086.	5.%	242856.	9.%	-4.%	-4.%
1963-1977	0.	3410025.	0.	0.%	209671.	6.%	353949.	10.%	-4.%	-4.%
1964-1978	0.	3690948.	0.	0.%	211162.	6.%	374706.	10.%	-4.%	-4.%
1965-1979	0.	5656065.	0.	0.%	291881.	5.%	653100.	12.%	-6.%	-6.%
1966-1980	0.	7187593.	0.	0.%	297448.	4.%	778680.	11.%	-7.%	-7.%
1967-1981	0.	8888967.	0.	0.%	299378.	3.%	1350535.	15.%	-12.%	-12.%
1968-1982	0.	10490665.	0.	0.%	304861.	3.%	2054375.	20.%	-17.%	-17.%
1969-1983	0.	11489952.	0.	0.%	313605.	3.%	2092141.	18.%	-15.%	-15.%
1970-1984	0.	12081626.	0.	0.%	314329.	3.%	2204560.	18.%	-16.%	-16.%
1971-1985	0.	11418044.	0.	0.%	344971.	3.%	2722258.	24.%	-21.%	-21.%
1972-1986	0.	12633757.	0.	0.%	411548.	3.%	2690543.	21.%	-18.%	-18.%
1973-1987	0.	13904044.	0.	0.%	1074640.	8.%	3074311.	22.%	-14.%	-14.%
1974-1988	0.	15103312.	0.	0.%	1217426.	8.%	4879290.	32.%	-24.%	-24.%
1975-1989	0.	18606195.	0.	0.%	2712039.	15.%	5143179.	28.%	-13.%	-13.%
1976-1990	0.	20456916.	0.	0.%	3139316.	15.%	5929713.	29.%	-14.%	-14.%
1977-1991	0.	20466647.	0.	0.%	3155047.	15.%	6183913.	30.%	-15.%	-15.%
1978-1992	0.	22330360.	0.	0.%	3943236.	18.%	6500412.	29.%	-11.%	-11.%
1979-1993	0.	25285621.	0.	0.%	3907387.	15.%	8058010.	32.%	-16.%	-16.%
1980-1994	0.	27277130.	0.	0.%	3884790.	14.%	9817579.	36.%	-22.%	-22.%
1981-1995	0.	32075818.	0.	0.%	5798932.	18.%	11965466.	37.%	-19.%	-19.%
1982-1996	0.	33229723.	0.	0.%	5687066.	17.%	13660418.	41.%	-24.%	-24.%
1983-1997	0.	39768603.	0.	0.%	7253730.	18.%	14609155.	37.%	-18.%	-18.%
1984-1998	0.	40526204.	0.	0.%	7131523.	18.%	16654692.	41.%	-23.%	-23.%
1985-1999	0.	40402976.	0.	0.%	7134579.	18.%	16550539.	41.%	-23.%	-23.%
1986-2000	0.	41156609.	0.	0.%	7066665.	17.%	16216233.	39.%	-22.%	-22.%
1987-2001	0.	40358459.	0.	0.%	7169360.	18.%	16124961.	40.%	-22.%	-22.%
1988-2002	0.	39937032.	0.	0.%	6528506.	16.%	15793496.	40.%	-23.%	-23.%
1989-2003	0.	55951238.	0.	0.%	6353117.	11.%	15490036.	28.%	-16.%	-16.%
1990-2004	0.	55410983.	0.	0.%	4897483.	9.%	19587574.	35.%	-27.%	-27.%

DELOITTE HASKINS & SELLS — DEPRECIATION SYSTEM - DSALVG01 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2004 — PAGE 1

KENTUCKY POWER COMPANY — 7-13-2005

ACCOUNT NO.: 10850000

TRANSMISSION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1954	0.	34583.	0.	0.%	15298.	44.%	7180.	21.%	23.%	23.%
1955	0.	47135.	0.	0.%	23025.	49.%	7889.	17.%	32.%	32.%
1956	0.	22861.	0.	0.%	5024.	22.%	5258.	23.%	-1.%	-1.%
1957	0.	134912.	0.	0.%	42741.	32.%	10113.	7.%	24.%	24.%
1958	0.	89413.	0.	0.%	39278.	44.%	23451.	26.%	18.%	18.%
1959	0.	109562.	0.	0.%	56914.	52.%	10968.	10.%	42.%	42.%
1960	0.	120308.	0.	0.%	25114.	21.%	12000.	10.%	11.%	11.%
1961	0.	97570.	0.	0.%	58122.	60.%	19975.	20.%	39.%	39.%
1962	0.	105122.	0.	0.%	48139.	46.%	35762.	34.%	12.%	12.%
1963	0.	81024.	0.	0.%	76939.	95.%	10727.	13.%	82.%	82.%
1964	0.	44999.	0.	0.%	2529.	6.%	8623.	19.%	-14.%	-14.%
1965	0.	456939.	0.	0.%	129041.	28.%	138735.	30.%	-2.%	-2.%
1966	0.	202844.	0.	0.%	54393.	27.%	73574.	36.%	-9.%	-9.%
1967	0.	378070.	0.	0.%	64988.	17.%	112497.	30.%	-13.%	-13.%
1968	0.	241351.	0.	0.%	13413.	6.%	57522.	24.%	-18.%	-18.%
1969	0.	600025.	0.	0.%	103002.	17.%	103107.	17.%	0.%	0.%
1970	0.	52004.	0.	0.%	17779.	34.%	12589.	24.%	10.%	10.%
1971	0.	153003.	0.	0.%	55726.	36.%	28344.	19.%	18.%	18.%
1972	0.	166793.	0.	0.%	56538.	34.%	36030.	22.%	12.%	12.%
1973	0.	238120.	0.	0.%	192316.	81.%	49235.	21.%	60.%	60.%
1974	0.	230313.	0.	0.%	339163.	147.%	45869.	20.%	127.%	127.%
1975	0.	137446.	0.	0.%	129176.	94.%	69379.	50.%	44.%	44.%
1976	0.	789389.	0.	0.%	143997.	18.%	32216.	4.%	14.%	14.%
1977	0.	250212.	0.	0.%	225156.	90.%	1431.	1.%	89.%	89.%
1978	0.	422125.	0.	0.%	-37889.	-9.%	-17686.	-4.%	-5.%	-5.%
1979	0.	138790.	0.	0.%	60197.	43.%	145231.	105.%	-61.%	-61.%
1980	0.	740426.	0.	0.%	303867.	41.%	118565.	16.%	25.%	25.%
1981	0.	1235156.	0.	0.%	137039.	11.%	72785.	6.%	5.%	5.%
1982	0.	348126.	0.	0.%	306936.	88.%	146727.	42.%	46.%	46.%
1983	0.	133764.	0.	0.%	137997.	103.%	79939.	60.%	43.%	43.%
1984	0.	248203.	0.	0.%	51497.	21.%	68152.	27.%	-7.%	-7.%
1985	0.	407649.	0.	0.%	306076.	75.%	38164.	9.%	66.%	66.%
1986	0.	620920.	0.	0.%	22842.	4.%	175660.	28.%	-25.%	-25.%
1987	0.	205446.	0.	0.%	197229.	96.%	69955.	34.%	62.%	62.%
1988	0.	325128.	0.	0.%	276527.	85.%	110394.	34.%	51.%	51.%
1989	0.	950539.	0.	0.%	370387.	39.%	122039.	13.%	26.%	26.%
1990	0.	455000.	0.	0.%	64159.	14.%	296114.	65.%	-51.%	-51.%
1991	0.	863065.	0.	0.%	59121.	7.%	327755.	38.%	-31.%	-31.%
1992	0.	1871867.	0.	0.%	1163291.	62.%	422506.	23.%	40 %	40.%
1993	0.	748707.	0.	0.%	-228274.	-30.%	245842.	33.%	-63 %	-63.%
1994	0.	908689.	0.	0.%	194052.	21.%	92692.	10.%	11.%	11.%
1995	0.	220890.	0.	0.%	42611.	19.%	151723.	69.%	-49.%	-49.%

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TRANSMISSION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1996	0.	-25138.	0.	0.%	-5644.	22.%	-6225.	25.%	-2.%	-2.%
1997	0.	984775.	0.	0.%	51684.	5.%	39136.	4.%	1.%	1.%
1998	0.	265039.	0.	0.%	284212.	107.%	215982.	81.%	26.%	26.%
1999	0.	1131697.	0.	0.%	231775.	20.%	33535.	3.%	18.%	18.%
2000	0.	727893.	0.	0.%	23740.	3.%	53562.	7.%	-4.%	-4.%
2001	0.	243225.	0.	0.%	101608.	42.%	823970.	339.%	-297.%	-297.%
2002	0.	433622.	0.	0.%	-31282.	-7.%	-54593.	-13.%	5.%	5.%
2003	0.	590516.	0.	0.%	305945.	52.%	1074786.	182.%	-130.%	-130.%
2004	0.	1107137.	0.	0.%	365788.	33.%	204960.	19.%	15.%	15.%
	0.	21087254.	0.	0.%	6673302.	32.%	5964144.	28.%	3.%	3.%

ROLLING BAND

	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1954-1968	0.	2166693.	0.	0.%	654958.	30.%	534274.	25.%	6.%	6.%
1955-1969	0.	2732135.	0.	0.%	742662.	27.%	630201.	23.%	4.%	4.%
1956-1970	0.	2737004.	0.	0.%	737416.	27.%	634901.	23.%	4.%	4.%
1957-1971	0.	2867146.	0.	0.%	788118.	27.%	657987.	23.%	5.%	5.%
1958-1972	0.	2899027.	0.	0.%	801915.	28.%	683904.	24.%	4.%	4.%
1959-1973	0.	3047734.	0.	0.%	954953.	31.%	709688.	23.%	8.%	8.%
1960-1974	0.	3168485.	0.	0.%	1237202.	39.%	744589.	23.%	16.%	16.%
1961-1975	0.	3185623.	0.	0.%	1341264.	42.%	801968.	25.%	17.%	17.%
1962-1976	0.	3877442.	0.	0.%	1427139.	37.%	814209.	21.%	16.%	16.%
1963-1977	0.	4022532.	0.	0.%	1604156.	40.%	779878.	19.%	20.%	20.%
1964-1978	0.	4363633.	0.	0.%	1489328.	34.%	751465.	17.%	17.%	17.%
1965-1979	0.	4457424.	0.	0.%	1546996.	35.%	888073.	20.%	15.%	15.%
1966-1980	0.	4740911.	0.	0.%	1721822.	36.%	867903.	18.%	18.%	18.%
1967-1981	0.	5773223.	0.	0.%	1804468.	31.%	867114.	15.%	16.%	16.%
1968-1982	0.	5743279.	0.	0.%	2046416.	36.%	901344.	16.%	20.%	20.%
1969-1983	0.	5635692.	0.	0.%	2171000.	39.%	923761.	16.%	22.%	22.%
1970-1984	0.	5283870.	0.	0.%	2119495.	40.%	888806.	17.%	23.%	23.%
1971-1985	0.	5639515.	0.	0.%	2407792.	43.%	914381.	16.%	26.%	26.%
1972-1986	0.	6107432.	0.	0.%	2374908.	39.%	1061697.	17.%	22.%	22.%
1973-1987	0.	6146085.	0.	0.%	2515599.	41.%	1095622.	18.%	23.%	23.%
1974-1988	0.	6233093.	0.	0.%	2599810.	42.%	1156781.	19.%	23.%	23.%
1975-1989	0.	6953319.	0.	0.%	2631034.	38.%	1232951.	18.%	20.%	20.%
1976-1990	0.	7270873.	0.	0.%	2566017.	35.%	1459686.	20.%	15.%	15.%
1977-1991	0.	7344549.	0.	0.%	2481141.	34.%	1755225.	24.%	10.%	10.%
1978-1992	0.	8966204.	0.	0.%	3419276.	38.%	2176300.	24.%	14.%	14.%
1979-1993	0.	9292786.	0.	0.%	3228891.	35.%	2439828.	26.%	8.%	8.%
1980-1994	0.	10062685.	0.	0.%	3362746.	33.%	2387289.	24.%	10.%	10.%

DELOITTE HASKINS & SELLS

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STUDY AS OF DECEMBER 31, 2004

KENTUCKY POWER COMPANY

7-13-2005

ACCOUNT NO.: 10850000

TRANSMISSION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1981-1995	0.	9543149.	0.	0.%	3101490.	32.%	2420447.	25.%	7.%	7.%
1982-1996	0.	8282855.	0.	0.%	2958807.	36.%	2341437.	28.%	7.%	7.%
1983-1997	0.	8919504.	0.	0.%	2703555.	30.%	2233846.	25.%	5.%	5.%
1984-1998	0.	9050779.	0.	0.%	2849770.	31.%	2369889.	26.%	5.%	5.%
1985-1999	0.	9934273.	0.	0.%	3030048.	31.%	2335272.	24.%	7.%	7.%
1986-2000	0.	10254517.	0.	0.%	2747712.	27.%	2350670.	23.%	4.%	4.%
1987-2001	0.	9876822.	0.	0.%	2826478.	29.%	2998980.	30.%	-2.%	-2.%
1988-2002	0.	10104998.	0.	0.%	2597967.	26.%	2874432.	28.%	-3.%	-3.%
1989-2003	0.	10370386.	0.	0.%	2627385.	25.%	3838824.	37.%	-12.%	-12.%
1990-2004	0.	10526984.	0.	0.%	2622786.	25.%	3921745.	37.%	-12.%	-12.%

DELOITTE HASKINS & SELLS — DEPRECIATION SYSTEM - DSALVG01 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2004 —

KENTUCKY POWER COMPANY — 7-13-2005

ACCOUNT NO.: 10860000

DISTRIBUTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1954	0.	345614.	0.	0.%	164293.	48.%	66201.	19.%	28.%	28.%
1955	0.	329795.	0.	0.%	163818.	50.%	68960.	21.%	29.%	29.%
1956	0.	340400.	0.	0.%	175639.	52.%	81844.	24.%	28.%	28.%
1957	0.	560530.	0.	0.%	243234.	43.%	141931.	25.%	18.%	18.%
1958	0.	505375.	0.	0.%	206808.	41.%	144792.	29.%	12.%	12.%
1959	0.	624939.	0.	0.%	259031.	41.%	152087.	24.%	17.%	17.%
1960	0.	492849.	0.	0.%	271181.	55.%	161636.	33.%	22.%	22.%
1961	0.	819969.	0.	0.%	381111.	46.%	170331.	21.%	26.%	26.%
1962	0.	558196.	0.	0.%	299388.	54.%	192682.	35.%	19.%	19.%
1963	0.	706977.	0.	0.%	279116.	39.%	194420.	28.%	12.%	12.%
1964	0.	773027.	0.	0.%	304668.	39.%	189822.	25.%	15.%	15.%
1965	0.	1012221.	0.	0.%	374123.	37.%	239135.	24.%	13.%	13.%
1966	0.	1071099.	0.	0.%	450349.	42.%	285103.	27.%	15.%	15.%
1967	0.	1463163.	0.	0.%	413889.	28.%	342901.	23.%	5.%	5.%
1968	0.	1330710.	0.	0.%	670448.	50.%	479783.	36.%	14.%	14.%
1969	0.	1560135.	0.	0.%	646533.	41.%	347617.	22.%	19.%	19.%
1970	0.	1143715.	0.	0.%	400222.	35.%	357897.	31.%	4.%	4.%
1971	0.	1315603.	0.	0.%	543957.	41.%	401721.	31.%	11.%	11.%
1972	0.	1475429.	0.	0.%	752589.	51.%	490837.	33.%	18.%	18.%
1973	0.	1773250.	0.	0.%	703812.	40.%	491738.	28.%	12.%	12.%
1974	0.	1273997.	0.	0.%	921165.	72.%	527796.	41.%	31.%	31.%
1975	0.	1413889.	0.	0.%	633350.	45.%	485488.	34.%	10.%	10.%
1976	0.	1770503.	0.	0.%	905056.	51.%	680443.	38.%	13.%	13.%
1977	0.	1790525.	0.	0.%	1032217.	58.%	928730.	52.%	6.%	6.%
1978	0.	2839810.	0.	0.%	1622814.	57.%	952797.	34.%	24.%	24.%
1979	0.	2379695.	0.	0.%	1368931.	58.%	1048294.	44.%	13.%	13.%
1980	0.	3067886.	0.	0.%	1455926.	47.%	1423814.	46.%	1.%	1.%
1981	0.	4492306.	0.	0.%	1883382.	42.%	1737241.	39.%	3.%	3.%
1982	0.	2552584.	0.	0.%	1586478.	62.%	1503023.	59.%	3.%	3.%
1983	0.	3917704.	0.	0.%	1560432.	40.%	1361570.	35.%	5.%	5.%
1984	0.	2274942.	0.	0.%	1275047.	56.%	1464480.	64.%	-8.%	-8.%
1985	0.	3390814.	0.	0.%	1033246.	30.%	1315547.	39.%	-8.%	-8.%
1986	0.	4122421.	0.	0.%	1703914.	41.%	1814294.	44.%	-3.%	-3.%
1987	0.	5062869.	0.	0.%	2341368.	46.%	1686747.	33.%	13.%	13.%
1988	0.	5092695.	0.	0.%	2009198.	39.%	1881879.	37.%	3.%	3.%
1989	0.	7285672.	0.	0.%	5727263.	79.%	1888999.	26.%	53.%	53.%
1990	0.	6337485.	0.	0.%	2563490.	40.%	2433166.	38.%	2.%	2.%
1991	0.	5330583.	0.	0.%	1639592.	31.%	2601095.	49.%	-18.%	-18.%
1992	0.	5047537.	0.	0.%	1220353.	24.%	2236974.	44.%	-20.%	-20.%
1993	0.	4862356.	0.	0.%	1829402.	38.%	2197784.	45.%	-8.%	-8.%
1994	0.	5874830.	0.	0.%	2155099.	37.%	1954453.	33.%	3.%	3.%
1995	0.	7390800.	0.	0.%	2159120.	29.%	2119861.	29.%	1.%	1.%

KENTUCKY POWER COMPANY 7-13-2005
ACCOUNT NO.: 10860000
DISTRIBUTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1996	0.	6260150.	0.	0.%	1342053.	21.%	1245388.	20.%	2.%	2.%
1997	0.	8613849.	0.	0.%	1918643.	22.%	1444506.	17.%	6.%	6.%
1998	0.	5385836.	0.	0.%	1292253.	24.%	804413.	15.%	9.%	9.%
1999	0.	4764283.	0.	0.%	440710.	9.%	262682.	6.%	4.%	4.%
2000	0.	7883448.	0.	0.%	1501740.	19.%	213654.	3.%	16.%	16.%
2001	0.	5934590.	0.	0.%	2190111.	37.%	2918529.	49.%	-12.%	-12.%
2002	0.	6806995.	0.	0.%	5075585.	75.%	1403071.	21.%	54.%	54.%
2003	0.	5434672.	0.	0.%	1560605.	29.%	1192686.	22.%	7.%	7.%
2004	0.	7250554.	0.	0.%	2946107.	41.%	1979653.	27.%	13.%	13.%
	0.	164109276.	0.	0.%	64598859.	39.%	50710495.	31.%	8.%	8.%

ROLLING BAND

ROLLING BAND	ADDITIONS	RETIREMENTS	REIMB. AMOUNT	RATIO	SALVAGE AMOUNT	RATIO	COST OF REMOVAL AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1954-1968	0.	10934864.	0.	0.%	4657096.	43.%	2911628.	27.%	16.%	16.%
1955-1969	0.	12149385.	0.	0.%	5139336.	42.%	3193044.	26.%	16.%	16.%
1956-1970	0.	12963305.	0.	0.%	5375740.	41.%	3481981.	27.%	15.%	15.%
1957-1971	0.	13938508.	0.	0.%	5744058.	41.%	3801858.	27.%	14.%	14.%
1958-1972	0.	14853407.	0.	0.%	6253413.	42.%	4150764.	28.%	14.%	14.%
1959-1973	0.	16121282.	0.	0.%	6750417.	42.%	4497710.	28.%	14.%	14.%
1960-1974	0.	16770340.	0.	0.%	7412551.	44.%	4873419.	29.%	15.%	15.%
1961-1975	0.	17691380.	0.	0.%	7774720.	44.%	5197271.	29.%	15.%	15.%
1962-1976	0.	18641914.	0.	0.%	8298665.	45.%	5707383.	31.%	14.%	14.%
1963-1977	0.	19874243.	0.	0.%	9031494.	45.%	6443431.	32.%	13.%	13.%
1964-1978	0.	22007076.	0.	0.%	10375192.	47.%	7201808.	33.%	14.%	14.%
1965-1979	0.	23613744.	0.	0.%	11439455.	48.%	8060280.	34.%	14.%	14.%
1966-1980	0.	25669409.	0.	0.%	12521258.	49.%	9244959.	36.%	13.%	13.%
1967-1981	0.	29090616.	0.	0.%	13954291.	48.%	10697097.	37.%	11.%	11.%
1968-1982	0.	30180037.	0.	0.%	15126880.	50.%	11857219.	39.%	11.%	11.%
1969-1983	0.	32767031.	0.	0.%	16016864.	49.%	12739006.	39.%	10.%	10.%
1970-1984	0.	33481838.	0.	0.%	16645378.	50.%	13855869.	41.%	8.%	8.%
1971-1985	0.	35728937.	0.	0.%	17278402.	48.%	14813519.	41.%	7.%	7.%
1972-1986	0.	38535755.	0.	0.%	18438359.	48.%	16226092.	42.%	6.%	6.%
1973-1987	0.	42123195.	0.	0.%	20027138.	48.%	17422002.	41.%	6.%	6.%
1974-1988	0.	45442640.	0.	0.%	21332524.	47.%	18812143.	41.%	6.%	6.%
1975-1989	0.	51454315.	0.	0.%	26138622.	51.%	20173346.	39.%	12.%	12.%
1976-1990	0.	56377911.	0.	0.%	28068762.	50.%	22121024.	39.%	11.%	11.%
1977-1991	0.	59937991.	0.	0.%	28803298.	48.%	24041676.	40.%	8.%	8.%
1978-1992	0.	63195003.	0.	0.%	28991434.	46.%	25349920.	40.%	6.%	6.%
1979-1993	0.	65217549.	0.	0.%	29198022.	45.%	26594907.	41.%	4.%	4.%
1980-1994	0.	68712684.	0.	0.%	29984190.	44.%	27501066.	40.%	4.%	4.%

KENTUCKY POWER COMPANY 7-13-2005

ACCOUNT NO.: 10860000

DISTRIBUTION PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1981-1995	0.	73035598.	0.	0.%	30687384.	42.%	28197113.	39.%	3.%	3.%
1982-1996	0.	74803442.	0.	0.%	30146055.	40.%	27705260.	37.%	3.%	3.%
1983-1997	0.	80864707.	0.	0.%	30478220.	38.%	27646743.	34.%	4.%	4.%
1984-1998	0.	82332839.	0.	0.%	30210041.	37.%	27089586.	33.%	4.%	4.%
1985-1999	0.	84822180.	0.	0.%	29375704.	35.%	25887788.	31.%	4.%	4.%
1986-2000	0.	89314814.	0.	0.%	29844198.	33.%	24785895.	28.%	6.%	6.%
1987-2001	0.	91126983.	0.	0.%	30330395.	33.%	25890130.	28.%	5.%	5.%
1988-2002	0.	92871109.	0.	0.%	33064612.	36.%	25606454.	28.%	8.%	8.%
1989-2003	0.	93213086.	0.	0.%	32616019.	35.%	24917261.	27.%	8.%	8.%
1990-2004	0.	93177968.	0.	0.%	29834863.	32.%	25007915.	27.%	5.%	5.%

DELOITTE HASKINS & SELLS

DEPRECIATION SYSTEM - DSALVG01 RELEASE 5.0

STUDY AS OF DECEMBER 31, 2004

KENTUCKY POWER COMPANY

ACCOUNT NO.: 10872000

GENERAL PLANT

7-15-2005

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1954	0.	6604.	0.	0.%	1932.	29.%	857.	13.%	16.%	16.%
1955	0.	4156.	0.	0.%	1153.	28.%	296.	7.%	21.%	21.%
1956	0.	11547.	0.	0.%	1175.	10.%	56.	0.%	10.%	10.%
1957	0.	17234.	0.	0.%	741.	4.%	261.	2.%	3.%	3.%
1958	0.	15852.	0.	0.%	631.	4.%	1442.	9.%	-5.%	-5.%
1959	0.	7961.	0.	0.%	315.	4.%	238.	3.%	1.%	1.%
1960	0.	35975.	0.	0.%	3171.	9.%	2193.	6.%	3.%	3.%
1961	0.	32219.	0.	0.%	1414.	4.%	949.	3.%	1.%	1.%
1962	0.	5803.	0.	0.%	3494.	60.%	1607.	28.%	33.%	33.%
1963	0.	29313.	0.	0.%	2469.	8.%	3333.	11.%	-3.%	-3.%
1964	0.	66108.	0.	0.%	570.	1.%	4221.	6.%	-6.%	-6.%
1965	0.	162447.	0.	0.%	888.	1.%	3091.	2.%	-1.%	-1.%
1966	0.	2451.	0.	0.%	342.	14.%	9583.	391.%	-377.%	-377.%
1967	0.	12153.	0.	0.%	3237.	27.%	-2422.	-20.%	47.%	47.%
1968	0.	24450.	0.	0.%	1281.	5.%	623.	3.%	3.%	3.%
1969	0.	97196.	0.	0.%	-3795.	-4.%	2768.	3.%	-7.%	-7.%
1970	0.	11186.	0.	0.%	2888.	26.%	103.	1.%	25.%	25.%
1971	0.	2926.	0.	0.%	-2089.	-71.%	71.	2.%	-74.%	-74.%
1972	0.	11324.	0.	0.%	514.	5.%	348.	3.%	1.%	1.%
1973	0.	16756.	0.	0.%	1921.	11.%	255.	2.%	10.%	10.%
1974	0.	36359.	0.	0.%	5212.	14.%	1097.	3.%	11.%	11.%
1975	0.	16603.	0.	0.%	747.	4.%	162.	1.%	4.%	4.%
1976	0.	43932.	0.	0.%	2256.	5.%	63.	0.%	5.%	5.%
1977	0.	20375.	0.	0.%	848.	4.%	206.	1.%	3.%	3.%
1978	0.	29848.	0.	0.%	449.	2.%	947.	3.%	-2.%	-2.%
1979	0.	110455.	0.	0.%	38474.	35.%	1771.	2.%	33.%	33.%
1980	0.	-26283.	0.	0.%	379792.	-1445.%	-193.	1.%	-1446.%	-1446.%
1981	0.	62146.	0.	0.%	2204.	4.%	0.	0.%	4.%	4.%
1982	0.	114845.	0.	0.%	37.	0.%	-300.	0.%	0.%	0.%
1983	0.	56853.	0.	0.%	69.	0.%	-624.	-1.%	1.%	1.%
1984	0.	28929.	0.	0.%	1152.	4.%	624.	2.%	2.%	2.%
1985	0.	180319.	0.	0.%	1726.	1.%	-635.	0.%	1.%	1.%
1986	0.	61942.	0.	0.%	603.	1.%	3785.	6.%	-5.%	-5.%
1987	0.	65632.	0.	0.%	4797.	7.%	2604.	4.%	3.%	3.%
1988	0.	66486.	0.	0.%	1612.	2.%	0.	0.%	2.%	2.%
1989	0.	80142.	0.	0.%	51.	0.%	11628.	15.%	-14.%	-14.%
1990	0.	1063124.	0.	0.%	141149.	13.%	50399.	5.%	9.%	9.%
1991	0.	289538.	0.	0.%	21722.	8.%	99427.	34.%	-27.%	-27.%
1992	0.	704613.	0.	0.%	49167.	7.%	-3992.	-1.%	8.%	8.%
1993	0.	437544.	0.	0.%	2090.	0.%	114740.	26.%	-26.%	-26.%
1994	0.	347501.	0.	0.%	37443.	11.%	804.	0.%	11.%	11.%
1995	0.	104629.	0.	0.%	11107.	11.%	47957.	46.%	-35.%	-35.%

KENTUCKY POWER COMPANY 7-15-2005

ACCOUNT NO.: 10872000

GENERAL PLANT

YEAR	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1996	0.	451507.	0.	0.%	4006.	1.%	-70222.	-16.%	16.%	16.%
1997	0.	295506.	0.	0.%	68506.	23.%	27111.	9.%	14.%	14.%
1998	0.	1326363.	0.	0.%	0.	0.%	524.	0.%	0.%	0.%
1999	0.	26757.	0.	0.%	-9336.	-35.%	393.	1.%	-36.%	-36.%
2000	0.	224558.	0.	0.%	0.	0.%	-35438.	-16.%	16.%	16.%
2001	0.	27540.	0.	0.%	0.	0.%	8861.	32.%	-32.%	-32.%
2003	0.	1740509.	0.	0.%	-100160.	-6.%	146609.	8.%	-14.%	-14.%
2004	0.	12449685.	0.	0.%	1932476.	16.%	0.	0.%	16.%	16.%
	0.	21011618.	0.	0.%	2620451.	12.%	438181.	2.%	10.%	10.%

ROLLING BAND

ROLLING BAND	ADDITIONS	RETIREMENTS	REIMBURSEMENTS AMOUNT	REIMBURSEMENTS RATIO	SALVAGE AMOUNT	SALVAGE RATIO	COST OF REMOVAL AMOUNT	COST OF REMOVAL RATIO	NET SALVAGE W/REIMB.	NET SALVAGE W/O REIMB.
1954-1968	0.	434273.	0.	0.%	22813.	5.%	26328.	6.%	-1.%	-1.%
1955-1969	0.	524865.	0.	0.%	17086.	3.%	28239.	5.%	-2.%	-2.%
1956-1970	0.	531895.	0.	0.%	18821.	4.%	28046.	5.%	-2.%	-2.%
1957-1971	0.	523274.	0.	0.%	15557.	3.%	28061.	5.%	-2.%	-2.%
1958-1972	0.	517364.	0.	0.%	15330.	3.%	28148.	5.%	-2.%	-2.%
1959-1973	0.	518268.	0.	0.%	16620.	3.%	26961.	5.%	-2.%	-2.%
1960-1974	0.	546666.	0.	0.%	21517.	4.%	27820.	5.%	-1.%	-1.%
1961-1975	0.	527294.	0.	0.%	19093.	4.%	25789.	5.%	-1.%	-1.%
1962-1976	0.	539007.	0.	0.%	19935.	4.%	24903.	5.%	-1.%	-1.%
1963-1977	0.	553579.	0.	0.%	17289.	3.%	23502.	4.%	-1.%	-1.%
1964-1978	0.	554114.	0.	0.%	15269.	3.%	21116.	4.%	-1.%	-1.%
1965-1979	0.	598461.	0.	0.%	53173.	9.%	18666.	3.%	6.%	6.%
1966-1980	0.	409731.	0.	0.%	432077.	105.%	15382.	4.%	102.%	102.%
1967-1981	0.	469426.	0.	0.%	433939.	92.%	5799.	1.%	91.%	91.%
1968-1982	0.	572118.	0.	0.%	430739.	75.%	7921.	1.%	74.%	74.%
1969-1983	0.	604521.	0.	0.%	429527.	71.%	6674.	1.%	70.%	70.%
1970-1984	0.	536254.	0.	0.%	434474.	81.%	4530	1.%	80.%	80.%
1971-1985	0.	705387.	0.	0.%	433312.	61.%	3792.	1.%	61.%	61.%
1972-1986	0.	764403.	0.	0.%	436004.	57.%	7506.	1.%	56.%	56.%
1973-1987	0.	818711.	0.	0.%	440287.	54.%	9762.	1.%	53.%	53.%
1974-1988	0.	868441.	0.	0.%	439978.	51.%	9507.	1.%	50.%	50.%
1975-1989	0.	912224.	0.	0.%	434817.	48.%	20038.	2.%	45.%	45.%
1976-1990	0.	1958745.	0.	0.%	575219.	29.%	70275.	4.%	26.%	26.%
1977-1991	0.	2204351.	0.	0.%	594685.	27.%	169639.	8.%	19.%	19.%
1978-1992	0.	2888589.	0.	0.%	643004.	22.%	165441.	6.%	17.%	17.%
1979-1993	0.	3296285.	0.	0.%	644645.	20.%	279234.	8.%	11.%	11.%
1980-1994	0.	3533331.	0.	0.%	643614.	18.%	278267.	8.%	10.%	10.%
1981-1995	0.	3664243.	0.	0.%	274929.	8.%	326417.	9.%	-1.%	-1.%

KENTUCKY POWER COMPANY

7-15-2005

ACCOUNT NO.: 10872000

GENERAL PLANT

			REIMBURSEMENTS		SALVAGE		COST OF REMOVAL		NET SALVAGE	
YEAR	ADDITIONS	RETIREMENTS	AMOUNT	RATIO	AMOUNT	RATIO	AMOUNT	RATIO	W/REIMB.	W/O REIMB.
1982-1996	0.	4053604.	0.	0.%	276731.	7.%	256195.	6.%	1.%	1.%
1983-1997	0.	4234265.	0.	0.%	345200.	8.%	283606.	7.%	1.%	1.%
1984-1998	0.	5503775.	0.	0.%	345131.	6.%	284754.	5.%	1.%	1.%
1985-1999	0.	5501603.	0.	0.%	334643.	6.%	284523.	5.%	1.%	1.%
1986-2000	0.	5545842.	0.	0.%	332917.	6.%	249720.	5.%	2.%	2.%
1987-2001	0.	5511440.	0.	0.%	332314.	6.%	254796.	5.%	1.%	1.%
1988-2002	0.	5445808.	0.	0.%	327517.	6.%	252192.	5.%	1.%	1.%
1989-2003	0.	7119831.	0.	0.%	225745.	3.%	398801.	6.%	-2.%	-2.%
1990-2004	0.	19489374.	0.	0.%	2158170.	11.%	387173.	2.%	9.%	9.%

Exhibit___(MJM-6)

Excessive Depreciation

Excessive Depreciation

An excessive depreciation rate is one that produces depreciation expense which is more than necessary to return a company's capital investment over the life of the asset. The concept of excessive depreciation is not new, and in fact was explained by the U.S. Supreme Court in a landmark 1934 decision, Lindheimer v. Illinois Bell Telephone Company, as follows:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies

> of the "behavior of large groups" of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, are always present. <u>The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience</u>.[1]

Excessive depreciation rates produce excessive depreciation expense. In other words, if an excessive depreciation rate is applied to the plant balance, it results in excessive depreciation expense. Since depreciation expense flows dollar-for-dollar into the revenue requirement, excessive depreciation expense results in an excessive revenue requirement.

Excessive depreciation also flows dollar-for-dollar into the accumulated depreciation reserve account. This can result in a depreciation reserve actually exceeding the gross plant balance. That is because the depreciation rate is excessive; it is more than necessary to fully depreciate the plant. This is what the Court was talking about in Lindheimer. Therefore, at the end of its life, this results in an accumulated depreciation account which *exceeds* the original cost in the plant account.

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[1] <u>Lindheimer v. Illinois Bell Telephone Company</u>, 292 U.S. 151, 168-170, 54 S.Ct. 658, 665-666 (1934). (Emphasis added; footnote deleted.)

The public accounting profession, through the Financial Accounting Standards Board ("FASB") has also addressed accumulated reserve excesses in its SFAS No. 143.[2] Paragraph B22 says the following:

> B22. Paragraph 37 of Statement 19 states that "estimated dismantlement, restoration, and abandonment costs...shall be taken into account in determining amortization and depreciation rates." Application of that paragraph has the effect of accruing an expense irrespective of the requirements for liability recognition in the FASB Concepts Statements. In doing so, it results in recognition of accumulated depreciation that can exceed the historical cost of a long-lived asset. The Board concluded that an entity should be precluded from including an amount for an asset retirement obligation in the depreciable base of a long-lived asset unless that amount also meets the recognition criteria in this Statement. When an entity recognizes a liability for an asset retirement obligation, it also will recognize an increase in the carrying amount of the related long-lived asset. <u>Consequently, depreciation of that asset will not result in the recognition of accumulated depreciation in excess of the historical cost of a long-lived asset</u>.[3]

As one can see from the above, as recently as 2002, the public accounting profession does not approve of depreciating an asset beyond its original cost. It actually used the word "excess," and it is obvious that it frowns upon accumulated depreciation balances that exceed the original cost of plant.

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[2] Statement of Financial Accounting Standards No. 143 ("SFAS No. 143") – Accounting for Asset Retirement Obligations.

[3] SFAS No. 143, paragraph B22 (emphasis added).

GAAP does not control ratemaking, but the rationale described above is both informative and makes sense.

Ultimately, ratepayers pay for excessive depreciation rates. As the U.S. Supreme Court said, the result is the extraction of capital contributions from ratepayers, which the Court decided was inappropriate. Current GAAP accounting rules highlight these amounts associated with negative net salvage and require that they be reported as Regulatory Liabilities ("amounts owed") to ratepayers.

Exhibit___(MJM-7)

Public Utility Depreciation Concepts

Regulatory Perspective

Depreciation Concepts

Public Utility Depreciation

From a regulator's perspective, the objective of public utility depreciation is straight-line capital recovery. This is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances.

There are several unique factors driving public utility depreciation rates. First, public utility depreciation is based on a "group life" as opposed to the lives of individual assets. Second, the cost of removing or disposing of an asset that is retired from service is charged to the accumulated depreciation reserve, as opposed to being recognized as an operating expense in the year incurred. Third, the original cost of a retired asset is also recorded in the accumulated depreciation reserve, as opposed to being written off in the year of the asset's retirement/disposal. Fourth, in certain jurisdictions public utility depreciation rates incorporate net salvage factors as discussed above. This is not the case for unregulated entities. Each of these factors affects the depreciation rates that are ultimately determined for the group of assets that are recorded in plant accounts designated by the FERC Uniform System of Accounts ("USOA").

Depreciation expense is one of the primary cost drivers of public utility revenue requirement calculations because these companies are capital intensive. An excessive depreciation rate can unreasonably increase the utility's revenue requirement and resulting service rates; thereby unnecessarily charging millions of dollars to a utility's customers.

Depreciation is a legitimate expense, but it is a major expense based on a substantial amount of judgment and complex analytical procedures, and it drives utility prices. Therefore, the measurement of depreciation and the calculation of the expense warrant careful regulatory consideration and scrutiny.

I discuss the fundamentals of public utility depreciation below, including the difference between the whole-life and remaining life techniques and the impact of life and net salvage estimation on depreciation rates.

Plant Additions, Retirements and Balances

Public utilities record their plant investment activity in the individual plant accounts set-forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA"). Additions, retirements and balances refer to individual plant accounts. For example, account 362-Station Equipment, is a plant account. An annual addition is the original cost of plant added to the account during the year. An annual retirement is the original cost of a prior addition which is now removed from service. The plant balance is what is left.

Depreciation Expense

Depreciation expense is a charge to operating expense to reflect the recovery of the cost of an asset. Public utility depreciation expense is typically straight-line over service life, which results in an equal share of the cost of assets being assigned or allocated to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant [and equipment] is in service.[1] Annual depreciation expense is a cost included in a public utility's revenue requirement.

Annual depreciation expense is calculated by applying a depreciation rate to plant balances. The resulting expense (also called accrual) is charged, just as any other expense, to the revenue requirement and from there it is charged to the utility's customers.

Depreciation is a non-cash expense in contrast to payroll expense, for example, which involves the current outlay of cash. That is, depreciation expense does not involve a specific payment during the current or test-year. Both depreciation and payroll are included as expenses in the income statement and revenue requirement, but no cash flows out of the company for depreciation expense. Instead of reducing the cash account, depreciation expense is recorded on the income statement as an expense and simultaneously recorded on the balance sheet in the accumulated depreciation account; which is shown as an offset to plant in service.

Accumulated depreciation (hereinafter called reserve or accumulated depreciation) is, in essence, a record of the previously recorded depreciation expense. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that has been recovered to date. It can be considered a measure of the depreciation recovered from ratepayers.

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1 Public Utility Depreciation Practices, August, 1996. National Association of Regulatory Utility Commissioners ("NARUC Manual"), p. 321.

Depreciation Rates

Depreciation rates such as Kentucky Power's are founded upon three fundamental parameters: a service life, a dispersion pattern and a net salvage ratio. Kentucky Power has used the remaining life technique to compute its rates. In order to understand remaining life depreciation, it is useful to first address whole-life depreciation.

Whole-Life Technique

The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life. This example does not include net salvage.

Table 1

Straight-Line Whole-Life Depreciation Rate
Assuming 10-Year Life

$$\frac{100\%}{10 \text{ yrs.}} = 10.0\%$$

Each year the 10.0 percent depreciation rate would be applied to plant in service to produce an annual depreciation expense. All things equal, at the end of 10 years, the plant balance will be 100%, and the depreciation reserve balance will be 100%. This equality is important to an understanding of certain issues in this case.

Kentucky Power includes net salvage in the depreciation rate calculation. A central issue in this case is negative net salvage. I will, therefore, use negative net salvage in my example. Negative net salvage is the net cost of removal of the asset after completion of its service life. For the remainder of this discussion

I use the terms negative net salvage, decommissioning and cost of removal interchangeably. Assuming a negative 5 percent (-5%) net salvage ratio, the equation above with a value for negative net salvage is as follows:

Table 2

Straight-Line Whole-Life Depreciation Rate
Assuming 10-Year Life and -5% Net Salvage

$$\frac{100\%-(-5\%)}{10 \text{ yrs.}} = 10.5\%$$

Negative net salvage increases the resulting whole-life depreciation rate from 10.0% to 10.5%. This happens because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 105%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset.

At the end of life under this scenario the plant balance will be 100% but the reserve will be 105%. In other words, unlike the "zero net salvage scenario" in Table 1; when negative net salvage is included in a depreciation rate there will not be an equality of plant and reserve at the end of an asset's life because the Company will have charged more depreciation than it paid for the original cost of the asset.

Under these circumstances, equality will only be achieved if the Company actually spends the additional money at the end of the asset's life. However, unless the Company has a legal liability to remove the asset, it is not required to spend the money. Furthermore, since accumulated depreciation is an "unfunded account", even though the Company collected unnecessary cost of removal amounts in the past, it will have already spent that money on whatever it chose: salaries, dividends, etc.

Remaining Life Technique

The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining life rather than the whole life of the asset.

If the hypothetical 10-year asset discussed above is 3 years old, its remaining life would be 7 years (10 – 3 = 7). The accumulated depreciation account would be 31.5 percent of the original cost because the 10.5 percent depreciation rate from Table 2 would have been applied for three years (3 x 10.5% = 31.5%). The remaining life depreciation rate would then be calculated as follows:

Table 3

Straight-Line Remaining Depreciation Life Rate
Assuming 10-year Life, 7-year Remaining Life
And -5% Net Salvage

$$\frac{100\% - (-5\%) - 31.5\%}{7 \text{ years}} = 10.5\%$$

In the examples shown in Tables 2 and 3, the remaining life depreciation rate and the whole-life depreciation rates are the same (10.5 percent), because I have assumed that the accumulated depreciation account is in balance. In other words, based on a continuation of the fundamental parameters, i.e., the 10-year service life and the negative 5 percent net salvage ratio, exactly the right amount of depreciation (31.5 percent) has been charged and collected in the past,

If either the service life or net salvage parameter changes during the life of the plant, the accumulated depreciation account will be out of balance, and the remaining life rate will be either higher or lower than whole-life rate depending on the direction of the imbalance. That is because the Company will have collected either too much depreciation or not enough depreciation in the past, given the current estimates of lives or future net salvage.

The difference between the actual amount recovered, as included in the book depreciation reserve, and a theoretical estimate of what should be in the book reserve, is called a "reserve imbalance." The remaining life technique is often used to deal with such reserve imbalances.

The remaining life technique has been accepted and used in many jurisdictions. Its primary failing is that if there is a reserve imbalance, positive or negative, it results in the application of an incorrect rate to new plant additions. In other words, the remaining life technique perpetuates the same imbalances it attempts to cure. This problem can be resolved by using whole-life rates and separate treatment for any reserve imbalances.

Impact of Life and Net Salvage Estimation

Utilities own thousands of assets, represented by millions of dollars of investment. Given the capital intensity of the industry, it is very difficult to track and depreciate every single asset that a utility owns. Public utility depreciation is, therefore, based on a group concept, which relies on averages of the service lives and remaining lives of the assets within a specific group.

These factors are necessarily estimates of the average service lives and average remaining lives of groups of assets. These estimates are in turn based on complex analytical procedures which involve not only the age of existing and retired assets, but also retirement dispersion patterns called "Iowa curves." The important point to remember is that service life, average age and Iowa curves are all used in the estimation of an average service life and average remaining life of a group of assets and are ultimately used to calculate the depreciation rate for that group of assets.

In depreciation analysis it is axiomatic that the shorter the life, the higher the resulting depreciation rate. If the depreciation rates are based on lives which are too short, the depreciation rates will be too high. What if the 10-year life I used in the earlier examples really should have been 30 years? For example, assume that the analyst conducted statistical analyses which indicated that the average life is actually 30 years. The following table shows the impact of continuing to use a shorter life.

Table 4

Impact of Reducing a Life From 30 Years to 10 Years

30 year life = 100%/30 = 3.3%

10 year life = 100%/10 = 10.0%

If the life should have been 30 years, the rate should have been 3.3 percent rather than the 10 percent depreciation rate based on a 10 year life. The shorter the life, the higher the rate. If the life is too short, the resulting rate is obviously excessive.

The estimation of future net salvage also has an impact on depreciation rates. Several of Kentucky Power's proposed depreciation rates contain negative net salvage factors which charge too much for future cost of removal because they are too negative. They result in excessive depreciation rates. The next table shows the impact on depreciation rates of increasing the cost of removal ratio.

Table 5

Impact of Increasing Cost of Removal Ratio

-5% ratio = 100 %-(-5)/30 = 3.5 %

-50% ratio = 100 %-(-50)/30 = 5.0 %

Increasing a cost of removal ratio from -5% to -50% increases the depreciation rate from 3.5% to 5.0%. If the estimated -50% cost of removal ratio is not supportable, obviously, the resulting 5.0% depreciation rate is excessive. The combination of these two factors, i.e., understated lives and overstated cost of removal ratios, compounds the excessive depreciation rate problem.

Exhibit___(MJM-8)

Response to AG-1-168

Regulatory Liability

Kentucky Power Company

REQUEST

With respect to the Regulatory Liability relating to asset cost of removal which you reclassified out of accumulated depreciation:

a. Do you agree that this constitutes a regulatory liability for regulatory purposes in Kentucky and for FERC purposes? If not, please explain why not.

b. Do you agree that this amount is a refundable obligation to ratepayers until it is spent on its intended purpose (cost of removal)? If not, why not?

c. Please explain the repayment provisions associated with this regulatory liability.

d. Explain when you expect to spend this money for cost of removal.

e. Explain what you have done with this money as you have collected it. Please provide all evidence in support of expenditures if the response is that the collected money has been spent on plant additions as it has been collected.

f. Identify and explain all other similar examples of Kentucky Power's advance collections of estimated future costs for which it does not have a legal obligation.

g. Does Kentucky Power agree that the Kentucky Public Service Commission will never know whether or not Kentucky Power will actually spend all of this money for cost of removal until and if Kentucky Power goes out of business? If not, why not?

h. Does Kentucky Power believe that amounts recorded in accumulated depreciation represent capital recovery? If not, why not?

i. Whose capital is reflected in accumulated depreciation – shareholders' or ratepayers'?

RESPONSE

a. For financial reporting purposes, the Company believes that these amounts are properly classified as a regulatory liability for SEC reporting purposes and should remain classified in Account 108, Accumulated Depreciation for FERC and Kentucky regulatory reporting purposes in accordance with FERC Order 631.

b. No. The Company does not believe the approved collection of removal costs through depreciation rates creates a refundable obligation. The definition of depreciation provides that net salvage is to be considered in depreciation.

c. The Company does not believe there is a repayment provision.

d. The money is spent on an ongoing basis as plant is retired.

e. The money has been spent as part of the ongoing operations of all aspects of the business.

f. The Company has not performed an analysis to identify the data requested.

g. The Company believes that the Kentucky Public Service Commission will be able to monitor the removal costs on an ongoing basis as a part of monitoring the accumulated provision for depreciation. The Company would agree that the amount of total removal costs cannot be determined until all property is retired.

h. Yes.

i. The shareholder's.

WITNESS James E. Henderson

Exhibit___(MJM-9)

Responses to Assorted Discovery Requests

Big Sandy Unit 1

Kentucky Power Company

REQUEST

Provide all internal life extension studies prepared by the Company. Life extension refers to any program, maintenance or capital, designed to extend lives and/or increase capacity of its existing plant-in-service. Identify the functions to which these studies relate.

RESPONSE

Neither Kentucky Power nor the AEP Service Corp has undertaken any unit life extension studies involving Big Sandy U1, Big Sandy U2 or Rockport. Expected operating life extends to 60 years or more based on the economic operation of the individual units. Individual component repair or replacement projects are considered on an as needed basis.

WITNESS Errol K. Wagner

Kentucky Power Company

REQUEST

Workpaper page 2 of 443.

a. Explain and provide documentation of the 'environmental constraints" relating to Big Sandy Unit 1.

b. Identify and explain the guarantees that the company is providing to the Kentucky Commission that it will actually spend the $32 million demolition cost for Big Sandy, and when it will spend the money.

c. Identify all alternatives to the conceptual demolition cost that were studied and explain why they were rejected.

RESPONSE

a. The expectation is that federal environmental regulations may not permit the continued operation of Big Sandy Unit 1 without the addition of FGD equipment.

b. The Company is not aware of any guarantees required by the Kentucky Commission.

c. No alternatives were studied.

WITNESS **James E. Henderson**

Kentucky Power Company

REQUEST

Refer to AG Request No. 161. Please provide all documents and correspondence related to the review of FIN 47 as they currently exist.

RESPONSE

The only potential Asset Retirement Obligations the Company has identified in connection with the review of FIN 47 is for asbestos removal and abatement at Big Sandy Generating Plant. The preliminary cost estimates, in 2005 dollars, for the asbestos removal and abatement is as follows:

Business Unit	Plant	Unit	Size	Fuel	In Service Date	O/S Date	Percent Asbestos	Cubic Yard	Dollars for Removal & Disposal
KPCo	Big Sandy	BS-1	260 MW	Coal	1963	2030	60	1054.56	$1,265,472
KPCo	Big Sandy	BS-2	800 MW	Coal	1969	2036	25	1352.0	$1,622,400

The removal dates will not correspond to the plant retirement dates (2015-2034) shown in the depreciation study. That is because it is not expected that asbestos removal would begin until some time after the plant is retired.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to Schedule l of the depreciation study included as Exhibit JEH-1 to Mr. Henderson's Testimony. Please confirm that the Company actually plans to retire Big Sandy l in 2015. Provide all support relied on for this assumption. If the Company does not actually plan to retire Big Sandy l in 2015, then please provide the Company's present projection of the retirement year and provide all support relied on for that assumption.

RESPONSE

2015 is the planed retirement date for Big Sandy Unit 1. Please refer to Page 2 of 443 of the depreciation study workpapers.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Please identify all federal and/or state requirements that will require the Company to retire Big Sandy 1 in 2015, if any. If there are no legal mandates to retire Big Sandy 1 in 2015, then please so state.

RESPONSE

The Company is not aware of any current legal mandates to retire Big Sandy 1 in 2015.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Please provide a copy of all studies, analyses, correspondence, and all other documents that address the retirement of Big Sandy 1.

RESPONSE

The Company is unaware of any specific studies, analyses, correspondence or other documents that specifically address the retirement of Big Sandy Unit 1.

WITNESS - James E. Henderson

KPSC Case No. 2005-00341
KIUC's Second Set Data Request
Order Date December 12, 2005
Item No. 4
Page 1 of 1

Kentucky Power Company

REQUEST

Please provide a copy of all studies, analyses, correspondence, and all other documents that address the replacement of the Big Sandy 1 capacity in 2015. If there are no responsive documents, then please explain why not.

RESPONSE

At this time, there are no analyses or other documents addressing the replacement of Big Sandy 1 capacity in 2015. There has not been a prior need to perform this type of analysis.

WITNESS – James Henderson

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. In addition to traditional regulatory engagements, Mr. Majoros has also provided consultation to the U.S. Department of Justice. His expertise has been called upon to address the accounting and plant life effects of electric plant modifications in environmental proceedings and lawsuits, and to estimate economic damages suffered by black farmers in discrimination suits.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Controller/Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RP79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
2003	FERC	ER03-409-000, ER03-666-000	Pacific Gas and Electric Co.
2005	US District Court, Northern District of AL, Northwestern Division 55/56/57/	CV 01-B-403-NW	Tennessee Valley Authority
State Regulatory Agencies			
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Edison Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.

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1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell

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1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban

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2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light
2003	Hawaii 42/	02-0391	Hawaiian Electric Company
2003	Illinois 28/	02-0864	SBC Illinois
2003	Indiana 28/	42393	SBC Indiana
2004	New Jersey 1/	ER03020110	Atlantic City Electric Co.
2004	Arizona 26/	E-01345A-03-0437	Arizona Public Service Company
2004	Michigan 27/	U-13531	SBC Michigan
2004	New Jersey 1/	GR03080683	South Jersey Gas Company
2004	Kentucky 36/	2003-00434,00433	Kentucky Utilities, Louisville Gas & Electric
2004	Florida 50/ 54/	031033-EI	Tampa Electric Company
2004	Kentucky 36/	2004-00067	Delta Natural Gas Company
2004	Georgia 23/	18300, 15392, 15393	Georgia Power Company
2004	Vermont 46/	6946, 6988	Central Vermont Public Service Corporation
2004	Delaware 24/	04-288	Delaware Electric Cooperative
2004	Missouri 58/	ER-2004-0570	Empire District Electric Company
2005	Florida 50/	041272-EI	Progress Energy Florida, Inc.
2005	Florida 50/	041291-EI	Florida Power & Light Company

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2005	California 59/	A.04-12-014	Southern California Edison Co.
2005	Kentucky 36/	2005-00042	Union Light Heat & Power
2005	Florida 50/	050045 & 050188-EI	Florida Power & Light Co.
2005	Kansas 38/ 40/	05-WSEE-981-RTS	Westar Energy, Inc.

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

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PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia 2/	93-1165-E-D	Potomac Edison
West Virginia 2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation
Florida 50/ 54/	030157-EI	Progress Energy Florida

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Clients

1/ New Jersey Rate Counsel/Advocate	33/ Michigan Attorney General
2/ West Virginia Consumer Advocate	34/ New Mexico Attorney General
3/ Pennsylvania OCA	35/ Environmental Protection Agency Enforcement Staff
4/ Florida Office of Public Advocate	36/ Kentucky Attorney General
5/ Toms River Fire Commissioner's	37/ North Dakota Public Service Commission
6/ Iowa Office of Consumer Advocate	38/ Kansas Industrial Group
7/ D.C. People's Counsel	39/ City of Witchita
8/ Maryland's People's Counsel	40/ Kansas Citizens' Utility Rate Board
9/ Idaho Public Service Commission	41/ NIPSCO Industrial Group
10/ Western Burglar and Fire Alarm	42/ Hawaii Division of Consumer Advocacy
11/ U.S. Dept. of Defense	43/ Nevada Bureau of Consumer Protection
12/ N.M. State Corporation Comm.	44/ GCI
13/ City of Philadelphia	45/ Wisc. Citizens' Utility Rate Board
14/ Resorts International	46/ Vermont Department of Public Service
15/ Woodlake Condominium Association	47/ Oklahoma Corporation Commission
16/ Illinois Attorney General	48/ National Association of Utility Consumer Advocates
17/ Mass Coalition of Municipalities	49/ Nova Scotia Utility and Review Board
18/ U.S. Department of Energy	50/ Florida Office of Public Counsel
19/ Arizona Electric Power Corp.	51/ Maryland Public Service Commission
20/ Kansas Corporation Commission	52/ MCI
21/ Public Service Comm. – Nevada	53/ Transmission Agency of Northern California
22/ SC Dept. of Consumer Affairs	54/ Florida Industrial Power Users Group
23/ Georgia Public Service Comm.	55/ Sierra Club
24/ Delaware Public Service Comm.	56/ Our Children's Earth Foundation
25/ Conn. Ofc. Of Consumer Counsel	57/ National Parks Conservation Association, Inc.
26/ Arizona Corp. Commission	58/ Missouri Office of the Public Counsel
27/ AT&T	59/ The Utility Reform Network
28/ AT&T/MCI	
29/ IN Office of Utility Consumer Counselor	
30/ Unitel (AT&T – Canada)	
31/ Public Interest Advocacy Centre	
32/ U.S. General Services Administration	