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PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY TO FILE	)	CASE NO. 2007-00565
DEPRECIATION STUDY	)	

ATTORNEY GENERAL'S RESPONSES TO
DISCOVERY REQUESTS OF STAFF OF
KENTUCKY PUBLIC SERVICE COMMISSION

Comes now the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and states as follows for his responses to the discovery requests of the staff of the Kentucky Public Service Commission.

Respectfully submitted,

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Certificate of Service and Filing

Counsel certifies that the responses set forth herein are true and accurate to the best of his knowledge, information, and belief formed after a reasonable inquiry. Counsel further certifies that an original and ten photocopies of the foregoing were served and filed by hand delivery to Beth O'Donnell, Executive Director, Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40601; furthermore, it was served by mailing a true and correct copy of the same, first class postage prepaid, to:

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all on this 27th day of June, 2008.

Lawrence W. Cook

Assistant Attorney General

Attorney General's Responses to
Commission Staff's First Data Requests
Case No. 2007-00565

WITNESS RESPONSIBLE:
Michael J. Majoros

Question 1. Refer to the Direct Testimony of Michael J. Majoros, Jr. ("Majoros Testimony"), pages 10 and 11 of 26.

a. Based on Mr. Majoros' experience and knowledge, indicate whether the average life group approach ("ALG") or the equal life group approach ("ELG") is the more common approach utilized to determine depreciation rates for regulated electric and gas utilities in the United States.

b. Are there conditions where it is more reasonable to utilize ELG rather than ALG? Explain the response.

c. Concerning Kentucky Utilities Company's ("KU") proposal to switch from ALG to ELG,

(1) Are there situations or circumstances where it would be reasonable to switch from ALG to ELG? Explain the response.

(2) Does Mr. Majoros believe the situations or circumstances identified in part (1) currently exist at KU? Explain the response.

RESPONSE:

a. The ALG procedure is the more common approach.

b. Mr. Majoros is not aware of any conditions where it is more appropriate to utilize ELG.

c. (1) Mr. Majoros is unaware of any situations or circumstances that would make it reasonable to switch from ALG to ELG, especially on a retroactive basis.

(2) N/A

Attorney General's Responses to
Commission Staff's First Data Requests
Case No. 2007-00565

WITNESS RESPONSIBLE:
Michael J. Majoros

Question 2. Refer to the Majoros Testimony, page 15 of 26. Mr. Majoros recommends that if ELG is approved, it should be applied prospectively and that new depreciation studies be undertaken every 3 years.

a. If ELG were to be approved, is Mr. Majoros saying that the depreciation rates for utility plant added during and after 2007 would reflect ELG while depreciation rates for pre-2007 utility plant would continue reflecting ALG? Explain the response.

b. If the Commission were to determine KU's depreciation rates would reflect ALG, how frequently would Mr. Majoros recommend depreciation studies be performed?

RESPONSE:

a. Yes. Ratepayers should not be penalized for having paid depreciation based on ALG in the past. Mr. Spanos' software, as well as Snavely King's, is designed to apply ALG or ELG at the vintage level. Hence, splitting plant is no more difficult than flipping a switch.

b. Mr. Majoros normally recommends studies every 3 to 5 years. However, in his opinion the use of ELG requires more vigilance that the underlying assumptions are being met.

WITNESS RESPONSIBLE:
Michael J. Majoros

Question 3. Refer to the Majoros Testimony, pages 16 and 17 of 26. Concerning Mr. Majoros' proposal of incorporating the present value of the cost of removal in depreciation rates:

a. Identify every state regulatory commission which has adopted the approach proposed by Mr. Majoros when determining a regulated electric or gas utility's depreciation rates. Include with this response a discussion of the circumstances which led the applicable state regulatory commission to adopt this approach.

b. Within the last 5 calendar years, indicate the number of proceedings where Mr. Majoros has proposed incorporating the present value of the cost of removal in depreciation rates. For each identified case, provide a discussion of the circumstances existing in the proceeding, the reasons offered in support of the approach, and indicate whether Mr. Majoros' proposal concerning a present value approach was adopted.

c. Does Mr. Majoros contend that accrual accounting requires that all expenses that are affected by inflation must be stated at a present value? Explain the response. In addition, provide applicable citations to generally accepted accounting principles ("GAAP") which require the statement of expenses at a present value.

d. Provide citations to independent auditors' reports or findings by state regulatory commissions that concluded that Mr. Spanos' "traditional" approach for the cost of removal has been found to be inconsistent with accrual accounting and GAAP. The citations or findings should have been issued within the last 5 calendar years.

RESPONSE:

a. See attached summary of recent decisions in which either Mr. Majoros or Mr. King have raised similar issues.

b. Mr. Majoros has testified regarding electric or gas depreciation over 30 times since 2003. During that period he has routinely provided a discussion of the incorporation of future inflation in net salvage ratios. He also typically provides several solutions, including the present value method, or methods such as the five-year average that are intended to remove the inflation. To his knowledge, no Commission has adopted his specific present value calculation. A discussion of his net salvage recommendations that have been adopted is provided in response to part a. above.

c. GAAP requires any legal retirement obligation and liability to be stated at its "fair value."

d. SFAS No. 143 does not allow companies in general to include future cost of removal in depreciation rates. That is GAAP. Paragraph B73 requires regulated utilities to report the excess collections as regulated liabilities.

Alternatives to TIFCA Approved by Public Service Commissions

NARUC 1996 Public Utility Depreciation Practices Manual

> Some commissions have abandoned the above procedure [gross salvage and cost of removal reflected in depreciation rates] and moved to current-period accounting for gross salvage and/or cost of removal. In some jurisdictions gross salvage and cost of removal are accounted for as income and expense, respectively, when they are realized. Other jurisdictions consider only gross salvage in depreciation rates, with the cost of removal being expensed in the year incurred.[1]

New Jersey

Company: Rockland Electric Company
Docket No.: New Jersey BPU Docket Nos. ER02080614 and ER02100724
SK Witness: Michael J. Majoros, Jr.
Order(s): Initial Decision, June 20, 2003
Summary Order, July 31, 2003

Discussion of Results:

The New Jersey Board of Public Utilities endorsed Mr. Majoros' testimony regarding SFAS No. 143, but used a net salvage allowance based on the average net salvage over a 10-year period, as recommended by Staff, instead of the five-year average recommended by Mr. Majoros.

As recommended by the Administrative Law Judge:

> RECO calculates its test year depreciation expense to be \$5.194 million. RECO ib 128. RECO 30, Page 28-29. RECO 11A, Exhibit P-2, Page-11. The Ratepayer Advocate disputes the Company's figure and proposes a depreciation expense level of \$3,864,000. Rib-74. Ratepayer Advocate witness Majoros also recommended that the amortization of the Theoretical Reserve Difference should be \$1.103 million rather than the company's proposed amortization amount of \$588,000. Ratepayer Advocate would exclude depreciation of the enhanced service reliability program and depreciation of post-test year plant. R-51. RJH-17.

[1] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, August 1996 ("NARUC Manual"), page 157.

Staff determined the depreciation expense to be $3,971,000. Sib Exhibit P-2, Schedule 13-14. Staff added a 10-year average net salvage of $150,000 to the total of $3,821,100. Sib 74.

The main controversy in the depreciation issue concerns net salvage and cost of removal and the interpretation of Statement of Financial Accounting Standards No. [143]. SFAS 143, paragraph B73. RECO rb Appendix 15.

Ratepayer Advocate witness Michael J. Majoros expressed his opinion that the company's depreciation proposal was unreasonable. In his pre-filed testimony Witness Majoros claims the Company's proposal will produce excessive depreciation and increase the revenue requirement. He also states the company's proposal is inconsistent with current thinking regarding cost, capital recovery and net salvage, particularly the cost of removal component of net salvage. R-36, Page 3. He traces the alleged excessive depreciation to a request for negative net salvage, which he claims, is unreasonable. R36-4. This results in an excessive revenue requirement. R-36-4. Witness Majoros recommends a depreciation expense of $3,863,900. R-36-20.

RECO witness Hutcheson disagrees with Mr. Majoros proposal and alleges that Majoros approach is a results driven exercise designed to under state depreciation rates, that he has pushed the recovery of net salvage far out into the future thereby relieving rate payers who benefit from the plant serving them today from any cost responsibility for retirement and removal of such plant. It imposes a cost on customers who never benefited from the plant to pay for its removal.

Staff concurs in part with the Ratepayer Advocate, supporting the intellectual foundation of FAS143, which supports "unbundled" depreciation rates, rates that exclude embedded cost of removal provisions. Staff would favor a cost of removal expense based upon a 10-year window of actual experience rather than the 5-year average used by the Ratepayer Advocate. Sib-74. Staff supports a $150,000 annual negative net salvage provision. Staff recommends a test year depreciation expense of $3,971,000.

> I **FIND** that the Staff's test-year depreciation expense of $3,971,000 to be reasonable.[2]

The Board of Public Utilities further endorsed the position, modifying only the amortization period for the reserve excess:

> Based on our review of the extensive record in this consolidated proceeding, the Board has determined that the Initial Decision, subject to certain modifications, which will be set forth herein, represents an appropriate resolution of this proceeding. Accordingly, except as specifically noted below, and as will be further explained in a detailed Final Decision and Order which shall be issued, the Board HEREBY ADOPTS and incorporates by reference as if completely set forth herein, as a fair resolution of the issues in this consolidated proceeding, the Initial Decision.[3]
>
> All the parties in the base rate case agree that there is a significant excess depreciation reserve. The Company proposed a 20-year amortization of its calculated reserve excess of $11.8 million. The RPA claimed the proper reserve excess was $22.1 million, based upon the Company's asset lives, but excluding the Company's future net salvage assumptions from the depreciation rates. The RPA accepted the Company's proposal of a 20-year amortization. Both Staff and the ALJ adopted the RPA's recommendation. The Board HEREBY MODIFIES the Initial Decision so that the RPA's recommended level of excess reserve is amortized back to ratepayers over 10 years. The Board finds this to be an appropriate action in order to offset the increase associated with the deferred balances that were incurred over the 4-year transition period, as well as the increase in BGS charges for current service.[4]

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[2] I/M/O Rockland Electric Company, OAL Docket Nos. PUC 07892-02 and PUC 09366-02, BPU Docket Nos. ER02080614 and ER02100724, (Initial Decision, June 10, 2003), p. 47-49.

[3] I/M/O Rockland Electric Company, BPU Docket Nos. ER02080614 and ER02100724, Summary Order, July 31, 2003, p. 2.

[4] Id., page 3, item 3.

Alternatives to TIFCA Approved by Public Service Commissions

Company: Jersey Central Power & Light Company
Docket No.: New Jersey BPU Docket Nos. ER0208056, ER0208057, EO02070417 and ER02030173
SK Witness: Michael J. Majoros, Jr.
Order(s): Summary Order, August 1, 2003

Discussion of Results:

The Board agreed with Mr. Majoros that the inclusion of net salvage in depreciation rates was inappropriate. It adopted Mr. Majoros' recommendation of a $4.8 million net salvage allowance, based on the cost of removal included in JCP&L's test year budget for transmission, distribution and general plant.

As Ordered by the Board:

> Depreciation Expense. The Company is requesting a net depreciation expense annualization adjustment of $1,515,000 and total annualized depreciation expenses of $114,547,000. The Company maintains that it is complying with the terms of a June 27, 1996 stipulation ("Final Stipulation") approved by the Board, by updating the book depreciation rate computations annually for plant additions, retirement, transfers and adjustments and keeping the negative net salvage rate percentages and depreciation service lives consistent with the separate Stipulation of Settlement of Depreciation Rates, also dated June 27, 1996, which was also approved by the Board as part of the Final Stipulation. *I/M/O the Petitions of Jersey Central Power & Light Company for Approval of an Increase in its Levelized Energy Adjustment Charge, Demand Side Factor, Implementation of a Remediation Adjustment Clause (RAC) Other Tariff Changes, Recovery of Crown/Vista and Freehold Buyout Costs, Changes in Depreciation Rates, Settlement of Phase 1 of the Board's Generic Proceeding on the Recovery of NUG Capacity Payments,* Docket Nos. ER95120633, ER95120634, EM95110532, EX93060255 and EO95030398, (March 24, 1997). The Board HEREBY FINDS, *consistent with the recommendations of the* RPA and Staff, that the Company's inclusion of net negative salvage value in depreciation rates is inappropriate and instead, HEREBY ADOPTS utilization of a net salvage allowance of $4.8 million which is the cost of removal reflected in the Company's test-year budget for transmission, distribution and general plant. Accordingly, the Board

HEREBY ADOPTS a deprecation expense in the amount of $77,146,000.[5]

Company: Public Service Electric & Gas (Electric)
Docket No.: New Jersey BPU Docket No. ER02050303
SK Witness: Michael J. Majoros, Jr.
Order(s): Decision and Order, Issued April 22, 2004

Discussion of Results:

In the Company's 1997 Restructuring filing, the Company proposed extending the average life used to establish depreciation on the Company's distribution investment from 28 to 45 years, resulting in a 2.49% remaining life depreciation rate. That rate incorporated zero net salvage. The Company also proposed amortizing the resulting depreciation reserve excess over seven years. The Board agreed with the amortization of the reserve excess, however it adopted a three-year, seven-month amortization period. The Company began the amortization but continued to use the old 3.52% depreciation rate. The Company failed to change the rate to 2.49%.

In the 2003 case, Docket No. ER02050303, the Company did not submit a depreciation study. Instead, they proposed no changes to their existing distribution plant rates and changes to their general plant rates based on the rates resulting from a Settlement in their last gas base rate case.

Mr. Majoros recommended the use of the 2.49% depreciation rate consistent with the Company's proposal in the Restructuring filing. In addition, he calculated an additional reserve excess of $115 million resulting from the Company's continued use of the 3.52% depreciation rate and recommended that excess be amortized over the remaining period of the initial reserve excess amortization. Mr. Majoros recommended that the additional excess be amortized over 2 years of the remaining of the original amortization period.

The Board agreed that the 2.49% rate should have been in use beginning in August 1999. The Board accepted a Settlement proposed amortization period of 29 months for the reserve excess. At the present time, the Company is using a 2.49% remaining life depreciation rate (for Distribution). The rate incorporates zero percent net salvage.

[5] I/M/O Jersey Central Power & Light Company, BPU Docket Nos. ER0208056, ER0208057, EO02070417 and ER02030173, Summary Order, August 1, 2003, p. 6.

Alternatives to TIFCA Approved by Public Service Commissions

Company: Public Service Electric & Gas (Gas)
Docket No.: New Jersey BPU Docket No. GR05100845
SK Witness: Michael J. Majoros, Jr.
Order(s): Decision and Order Adopting Initial Decision and Stipulation of Settlement, Issued November 9, 2006

Discussion of Results:

In this case, the Company proposed a $42.6 million increase in annual depreciation expense, relative to current depreciation rates based on December 31, 2003 plant balances. The increase was driven primarily by a large increase in distribution depreciation expense. General and common plant were not included in the Company's depreciation study. Of PSE&G's calculated annual depreciation expense (based on 2003 plant balances), over half related to estimated future costs of removal for non-legal AROs ($72.1 million out of a total accrual of $134.5 million). The Company also identified $134.4 million relating to excess collections for cost of removal in its 2003 depreciation reserve. This is part of the regulatory liability for non-legal AROs identified by SFAS No. 143.

Mr. Majoros recommended that future net salvage be removed from the depreciation rates and replaced with a normalized net salvage allowance based on PSE&G's actual experience from 1999-2003. He also recommended that the $134.4 million cost of removal reserve be amortized back to ratepayers over a three-year period. Finally, he recommended changes to two lives. Overall, Mr. Majoros's recommendations resulted in a $74.5 million decrease based on December 31, 2003 plant balances.

This case was settled. The parties agreed to Mr. Majoros's depreciation rates, a $6.375 million annual allowance for cost of removal, and a five-year amortization of the $148.495 million cost of removal regulatory liability that existed as of December 31, 2005. Specifically:

> 3. The parties agree on the following changes to the Company's depreciation rates and accumulated gas plant depreciation reserve. The parties agree that the Company's composite gas-only plant depreciation rate shall be 1.644% based upon actual plant balances as of the end of the test year, September 30, 2005. The depreciation rates, as delineated in Attachment B to the Stipulation of Settlement, attached hereto and incorporated herein by reference, shall be applied to the corresponding functional accounts. The existing rates for common plant and General Gas Plant shall continue, as these rates were not at issue in this case.
>
> As of December 31, 2005, the Company's depreciation reserve included $148.495 million previously collected for

Cost of Removal (COR) but not yet expended for that purpose. The parties agree that the Company will amortize accumulated depreciation reserve associated with COR at an annual rate of $13.2 million. This $13.2 million annual rate amortization will continue for a period of sixty (60) months, beginning with the implementation of the new base rates resulting from this proceeding. The Company shall not be entitled to recover any amounts claimed to be overpaid to ratepayers in the event the rates resulting from this proceeding remain in effect beyond the five-year amortization period.

The expense for COR recoverable through rates shall be $6.375 million on an annual basis reflecting the average actual annual expenditure on COR for the five year period 1999 through 2003. The annual recovery as determined above will be charged to depreciation expense and credited to the depreciation reserve. Actual cost of removal incurred will continue to be debited to the depreciation reserve. Therefore, any over or under recovery of actual expense will be reflected in the depreciation reserve. The parties acknowledge that under this Settlement, the Board will continue the above policy to allow full recovery of and make the Company whole on its actual and prudently incurred cost of removal. All amounts associated with Cost of Removal which remain in the depreciation reserve will continue to be *an offset to the Company's rate base. The parties reserve* their rights to argue their respective positions as to the calculation of future remaining life depreciation rates in subsequent rate cases.

The Company has recorded in its depreciation reserve $72.467 million associated with its legal Asset Retirement Obligation (ARO) for its gas plant as of December 31, 2005 for financial reporting purposes. The Company has also recorded a regulatory asset in conjunction with the legal ARO as of December 31, 2005 for financial reporting purposes. The Company has represented that it intends to continue to record the accretion of the legal ARO as a regulatory asset. As long as BPU policy provides for full recovery of actual Cost of Removal expenditures, the Company will not seek recovery of such regulatory asset, since that asset is extinguished as the actual Cost of

> Removal is incurred and debited to the depreciation reserve, as described above.[6]

Company: Atlantic City Electric Company
Docket No.: New Jersey BPU Docket No. ER03020110 et al
SK Witness: Michael J. Majoros, Jr.
Order(s): Decision and Order, Issued May 26, 2005

Discussion of Results:

Atlantic City Electric did not file a depreciation study in conjunction with this rate case, choosing instead to maintain the existing rates, which were established in 1983. The existing rates were remaining life rates for the transmission and distribution functions, and whole-life rates for the general plant function. The rates did not include a provision for net salvage.

Testifying for the Ratepayer Advocate, Mr. Majoros performed a complete depreciation study. As a result of that study he recommended a change in rates. Mr. Majoros calculated remaining life rates for the transmission and distribution functions, and whole-life rates for the general plant function, consistent with the Company's existing rates. He also recommended a net salvage allowance based on the Company's 5-year average net salvage experience.

In discovery, the Commission Staff had Mr. Majoros prepare calculations of whole-life rates for transmission and distribution, along with a calculation of the reserve excess/deficiency. These calculations were apparently used in the settlement, as noted below.

This was a settled case. The parties agreed to the following regarding depreciation:

> The Signatory Parties agree to a change in depreciation technique to the Whole Life Method with an amortization of any calculated excesses or deficiencies in the depreciation reserve, and a separate annual allowance of $2.9 million for net salvage. Atlantic will track this annual net salvage allowance separately within depreciation expense and accumulated depreciation and will track actual net salvage. As a result of the change in depreciation rates set forth in paragraph 3, and this change in technique, there will be a net excess depreciation reserve of $130.974 million. This

[6] I/M/O Public Service Electric and Gas Company, BPU Docket No. GR05100845, Decision and Order Adopting Initial Decision and Stipulation of Settlement, November 11, 2006, p. 4.

> amount will be amortized over approximately 8.25 years, beginning on the date the rates resulting from this Stipulation become effective e, on a cents per kWh basis, applicable to all kWh to which the Company's Transition Bond Charge is applied. The rate impact of this adjustment is approximately $15.8 million.[7]

Pennsylvania

The 5-year rolling net salvage allowance approach is used by the Pennsylvania Public Utility Commission in utility cases.[8] The allowance is incorporated as a separate specifically identifiable amount in depreciation expense. Depreciation rates do not incorporate future net salvage factors.

Vermont

Company: Central Vermont Public Service Corporation
Case No.: Vermont Docket Nos. 6946 and 6988
SK Witness: Michael J. Majoros, Jr.
Order(s): Order, Issued March 29, 2005

Discussion of Results:

Testifying for the Vermont Department of Public Service ("DPS"), Mr. Majoros recommended the use of a net salvage allowance based on a 5-year average of actual net salvage experience. As the Company had been experiencing positive net salvage on average, Mr. Majoros recommended $0 net salvage allowance. In addition, Mr. Majoros recommended that CVPS be required show collections for net salvage separately from accumulated depreciation through the use of subsidiary accounts.

While the Board did not implement Mr. Majoros' recommendation to use a $0 net salvage allowance, the Board did agree to the separate tracking of net salvage collections:

> The DPS has highlighted an important policy issue — in contrast to collections for depreciation, which enable the utility to recover costs that it has already incurred, collections for net salvage are, in essence, prepayments by ratepayers

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[7] I/M/O Atlantic City Electric Company, BPU Docket Nos. ER03020110, ER04060423, EO03020091 and EM02090633, Decision and Order Adopting Initial Decision and Stipulation of Settlement, May 26, 2005, pages 5-6.

[8] See Penn Sheraton et. al. v. Pennsylvania Public Utility Commission, 198 Pa. Super. 618, 184 A. 2d. 234 (1962).

> for expenses that the utility estimates it will incur at some point in the future. This is a significant distinction, and one that persuades us that collections for net salvage should be tracked and reported separately from other funds collected via depreciation expense. For this reason, we accept the DPS's recommendation that we require CVPS to follow the recording and reporting requirements of FERC Order 631 for Vermont jurisdictional ratemaking purposes. In other words, CVPS must track and report its prior and future net salvage collections in a separate subsidiary account, and we expect this separate account to be shown in future cost-of-service filings.[9]

California

Company: Southern California Edison Company
Case No.: California Application 04-12-014
SK Witness: Michael J. Majoros, Jr.
Order(s): D.06-05-016, issued May 11, 2006

Discussion of Results:

In this case, the Company requested an increase in depreciation expense of $150.4 million (based on 2003 plant balances), which was a 36% increase in depreciation expense. The increase was primarily driven by cost of removal estimates, both those proposed by the company, and the "reserve deficit" the Company calculated because it believed its current cost of removal estimates were too low.

Mr. Majoros testified on behalf of The Utility Reform Network ("TURN"). Although he accepted all of the Company's proposed service lives, he recommended the following:

> I recommend that the regulatory liability [$2.1 billion as of December 31, 2004] resulting from SCE's collection of excessive non-legal ARO charges be separated from accumulated depreciation and specifically recognized by the CPUC as a regulatory liability for regulatory reporting, regulatory analysis and ratemaking purposes in California. I recommend that the CPUC consider whether to maintain this regulatory liability as a permanent rate base offset representing customer-provided or to amortize it back to

[9] Investigation into the Existing Rates of Central Vermont Public Service Corporation, Docket Nos. 6946 and 6988, Order, Issued March 29, 2005, page 114.

> ratepayers over some fixed period. In either case, the regulatory liability would remain as a rate base offset until fully amortized.[10]
>
> On a going-forward basis, I recommend that non-legal ARO recovery be separated from the capital recovery component of depreciation. The capital recovery depreciation rates, reflecting Mr. Pierce's life and curve requests are shown on Exhibit___(MJM-11). Beyond that, I recommend that TIFCA be discontinued, and that any one of the following approaches be approved: cash basis, normalized net salvage allowance, or net present value basis. I do not recommend the SFAS No. 143 approach because these are not legal AROs and because that method is too complicated.[11]

The Company fought hard against Mr. Majoros' recommendations, including the recognition of the regulatory liability. In addition to its own depreciation witness, Mr. Pierce, SCE put forth rebuttal testimony from William Stout of Gannett Fleming, Inc., and Jan Umbaugh of Deloitte & Touche. Furthermore, two other California utilities submitted testimony rebutting Mr. Majoros – San Diego Gas & Electric Company and Pacific Gas & Electric Company.

On May 11, 2006 the California PUC voted out its decision. Concerning Mr. Majoros' recommendation regarding the recognition of a regulatory liability for past collections for cost of removal, the CPUC stated:

> TURN's request that the balance of funds collected for cost of removal related to non-ARO assets be recognized as a regulatory liability for ratemaking purposes is reasonable and will be adopted.[12]

The CPUC adopted the Office of Ratepayer Advocates' ("ORA") recommendations for net salvage, which were based on a 15-year historical period, as opposed to SCE's 10-year historical period. These come in between Mr. Majoros and the Company. It also stated that "in its next GRC, SCE should, as part of its account-by-account analysis, analyze the effects of past inflation on its proposed cost of removal rates and justify the implicit inflation rates reflected in its proposed rates."[13]

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[10] Application of Southern California Edison Company, A. 04-12-014, Majoros Direct Testimony, pp. 43-44.

[11] Id., p. 44.

[12] Application of Southern California Edison Company, A. 04-12-014, D 06-05-016, page 204, also Finding of Fact 122.

[13] Id., page 208, also Conclusion of Law 33.

Alternatives to TIFCA Approved by Public Service Commissions

Company: Pacific Gas & Electric Company
Case No.: California Application 05-12-002
SK Witness: Michael J. Majoros, Jr.
Order(s): D.07-03-044, issued March 15, 2007

Discussion of Results:

In the Opinion adopting the Settlement Agreement in this case, the Commission modified the Settlement Agreement to include "a requirement for PG&E to record a regulatory liability for $2.1 billion that PG&E has collected in rates but not yet spent to retire and remove assets from service."[14]

As stated in the Opinion:

> Our adoption of a regulatory liability for PG&E's pre-funded removal costs is consistent with our resolution of the same issue in the most recent SCE GRC proceeding. There, we held that:
>
> > TURN's request that the balance of funds collected for cost of removal...be recognized as a regulatory liability for ratemaking purposes is reasonable and will be adopted. The balance...is substantial, amounting to $2.1 billion as of the end of 2004. This balance is already recognized as a regulatory liability for financial reporting purposes. SCE has not demonstrated any potential harm to the company...Formal recognition of our ratemaking responsibilities is a reasonable course of action and will establish regulatory certainty regarding ratemaking treatment and principles that all parties generally agree is appropriate. (D.06-05-016, *mimeo.*, p. 204.)
>
> We see no reason to treat PG&E differently from SCE.[15]

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[14] Application of Pacific, Gas & Electric Company, A.05-12-002, D. 07-03-044, p. 3.
[15] Id., p. 217-218.

Missouri

Company: Laclede Gas Company
Case No.: Missouri GR-99-315
SK Witness: None
Order(s): Second Report and Order, Issued June 28, 2001

Discussion of Results:

In this case, the Commission Staff recommended that Laclede's future cost of removal be based on the actual cost of removal the Company was experiencing. The Commission agreed:

> Currently, Laclede is recovering more in depreciation for net salvage than it is spending. In addition, ratepayers will pay $2.3 million more in depreciation annually under Laclede's method of calculation. Under Laclede's theory, it would be allowed to recover from its *current* customers the estimated cost of *future* expenditures. Laclede has no definite plans for the removal of the major assets involved in this net salvage calculation. Laclede is not currently spending funds on the removal or salvage of these assets. Laclede's arguments for spreading the costs of the removal of these assets among different generations of customers were not persuasive because of the uncertainty of how much cost will be incurred for removal, when the removal will occur, or if the removal will occur at all. Therefore, the Commission finds that Laclede has failed to meet its burden of showing that its depreciation calculation for net salvage is just and reasonable. Laclede has not shown why it is just and reasonable to recover from its current customers more than its current expenditures for net salvage.
>
> The Commission finds that Staff's proposed calculation of net salvage cost is just and reasonable. Staff's proposed calculation will allow Laclede to collect from its current customers the amount Laclede is currently expending for final net salvage cost for mass property accounts. Staff's calculation will also allow recovery of the amount Laclede is expending for interim cost of removal for life span property accounts. Thus, Staff's calculation will allow Laclede to recover the amounts it is currently spending for net salvage without overrecovering from its ratepayers, which is a just and reasonable result. This level of net salvage is adequate to allow Laclede to fully recover the net salvage of all plant.

> The Commission finds, therefore, that the calculation of net salvage cost in this case shall be performed in accordance with Staff's recommendations. Thus, current depreciation rates should reflect a net salvage component of the depreciation rate that, when multiplied by the plant balance, gives an annual accrual consistent with the current net salvage amounts experienced by Laclede. Laclede's current depreciation rates reflect this computation, and therefore, should remain unchanged, with the exception of Account 362, Gas Holders. This will result in an annual accrual of $21,054,647.[16]

Laclede appealed the Commission's decision to the Circuit Court of Cole County (Case No. 01CV325280) and then to the Missouri Western District Court of Appeals (Case No. WD61486). The appeal was dismissed and remanded to the Commission, with the instruction to provide clearer, more detailed findings of fact.[17]

The Commission reopened the case to take further evidence on the issues of depreciation and net salvage on May 4, 2004.[18] On January 11, 2005, Missouri's Public Service Commission reversed its position. However, it did require Laclede to separately track net salvage in the depreciation reserve.[19]

Company: Empire District Electric Company
Case No.: Missouri ER-2001-299
SK Witness: None
Order(s): Report and Order, Issued September 20, 2001.

Discussion of Results:

In this case, the Commission Staff again recommended that future net salvage be based on actual experience, and expensed, rather than be bundled into depreciation rates. The Commission agreed, stating:

> The Staff and Empire also disagree on whether depreciation rates should include net salvage value. Inclusion of net

[16] I/M/O Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedules, Case No. GR-99-315, Second Report and Order, Issued June 28, 2001, pages 3-4.

[17] I/M/O Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedules, Case No. GR-99-315, Order Directing Filing of Proposed Findings of Fact, Issued February 27, 2004, page 1.

[18] I/M/O Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedules, Case No. GR-99-315, Order Setting Hearing and Prehearing Conference, Issued May 4, 2004, page 1.

[19] I/M/O Laclede Gas Company's Tariff to Revise Natural Gas Rate Schedules, Case No. GR-99-315, Third Report and Order, Issued January 11, 2005.

> salvage value creates the need to project the date that plant will be removed, the cost of removal at the time it is removed and the gross salvage value, for plant that may never be removed or at least not be removed for some considerable time after it is retired. Unit 6 at Empire's Riverton site was retired, but presently remains on site. This uncertainty provides sufficient grounds to reject Empire's determination of net salvage cost. The Staff's approach of treating net salvage cost as an expense based on Empire's recent historical data reduces this uncertainty. Additionally, separately stating net salvage cost, rather than incorporating it in depreciation rates, appropriately identifies the significance of net salvage cost on rates. The Commission finds that net salvage cost considered in setting rates should be based on historical net salvage cost that Empire has actually incurred in the recent past and that it should be treated as an expense.[20]

The Commission Staff's treatment of net salvage remained unchanged in Empire's next rate case, Case No. ER-2002- 424. As stated in the Stipulation in that case, "consistent with existing Staff policy, the depreciation rates agreed to by the Parties do not include a provision for net salvage (cost of removal less salvage). Instead, net salvage has been included in the income statement in determining cost of service based upon the Company's actual historical experience."[21]

Company: Empire District Electric Company
Case No.: Missouri ER-2004-0570
SK Witness: Michael J. Majoros, Jr.
Order(s): Report and Order, Issued March 10, 2005

In Empire's most recent rate case, Case No. ER-2004-0570, Empire once again requested to incorporate net salvage as a component of depreciation rates. The Commission Staff recommended expensing net salvage, consistent with their existing policy, and Empire's existing rates. Mr. Majoros, testifying on behalf of the Office of Public Counsel, recommended a net salvage allowance based on the most recent five-years experience. On March 10, 2005, the Missouri PSC reversed it prior position.[22]

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[20] I/M/O Empire District Electric Company's Tariff Sheets etc., Case No ER-2001-299, Report and Order, Issued September 20, 2001, page 11.

[21] I/M/O Empire District Electric Company, etc., Case No. ER-2002-424, Report and Order, Issued November 14, 2002, Attachment A, page 4.

[22] I/M/O Empire District Electric Company, etc., Case No ER-2004-0570, Report and Order, Issued March 10, 2005.

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Oklahoma

Company: Empire District Electric Company
Cause No.: Oklahoma PUD 200300121
SK Witness: Mr. Majoros acted as consultant to the Commission, but not as witness.
Order(s): Order No. 478532, Issued July 31, 2003

Discussion of Results:

In this case Empire District Electric Company proposed the same depreciation rates that were ordered by the Missouri Public Service Commission in Case No. ER-2001-299. In other words, the depreciation rates proposed by the Company did not include a provision for net salvage. The Staff of the Oklahoma Corporation Commission agreed with the Company's proposal, specifically noting the net salvage issue.

> Staff's two major depreciation related issues are the salvage value and life assumptions made by the Missouri's Staff. Staff finds the salvage cost assumption as presented by the Missouri Commission acceptable. The first reason being that the Missouri Commission rejected Empire's proposed ratio of current net salvage (Gross Salvage less Cost of Removal) to the same Plant's original cost as a factor to multiply times current plant balance to estimate the net salvage that it anticipates will be required to remove the currently active plant from service decades in the future. Doing so would have helped Empire calculate a net salvage that is negative, nil, or positive meaning that the net salvages [sic] becomes a cost. The net result in this case is a net salvage cost than [sic] can be as large or larger than the original cost of the same plant. Missouri proposed that the Company collect net salvage at the current level that the Company is experiencing. The Missouri Commission also determined that Empire would have collected $1.5 million more annually than it was spending for net plant removal (Net Salvage Cost).[23]

This case was settled in Order No. 478532, dated July 31, 2003. The Joint Stipulation and Settlement Agreement attached to that Order did not discuss depreciation.

[23] I/M/O Empire District Electric Company, Cause No. PUD 200300121, Prefiled Responsive Testimony of Mutombo Lukasu, page 25.

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Kentucky

Company: Jackson Energy Cooperative Corporation
Case No.: Kentucky 2000-00373
SK Witness: Michael J. Majoros, Jr.
Order(s): Order, Issued May 21, 2001

Discussion of Results:

Testifying for the Attorney General, Mr. Majoros recommended the use of a net salvage allowance based on a 5-year average of actual net salvage experience for distribution plant. The Commission agreed with his recommendation:

> The Commission agrees with the AG. ... Concerning the treatment of net salvage, while the Commission agrees that net salvage is normally recovered as part of the depreciation rates, the AG has offered persuasive reasons supporting a departure in this case from the normal approach. The Commission finds that it is reasonable under these circumstances to use the average net salvage allowance approach proposed by the AG. This approach should be utilized until Jackson Energy undertakes a new depreciation study.[24]

Company: Fleming-Mason Energy Cooperative Corporation
Case No.: Kentucky 2001-00244
SK Witness: Michael J. Majoros, Jr.
Order(s): Order, Issued August 7, 2002

Discussion of Results:

Mr. Majoros testified on behalf of the Attorney General in this proceeding. As in the Jackson Energy case, he recommended the use of a net salvage allowance:

> The AG proposes that the net salvage component normally included in depreciation rates be recovered using an average net salvage allowance approach, which is similar to the approach adopted for Jackson Energy. Under the AG's proposal, an amount representing the 5-year average net salvage experience is added to the distribution plant remaining life depreciation expense in lieu of Fleming-

[24] I/M/O The Application of Jackson Energy Cooperative for an Adjustment of Rates, Case No. 2000-373, Order Issued May 21, 2001, pages 33-34.

Mason's proposed net salvage ratios. The amount should be prorated to the accounts in proportion to actual net salvage experience. The AG recommends this approach for at least the next 5 years, at which time another depreciation study could be conducted.[25]

Fleming-Mason has not offered comments on nor expressed concerns about the AG's proposal.[26]

The Commission agrees with the AG. While the Commission agrees that net salvage is normally recovered as part of the depreciation rates, the arguments offered by the AG are persuasive reasons for supporting a departure in this case from the normal approach. The Commission finds that it is reasonable under the circumstances in this case to use the average net salvage allowance approach proposed by the AG. This approach should be utilized until Fleming-Mason undertakes a new depreciation study.[27]

Kansas

Company:	Westar Energy, Inc. / Kansas Gas & Electric Company
Docket No.:	Kansas No. 05-WSEE-981-RTS
SK Witness:	Michael J. Majoros
Order(s):	Order on Rate Applications, Issued December 28, 2005 Order on Petitions for Reconsideration and Clarification, Issued February 13, 2006 Kansas Industrial Consumers Group, Inc. v. Kansas Corporation Comm'n, 35 Kan. App. 2d___, ___P.3d___(No. 96,228, filed July 7, 2006)

Discussion of Results:

Mr. Majoros testified on behalf of the Citizens' Utility Ratepayer Board ("CURB"), Kansas Industrial Consumers ("KIC") and the Unified School District No. 259. *Regarding net salvage, Mr. Majoros recommended the following:*

25 I/M/O Adjustment of Rates of Fleming-Mason Cooperative, Case No. 2001-00244, Order Issued August 7, 2002, pages 22-23.
26 Id., page 23.
27 Id.

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> I also recommend discounting all of Mr. Spanos' dismantling and future cost of removal parameters to their fair net present value, using a 3 percent inflation factor. I recommend that the Commission split depreciation rates into separate capital recovery and cost of removal components. Finally, I recommend that the KCC specifically recognize the refundable regulatory liability resulting from Westar's collection of excessive non-legal ARO charges. The KCC should recognize this as a regulatory liability for regulatory reporting, regulatory analysis, and ratemaking purposes in Kansas.[28]

In revised tables to his testimony, Mr. Majoros later adopted some of the recommendations of Commission Staff witness Larry Holloway – specifically the recommendations to removal terminal net salvage from the calculation and to combine the rates for transmission and distribution for the two Companies.

The Commission sided with the Company in this case on all issues. However, Westar appears to have agreed to the use of a regulatory liability to track the funds recovered for terminal net salvage:

> To prevent double counting, Westar recommended that the Commission find that amounts recorded to Account 108 for terminal net salvage are treated as a regulatory liability for ratemaking purposes. Westar Reply Brief, 37n15.[29]
>
> Consistent with Westar's concession, the Commission orders that a regulatory liability should be recorded to track the funds recovered.[30]

Mr. Majoros' clients filed Petitions for Reconsideration. The Commission did not change its recommendation; however, it did offer some clarification regarding the regulatory liability for terminal net salvage:

> The Commission reminds the parties that its intent in tracking the terminal net salvage values separately and determining that the amounts should be considered a liability is to establish the fact that Westar has an obligation to refund to ratepayers any amount of terminal net salvage not used for demolishing, dismantlement or

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[28] I/M/O Westar Energy, Docket No. 05-WSEE-981-RTS, Majoros Direct Testimony, pp. 35-36.

[29] I/M/O Westar Energy, Docket No. 05-WSEE-981-RTS, Order on Rate Applications, Issued December 28, 2005, p. 44.

[30] Id., p 45

> otherwise removing plant. The point is this: The regulatory liability will track these funds collected for terminal net salvage and will ensure that when Westar dismantles existing plant to make room for additional generation, the cost of that dismantlement will not be capitalized and added to rate base.[31]

The Commission also stated the following regarding the inclusion of inflation in the calculation of future terminal net salvage:

> CURB argued the issue is whether the time value of money is considered. From the Commission's view of the evidence presented, it is clear that the Spanos study did inflate the terminal net salvage values to reflect an estimate of the future cost to dismantle. Based on the record, the Commission believes this approach is appropriate. The Commission recognizes this approach is controversial. Therefore, <u>policy regarding the depreciation concepts of terminal net salvage value and inflating terminal net salvage values is best determined in a generic proceeding</u>. While the facts in this case clearly support the inflation of terminal net salvage values to meet future costs, <u>the Commission's decision should not be viewed as establishing general policies regarding terminal net salvage value</u>.[32]

The case was appealed to the Kansas Court of Appeals by CURB, KIC and USD 259 in 3 separate appeals. In the appeal, the Petitioners took "issue with the Commission's order permitting Westar to depreciate its facilities by including 'terminal net salvage' costs adjusted for inflation."[33]

> Petitioners argue there was not substantial competent evidence to support the use of terminal net salvage depreciation because there was no evidence Westar had or ever planned to completely dismantle any of its retired facilities. Accordingly, they contend the inclusion of terminal net salvage depreciation was speculative. Petitioners also contend the inflation adjustment adopted by the Commission was not supported by substantial competent evidence.[34]

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[31] I/M/O Westar Energy, Docket No. 05-WSEE-981-RTS, Order on Petitions for Reconsideration and Clarification, Issued February 13, 2006, p. 49.

[32] Id., pp. 52-53 (emphasis added).

[33] Kansas Industrial Consumers Group, Inc. v. Kansas Corporation Comm'n, 35 Kan. App. 2d___, ___P.3d___(No. 96,228, filed July 7, 2006). (no page numbers)

[34] Id.

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The Court agreed with the Petitioners.

> Based upon a review of the entire record, we agree the Petitioners have reason to complain about the Commission's order concerning depreciation. There was no concrete evidence before the Commission that Westar ever intended to actually dismantle any of its existing steam generation plants at any time in the future. The evidence indicated the Ripley plant had not been used as a generating facility since 1987, but was still standing. There was no evidence that substantial dismantling had been planned regarding any facility which had even been partially taken out of generation. Despite testimony about Westar's plans to increase generating capacity, none of Westar's witnesses actually testified to any likelihood that the company would dismantle plants in the future and build new plants on the same site.[35]
>
> We are not rejecting the inclusion of terminal net salvage depreciation if and when it is supported by evidence before the Commission. We note the Commission has permitted the use of terminal net salvage depreciation in a prior rate case without any objection by the parties, which included KIC. We also note that regulatory commissions in other states have permitted terminal net salvage depreciation. However, in order to uphold an order permitting terminal net salvage depreciation, we conclude there must be *some evidence* that the utility has a reasonable and detailed plan to actually dismantle a generating facility upon retirement. Westar presented no evidence of even tentative plans in this case, even after the Commission's staff and the intervenors vociferously objected to the lack of any plans. Instead, Spanos' testimony was based upon case studies from other areas and was completely speculative as to the realities of Westar's operations. Even the specific survey referred to by Majoros indicated that only 15 out of 86 facilities in other states were dismantled upon retirement. However, based on the Commission's order, Westar would be entitled to include terminal net salvage depreciation in 100% of its steam generation facilities.[36]

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[35] *Id.*

[36] Id.

The Commission essentially acknowledges the problem with its depreciation order by determining that Westar would be required to make detailed showings in *future* rate cases in order to recover costs for terminal net salvage. The future standard was derived from Holloway's testimony, which apparently was rejected by the Commission in *this case* but will be adopted by the Commission in future cases. While it is commendable for the Commission to require a higher standard of evidence in future rate cases, this determination only adds to the arbitrary nature of the Commission's order in this case.[37]

The Commission's adoption of Spanos' depreciation calculations using an inflation adjustment is even more troubling. Although the Commission permitted terminal net salvage depreciation in a prior rate case without objection by the parties, the Commission's prior order did not include the inflation adjustment as calculated by Spanos in this case. Thus, the Commission's order represented a departure from prior policy without an explanation by the Commission for doing so. See *Western Resources, Inc. v. Kansas Corporation Comm'n,* 30 Kan. App. 2d 348, Syl. ¶ 7, 42 P.3d 162, *rev. denied* 274 Kan. 1119 (2002) (when an administrative agency deviates from a policy it had adopted earlier, it must explain the basis for the change). Other than Spanos' conclusory testimony, there was no evidence before the Commission to support the adoption of the inflation adjustment in calculating depreciation costs. Holloway and Majoros testified in considerable detail that the inflation adjustment was improper under the circumstances and resulted in charging future inflation to current customers. According to Majoros' testimony, Spanos' inflation adjustment nearly tripled the cost of Westar's depreciation as determined in 2001.

Determining an appropriate depreciation expense is a complex issue in any rate case and inherently involves "speculation" to the degree it requires projection of future events. See *Western Resources, Inc.*, 30 Kan. App. 2d at 368-73. <u>However, the need to project future events is not license for the Commission to engage in unchecked speculation.</u> The effect of the Commission's order turns on its head the general principle that changes in rates due to

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37 Id.

> future or nontest year events be, at least to some degree, known and measurable. See *Kansas Industrial Consumers,* 30 Kan. App. 2d at 343. The underlying assumption of the Commission's decision is that Westar will likely significantly dismantle all or most of its steam generation facilities at the end of their operating life. The Commission then multiplies the effect of this assumption by applying an inflation factor. There is no evidence in the record that comparable utilities dismantle or plan to dismantle most or all of their steam facilities. Likewise, the Commission relied on no evidence that Westar had even *tentative* plans to significantly dismantle any of its facilities. The cumulative effect of this lack of evidence renders the Commission's order ""so wide of the mark as to be outside the realm of fair debate. [Citations omitted.]"" *Williams Natural Gas Co. v. Kansas Corporation Comm'n,* 22 Kan. App. 2d 326, 335, 916 P.2d 52, *rev. denied* 260 Kan. 1002 (1996). Based upon a review of the entire record, we conclude the Commission's order permitting Westar to include terminal net salvage depreciation adjusted for inflation for all of its steam generation facilities was not supported by substantial competent evidence and must be reversed.[38]

This is an important decision. It sets forth the need for actual dismantlement plans – not just speculation, it rejects the charging of future inflation to current ratepayers, and it provides minimum intellectual standards upon which to base a decision, even in an area where Commissions generally have wide discretion.

Company: Kansas Gas Service
Docket No.: Kansas No. 06-KGSG-1209-RTS
SK Witness: Michael J. Majoros, Jr.
Order(s): Order Granting Joint Motion and Approving Stipulated Settlement Agreement, Issued November 16, 2006

Discussion of Results:

In this case, KGS proposed a $5.5 million reduction in depreciation expense, based on plant balances as of December 31, 2005. The Company did not separate its proposed depreciation expense accrual into capital recovery and net salvage, however, Mr. Majoros was able to estimate that of the $35.5 million accrual (based on December 31, 2005 plant), $9.7 million related to future cost of removal collections.

[38] Id. (Emphasis added.)

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KGS acknowledged that it had a regulatory liability for cost of removal collections in its 10-K report, but unlike most utilities, it did not quantify that regulatory liability. During discovery, the Company quantified the amount as being $1.7 million.

Mr. Majoros recommended that the Kansas Corporation Commission ("KCC") recognize KGS's non-legal AROs as a regulatory liability for ratemaking purposes in Kansas. He also recommended that instead of including future net salvage ratios in the depreciation rates, the KCC should adopt capital recovery rates coupled with a $2.4 million normalized net salvage allowance based upon the most recent five years of actual experience.

The settlement included specific details regarding depreciation. According to the Settlement:

> Kansas Gas Service will recognize a regulatory liability for tracking the component of the depreciation expense accrual associated with the cost of removal in a unique sub account, separate from the investment and salvage accruals, within the accumulated depreciation reserve. Initially, this amount will be $1,669,000 as of December 31, 2005. The cost of removal component of Kansas Gas Service's depreciation accrual will be accrued into the cost of removal sub account of the accumulated depreciation reserve monthly and realized cost of removal will be posted to the sub account as incurred.[39]

The parties to the settlement also agreed that the Commission should open a generic docket to review and investigate depreciation policies and practices. The KCC approved the Stipulated Settlement Agreement, with specific mention of the agreements regarding depreciation.

> B. Regarding depreciation issues, the Commission finds that the amounts recorded to Account 108 for the costs of removal are to be hereafter treated as a regulatory liability for rate making purposes, as set forth in paragraph 17 of the Settlement Agreement. *The Commission further finds that Staff should* continue to investigate the need for a generic docket regarding cost of removal depreciation and file an appropriate motion asking that such a generic docket be opened, as discussed in the above Order.[40]

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[39] I/M/O Kansas Gas Service, Stipulated Settlement Agreement, October 25, 2006, p. 5.

[40] *I/M/O* Kansas Gas Service, Order Granting Joint Motion and Approving Stipulated Settlement Agreement, November 16, 2006, pp. 5-6.

Michigan

Company: Consumers Energy Company
Case No.: Michigan U-12999
SK Witness: Charles W. King
Order(s): Proposal For Decision, Issued June 28, 2004
Opinion and Order, Issued October 14, 2004
Order Initiating Generic Proceeding, Issued October 14, 2004

Discussion of Results:

In this case, Snavely King testified on behalf of the Attorney General. Mr. King recommended "basing net salvage factors on the ratios of the most recent five years of actual salvage experience to plant-in-service."[41] The ALJ recommended that the Commission adopt the net salvage ratios and recommended removal cost allowances set forth by Mr. King.

The Commission recognized that net salvage was a major issue it its Opinion and Order:

> Consumers would continue the traditional approach to calculating and recovering net salvage; that approach maintains the *status quo* but does not address the singular issue raised by the remaining parties regarding the absolute size of the negative net salvage values proposed by Consumers and the formidable present net-salvage level within the company's books. The Staff's position reduces net-salvage values through the use of a five-year rather than a ten-year average of recent experience, but (as pointed out by Consumers) does so through use of a simplified company-wide average rather than on a functional plant group basis. Such an approach can mask anomalies that may exist within specific classes of gas utility plant. ABATE advocates utilization of a completely revised approach—net-salvage cost would become an expense item separate from depreciation and collected as such in Consumers' rates. The Attorney General would also separate net salvage from depreciation, but would recover that cost through depreciation expense, albeit with a similar current-cost result as ABATE. This "separation" concept has not been adopted

[41] I/M/O Consumers Energy Company, Case No. U-12999, Proposal For Decision, Issued June 28, 2004, page 15.

> in Michigan before, although other state commissions have considered it.[42]

However, the Commission was concerned with the magnitude of the net salvage adjustments proposed by the parties, including the AG.

> The gulf between the positions of the various parties is approximately $50 million in the amount of annual depreciation expense that is appropriate for recovery, or approximately one-half of the amount that the Commission has previously found appropriate as a depreciation expense for Consumers. The effect of such a considerable shift in cost recovery on both customer rates and quality of service could similarly be large, and it should not be undertaken lightly. The Commission is persuaded that the abrupt shift in the method and the manner of cost of removal recovery as proposed either by ABATE or the Attorney General is ill-advised at this juncture without further industry-wide comment, discussion, and review. The Commission provides for this in a companion order issued today in Case No. U-14292.[43]
>
> The Commission is equally not persuaded that a shift to a simplified five-year company-wide average as proposed by the Staff should be implemented. However, the Commission is concerned that the large negative net-salvage values that result from Consumers' analysis of ten years of data (or the projected costs for storage wells and related matters) do not provide an accurate illustration of the costs that Consumers will bear to retire its assets in the future. The large variance between Consumers' incurred removal costs and its projected costs has been amply pointed out by the Attorney General and by ABATE. Thus, Consumers' proffered rates will not alleviate this concern of the remaining parties.[44]

The Commission decided that the Company should continue to use its existing depreciation rates for the time being. In addition, the Commission opened a Generic Proceeding to "review Statement of Financial Accounting Standards No. 143, Federal Regulatory Commission Order No. 631, and their accounting and ratemaking issues (as well as other matters that are related to the retirement of tangible long-lived assets and

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[42] I/M/O Consumers Energy Company, Case No. U-12999, Opinion and Order, Issued October 14, 2004, pages 12-13 (emphasis added)
[43] Id., page 13.
[44] Id.

the associated asset retirement costs) for Commission-jurisdictional electric and gas entities."[45] The results of that proceeding are discussed below.

Company: Generic Proceeding
Case No.: Michigan U-14292
SK Witness: Charles W. King
Order(s): Opinion and Order, Issued June 26, 2007

Discussion of Results:

This case was a generic proceeding opened to "review future treatment of SFAS No. 143-related issues, proper future ratemaking policy regarding those issues, necessary Uniform System of Accounts (USoA) revisions, and other matters that are related to the retirement of tangible long lived assets and the associated retirement costs."[46] Mr. King testified on behalf of the Attorney General.

In its Order, the Commission noted that the use of TIFCA to estimate future removal costs was no longer suitable:

> The Commission agrees with the Staff, the Attorney General, and ABATE that there are apparent problems with the current method for calculating future cost of removal expense as demonstrated by the significant (and increasing) cost of removal depreciation expense accruals for several utilities.[47]
>
> The Commission likewise agrees that the current practice of calculating cost of removal ratios, by comparing removal costs in today's dollars with the original cost of the plant being retired, is no longer suitable. As the Staff observed, the first problem with this approach is that it assumes that past, generally higher inflation rates will continue into the future. Second, the traditional method fails to take into account the time value of money.[48]

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[45] I/M/O Commission's Motion to Establish Appropriate Accounting and Ratemaking Treatment for Statement of Financial Accounting Standards No. 143, Case No. U-14292, Order Initiating Generic Proceeding and Notice of Hearing, Issued October 14, 2004, page 6.

[46] I/M/O Commission's Motion to Establish Appropriate Accounting and Ratemaking Treatment for Statement of Financial Accounting Standards No. 143, Case No. U-14292, Opinion and Order, Issued June 26, 2007, page 3

[47] Id., p. 32.

[48] Id., pp. 32-33.

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The Commission did not select a replacement methodology for TIFCA, choosing to defer the selection until it had more information:

> The Commission therefore directs the large utilities to file new depreciation cases in 2008, using 2007 cost of removal expenses as a basis, and to calculate cost of removal depreciation under: 1) the current method for calculating cost of removal; 2) the current method for calculating cost of removal using the standard retirement units proposed by the Staff; 3) the method proposed by Mr. Czech and using the standard retirement units proposed by the Staff; and 4) an SFAS No. 143 approach that considers the time value of money applied to required AROs and other AROs, with and without the standard retirement units proposed by the Staff. This additional information will allow the Commission to assess the propriety of the different proposals and the efficacy of implementing them for each individual utility.[49]

In its Order, the Commission also "deferred approval of regulatory asset and regulatory liability accounting until after the USoAs for electric and gas utilities were amended."[50]

Georgia

Company: Georgia Power Company
Docket No.: Georgia 4007-U
SK Witness: Charles W. King
Order(s): Order, Issued 1991

Discussion of Results:

As described in the Georgia Public Service Commission's April 29, 2002 Proposed Final Order, Atlanta Gas Light Docket No. 14311-U, "In 1991, in Docket No. 4007-U, and again on December 20, 2001 in Docket No. 14000-U, the Commission approved a procedure [recommended by Staff witness Charles W. King] for computing net removal and salvage ratios for the Georgia Power Company that avoids the distorting effect of comparing dollars of very different values. Under this procedure, the utility develops an estimate of the total current cost of removing all existing plant in each account. This estimate is then ratioed to the current investment in the existing plant to derive the net removal cost ratio."[51]

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[49] Id., p. 33.
[50] Id., p. 35.
[51] IN RE: Earnings Review to Establish Just and Reasonable Rates for Atlanta Gas Light Company, Georgia Public service Commission, Docket No. 14311-U, Proposed Final Order of the Public Service Commission's Advocate Staff

Company: Georgia Power Company
Docket No.: Georgia 14000-U
SK Witness: Charles W. King
Order(s): Order, Issued December 20, 2001

Discussion of Results:

As explained above, the Georgia Public Service Commission first adopted Mr. King's recommended depreciation rates for this Company in 1991, Docket No. 4007-U. Mr. King's rates included a provision for net salvage which was calculated by developing an estimate of the total current cost of removing all existing plant in each account and then applying that estimate to the current investment in the existing plant to derive the net removal cost ratio. This methodology is different from the "traditional" methodology used by GA Power and other companies in that it removes the distortion caused by comparing current cost of removal dollars to very old retirement dollars.

In the Company's 2001 rate case, Georgia Power Company filed depreciation rates using that procedure and the Commission again agreed with Mr. King's recommended rates, which included the same net salvage methodology in use since 1991. In this case, the Commission adopted an Alternative Rate Plan, which included the following language:

> The Company shall reduce its annual depreciation expenses by $66.548 million to reflect the depreciation rates recommended by Staff, except that the Company shall utilize a fifty-year life for setting depreciation rates for Plant Vogtle.[52]

Company: Georgia Power Company
Docket No.: Georgia 18300-U
SK Witness: Charles W. King
Order(s): Order, Issued December 22, 2004.

As in the previous GA Power Rate cases, Mr. King testified on behalf of the Georgia Public Service Commission's Adversary Staff. Georgia Power once again, used Mr. King's recommended net salvage approach. However, in the 2004 rate case, he also recommended "the complete separation of pure depreciation, that is, the recovery of

[52] Georgia Power Company's 2001 Rate Case, Docket No. 14000-U, Order, Issued December 20, 2001, Exhibit A, Consent to Alternative Rate Plan.

capital investment, from the recovery of net removal costs."[53] Mr. King proposed "separate schedules of rates for these two functions", using his net salvage recommendations.[54]

Although it is not explicitly stated in the Order, it is Mr. King's understanding that with the exception of the life span for Plant Vogtle, the Commission adopted his depreciation rate recommendations, including those for net salvage.

Company: Atlanta Gas Light Company
Docket No.: Georgia 14311-U
SK Witness: Charles W. King
Order(s): Order, Issued April 29, 2002

Discussion of Results:

In this case, Mr. King recommended the same net salvage methodology for Atlanta Gas Light that had been ordered for, and in use by Georgia Power Company since 1991. The procedure calls for the utility to develop an estimate of the total current cost of removing all existing plant in each account and then ratio that estimate to the current investment in the existing plant to derive the net removal cost ratio. This methodology removes the distorting effect of comparing dollars of very different values from the net salvage ratio.

The Commission agreed with Mr. King's recommendations:

> The Commission further finds that it is reasonable to require the Company to utilize the depreciation rates recommended by the Advocacy Staff witness Mr. King.[55]

Company: Atlanta Gas Light Company
Docket No.: Georgia 18638-U
SK Witness: Charles W. King
Order(s): Order, Issued April 27, 2005

In this case, Mr. King, testifying on behalf of the GPSC Adversary Staff, recommended the use of "two sets of rates, one being "pure" depreciation rates that only recover capital previously expended, and the other removal cost rates that accrue funds to

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[53] Georgia Power Company's 2004 Rate Case, Docket No. 18300-U, Direct Testimony of Charles W. King, page 4.
[54] Id.
[55] I/M/O Atlanta Gas Light Company, Docket No 14311-U, Order, Issued April 29, 2002, page 6.

remove, dismantle or otherwise dispose of property currently in service."[56] Additionally, Mr. King recommended "the Commission retain the present system for developing removal cost allowances. That procedure compares an estimate of the lifetime cost of removal, expressed in current dollars, to the original cost of each account that may incur such costs."[57]

The Commission agreed, stating:

> The Commission finds as a matter of fact that the depreciation rates proposed by the Commission's Adversary Staff are fair, just and reasonable.[58]

Although Commissioner Stan Wise dissented with the Commission's Order, he agreed with the Order in the area of depreciation rates.[59] On May 9, 2005, Atlanta Gas Light filed a Petition For Rehearing, Reconsideration and Oral Argument. As of May 11, 2005, the Commission had not responded to that petition.

Company: Savannah Electric and Power Company
Docket No.: Georgia 19758-U
SK Witness: Charles W. King
Order(s): Order, Issued May 17, 2005 (based on Stipulation)

Mr. King testified on behalf of the Adversary Staff. As with the most recent Atlanta Gas Light case, he recommended "two sets of rates, one being "pure" depreciation rates that only recover capital previously expended, and the other removal cost rates that accrue funds to remove, dismantle or otherwise dispose of property currently in service."[60] He also recommended that "the Commission apply the procedure for developing removal cost allowances that Savannah Electric uses for its production plant and that the Georgia Power and Atlanta Gas Light Companies use for all plant categories that incur removal costs. That procedure compares an estimate of the lifetime cost of removal, expressed in current dollars, to the original cost of each account that may incur such costs."[61]

In the Accounting Order Stipulation agreed to in this case, Mr. King's recommendations were for the most part accepted:

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[56] I/M/O Atlanta Gas Light Company, Docket No. 18638-U, Direct Testimony of Charles W. King, page 4.
[57] Id.
[58] I/M/O Atlanta Gas Light Company, Docket No. 18638-U, Order, Issued April 27, 2005, page 6.
[59] I/M/O Atlanta Gas Light Company, Docket No. 18638-U, Order, Issued April 27, 2005, Dissenting Opinion of Commissioner Stan Wise, page 2.
[60] In Re: Savannah Electric and Power Company 2004 Rate Case, Docket No. 19758-U, Direct Testimony of Charles W. King, page 4.
[61] Id., page 5.

> For the purpose of this decision, Staff recommended depreciation rates shall be used with the exception that the McIntosh Combined Cycle Units service life shall be set at 35 years and the depreciation rate for account 397 (telecommunications equipment) shall be corrected.[62]

The Commission adopted the stipulation in its May 17, 2005 Order.

Delaware

Company: Delmarva Power & Light Company
Docket No.: Delaware Docket No. 05-304
SK Witness: Michael J. Majoros, Jr.
Order(s): Findings and Recommendation of the Hearing Examiner, Issued April 14, 2006
Findings, Opinion and Order No. 6930, Issued June 6, 2006.

Discussion of Results:

Mr. Majoros initially filed testimony recommending that the DPSC specifically recognize the regulatory liability resulting from Delmarva's collection of excessive non-legal ARO charges as a refundable regulatory liability for regulatory reporting, regulatory analysis, and ratemaking purposes in Delaware. He also recommended that the DPSC require separate capital recovery versus cost of removal depreciation rates. Mr. Majoros recommended any of four alternatives for the treatment of future net salvage. These were expensing, the normalized net salvage allowance approach, the net present value approach or the SFAS No. 143 fair value approach. He prepared his calculations using the net present value approach, which discounted all of Delmarva's proposed future cost of removal parameters to their net present value.

At the request of the Commission staff, Mr. Majoros filed supplemental direct testimony recommending that Delmarva's existing regulatory liability for cost of removal collections be amortized back to ratepayers over a period from 5 to 10 years in order to mitigate a significant spike to energy prices. Mr. Majoros recalculated his proposed depreciation rates to reflect the removal of this portion of the depreciation reserve from the rate calculations. His recommendations regarding future net salvage parameters did not change.

The Hearing Examiner did not require the establishment of a regulatory liability for cost of removal. However, he did adopt the normalized net salvage allowance approach for the treatment of future net salvage. This was one of the approaches Mr. Majoros

[62] Docket 19758-U, Accounting Order Stipulation, page 2.

recommended, and it is also the approach the Division of the Public Advocate's ("DPA") depreciation witness recommended. As stated by the Hearing Examiner,

> 139. For purposes of this case, at this time, the five-year rolling average for recovery of cost of removal provides a reasonable and preferred method for addressing this controversial aspect of depreciation, and better conforms with the generally accepted accounting principles articulated in Statement of Financial Accounting Standards No. 143 (SFAS 143) by not treating non-legal asset retirement obligations (AROs) as if they were legal AROs. (DPA Proposed Findings at 37.) In contrast, Delmarva's method of including estimated future cost of removal in the depreciation rates essentially treats a non-legal ARO as if it were a legal ARO. (Id.)[63]
>
> 140. Advantages offered by this approach include that it is simple, straight-forward and easy to implement, and avoids charging current customers for estimated future costs and estimated future inflation. (Id.) In addition, while it marks a departure from past practices, it is strongly endorsed by two credible expert witnesses, and it establishes a sensible and verifiable method to recover such costs. Even if the five-year average proves to be low, it is unlikely that the Company will suffer any shortfall in the short term (judging from the large size of the existing COR reserve, which is still available for retirements) and, in the long term, any necessary increases (or decreases) will occur in future rate cases, just as with any normalized expense. I agree with DPA, therefore, that the cost of removal should be separated from the calculation of depreciation rates and a normalized allowance should be provided for cost of removal expense, using a five-year average. This adjustment to Delaware distribution operations results in a reduction to Delmarva's proposal of $5,625,282. (Id.; Exh. 41 (Smith) at Exhibit RCS-1, Schedule 1, column K.)[64]
>
> 141. I recognize that, on its face, DPA's proposal may appear to conflict with many of the reasons proffered above

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[63] I/M/O Delmarva Power & Light Company, Docket No. 05-304, Findings and Recommendations of the Hearing Examiner, April 14, 2006, p. 71.

[64] Id., pp. 71-72.

> in support of my recommendations regarding protection of the COR reserve, such as its proper classification as a depreciation reserve and the potential for intergenerational inequities if it is compromised. However, the COR reserve, as it now stands, was collected under an approach, approved by the Commission, that estimated future removal costs and recovered such costs in depreciation rates. It is reasonable, therefore, for the Commission to protect those funds already in the depreciation reserve account that are earmarked for future removals. As noted by Delmarva, however, DPA's approach is radically different in that it relies not on estimates of actual future removal costs but on a prediction that future removal costs will approximate the five-year historical average of such costs. (Delmarva PHB at 145.) Under DPA's proposal, removal costs will be separated from depreciation rates, and are viewed and recorded as a recurring operational expense rather than as a capital cost subject to depreciation. Because of this fundamental difference in how such costs will be viewed and recorded, the DPA proposal is not inconsistent with my earlier recommendations, which only relate to protection of, and accounting treatment for, the existing COR reserve.[65]

The Commission agreed with the Hearing Examiner.

> 174. <u>Discussion and Decision</u>. We adopt the Hearing Examiner's findings and recommendations that a rolling five-year average of actual depreciation expense be used for the removal cost component of depreciation - but, pursuant to the Company's request, we note that we will not be adverse to re-examining this issue in a future base rate case. That having been said, we recognize that using a rolling five-year average of depreciation expense is an approach that is used in only two other states, and represents a departure from our prior method of determining the amount of depreciation expense to be included in rates.[66]
>
> 175. We are troubled, however, by the amount of depreciation expense that has been collected over the years and remains in the Company's depreciation reserve ($105 million on a system-wide basis) and that the Company's proposed rates would collect on an annual basis $15.9

[65] Id., pp. 72-73.

[66] I/M/O Delmarva Power & Light Company, Docket No. 05-304, Findings, Opinion and Order No. 6930, pp. 87-88.

million). The record evidence shows, and the Company did not dispute, that its test period depreciation expense was $6.2 million and that its depreciation expense has averaged $4 million over the last 5 years. With respect to other expenses that a utility incurs, we use a test period expense level to set the expense level going forward, or we normalize expenses over some period of years if we believe that the test period level is unrepresentative of what can be expected in the future. Here, however, it seems to us that the attempt to estimate what future removal costs will be in the future is nothing more than conjecture.[67]

176. In this regard, we note that the expenses being discussed here are removal costs only. They are not the costs to replace the asset being removed. The replacement costs are placed into rate base when the replacement asset becomes used and useful in providing utility services, and the utility earns a return of, as well as on, that investment. The expenses being discussed here relate solely to the cost of removing an asset that has served out its useful life.[68]

177. For the foregoing reasons, as well as those set forth by the Hearing Examiner, we adopt the Hearing Examiner's findings and recommendations, with the caveat that we will reconsider this issue in the Company's next base rate case should the Company choose to raise it.[69]

Maryland

Company: Washington Gas Light Company
Docket No.: Maryland Case No. 8960
SK Witness: Michael J. Majoros, Jr.
Order(s): Order No. 79193, Issued June 18, 2004

In this case, Mr. Majoros discussed two alternatives to the Company's TIFCA net salvage calculations - the SFAS No. 143 fair value approach and the normalized net salvage allowance approach. He recommended the use of a five-year average net salvage allowance. Washington Gas Light had not calculated and disclosed its regulatory liability for non-legal AROs. Mr. Majoros performed the calculation and discussed the issue.

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67 Id., p. 88.
68 Id.
69 Id., pp. 88-89.

Alternatives to TIFCA Approved by Public Service Commissions

Although the Commission did not adopt Mr. Majoros's net salvage recommendations, it did acknowledge the need for future review and consideration of the issue in the next proceeding. Significantly, the Commission will examine how actual removal costs compare to the estimates used in the derivation of the depreciation rates.

> While we are affirming the Hearing Examiner's decision to continue the straight-line depreciation recovery of removal costs, Staff and OPC have raised questions which warrant consideration in the next depreciation proceeding. In addition to the traditional questions of service life, adequacy of reserve, etc., in the future we will examine how actual removal costs compare to the estimates used in the derivation of the depreciation rates.[70]

Company: Potomac Electric Power Company
Docket No.: Maryland Case No. 9092
SK Witness: Charles W. King
Order(s): Order No. 81517, Issued July 19, 2007

Testifying on behalf of the Office of People's Counsel, Mr. King recommended using the rolling five-year average method of collecting removal costs. He also recommended amortizing the existing cost of removal reserve back to ratepayers. The Company had calculated its net salvage ratios using TIFCA and Staff used the Present Value Method.[71]

Although the Commission did not adopt Mr. King's recommendations, it did adopt Staff's Present Value Method of estimating net salvage, stating:

> ...because future costs are discounted to a "present value," today's ratepayers will pay only their fair share of recovery costs in "real" dollars rather than the inflated amounts under the Straight Line Method. In our opinion, the Present Value Method strikes an appropriate balance between the interests of current and future ratepayers.[72]

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[70] I/M/O Washington Gas Light Company, Case No. 8960, Order No. 79193, Issued June 18, 2004.
[71] I/M/O Potomac Electric Power Company, Case No. 9092, Order No. 81517, Issued July 19, 2007.
[72] Id., p. 31.

Alternatives to TIFCA Approved by Public Service Commissions

Arkansas

Company: CenterPoint Energy Arkla
Docket No.: Arkansas Docket No. 04-121-U
SK Witness: None
Order(s): Order No. 16, Issued September 19, 2005

In this case, the Company initially proposed to continue using its existing depreciation rates. Due to concerns over the level of negative net salvage that were raised in the case in which those rates adopted, Commission Staff Witness Freier prepared a new depreciation study and recommended new rates. Ms. Freier found that high net negative salvage for the mains and services accounts was the primary factor causing the difference between her proposed rates and the current rates.[73]

Arkla's net salvage ratios had been estimated using TIFCA. Ms. Freier developed her net salvage ratios by restating retirements, gross salvage and cost of removal on a constant price level, to remove the historical inflation inherent in the TIFCA methodology.[74]

The Company submitted a new depreciation study in response to Ms. Freier, and again used TIFCA to estimate future net salvage ratios. However, the Commission adopted Ms. Freier's study:

> We are also very concerned about the high level of negative net salvage associated with Arkla's mains and services. This issue arose previously in Arkla Docket No. 01-243-U in which Arkla was directed to perform a removal cost study. ... Ms. Freier's methodology for calculating net salvage on a constant dollar basis represents a departure from the historical procedure we have followed to set Arkla's depreciation rates. However, we note that the net salvage allowances recommended by Ms. Freier of -70 percent for Mains and - 115 percent for Services are still significant and are in line with experience elsewhere as cited by Mr. Spanos. Moreover, the use of remaining life depreciation will ensure that Arkla will fully recover its original investment and the actual amount it incurs for negative net salvage. Accordingly, we adopt Staffs proposed net salvage values and, in turn, Staffs depreciation rates as a means of capping net salvage cost.[75]

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[73] I/M/O CenterPoint Energy Arkla, Docket No. 04-121-U, Order No. 16, Issued September 19, 2005, p. 25.

[74] Is., p. 26.

[75] Id., p. 29.

Alternatives to TIFCA Approved by Public Service Commissions

CenterPoint Arkla is currently involved in a new rate case, Docket No. 06-161-U. Both parties (the Company and Staff) are standing by their positions in Docket No. 04-121-U, and as of September, 2007, an Order has not been issued.

Attorney General's Responses to
Commission Staff's First Data Requests
Case No. 2007-00565

WITNESS RESPONSIBLE:
Michael J. Majoros

Question 4. Refer to the Majoros Testimony, pages 20 through 22 of 26. Concerning Mr. Majoros' references to the requirements of Statement of Financial Accounting Standards ("SFAS") No. 143:

a. Does Mr. Majoros agree that SFAS No. 143 discusses the establishment of the fair value of a liability for an asset retirement obligation, and recommends that a present value technique is often the best available technique to estimate the fair value of the liability?

b. Does Mr. Majoros agree that SFAS No. 143 does not discuss determining the fair value of ongoing expenses using a present value technique?

c. Does Mr. Majoros agree that in accrual accounting, there are significant differences between liability accounts and expense accounts?

d. On page 22 of 26, Mr. Majoros states, "The Commission may choose to use something other than the 'credit-adjusted risk-free rate' described in SFAS No. 143 for calculating the present value of the future obligation, but the underlying principle of accrual accounting remains."

(1) Does Mr. Majoros agree that, under the concept of accrual accounting, future obligations are considered liabilities, not ongoing expenses?

(2) If the Commission is to be consistent with GAAP, upon what basis could the Commission choose to use something other than the credit-adjusted risk-free rate as described in SFAS No. 143?

(3) Provide the credit-adjusted risk-free rate for KU as of December 31, 2006. Include all supporting workpapers, calculations, and assumptions.

RESPONSE:

a. Yes.

b. Yes.

c. Yes.

d. (1) The definition of a liability is lengthy and complex. Mr. Majoros cannot answer the question without more information.

(2) Yes.

(3) KU provided its credit-adjusted risk-free rate in response to AG 1-90. For SFAS No. 143 purposes the rate was 6.61%. For FIN 47 purposes the Company used 5.837%. Mr. Majoros has not made his own calculation of the credit-adjusted risk-free rate for December 31, 2006.

Attorney General's Responses to
Commission Staff's First Data Requests
Case No. 2007-00565

WITNESS RESPONSIBLE:
Michael J. Majoros

Question 5. Refer to the Majoros Testimony, page 23 of 26. Mr. Majoros states that the treatment of costs of removal proposed by Mr. Spanos is not required under the Federal Energy Regulatory Commission's Uniform System of Accounts ("FERC USoA"). Are there any provisions of the FERC USoA that require the use of the present value approach proposed by Mr. Majoros? If yes, provide specific citations to the applicable provisions of the FERC USoA.

RESPONSE:

Yes. The FERC USoA requires legal asset retirement obligations to be stated at their "fair value." See Part 35, General Instruction 25.A.

Attorney General's Responses to
Commission Staff's First Data Requests
Case No. 2007-00565

WITNESS RESPONSIBLE:
Michael J. Majoros

Question 6. Refer to the Majoros Testimony, pages 24 and 25 of 26, and Exhibit MJM-2, pages 10 through 18 of 18.

a. Explain in detail why using the Handy-Whitman Index for the South Atlantic Region is the appropriate way to measure inflation, as opposed to using other indices like the Consumer Price Index – Urban.
b. Explain in detail why it is appropriate to use the "Handy-Whitman indications" to discount Mr. Spanos' cost of removal proposals.
c. Explain in detail why, if Mr. Majoros is proposing to state the costs of removal at a present value, he has used a factor based on inflation rather than the credit-adjusted risk-free rate prescribed in SFAS No. 143.
d. Provide all supporting workpapers, calculations, and assumptions utilized to determine the values shown in Exhibit MJM-3, pages 8 through 14 of 14, for columns 3, 4, 5, and 10.

RESPONSE:

a. In Mr. Majoros's opinion, other indices may be appropriate. Mr. Majoros selected Handy-Whitman in an attempt to avoid controversy.

b. The Handy-Whitman index is specific to additions to the accounts involved and since cost of removal is typically a function of plant additions, Handy-Whitman is appropriate.

c. Again, Mr. Majoros was attempting to avoid controversy and also because he is not proposing to capitalize and accrete the future costs.

d. See attached Excel file. The Handy-Whitman indices found in columns 3 and 4 can be found in The Handy-Whitman Index of Public Utility Construction Costs, a copyrighted publication which is available from Whitman, Requardt & Associates, LLP. The indices used in column 3 correspond to the year shown in column 2.

KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006
SNAVELY KING RECOMMENDED RATES

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	ALG COMPOSITE REMAINING LIFE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)=(6)/(7)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(4)
	DEPRECIABLE PLANT								
	STEAM PRODUCTION PLANT								
311.00	STRUCTURES AND IMPROVEMENTS								
	TYRONE UNIT 3	100-S1.5	0.00	5,447,348	5,719,715	(272,367)	-	-	-
	TYRONE UNITS 1 & 2	100-S1.5	0.00	594,089	623,794	(29,705)	-	-	-
	GREEN RIVER UNIT 3	100-S1.5	0.00	2,818,747	2,959,685	(140,938)	-	-	-
	GREEN RIVER UNIT 4	100-S1.5	0.00	4,475,384	4,699,153	(223,769)	-	-	-
	GREEN RIVER UNITS 1 & 2	100-S1.5	0.00	2,596,589	2,726,419	(129,830)	-	-	-
	E W BROWN STEAM UNIT 1	100-S1.5	(2.75)	4,294,489	4,007,644	404,743	19.4	20,863	0.49
	E W BROWN STEAM UNIT 2	100-S1.5	(2.74)	1,542,704	1,595,211	(10,237)	19.5	(525)	(0.03)
	E W BROWN STEAM UNIT 3	100-S1.5	(2.76)	12,466,775	11,779,068	1,031,790	19.3	53,461	0.43
	GHENT UNIT 1 SCRUBBER	100-S1.5	(2.75)	24,298,756	13,016,631	11,950,341	19.4	615,997	2.54
	GHENT UNIT 1	100-S1.5	(2.77)	17,160,534	16,736,391	899,490	19.2	46,848	0.27
	GHENT UNIT 2	100-S1.5	(2.70)	16,175,820	15,355,831	1,256,736	20.0	62,837	0.39
	GHENT UNIT 3	100-S1.5	(2.07)	43,264,065	30,770,444	13,389,188	28.6	468,153	1.08
	GHENT UNIT 4	100-S1.5	(2.06)	22,674,769	14,633,236	8,508,633	28.7	296,468	1.31
	SYSTEM LABORATORY	100-S1.5	(2.06)	805,717	488,697	333,618	28.8	11,584	1.44
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS			158,615,766	125,112,119	36,967,692		1,575,686	0.99
312.00	BOILER PLANT EQUIPMENT								
	TYRONE UNIT 3	65-R2	(14.45)	12,078,003	9,052,070	4,771,204	11.3	422,230	3.50
	TYRONE UNITS 1 & 2	65-R2	(14.53)	3,531,623	4,193,561	(148,793)	11.1	(13,405)	(0.38)
	GREEN RIVER UNIT 3	65-R2	(14.45)	11,195,262	9,565,842	3,247,135	11.3	287,357	2.57
	GREEN RIVER UNIT 4	65-R2	(14.45)	23,652,945	17,191,266	9,879,529	11.3	874,295	3.70
	GREEN RIVER UNITS 1 & 2	65-R2	(14.49)	399,431	382,655	74,654	11.2	6,666	1.67
	E W BROWN STEAM UNIT 1	65-R2	(11.68)	35,546,187	22,971,136	16,726,846	18.7	894,484	2.52
	E W BROWN STEAM UNIT 2	65-R2	(11.68)	29,161,950	18,640,534	13,927,532	18.7	744,788	2.55
	E W BROWN STEAM UNIT 3	65-R2	(11.71)	79,655,481	54,260,794	34,722,343	18.6	1,866,793	2.34
	PINEVILL UNIT 3	65-R2	(20.00)	279,751	335,702	(0)	-	-	-
	GHENT UNIT 1 SCRUBBER	65-R2	(11.61)	86,520,258	40,651,742	55,913,518	18.9	2,958,387	3.42
	GHENT UNIT 1	65-R2	(11.64)	162,626,761	77,653,906	103,902,610	18.8	5,526,735	3.40
	GHENT UNIT 2	65-R2	(11.48)	89,742,087	67,526,984	32,517,495	19.3	1,684,844	1.88
	GHENT UNIT 3	65-R2	(9.12)	244,747,430	118,161,545	148,906,851	27.3	5,454,463	2.23
	GHENT UNIT 4	65-R2	(9.06)	247,916,189	107,189,341	163,188,055	27.5	5,934,111	2.39
	GHENT LOCOMOTIVES - RAIL CARS	25-R2	13.96	7,647,232	3,735,435	2,844,243	12.5	227,539	2.98
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT			1,034,700,591	551,512,513	590,473,222		26,869,287	2.60

KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006
SNAVELY KING RECOMMENDED RATES

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	ALG COMPOSITE REMAINING LIFE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)=(6)/(7)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(4)
314.00	TURBOGENERATOR UNITS								
	TYRONE UNIT 3	55-R2.5 *	(10.60)	4,154,427	3,150,207	1,444,569	11.4	126,718	3.05
	TYRONE UNITS 1 & 2	55-R2.5 *	(15.00)	1,592,029	1,830,833	0	-	-	-
	GREEN RIVER UNIT 3	55-R2.5 *	(10.60)	4,214,808	3,456,160	1,205,417	11.4	105,738	2.51
	GREEN RIVER UNIT 4	55-R2.5 *	(10.60)	10,005,417	7,204,057	3,861,934	11.4	338,766	3.39
	E W BROWN STEAM UNIT 1	55-R2.5 *	(8.83)	4,997,832	4,768,484	670,657	17.4	38,544	0.77
	E W BROWN STEAM UNIT 2	55-R2.5 *	(8.52)	10,874,094	6,624,591	5,175,976	18.6	278,278	2.56
	E W BROWN STEAM UNIT 3	55-R2.5 *	(8.49)	27,652,379	15,467,528	14,532,538	18.7	777,141	2.81
	PINEVILL UNIT 3	55-R2.5 *	(15.00)	6	7	(0)	-	-	-
	GHENT UNIT 1	55-R2.5 *	(8.65)	25,577,292	19,103,945	8,685,783	18.1	479,878	1.88
	GHENT UNIT 2	55-R2.5 *	(8.46)	29,546,661	22,424,968	9,621,340	18.8	511,773	1.73
	GHENT UNIT 3	55-R2.5 *	(6.88)	39,424,928	24,916,555	17,220,808	25.6	672,688	1.71
	GHENT UNIT 4	55-R2.5 *	(6.76)	51,736,214	29,734,684	25,498,898	26.2	973,240	1.88
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS			209,776,086	138,682,019	87,917,941		4,302,765	2.05
315.00	ACCESSORY ELECTRIC EQUIPMENT								
	TYRONE UNIT 3	70-S3 *	(5.00)	570,737	599,274	(0)	-	-	-
	TYRONE UNITS 1 & 2	70-S3 *	(5.00)	828,017	869,418	(0)	-	-	-
	GREEN RIVER UNIT 3	70-S3 *	(5.00)	741,257	778,320	(0)	-	-	-
	GREEN RIVER UNIT 4	70-S3 *	(2.98)	1,145,214	1,010,620	168,722	11.5	14,671	1.28
	E W BROWN STEAM UNIT 1	70-S3 *	(2.08)	3,329,622	2,136,619	1,262,259	19.5	64,731	1.94
	E W BROWN STEAM UNIT 2	70-S3 *	(2.08)	997,856	954,378	64,233	19.5	3,294	0.33
	E W BROWN STEAM UNIT 3	70-S3 *	(2.09)	5,145,132	4,865,606	387,059	19.4	19,952	0.39
	PINEVILL UNIT 3	70-S3 *	(5.00)	4,091	4,296	(0)	-	-	-
	GHENT UNIT 1 SCRUBBER	70-S3 *	(2.08)	3,016,764	1,580,263	1,499,270	19.5	76,886	2.55
	GHENT UNIT 1	70-S3 *	(2.11)	7,641,005	7,214,612	587,618	19.2	30,605	0.40
	GHENT UNIT 2	70-S3 *	(2.04)	10,785,959	10,038,015	967,978	19.9	48,642	0.45
	GHENT UNIT 3	70-S3 *	(1.43)	25,961,222	19,793,702	6,538,765	27.8	235,207	0.91
	GHENT UNIT 4	70-S3 *	(1.40)	21,911,934	15,446,906	6,771,796	28.3	239,286	1.09
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT			82,078,830	65,292,029	18,247,699		733,275	0.89
316.00	MISCELLANEOUS PLANT EQUIPMENT								
	TYRONE UNIT 3	70-R1.5 *	0.00	508,751	329,761	178,990	11.3	15,840	3.11
	TYRONE UNITS 1 & 2	70-R1.5 *	0.00	59,096	59,096	0	-	-	-
	GREEN RIVER UNIT 3	70-R1.5 *	0.00	153,390	84,649	68,741	11.3	6,083	3.97
	GREEN RIVER UNIT 4	70-R1.5 *	0.00	2,096,052	1,455,549	640,503	11.3	56,682	2.70
	GREEN RIVER UNITS 1 & 2	70-R1.5 *	0.00	84,748	84,748	(0)	-	-	-
	E W BROWN STEAM UNIT 1	70-R1.5 *	0.00	424,041	243,531	180,510	18.8	9,602	2.26
	E W BROWN STEAM UNIT 2	70-R1.5 *	0.00	85,648	74,409	11,239	18.5	608	0.71
	E W BROWN STEAM UNIT 3	70-R1.5 *	0.00	4,233,636	2,389,102	1,844,534	18.7	98,638	2.33
	PINEVILL UNIT 3	70-R1.5 *	0.00	56,611	56,611	-	-	-	-
	GHENT UNIT 1 SCRUBBER	70-R1.5 *	0.00	985,410	454,155	531,255	18.8	28,258	2.87
	GHENT UNIT 1	70-R1.5 *	0.00	1,756,977	1,308,821	448,156	18.5	24,225	1.38
	GHENT UNIT 2	70-R1.5 *	0.00	1,493,093	1,187,409	305,684	19.2	15,921	1.07
	GHENT UNIT 3	70-R1.5 *	0.00	3,118,292	1,956,104	1,162,188	26.7	43,528	1.40
	GHENT UNIT 4	70-R1.5 *	0.00	6,052,103	2,685,232	3,366,871	27.4	122,879	2.03
	SYSTEM LABORATORY	70-R1.5 *	0.00	2,198,264	525,026	1,673,238	27.8	60,188	2.74
	TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT			23,306,111	12,894,203	10,411,908		482,451	2.07
	TOTAL STEAM PRODUCTION PLANT			1,508,477,405	893,492,883	744,018,462		33,963,463	

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	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	ALG COMPOSITE REMAINING LIFE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)=(6)/(7)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(4)
	HYDROELECTRIC PRODUCTION PLANT								
330.10	LAND AND LAND RIGHTS DIX DAM	100-R4	0.00	879,311	905,781	(26,470)	-	-	-
	TOTAL ACCOUNT 330.1 - LAND RIGHTS			879,311	905,781	(26,470)		-	-
331.00	STRUCTURES AND IMPROVEMENTS DIX DAM	90-S2.5	(2.08)	453,195	316,800	145,821	27.3	5,341	1.18
	TOTAL ACCOUNT 331 - STRUCTURES AND IMPROVEMENTS			453,195	316,800	145,821		5,341	1.18
332.00	RESERVOIRS, DAMS & WATERWAY DIX DAM	100-S2.5	0.00	7,954,452	6,384,461	1,569,991	27.6	56,884	0.72
	TOTAL ACCOUNT 332 - RESERVOIRS, DAMS & WATERWAYS			7,954,452	6,384,461	1,569,991		56,884	0.72
333.00	WATER WHEELS, TURBINES & GENERATORS DIX DAM	80-R3	(6.45)	420,537	394,072	53,589	24.7	2,170	0.52
	TOTAL ACCOUNT 333 - WATER WHEELS, TURBINES & GENERATORS			420,537	394,072	53,589		2,170	0.52
334.00	ACCESSORY ELECTRIC EQUIPMENT DIX DAM	40-L2.5	0.00	85,383	76,888	8,495	12.0	708	0.83
	TOTAL ACCOUNT 334 - ACCESSORY ELECTRIC EQUIPMENT			85,383	76,888	8,495		708	0.83
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT DIX DAM	35-L1	0.00	101,513	39,455	62,058	17.2	3,608	3.55
	TOTAL ACCOUNT 335 - MISCELLANEOUS POWER PLANT EQUIPMENT			101,513	39,455	62,058		3,608	3.55
336.00	ROADS, RAILROADS, & BRIDGES DIX DAM	55-R4	0.00	46,976	48,390	(1,414)	-	-	-
	TOTAL ACCOUNT 336 - ROADS, RAILROADS & BRIDGES			46,976	48,390	(1,414)		-	-
	TOTAL HYDROELECTRIC PRODUCTION PLANT			9,941,367	8,165,847	1,812,071		68,711	

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	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	ALG COMPOSITE REMAINING LIFE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)=(6)/(7)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(4)
	OTHER PRODUCTION PLANT								
340.10	LAND RIGHTS								
	E W BROWN CT UNIT 9 GAS PIPE	30-R0.5 *	0.00	176,409	71,698	104,711	20.0	5,236	2.97
	TOTAL ACCOUNT 340.1 - LAND RIGHTS			176,409	71,698	104,711		5,236	2.97
341.00	STRUCTURES AND IMPROVEMENTS								
	PADDY'S RUN GENERATOR 13	40-R2.5 *	0.00	1,910,328	374,109	1,536,219	26.5	57,971	3.03
	E W BROWN CT UNIT 5	40-R2.5 *	0.00	775,082	149,820	625,262	26.5	23,595	3.04
	E W BROWN CT UNIT 6	40-R2.5 *	0.00	192,814	36,791	156,023	26.5	5,888	3.05
	E W BROWN CT UNIT 7	40-R2.5 *	0.00	544,966	126,941	418,025	26.2	15,955	2.93
	E W BROWN CT UNIT 8	40-R2.5 *	0.00	2,012,655	717,642	1,295,013	24.7	52,430	2.61
	E W BROWN CT UNIT 9	40-R2.5 *	0.00	4,641,055	1,654,146	2,986,909	24.7	120,927	2.61
	E W BROWN CT UNIT 10	40-R2.5 *	0.00	1,865,719	662,603	1,203,116	24.7	48,709	2.61
	E W BROWN CT UNIT 11	40-R2.5 *	0.00	1,858,754	579,307	1,279,447	25.3	50,571	2.72
	TRIMBLE COUNTY CT UNIT 5	40-R2.5 *	0.00	3,740,231	592,365	3,147,866	26.8	117,458	3.14
	TRIMBLE COUNTY CT UNIT 6	40-R2.5 *	0.00	3,588,684	588,760	2,999,924	26.8	111,937	3.12
	TRIMBLE COUNTY CT UNIT 7	40-R2.5 *	0.00	3,559,155	343,098	3,216,057	27.2	118,237	3.32
	TRIMBLE COUNTY CT UNIT 8	40-R2.5 *	0.00	3,548,852	342,104	3,206,748	27.2	117,895	3.32
	TRIMBLE COUNTY CT UNIT 9	40-R2.5 *	0.00	3,655,976	352,432	3,303,544	27.2	121,454	3.32
	TRIMBLE COUNTY CT UNIT 10	40-R2.5 *	0.00	3,653,030	352,147	3,300,883	27.2	121,356	3.32
	HAEFLING UNITS 1, 2 & 3	40-R2.5 *	0.00	434,853	337,009	97,844	3.5	27,955	6.43
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS			35,982,154	7,209,274	28,772,880		1,112,338	3.09
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES								
	PADDY'S RUN GENERATOR 13	45-R2.5 *	(2.24)	1,995,102	402,765	1,637,027	27.0	59,964	3.01
	E W BROWN CT UNIT 5	45-R2.5 *	(2.24)	727,929	147,963	596,272	27.0	21,841	3.00
	E W BROWN CT UNIT 6	45-R2.5 *	(2.26)	146,515	38,566	111,260	26.9	4,136	2.82
	E W BROWN CT UNIT 7	45-R2.5 *	(2.26)	145,745	38,363	110,676	26.9	4,114	2.82
	E W BROWN CT UNIT 8	45-R2.5 *	(2.32)	19,613	7,132	12,936	26.1	496	2.53
	E W BROWN CT UNIT 9	45-R2.5 *	(2.32)	1,932,186	694,487	1,282,526	26.1	49,139	2.54
	E W BROWN CT UNIT 10	45-R2.5 *	(2.32)	31,737	11,607	20,866	26.0	803	2.53
	E W BROWN CT UNIT 11	45-R2.5 *	(2.30)	52,430	17,145	36,491	26.4	1,382	2.64
	E W BROWN CT UNIT 9 GAS PIPE	45-R2.5 *	(2.34)	8,106,132	3,135,265	5,160,550	25.8	200,021	2.47
	TRIMBLE COUNTY CT UNIT 5	45-R2.5 *	(2.23)	239,585	40,738	204,189	27.4	7,452	3.11
	TRIMBLE COUNTY CT UNIT 6	45-R2.5 *	(2.23)	239,246	40,695	203,886	27.4	7,441	3.11
	TRIMBLE COUNTY CT PIPELINE	45-R2.5 *	(2.22)	4,850,114	786,421	4,171,366	27.5	151,686	3.13
	TRIMBLE COUNTY CT UNIT 7	45-R2.5 *	(2.21)	578,059	57,997	532,837	27.7	19,236	3.33
	TRIMBLE COUNTY CT UNIT 8	45-R2.5 *	(2.21)	576,386	57,829	531,295	27.7	19,180	3.33
	TRIMBLE COUNTY CT UNIT 9	45-R2.5 *	(2.21)	593,786	59,574	547,335	27.7	19,759	3.33
	TRIMBLE COUNTY CT UNIT 10	45-R2.5 *	(2.21)	593,307	59,526	546,893	27.7	19,743	3.33
	HAEFLING UNITS 1, 2 & 3	45-R2.5 *	0.00	181,132	190,189	(9,057)	-	-	-
	TOTAL ACCOUNT 342 - FUEL HOLDERS, PRODUCERS AND ACCESSORIES			21,009,005	5,786,262	15,697,349		586,395	2.79

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	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ALG COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
343.00	PRIME MOVERS								
	PADDY'S RUN GENERATOR 13	35-R1	(2.63)	17,420,149	3,208,506	14,669,792	23.9	613,799	3.52
	E W BROWN CT UNIT 5	35-R1	(2.63)	13,164,181	2,305,155	11,205,244	24.0	466,885	3.55
	E W BROWN CT UNIT 6	35-R1	(2.65)	30,399,242	6,414,963	24,789,859	23.6	1,050,418	3.46
	E W BROWN CT UNIT 7	35-R1	(2.65)	30,001,198	6,051,587	24,744,643	23.7	1,044,078	3.48
	E W BROWN CT UNIT 8	35-R1	(2.71)	20,074,864	5,994,874	14,624,019	22.8	641,404	3.20
	E W BROWN CT UNIT 9	35-R1	(2.73)	21,502,645	6,950,677	15,138,991	22.5	672,844	3.13
	E W BROWN CT UNIT 10	35-R1	(2.73)	19,670,647	6,157,363	14,050,293	22.6	621,694	3.16
	E W BROWN CT UNIT 11	35-R1	(2.68)	34,239,853	8,782,372	26,375,109	23.2	1,136,858	3.32
	TRIMBLE COUNTY CT UNIT 5	35-R1	(2.62)	30,530,610	4,681,480	26,649,032	24.1	1,105,769	3.62
	TRIMBLE COUNTY CT UNIT 6	35-R1	(2.62)	30,442,270	4,692,426	26,557,431	24.1	1,101,968	3.62
	TRIMBLE COUNTY CT UNIT 7	35-R1	(2.59)	22,773,833	2,046,994	21,316,682	24.5	870,069	3.82
	TRIMBLE COUNTY CT UNIT 8	35-R1	(2.59)	22,568,266	2,036,130	21,116,675	24.5	861,905	3.82
	TRIMBLE COUNTY CT UNIT 9	35-R1	(2.59)	22,401,685	2,020,924	20,960,965	24.5	855,550	3.82
	TRIMBLE COUNTY CT UNIT 10	35-R1	(2.59)	22,378,126	2,018,755	20,938,966	24.5	854,652	3.82
	TOTAL ACCOUNT 343 - PRIME MOVERS			337,567,593	63,352,206	283,137,702		11,897,893	3.52
344.00	GENERATORS								
	PADDY'S RUN GENERATOR 13	55-S3	(2.43)	5,165,636	1,003,503	4,308,144	29.1	148,046	2.85
	E W BROWN CT UNIT 5	55-S3	(2.43)	2,831,528	548,012	2,352,322	29.1	80,836	2.85
	E W BROWN CT UNIT 6	55-S3	(2.44)	3,712,349	930,433	2,872,497	29.0	99,052	2.67
	E W BROWN CT UNIT 7	55-S3	(2.44)	3,722,768	931,357	2,882,267	29.0	99,389	2.67
	E W BROWN CT UNIT 8	55-S3	(2.47)	4,953,961	1,736,820	3,339,504	28.5	117,176	2.37
	E W BROWN CT UNIT 9	55-S3	(2.48)	5,452,041	2,153,184	3,434,068	28.3	121,345	2.23
	E W BROWN CT UNIT 10	55-S3	(2.47)	4,944,693	1,733,570	3,333,257	28.5	116,956	2.37
	E W BROWN CT UNIT 11	55-S3	(2.46)	5,187,040	1,694,228	3,620,413	28.6	126,588	2.44
	TRIMBLE COUNTY CT UNIT 5	55-S3	(2.42)	3,763,275	610,505	3,243,841	29.2	111,090	2.95
	TRIMBLE COUNTY CT UNIT 6	55-S3	(2.42)	3,757,947	609,864	3,239,025	29.2	110,926	2.95
	TRIMBLE COUNTY CT UNIT 7	55-S3	(2.42)	2,950,282	282,683	2,738,996	29.3	93,481	3.17
	TRIMBLE COUNTY CT UNIT 8	55-S3	(2.42)	2,937,930	281,499	2,727,529	29.3	93,090	3.17
	TRIMBLE COUNTY CT UNIT 9	55-S3	(2.42)	2,957,520	283,376	2,745,716	29.3	93,710	3.17
	TRIMBLE COUNTY CT UNIT 10	55-S3	(2.42)	2,954,149	283,053	2,742,586	29.3	93,604	3.17
	HAEFLING UNITS 1, 2 & 3	55-S3	0.00	4,023,003	4,224,153	(201,150)	-	-	-
	TOTAL ACCOUNT 344 - GENERATORS			59,334,142	17,306,240	43,379,015		1,505,288	2.54
345.00	ACCESSORY ELECTRIC EQUIPMENT								
	PADDY'S RUN GENERATOR 13	45-R3	0.00	2,456,320	488,379	1,967,941	27.8	70,789	2.88
	E W BROWN CT UNIT 5	45-R3	0.00	1,332,167	264,860	1,067,307	27.8	38,392	2.88
	E W BROWN CT UNIT 6	45-R3	0.00	1,354,817	349,592	1,005,225	27.4	36,687	2.71
	E W BROWN CT UNIT 7	45-R3	0.00	1,347,700	347,755	999,945	27.4	36,494	2.71
	E W BROWN CT UNIT 8	45-R3	0.00	1,797,054	650,416	1,146,638	26.4	43,433	2.42
	E W BROWN CT UNIT 9	45-R3	0.00	3,226,186	1,256,027	1,970,159	26.4	74,627	2.31
	E W BROWN CT UNIT 10	45-R3	0.00	1,804,419	637,098	1,167,321	26.5	44,050	2.44
	E W BROWN CT UNIT 11	45-R3	0.00	916,326	308,077	608,249	26.7	22,781	2.49
	TRIMBLE COUNTY CT UNIT 5	45-R3	0.00	1,677,092	279,094	1,397,998	27.9	50,107	2.99
	TRIMBLE COUNTY CT UNIT 6	45-R3	0.00	1,674,719	278,801	1,395,918	27.9	50,033	2.99
	TRIMBLE COUNTY CT UNIT 7	45-R3	0.00	3,146,235	308,469	2,837,766	28.2	100,630	3.20
	TRIMBLE COUNTY CT UNIT 8	45-R3	0.00	3,137,127	307,577	2,829,550	28.2	100,339	3.20
	TRIMBLE COUNTY CT UNIT 9	45-R3	0.00	3,231,827	316,862	2,914,965	28.2	103,368	3.20
	TRIMBLE COUNTY CT UNIT 10	45-R3	0.00	3,229,223	316,607	2,912,616	28.2	103,284	3.20
	HAEFLING UNITS 1, 2 & 3	45-R3	0.00	621,207	621,207	-	-	-	-
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT			30,952,420	6,730,821	24,221,599		875,015	2.83

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	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	ALG COMPOSITE REMAINING LIFE	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(6)/(7)	(9)=(8)/(4)
346.00	MISCELLANEOUS PLANT EQUIPMENT								
	PADDY'S RUN GENERATOR 13	35-R2	* 0.00	1,089,549	224,313	865,236	24.8	34,889	3.20
	E W BROWN CT UNIT 5	35-R2	* 0.00	2,108,910	435,769	1,673,141	24.8	67,465	3.20
	E W BROWN CT UNIT 6	35-R2	* 0.00	48,959	7,842	41,117	25.2	1,632	3.33
	E W BROWN CT UNIT 7	35-R2	* 0.00	35,648	6,968	28,680	24.9	1,152	3.23
	E W BROWN CT UNIT 8	35-R2	* 0.00	230,069	86,699	143,370	22.5	6,372	2.77
	E W BROWN CT UNIT 9	35-R2	* 0.00	760,256	287,309	472,947	22.5	21,020	2.76
	E W BROWN CT UNIT 10	35-R2	* 0.00	274,391	94,590	179,801	23.0	7,817	2.85
	E W BROWN CT UNIT 11	35-R2	* 0.00	548,588	111,544	437,044	24.7	17,694	3.23
	TRIMBLE COUNTY CT UNIT 5	35-R2	* 0.00	15,274	324	14,950	26.3	568	3.72
	TRIMBLE COUNTY CT UNIT 7	35-R2	* 0.00	8,889	899	7,990	25.7	311	3.50
	TRIMBLE COUNTY CT UNIT 8	35-R2	* 0.00	8,861	895	7,966	25.7	310	3.50
	TRIMBLE COUNTY CT UNIT 9	35-R2	* 0.00	9,114	921	8,193	25.7	319	3.50
	TRIMBLE COUNTY CT UNIT 10	35-R2	* 0.00	9,106	921	8,185	25.7	318	3.50
	HAEFLING UNITS 1, 2 & 3	35-R2	* 0.00	35,805	35,805	-	-	-	-
	TOTAL ACCOUNT 346 - MISCELLANEOUS PLANT EQUIPMENT			5,183,418	1,294,799	3,888,619		159,867	3.08
	TOTAL OTHER PRODUCTION PLANT			490,205,140	101,751,300	399,201,876		16,142,032	
	TRANSMISSION PLANT								
350.10	LAND AND LAND RIGHTS	60-R3	0.00	23,341,455	15,050,587	8,290,868	36.1	229,664	0.98
352.10	STRUCTURES & IMPROVEMENTS-NON SYS CONTROL/COM	65-S2.5	(5.08)	6,979,653	3,813,782	3,520,438	45.7	77,034	1.10
352.20	STRUCTURES & IMPROVEMENTS - SYS CONTROL/COM	60-R3	(6.50)	1,167,763	813,907	429,782	38.6	11,134	0.95
353.10	STATION EQUIPMENT - NON SYS CONTROL/COM	60-R2	(3.72)	173,142,341	59,471,929	120,111,307	43.2	2,780,354	1.61
353.20	STATION EQUIPMENT - SYS CONTROL/COM	30-R2.5	(7.68)	14,749,281	16,016,356	(134,331)	24.6	(5,461)	(0.04)
354.00	TOWERS AND FIXTURES	70-R4	(6.54)	63,308,079	42,955,413	24,493,015	47.4	516,730	0.82
355.00	POLES AND FIXTURES	50-R2	(16.88)	91,302,831	64,368,697	42,345,852	39.3	1,077,503	1.18
356.00	OVERHEAD CONDUCTORS AND DEVICES	60-R3	(12.98)	129,755,652	100,060,047	46,537,889	40.7	1,143,437	0.88
357.00	UNDERGROUND CONDUIT	40-L2.5	0.00	448,760	134,595	314,165	26.9	11,679	2.60
358.00	UNDERGROUND CONDUCTORS AND DEVICES	35-R3	0.00	1,114,762	802,730	312,032	22.2	14,055	1.26
	TOTAL TRANSMISSION PLANT			505,310,598	303,488,243	246,221,017		5,856,130	
	DISTRIBUTION PLANT								
360.10	LAND AND LAND RIGHTS	65-R4	0.00	1,496,173	1,022,041	474,132	48.6	9,756	0.65
361.00	STRUCTURES AND IMPROVEMENTS	60-R2.5	(2.20)	4,457,894	1,509,377	3,046,590	46.0	66,230	1.49
362.00	STATION EQUIPMENT	52-R2	(3.69)	100,792,638	30,916,216	73,595,670	37.0	1,989,072	1.97
364.00	POLES, TOWERS, AND FIXTURES	48-S0	(13.69)	193,793,679	108,962,347	111,361,686	38.5	2,892,511	1.49
365.00	OVERHEAD CONDUCTORS AND DEVICES	48-R2	(23.04)	160,861,758	105,672,071	116,860,236	34.4	3,397,100	1.88
366.00	UNDERGROUND CONDUIT	55-S4	0.00	1,728,496	702,456	1,026,040	30.7	33,421	1.93
367.00	UNDERGROUND CONDUCTORS AND DEVICES	44-S0.5	(1.26)	70,302,254	18,432,179	52,755,884	37.6	1,403,082	2.00
368.00	LINE TRANSFORMERS	40-R2	(8.41)	238,763,304	85,924,490	172,940,490	27.1	6,381,568	2.67
369.00	SERVICES	43-R1.5	(9.76)	83,111,706	53,033,588	38,189,821	33.3	1,146,841	1.38
370.00	METERS	40-R1.5	0.00	64,856,075	26,969,792	37,886,283	27.5	1,377,683	2.12
371.00	INSTALLATIONS ON CUSTOMER PREMISES	20-R0.5	(6.30)	18,276,456	14,013,191	5,414,684	14.0	386,763	2.12
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	33-R1	(1.63)	53,640,293	23,870,883	30,643,747	26.4	1,160,748	2.16
	TOTAL DISTRIBUTION PLANT			1,012,100,728	471,028,631	644,195,263		20,244,776	

KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006
SNAVELY KING RECOMMENDED RATES

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	ALG COMPOSITE REMAINING LIFE (7)	CALCULATED ANNUAL ACCRUAL AMOUNT (8)=(6)/(7)	CALCULATED ANNUAL ACCRUAL RATE (9)=(8)/(4)
	GENERAL PLANT								
390.10	STRUCTURES AND IMPROVEMENTS-TO OWNED PROPERTY	60-S0	(1.14)	32,199,743	8,632,707	23,934,114	47.1	508,155	1.58
390.20	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	30-R1	(2.47)	531,973	372,366	172,747	22.4	7,712	1.45
391.10	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0.00	6,646,812	2,868,652	3,778,160	13.6	277,806	4.18
391.20	NON PC COMPUTER EQUIPMENT	5-SQ	0.00	11,291,985	7,567,325	3,724,660	3.3	1,128,685	10.00
391.30	CASH PROCESSING EQUIPMENT	10-SQ	0.00	817,575	532,363	285,212	6.3	45,272	5.54
391.40	PERSONAL COMPUTER EQUIPMENT	4-SQ	0.00	1,932,339	779,327	1,153,012	2.8	411,790	21.31
393.00	STORES EQUIPMENT	25-SQ	0.00	738,677	289,571	449,106	11.6	38,716	5.24
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0.00	5,333,517	1,597,795	3,735,722	14.7	254,131	4.76
395.00	LABORATORY EQUIPMENT	15-SQ	0.00	3,202,202	1,586,334	1,615,868	1.8	897,704	28.03
396.00	POWER OPERATED EQUIPMENT	17-R5	0.00	270,942	99,450	171,492	9.9	17,322	6.39
397.10	COMMUNICATION EQUIPMENT - CARRIER	15-SQ	0.00	7,578,906	1,666,583	5,912,323	10.9	542,415	7.16
397.20	COMMUNICATION EQUIPMENT - REMOTE CONTROL	15-SQ	0.00	3,913,060	1,567,195	2,345,865	7.5	312,782	7.99
397.30	COMMUNICATION EQUIPMENT - MOBILE	15-SQ	0.00	4,659,773	1,806,815	2,852,958	8.4	339,638	7.29
398.00	MISCELLANEOUS EQUIPMENT	10-SQ	0.00	394,809	252,657	142,152	1.8	78,973	20.00
	TOTAL GENERAL PLANT			79,512,313	29,619,140	50,273,390		4,861,101	
	TOTAL DEPRECIABLE PLANT			3,605,547,551	1,807,546,044	2,085,722,079		81,136,214	
	KU PROPOSED							111,765,099	
	DIFFERENCE							(30,628,885)	

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE

Sources:
Cols. (1), (2), (4), (5) and (7) from response to AG-1-27.
Col. (3) from pages 8-14.
KU Proposed from Application Exhibit 2.

KENTUCKY UTILITIES
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2006
CALCULATION OF PRESENT VALUE OF SPANOS FUTURE NET SALVAGE PROPOSALS

	ACCOUNT	1ST YR IN SPANOS NS STUDY	START YEAR COST INDEX	Jan 2007 COST INDEX	COMPOUND GROWTH RATE	ORIGINAL COST	ALG COMPOSITE REMAINING LIFE	SPANOS FUTURE NET SALVAGE %	SPANOS FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(6)*(8)	(10)	(11)=(10)/(6)
	DEPRECIABLE PLANT										
	STEAM PRODUCTION PLANT		19								
311.00	STRUCTURES AND IMPROVEMENTS										
	TYRONE UNIT 3	1988	226	406	3.13%	5,447,348	-	(5)			-
	TYRONE UNITS 1 & 2	1988	226	406	3.13%	594,089	-	(5)			-
	GREEN RIVER UNIT 3	1988	226	406	3.13%	2,818,747	-	(5)			-
	GREEN RIVER UNIT 4	1988	226	406	3.13%	4,475,384	-	(5)			-
	GREEN RIVER UNITS 1 & 2	1988	226	406	3.13%	2,596,589	-	(5)			-
	E W BROWN STEAM UNIT 1	1988	226	406	3.13%	4,294,489	19.4	(5)	(214,724)	(118,090)	(2.75)
	E W BROWN STEAM UNIT 2	1988	226	406	3.13%	1,542,704	19.5	(5)	(77,135)	(42,291)	(2.74)
	E W BROWN STEAM UNIT 3	1988	226	406	3.13%	12,466,775	19.3	(5)	(623,339)	(343,869)	(2.76)
	GHENT UNIT 1 SCRUBBER	1988	226	406	3.13%	24,298,756	19.4	(5)	(1,214,938)	(668,167)	(2.75)
	GHENT UNIT 1	1988	226	406	3.13%	17,160,534	19.2	(5)	(858,027)	(474,798)	(2.77)
	GHENT UNIT 2	1988	226	406	3.13%	16,175,820	20.0	(5)	(808,791)	(436,652)	(2.70)
	GHENT UNIT 3	1988	226	406	3.13%	43,264,065	28.6	(5)	(2,163,203)	(895,954)	(2.07)
	GHENT UNIT 4	1988	226	406	3.13%	22,674,769	28.7	(5)	(1,133,738)	(468,126)	(2.06)
	SYSTEM LABORATORY	1988	226	406	3.13%	805,717	28.8	(5)	(40,286)	(16,583)	(2.06)
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS					158,615,786			(7,134,181)	(3,464,530)	
312.00	BOILER PLANT EQUIPMENT										
	TYRONE UNIT 3	1988	293	506	2.92%	12,078,003	11.3	(20)	(2,415,601)	(1,744,928)	(14.45)
	TYRONE UNITS 1 & 2	1988	293	506	2.92%	3,531,623	11.1	(20)	(706,325)	(513,165)	(14.53)
	GREEN RIVER UNIT 3	1988	293	506	2.92%	11,195,262	11.0	(20)	(2,239,052)	(1,617,397)	(14.45)
	GREEN RIVER UNIT 4	1988	293	506	2.92%	23,652,945	11.0	(20)	(4,730,589)	(3,417,179)	(14.45)
	GREEN RIVER UNITS 1 & 2	1988	293	506	2.92%	399,431	11.2	(20)	(79,886)	(57,873)	(14.49)
	E W BROWN STEAM UNIT 1	1988	293	506	2.92%	35,546,187	18.7	(20)	(7,109,237)	(4,150,278)	(11.68)
	E W BROWN STEAM UNIT 2	1988	293	506	2.92%	29,161,950	18.7	(20)	(5,832,390)	(3,404,871)	(11.68)
	E W BROWN STEAM UNIT 3	1988	293	506	2.92%	79,655,481	18.6	(20)	(15,931,096)	(9,327,168)	(11.71)
	PINEVILL UNIT 3	1988	293	506	2.92%	279,751	-	(20)	(55,950)	(55,950)	(20.00)
	GHENT UNIT 1 SCRUBBER	1988	293	506	2.92%	86,520,258	18.9	(20)	(17,304,052)	(10,043,891)	(11.61)
	GHENT UNIT 1	1988	293	506	2.92%	162,626,761	18.8	(20)	(32,525,352)	(18,933,295)	(11.64)
	GHENT UNIT 2	1988	293	506	2.92%	89,742,087	19.3	(20)	(17,948,417)	(10,298,654)	(11.48)
	GHENT UNIT 3	1988	293	506	2.92%	244,747,430	27.0	(20)	(48,949,486)	(22,310,238)	(9.12)
	GHENT UNIT 4	1988	293	506	2.92%	247,916,189	27.5	(20)	(49,583,238)	(22,469,375)	(9.06)
	GHENT LOCOMOTIVES - RAIL CARS	1988	293	506	2.92%	7,647,232	12.5	20	1,529,446	1,067,301	13.96
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT					1,034,700,591			(203,881,225)	(107,276,962)	

KENTUCKY UTILITIES
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CALCULATION OF PRESENT VALUE OF SPANOS FUTURE NET SALVAGE PROPOSALS

	ACCOUNT	1ST YR IN SPANOS NS STUDY	START YEAR COST INDEX	Jan 2007 COST INDEX	COMPOUND GROWTH RATE	ORIGINAL COST	ALG COMPOSITE REMAINING LIFE	SPANOS FUTURE NET SALVAGE %	SPANOS FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(6)*(8)	(10)	(11)=(10)/(6)
314.00	TURBOGENERATOR UNITS										
	TYRONE UNIT 3	1994	326	484	3.09%	4,154,427	11.4	(15)	(623,164)	(440,488)	(10.60)
	TYRONE UNITS 1 & 2	1994	326	484	3.09%	1,592,029	-	(15)	(238,804)	(238,804)	(15.00)
	GREEN RIVER UNIT 3	1994	326	484	3.09%	4,214,808	11.4	(15)	(632,221)	(446,890)	(10.60)
	GREEN RIVER UNIT 4	1994	326	484	3.09%	10,005,417	11.4	(15)	(1,500,813)	(1,060,860)	(10.60)
	E W BROWN STEAM UNIT 1	1994	326	484	3.09%	4,997,832	17.4	(15)	(749,675)	(441,474)	(8.83)
	E W BROWN STEAM UNIT 2	1994	326	484	3.09%	10,874,094	18.6	(15)	(1,631,114)	(926,097)	(8.52)
	E W BROWN STEAM UNIT 3	1994	326	484	3.09%	27,652,379	18.7	(15)	(4,147,857)	(2,347,872)	(8.49)
	PINEVILL UNIT 3	1994	326	484	3.09%	6	-	(15)	(1)	(1)	(15.00)
	GHENT UNIT 1	1994	326	484	3.09%	25,577,292	18.1	(15)	(3,836,594)	(2,211,701)	(8.65)
	GHENT UNIT 2	1994	326	484	3.09%	29,546,661	18.8	(15)	(4,431,999)	(2,501,087)	(8.46)
	GHENT UNIT 3	1994	326	484	3.09%	39,424,928	25.6	(15)	(5,913,739)	(2,713,431)	(6.88)
	GHENT UNIT 4	1994	326	484	3.09%	51,736,214	26.2	(15)	(7,760,432)	(3,498,331)	(6.76)
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS					209,776,088			(31,466,413)	(16,825,036)	
315.00	ACCESSORY ELECTRIC EQUIPMENT										
	TYRONE UNIT 3	1991	297	610	4.60%	570,737	-	(5)	(28,537)	(28,537)	(5.00)
	TYRONE UNITS 1 & 2	1991	297	610	4.60%	828,017	-	(5)	(41,401)	(41,401)	(5.00)
	GREEN RIVER UNIT 3	1991	297	610	4.60%	741,257	-	(5)	(37,063)	(37,063)	(5.00)
	GREEN RIVER UNIT 4	1991	297	610	4.60%	1,145,214	11.5	(5)	(57,261)	(34,138)	(2.98)
	E W BROWN STEAM UNIT 1	1991	297	610	4.60%	3,329,622	19.5	(5)	(166,481)	(69,262)	(2.08)
	E W BROWN STEAM UNIT 2	1991	297	610	4.60%	997,856	19.5	(5)	(49,893)	(20,757)	(2.08)
	E W BROWN STEAM UNIT 3	1991	297	610	4.60%	5,145,132	19.4	(5)	(257,257)	(107,511)	(2.09)
	PINEVILL UNIT 3	1991	297	610	4.60%	4,091	-	(5)	(205)	(205)	(5.00)
	GHENT UNIT 1 SCRUBBER	1991	297	610	4.60%	3,016,784	19.5	(5)	(150,839)	(62,755)	(2.08)
	GHENT UNIT 1	1991	297	610	4.60%	7,641,005	19.2	(5)	(382,050)	(161,106)	(2.11)
	GHENT UNIT 2	1991	297	610	4.60%	10,785,959	19.9	(5)	(539,298)	(220,368)	(2.04)
	GHENT UNIT 3	1991	297	610	4.60%	25,961,222	27.8	(5)	(1,298,061)	(371,804)	(1.43)
	GHENT UNIT 4	1991	297	610	4.60%	21,911,934	28.3	(5)	(1,095,597)	(306,834)	(1.40)
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT					82,078,830			(4,103,942)	(1,461,741)	
316.00	MISCELLANEOUS PLANT EQUIPMENT										
	TYRONE UNIT 3					508,751	11.3	0	-	-	-
	TYRONE UNITS 1 & 2					59,096	-	0	-	-	-
	GREEN RIVER UNIT 3					153,390	11.3	0	-	-	-
	GREEN RIVER UNIT 4					2,096,052	11.3	0	-	-	-
	GREEN RIVER UNITS 1 & 2					84,748	-	0	-	-	-
	E W BROWN STEAM UNIT 1					424,041	18.8	0	-	-	-
	E W BROWN STEAM UNIT 2					85,648	18.5	0	-	-	-
	E W BROWN STEAM UNIT 3					4,233,636	18.7	0	-	-	-
	PINEVILL UNIT 3					56,611	-	0	-	-	-
	GHENT UNIT 1 SCRUBBER					985,410	18.8	0	-	-	-
	GHENT UNIT 1					1,756,977	18.5	0	-	-	-
	GHENT UNIT 2					1,493,093	19.2	0	-	-	-
	GHENT UNIT 3					3,118,202	26.7	0	-	-	-
	GHENT UNIT 4					6,052,103	27.4	0	-	-	-
	SYSTEM LABORATORY					2,198,264	27.8	0	-	-	-
	TOTAL ACCOUNT 316 - MISCELLANEOUS PLANT EQUIPMENT					23,306,111			-	-	
	TOTAL STEAM PRODUCTION PLANT					1,508,477,405			(246,585,761)	(129,028,269)	

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CALCULATION OF PRESENT VALUE OF SPANOS FUTURE NET SALVAGE PROPOSALS

	ACCOUNT	1ST YR IN SPANOS NS STUDY	START YEAR COST INDEX	Jan 2007 COST INDEX	COMPOUND GROWTH RATE	ORIGINAL COST	ALG COMPOSITE REMAINING LIFE	SPANOS FUTURE NET SALVAGE %	SPANOS FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(6)*(8)	(10)	(11)=(10)/(6)
	HYDROELECTRIC PRODUCTION PLANT										
330.10	LAND AND LAND RIGHTS										
	DIX DAM					879,311		0	-	-	-
	TOTAL ACCOUNT 330.1 - LAND RIGHTS					879,311			-	-	
331.00	STRUCTURES AND IMPROVEMENTS										
	DIX DAM	1990	235	406	3.27%	453,195	27.3	(5)	(22,660)	(9,414)	(2.08)
	TOTAL ACCOUNT 331 - STRUCTURES AND IMPROVEMENTS					453,195			(22,660)	(9,414)	
332.00	RESERVOIRS, DAMS & WATERWAY										
	DIX DAM					7,954,452	27.6	0	-	-	-
	TOTAL ACCOUNT 332 - RESERVOIRS, DAMS & WATERWAYS					7,954,452			-	-	
333.00	WATER WHEELS, TURBINES & GENERATORS										
	DIX DAM	1992	325	424	1.79%	420,537	24.7	(10)	(42,054)	(27,132)	(6.45)
	TOTAL ACCOUNT 333 - WATER WHEELS, TURBINES & GENERATORS					420,537			(42,054)	(27,132)	
334.00	ACCESSORY ELECTRIC EQUIPMENT										
	DIX DAM					85,383	12.0	0	-	-	-
	TOTAL ACCOUNT 334 - ACCESSORY ELECTRIC EQUIPMENT					85,383			-	-	
335.00	MISCELLANEOUS POWER PLANT EQUIPMENT										
	DIX DAM					101,513	17.2	0	-	-	-
	TOTAL ACCOUNT 335 - MISCELLANEOUS POWER PLANT EQUIPMENT					101,513			-	-	
336.00	ROADS, RAILROADS, & BRIDGES										
	DIX DAM					46,976	-	0	-	-	-
	TOTAL ACCOUNT 336 - ROADS, RAILROADS & BRIDGES					46,976			-	-	
	TOTAL HYDROELECTRIC PRODUCTION PLANT					9,941,367			(64,713)	(36,546)	

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CALCULATION OF PRESENT VALUE OF SPANOS FUTURE NET SALVAGE PROPOSALS

	ACCOUNT	1ST YR IN SPANOS NS STUDY	START YEAR COST INDEX	Jan 2007 COST INDEX	COMPOUND GROWTH RATE	ORIGINAL COST	ALG COMPOSITE REMAINING LIFE	SPANOS FUTURE NET SALVAGE %	SPANOS FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(6)*(8)	(10)	(11)=(10)/(6)
	OTHER PRODUCTION PLANT										
340.10	LAND RIGHTS										
	E W BROWN CT UNIT 9 GAS PIPE					176,409	20.0	0	-	-	-
	TOTAL ACCOUNT 340.1 - LAND RIGHTS					176,409			-	-	
341.00	STRUCTURES AND IMPROVEMENTS										
	PADDY'S RUN GENERATOR 13					1,910,328	26.5	0	-	-	-
	E W BROWN CT UNIT 5					775,082	26.5	0	-	-	-
	E W BROWN CT UNIT 6					192,814	26.5	0	-	-	-
	E W BROWN CT UNIT 7					544,966	26.2	0	-	-	-
	E W BROWN CT UNIT 8					2,012,655	24.7	0	-	-	-
	E W BROWN CT UNIT 9					4,641,055	24.7	0	-	-	-
	E W BROWN CT UNIT 10					1,865,719	24.7	0	-	-	-
	E W BROWN CT UNIT 11					1,858,754	25.3	0	-	-	-
	TRIMBLE COUNTY CT UNIT 5					3,740,231	26.8	0	-	-	-
	TRIMBLE COUNTY CT UNIT 6					3,588,684	26.8	0	-	-	-
	TRIMBLE COUNTY CT UNIT 7					3,559,155	27.2	0	-	-	-
	TRIMBLE COUNTY CT UNIT 8					3,548,852	27.2	0	-	-	-
	TRIMBLE COUNTY CT UNIT 9					3,655,976	27.2	0	-	-	-
	TRIMBLE COUNTY CT UNIT 10					3,653,030	27.2	0	-	-	-
	HAEFLING UNITS 1, 2 & 3					434,853	3.5	0	-	-	-
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS					35,982,154			-	-	
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES										
	PADDY'S RUN GENERATOR 13	1988 1/	261	457	2.99%	1,995,102	27.3	(5)	(99,755)	(44,630)	(2.24)
	E W BROWN CT UNIT 5	1988 1/	261	457	2.99%	727,929	27.3	(5)	(36,396)	(16,284)	(2.24)
	E W BROWN CT UNIT 6	1988 1/	261	457	2.99%	146,515	26.9	(5)	(7,326)	(3,316)	(2.26)
	E W BROWN CT UNIT 7	1988 1/	261	457	2.99%	145,745	26.9	(5)	(7,287)	(3,299)	(2.26)
	E W BROWN CT UNIT 8	1988 1/	261	457	2.99%	19,613	26.1	(5)	(981)	(455)	(2.32)
	E W BROWN CT UNIT 9	1988 1/	261	457	2.99%	1,932,186	26.1	(5)	(96,609)	(44,778)	(2.32)
	E W BROWN CT UNIT 10	1988 1/	261	457	2.99%	31,737	26.0	(5)	(1,587)	(738)	(2.32)
	E W BROWN CT UNIT 11	1988 1/	261	457	2.99%	52,430	26.4	(5)	(2,622)	(1,204)	(2.30)
	E W BROWN CT UNIT 9 GAS PIPE	1988 1/	261	457	2.99%	8,106,132	25.8	(5)	(405,307)	(189,527)	(2.34)
	TRIMBLE COUNTY CT UNIT 5	1988 1/	261	457	2.99%	239,585	27.4	(5)	(11,979)	(5,344)	(2.23)
	TRIMBLE COUNTY CT UNIT 6	1988 1/	261	457	2.99%	239,246	27.4	(5)	(11,962)	(5,336)	(2.23)
	TRIMBLE COUNTY CT PIPELINE	1988 1/	261	457	2.99%	4,850,114	27.5	(5)	(242,506)	(107,859)	(2.22)
	TRIMBLE COUNTY CT UNIT 7	1988 1/	261	457	2.99%	578,059	27.7	(5)	(28,903)	(12,780)	(2.21)
	TRIMBLE COUNTY CT UNIT 8	1988 1/	261	457	2.99%	576,386	27.7	(5)	(28,819)	(12,743)	(2.21)
	TRIMBLE COUNTY CT UNIT 9	1988 1/	261	457	2.99%	593,786	27.7	(5)	(29,689)	(13,127)	(2.21)
	TRIMBLE COUNTY CT UNIT 10	1988 1/	261	457	2.99%	593,307	27.7	(5)	(29,665)	(13,117)	(2.21)
	HAEFLING UNITS 1, 2 & 3	1988 1/	261	457	2.99%	181,132	-	(5)	-	-	-
	TOTAL ACCOUNT 342 - FUEL HOLDERS, PRODUCERS AND ACCESSORIES					21,009,005			(1,041,394)	(474,537)	

KENTUCKY UTILITIES
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CALCULATION OF PRESENT VALUE OF SPANOS FUTURE NET SALVAGE PROPOSALS

	ACCOUNT	1ST YR IN SPANOS NS STUDY	START YEAR COST INDEX	Jan 2007 COST INDEX	COMPOUND GROWTH RATE	ORIGINAL COST	ALG COMPOSITE REMAINING LIFE	SPANOS FUTURE NET SALVAGE %	SPANOS FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(6)*(8)	(10)	(11)=(10)/(6)
343.00	PRIME MOVERS										
	PADDY'S RUN GENERATOR 13	1988 1/	299 2/	498 2/	2.72%	17,420,149	23.9	(5)	(871,007)	(458,635)	(2.63)
	E W BROWN CT UNIT 5	1988 1/	299 2/	498 2/	2.72%	13,164,181	24.0	(5)	(658,209)	(345,656)	(2.63)
	E W BROWN CT UNIT 6	1988 1/	299 2/	498 2/	2.72%	30,399,242	23.6	(5)	(1,519,962)	(806,816)	(2.65)
	E W BROWN CT UNIT 7	1988 1/	299 2/	498 2/	2.72%	30,001,198	23.7	(5)	(1,500,060)	(794,118)	(2.65)
	E W BROWN CT UNIT 8	1988 1/	299 2/	498 2/	2.72%	20,074,864	22.8	(5)	(1,003,743)	(544,363)	(2.71)
	E W BROWN CT UNIT 9	1988 1/	299 2/	498 2/	2.72%	21,502,645	22.5	(5)	(1,075,132)	(587,793)	(2.73)
	E W BROWN CT UNIT 10	1988 1/	299 2/	498 2/	2.72%	19,670,647	22.6	(5)	(983,532)	(536,272)	(2.73)
	E W BROWN CT UNIT 11	1988 1/	299 2/	498 2/	2.72%	34,239,853	23.2	(5)	(1,711,993)	(918,556)	(2.68)
	TRIMBLE COUNTY CT UNIT 5	1988 1/	299 2/	498 2/	2.72%	30,530,610	24.1	(5)	(1,526,530)	(799,502)	(2.62)
	TRIMBLE COUNTY CT UNIT 6	1988 1/	299 2/	498 2/	2.72%	30,442,270	24.1	(5)	(1,522,114)	(797,189)	(2.62)
	TRIMBLE COUNTY CT UNIT 7	1988 1/	299 2/	498 2/	2.72%	22,773,833	24.5	(5)	(1,138,692)	(590,009)	(2.59)
	TRIMBLE COUNTY CT UNIT 8	1988 1/	299 2/	498 2/	2.72%	22,568,286	24.5	(5)	(1,128,414)	(584,683)	(2.59)
	TRIMBLE COUNTY CT UNIT 9	1988 1/	299 2/	498 2/	2.72%	22,401,685	24.5	(5)	(1,120,084)	(580,367)	(2.59)
	TRIMBLE COUNTY CT UNIT 10	1988 1/	299 2/	498 2/	2.72%	22,378,128	24.5	(5)	(1,118,906)	(579,757)	(2.59)
	TOTAL ACCOUNT 343 - PRIME MOVERS					337,567,593			(16,878,380)	(8,923,716)	
344.00	GENERATORS										
	PADDY'S RUN GENERATOR 13	1988 1/	314	503	2.51%	5,185,636	29.1	(5)	(259,282)	(126,030)	(2.43)
	E W BROWN CT UNIT 5	1988 1/	314	503	2.51%	2,831,528	29.1	(5)	(141,576)	(68,817)	(2.43)
	E W BROWN CT UNIT 6	1988 1/	314	503	2.51%	3,712,349	29.0	(5)	(185,617)	(90,448)	(2.44)
	E W BROWN CT UNIT 7	1988 1/	314	503	2.51%	3,722,788	29.0	(5)	(186,139)	(90,702)	(2.44)
	E W BROWN CT UNIT 8	1988 1/	314	503	2.51%	4,953,961	28.5	(5)	(247,698)	(122,204)	(2.47)
	E W BROWN CT UNIT 9	1988 1/	314	503	2.51%	5,452,041	28.3	(5)	(272,602)	(135,159)	(2.48)
	E W BROWN CT UNIT 10	1988 1/	314	503	2.51%	4,944,693	28.5	(5)	(247,235)	(121,975)	(2.47)
	E W BROWN CT UNIT 11	1988 1/	314	503	2.51%	5,187,040	28.6	(5)	(259,352)	(127,637)	(2.46)
	TRIMBLE COUNTY CT UNIT 5	1988 1/	314	503	2.51%	3,763,275	29.2	(5)	(188,164)	(91,235)	(2.42)
	TRIMBLE COUNTY CT UNIT 6	1988 1/	314	503	2.51%	3,757,947	29.2	(5)	(187,897)	(91,106)	(2.42)
	TRIMBLE COUNTY CT UNIT 7	1988 1/	314	503	2.51%	2,950,282	29.3	(5)	(147,514)	(71,348)	(2.42)
	TRIMBLE COUNTY CT UNIT 8	1988 1/	314	503	2.51%	2,937,930	29.3	(5)	(146,897)	(71,049)	(2.42)
	TRIMBLE COUNTY CT UNIT 9	1988 1/	314	503	2.51%	2,957,520	29.3	(5)	(147,876)	(71,523)	(2.42)
	TRIMBLE COUNTY CT UNIT 10	1988 1/	314	503	2.51%	2,954,149	29.3	(5)	(147,707)	(71,442)	(2.42)
	HAEFLING UNITS 1, 2 & 3	1988 1/	314	503	2.51%	4,023,003	-	(5)	-	-	-
	TOTAL ACCOUNT 344 - GENERATORS					59,334,142			(2,765,557)	(1,350,675)	
345.00	ACCESSORY ELECTRIC EQUIPMENT										
	PADDY'S RUN GENERATOR 13					2,456,320	27.8	0	-	-	-
	E W BROWN CT UNIT 5					1,332,167	27.8	0	-	-	-
	E W BROWN CT UNIT 6					1,354,817	27.4	0	-	-	-
	E W BROWN CT UNIT 7					1,347,700	27.4	0	-	-	-
	E W BROWN CT UNIT 8					1,797,054	26.4	0	-	-	-
	E W BROWN CT UNIT 9					3,226,186	26.4	0	-	-	-
	E W BROWN CT UNIT 10					1,804,419	26.5	0	-	-	-
	E W BROWN CT UNIT 11					916,326	26.7	0	-	-	-
	TRIMBLE COUNTY CT UNIT 5					1,677,092	27.9	0	-	-	-
	TRIMBLE COUNTY CT UNIT 6					1,674,719	27.9	0	-	-	-
	TRIMBLE COUNTY CT UNIT 7					3,146,235	28.2	0	-	-	-
	TRIMBLE COUNTY CT UNIT 8					3,137,127	28.2	0	-	-	-
	TRIMBLE COUNTY CT UNIT 9					3,231,827	28.2	0	-	-	-
	TRIMBLE COUNTY CT UNIT 10					3,229,223	28.2	0	-	-	-
	HAEFLING UNITS 1, 2 & 3					621,207	-	0	-	-	-
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT					30,952,420			-	-	

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	ACCOUNT	1ST YR IN SPANOS NS STUDY	START YEAR COST INDEX	Jan 2007 COST INDEX	COMPOUND GROWTH RATE	ORIGINAL COST	ALG COMPOSITE REMAINING LIFE	SPANOS FUTURE NET SALVAGE %	SPANOS FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE $	PV FUTURE NET SALVAGE %
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(6)*(8)	(10)	(11)=(10)/(6)
346.00	MISCELLANEOUS PLANT EQUIPMENT										
	PADDY'S RUN GENERATOR 13					1,089,549	24.8	0	-	-	-
	E W BROWN CT UNIT 5					2,108,910	24.8	0	-	-	-
	E W BROWN CT UNIT 6					48,959	25.2	0	-	-	-
	E W BROWN CT UNIT 7					35,648	24.9	0	-	-	-
	E W BROWN CT UNIT 8					230,069	22.5	0	-	-	-
	E W BROWN CT UNIT 9					760,258	22.5	0	-	-	-
	E W BROWN CT UNIT 10					274,391	23.0	0	-	-	-
	E W BROWN CT UNIT 11					548,588	24.7	0	-	-	-
	TRIMBLE COUNTY CT UNIT 5					15,274	26.3	0	-	-	-
	TRIMBLE COUNTY CT UNIT 7					8,869	25.7	0	-	-	-
	TRIMBLE COUNTY CT UNIT 8					8,861	25.7	0	-	-	-
	TRIMBLE COUNTY CT UNIT 9					9,114	25.7	0	-	-	-
	TRIMBLE COUNTY CT UNIT 10					9,106	25.7	0	-	-	-
	HAEFLING UNITS 1, 2 & 3					35,805	-	0	-	-	-
	TOTAL ACCOUNT 346 - MISCELLANEOUS PLANT EQUIPMENT					5,183,418			-	-	
	TOTAL OTHER PRODUCTION PLANT					490,205,140			(20,685,330)	(10,748,928)	
	TRANSMISSION PLANT										
350.10	LAND AND LAND RIGHTS					23,341,455	36.1	0	-	-	-
352.10	STRUCTURES & IMPROVEMENTS-NON SYS CONTROL/COM	1988	258 2/	501 2/	3.55%	6,979,653	45.7	(25)	(1,744,913)	(354,335)	(5.08)
352.20	STRUCTURES & IMPROVEMENTS - SYS CONTROL/COM	1988	258 2/	501 2/	3.55%	1,167,783	38.6	(25)	(291,946)	(75,947)	(6.50)
353.10	STATION EQUIPMENT - NON SYS CONTROL/COM	1988	258	541	3.97%	173,142,341	43.2	(20)	(34,628,468)	(6,441,778)	(3.72)
353.20	STATION EQUIPMENT - SYS CONTROL/COM	1988	258	541	3.97%	14,749,281	24.6	(20)	(2,949,856)	(1,132,043)	(7.68)
354.00	TOWERS AND FIXTURES	1988	247	423	2.87%	63,308,079	47.4	(25)	(15,827,020)	(4,139,166)	(6.54)
355.00	POLES AND FIXTURES	1988	254	469	3.28%	91,302,831	39.3	(60)	(54,781,698)	(15,409,824)	(16.88)
356.00	OVERHEAD CONDUCTORS AND DEVICES	1988	294	552	3.37%	129,755,652	40.7	(50)	(64,877,826)	(16,836,022)	(12.99)
357.00	UNDERGROUND CONDUIT					448,760	26.9	0	-	-	-
358.00	UNDERGROUND CONDUCTORS AND DEVICES					1,114,762	22.2	0	-	-	-
	TOTAL TRANSMISSION PLANT					505,310,593			(175,101,728)	(44,389,115)	
	DISTRIBUTION PLANT										
360.10	LAND AND LAND RIGHTS					1,496,173	48.6	0	-	-	-
361.00	STRUCTURES AND IMPROVEMENTS	1988	242 2/	453 2/	3.35%	4,457,894	46.0	(10)	(445,789)	(97,915)	(2.20)
362.00	STATION EQUIPMENT	1988	259	532	3.86%	100,792,638	37.0	(15)	(15,118,896)	(3,723,337)	(3.69)
364.00	POLES, TOWERS, AND FIXTURES	1988	241	434	3.14%	193,793,679	38.5	(45)	(87,207,155)	(26,522,089)	(13.69)
365.00	OVERHEAD CONDUCTORS AND DEVICES	1988	276	530	3.49%	180,861,758	34.4	(75)	(135,646,319)	(41,677,677)	(23.04)
366.00	UNDERGROUND CONDUIT					1,728,496	30.7	0	-	-	-
367.00	UNDERGROUND CONDUCTORS AND DEVICES	1988	230	461	3.73%	70,302,254	37.6	(5)	(3,515,113)	(887,023)	(1.26)
368.00	LINE TRANSFORMERS	1988	213	391	3.25%	238,783,304	27.1	(20)	(47,756,661)	(20,073,048)	(8.41)
369.00	SERVICES	1988	199	378	3.43%	83,111,706	33.3	(30)	(24,933,512)	(8,110,622)	(9.76)
370.00	METERS					64,856,075	27.5	0	-	-	-
371.00	INSTALLATIONS ON CUSTOMER PREMISES	1988	242 2/	453 2/	3.35%	18,276,458	14.0	(10)	(1,827,646)	(1,152,246)	(6.30)
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	1988	264	592	4.34%	53,640,293	26.4	(5)	(2,682,015)	(873,694)	(1.63)
	TOTAL DISTRIBUTION PLANT					1,012,100,728			(319,133,105)	(103,117,649)	

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	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=(6)*(8)	(10)	(11)=(10)/(6)
	GENERAL PLANT										
390.10	STRUCTURES AND IMPROVEMENTS-TO OWNED PROPERTY	1988	261 3/	474 3/	3.19%	32,199,743	47.1	(5)	(1,609,987)	(366,852)	(1.14)
390.20	STRUCTURES AND IMPROVEMENTS - LEASED PROPERTY	1988	261 3/	474 3/	3.19%	531,973	22.4	(5)	(26,599)	(13,164)	(2.47)
391.10	OFFICE FURNITURE AND EQUIPMENT					8,646,812	13.6	0	-	-	-
391.20	NON PC COMPUTER EQUIPMENT					11,291,965	3.3	0	-	-	-
391.30	CASH PROCESSING EQUIPMENT					817,575	6.3	0	-	-	-
391.40	PERSONAL COMPUTER EQUIPMENT					1,932,339	2.8	0	-	-	-
393.00	STORES EQUIPMENT					738,677	11.6	0	-	-	-
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT					5,333,517	14.7	0	-	-	-
395.00	LABORATORY EQUIPMENT					3,202,202	1.8	0	-	-	-
396.00	POWER OPERATED EQUIPMENT					270,942	9.9	0	-	-	-
397.10	COMMUNICATION EQUIPMENT - CARRIER					7,578,906	10.9	0	-	-	-
397.20	COMMUNICATION EQUIPMENT - REMOTE CONTROL					3,913,060	7.5	0	-	-	-
397.30	COMMUNICATION EQUIPMENT - MOBILE					4,659,773	8.4	0	-	-	-
398.00	MISCELLANEOUS EQUIPMENT					394,809	1.8	0	-	-	-
	TOTAL GENERAL PLANT					79,512,313			(1,636,586)	(380,016)	
	TOTAL DEPRECIABLE PLANT					3,605,547,551			(763,207,223)	(287,700,523)	

1/ Account not included in Spanos net salvage studies - used 1988 as starting year.
2/ Account not included in H-W - used total function.
3/ Function not included in H-W - used "Total Plant - All Steam & Hydro Gen."

Sources:
Col. (2) from Spanos Depreciation Study, Section III.
Cols. (3) and (4) from Handy-Whitman Index of Public Utility Construction Costs.
Cols. (6), (7) and (8) from response to AG-1-27.

Attorney General's Responses to
Commission Staff's First Data Requests
Case No. 2007-00565

WITNESS RESPONSIBLE:
Michael J. Majoros

Question 7. Refer to the Majoros Testimony, Exhibit MJM-2, pages 3 through 5 of 18, and Exhibit MJM-3, pages 4 through 6 of 14. KU and Louisville Gas and Electric Company ("LG&E") jointly own 10 combustion turbines ("CTs"). The CTs are Paddy's Run – Generator 13, E. W. Brown CTs 5 through 7, and Trimble County CTs 5 through 10. Although jointly owned, KU and LG&E have proposed different depreciation rates for these CTs. Mr. Majoros has also proposed different depreciation rates for these commonly owned CTs.

a. Was Mr. Majoros aware that KU and LG&E jointly owned these 10 CTs?

b. Explain why Mr. Majoros believes it is reasonable for utility plant jointly owned by two affiliated, regulated utilities to be depreciated using different depreciation rates.

RESPONSE:

a. Mr. Majoros was aware of the joint ownership, which is discussed in KU's responses to PSC 1-10 and 2-6.

b. Mr. Majoros does not necessarily believe that a utility plant jointly owned by affiliates should be depreciated using different rates. Due to the magnitude of other issues in this case (the retroactive application of ELG, primarily) Mr. Majoros chose to focus on only two issues – eliminating ELG and removing future inflation from the Companies' net salvage proposals. He opted not to address lives or other depreciation aspects. Please see page 5 of his testimony.