BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE FILING OF GENERAL RATE CASE INFORMATION BY TUCSON ELECTRIC POWER COMPANY PURSUANT TO DECISION NO. 62103	Docket No. E-01933A-04-0408

Staff of the Arizona Corporation Commission hereby files its Direct Testimony in the above-referenced matter.

RESPECTFULLY SUBMITTED this 24th day of June 2005.

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DIRECT

TESTIMONY

OF

JAMES J. DORF

CHIEF ACCOUNTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 24, 2005

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
FILING OF RATE CASE INFORMATION
PURSUANT TO DECISION NO. 62103
DOCKET NO. W-01933A-04-0408

The direct testimony of Staff witness James J. Dorf addresses the following issues:

Background – Tucson Electric Power Company ("TEP") is an Arizona utility providing electricity to approximately 367,000 customers in the Tucson, Arizona area. TEP is the largest subsidiary of UniSource Energy Corporation ("UniSource").

In June of 1999, TEP entered into settlement discussions with various other parties to resolve all outstanding issues in several dockets[1]. On November 30, 1999, the Commission issued Decision No. 62103 which approved this Settlement with a few specific alterations and additions. The Decision required, among other things, that the Company file general rate case information on or before June 1, 2004. The Decision also precluded the Company from requesting with its filing a rate increase or any change that would result in an increase in any customer's overall bill.

TEP made its filing June 1, 2004 and Staff found that filing to be deficient. On September 15, 2004, TEP submitted a revised filing and Staff found the revised filing sufficient on October 14, 2004.

Testimony – Testimony offered herein provides Staff's comments and analysis in the following areas:

1) A summary of TEP's filing.
2) A historical background on why TEP was required to make this filing.
3) A review of TEP's recent financial performance and whether it is over-earning.
4) A summary of Staff's audit and review procedures.
5) A description of Staff's pro forma adjustments.
6) Other TEP matters.
7) Staff conclusions.

[1] Docket Nos. E-01933A-098-0471 (Stranded Cost Recovery), E-01933A-97-0772 (Unbundled Tariffs), and RE-00000C-94-0165 (Competition in the Provision of Electric Service).

INTRODUCTION

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

A. My name is James J. Dorf. I am the Chief Accountant employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as the Chief Accountant.

A. I am responsible for supervising the examination and verification of financial and statistical information included in utility rate applications, developing revenue requirements, designing rates, and preparing written reports and/or testimonies and related schedules that present Staff's recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science, Accounting from Northern Michigan University and a Master of Science in Business Administration from Northern Illinois University. I am also a Certified Public Accountant. My qualifications and professional experience are summarized at Exhibit 1.

Q. What is the scope and order of your testimony in this case?

A. I am presenting Staff's analysis and recommendations regarding Tucson Electric Power Company's ("TEP" or "Company") filing of general rate case information pursuant to Arizona Corporation Commission ("Commission") Decision No. 62103, docketed November 30, 1999. I will provide a summary of the instant filing and provide some historical background on why TEP was required to make this filing. I will offer Staff's evaluation as to whether TEP has been earning in excess of its cost of capital. I will also address Staff's adjustments to the Company's jurisdictional rate base and test year jurisdictional revenues and operating expenses.

SUMMARY OF TEP'S RATE FILING

Q. Please provide an overview of the Company's filings in this case.

A. On June 1, 2004, TEP presented its filing of general rate case information using a test year ending December 31, 2003. The Company was required to make a general rate filing pursuant to Decision 62103.

That Decision required, among other things, that the Company file general rate case information on or before June 1, 2004. The Company was also precluded by that Decision from requesting within the filing a rate increase or any change that would result in an increase in any customer's overall bill. Furthermore, that Decision froze TEP's rates until December 31, 2008.

Q. Has the Company made any supplemental filings?

A. The Company also filed on May 5, 2005, a Motion for Declaratory Order and Request for a Procedural Conference. The Company requests "a declaratory order stating the methodology that the Commission will apply to determine TEP's rates for generation, after the current Competition Transition Charge ("CTC") terminates in 2008". In a June 10, 2005 procedural order, the Administrative Law Judge took no action on TEP's motion, suggesting that TEP consider different procedural venues if it wishes to pursue matters raised in its motion.

Q. Is the Company proposing a rate decrease?

A. No, it is not. The Company's Supplemental Notice of Filing indicated that "but for the 2008 Rate Freeze Provision, the Company could request a rate increase of approximately 16%".[2] If TEP were requesting an increase, its position would equate to a revenue increase of $111.7 million or 17.94 percent,[3] which would produce an overall return of 8.78 percent on Original Cost Rate Base ("OCRB") and an overall return of 6.52 percent on Fair Value Rate Base ("FVRB").

Q. What debt and equity costs comprise the Company's proposed cost of capital?

A. The Company proposes 6.97 percent for debt cost and 11.50 percent for the cost of equity capital for an overall 8.78 percent rate of return on OCRB.

Q. Is the Company proposing a hypothetical capital structure as it did in its prior general rate case?

A. Yes. TEP's actual capital structure at the end of the test year was composed of 73.62 percent debt and 26.39 percent equity. It proposes to use a 60 percent debt and 40 percent equity capital structure.

HISTORICAL BACKGROUND

Q. Can Staff provide a historical background with respect to the possibility of a rate decrease in this case?

A. Yes. At the time of the 1999 settlement, there was concern that potential retail competition in electric generation would decrease generation costs and such cost savings

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[2] Supplemental Notice of Filing and Request for Procedural Conference, September 15, 2004, Docket No. E-01933A-04-0408, page1 lines 24 and 25.
[3] Percent increase excludes CTC revenues.

might not be passed on to ratepayers since TEP's rates were frozen until December 31, 2008. The Commission required that a rate review be performed in order to determine if TEP was over-earning to address this concern.

Q. Has there been meaningful retail competition in markets served by TEP?

A. No meaningful retail competition has emerged. In accordance with the provisions of the Commission's Retail Electric Competition Rules (A.A.C. R14-2-1601), it was expected that TEP, by 2004, would have:

1. Divested its generation assets.
2. Acquired at least 50 percent of its power through a competitive bid process.
3. Experienced significant customer loss to direct access service within its service territory.

Q. Have any of these anticipated activities occurred?

A. No, they have not materialized. TEP's generation assets have not been divested. There are currently no direct access customers in TEP's service territory.

Q. Are there other reasons why an earnings review would be appropriate?

A. For example, if a company reports earnings in excess of its authorized return, this might suggest the possibility that a rate reduction is in order.

Q. Did Staff evaluate whether TEP was over-earning?

A. Yes, Staff's evaluation concludes that TEP did not have excess earnings during the test year. Staff's evaluation is presented below.

REVIEW OF TEP'S FINANCIAL RESULTS

Q. Did Staff review TEP's financial results to determine if it is over-earning?

A. Yes, it did. The authorized return on equity in Decision No. 62103 was 10.68 percent. Staff reviewed the Company's calculated returns submitted with its filing. On the Company's Schedule A-2, the calculated returns on end of year equity for the years 2001 through 2003 were 23.60 percent, 16.00 percent, and 15.42 percent[4], respectively (Schedule A-2).[5] However, those amounts were based upon TEP's total earnings.

It should be noted that if the net earnings for years 2001 through 2003 are adjusted to singularly eliminate the Fixed CTC, the resulting returns on ending equity decrease to approximately 13.32 percent, 6.74 percent, and 8.51 percent, respectively.[6]

Based on the Company's adjusted test year income which excludes the non-jurisdictional revenues and expenses, the Fixed CTC and other normalization adjustments, the return on average and ending equity fall to 2.43 percent and 1.93 percent, respectively (Schedule A-2).

Q. Has the Fixed CTC had an impact on the Company's earnings?

A. Yes. The Fixed CTC has contributed the following net of tax earnings for TEP: 2000, $36.5 million; 2001, $33.9 million; 2002, $30.9 million; and 2003, $27.5 million. The Fixed CTC contribution amount will continue to decline as the CTC balance is amortized.

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[4] Excludes the effects of an Extraordinary Item totaling $67.5 million recorded in 2003 to implement SFAS No. 143. See Staff testimony on SFAS 143.

[5] An increasing equity level causes the return on average equity to exceed the return on year endequity.

[6]For example, year 2003 was calculated as $61,441,000, less $27,531,000 (CTC revenue less amortization and taxes) = $33,909,647 divided by ending equity of $398,503,853.

A discussion regarding the potential continuation or adjustment of the Fixed CTC is presented later in this testimony.

Q. Why does the Fixed CTC increase TEP's earnings?

A. The Fixed CTC allows TEP to recover $450 million in stranded costs approved in Decision No. 62103. The charge is related to the proposed deregulation of electric generation. The Commission allowed TEP to recover prudently incurred generation costs during a transition period ending December 31, 2008.

Q. Did Staff treat the Fixed CTC differently from TEP's other revenues and expenses?

A. Because the Fixed CTC has a separate charge per kWh and a separate amortization schedule, Staff excluded the Fixed CTC from its analysis and has thus isolated the Fixed CTC as a separate component of this case.

Q. Has Staff analyzed the Fixed CTC and made a determination as to its efficacy?

A. Yes, please refer to the section discussing the Fixed CTC in the Other TEP Matters section of this testimony.

Q. Did Staff review any other earnings data?

A. Yes. Staff also reviewed earnings for 2004. TEP earned $46,126,671 for a return on ending equity of 11.33 percent.[7] Assuming the Fixed CTC amounts were comparable to 2003, removing the Fixed CTC causes the return on equity to fall to 4.58 percent.[8]

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[7]Tucson Electric Power Company, Federal Energy Regulatory Commission Form 1, 2004.
[8] $46,126,671, less $27,500,000 = $18,626,671 divided by $406,958,212.

Q. Based upon Staff's adjusted revenue requirement in this case, does it appear that TEP is over-earning?

A. Staff's findings show that TEP is not over-earning. For purposes of its review in this case, Staff determined that the Company's approximate operating income deficiency is $40.9 million. After applying the gross revenue conversion factor, Staff calculated TEP's revenue deficiency as $66.9 million (see Schedule JJD-1). This implies a required operating income of $79.6 million. Thus, Staff concludes TEP is not over-earning and that no decrease in TEP's rates is warranted.

SUMMARY OF STAFF'S AUDIT REVIEW

Q. What was the scope of Staff's audit of TEP's filing in this matter?

A. Initially, Staff proceeded to process this filing as if it were a general rate case proceeding. Staff concluded at the outset that it would audit the TEP filing as a rate case in order to provide the Commission with sufficient information to make a decision regarding whether TEP was over-earning. However, once Staff completed its audit, financial analysis, and adjustments to rate base and operating revenues and expenses, it became clear that TEP was not over-earning and that certain aspects of this case could be approached differently because Staff would not be making any recommendations that, if adopted, would change TEP's rates or impact customer bills.

Q. What audit and review procedures did Staff perform?

A. Staff performed a regulatory audit of the Company's filing and records. The regulatory audit consisted of examining and testing financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USOA").

Staff conducted a complete review of each of the Company's proposed adjustments and the basic underlying financial data. Staff also conducted interviews of Company witnesses and performed substantive audit procedures at the Company's administrative offices. Staff's procedures included reviewing numerous discovery responses in assessing the efficacy of the information provided by TEP.

Staff also utilized an outside consultant, Overland Consulting, to provide Staff members specialized electric utility audit training and audit program development. Overland Consulting also reviewed Staff's testimony.

Q. If Staff initially treated this case as a general rate case, why then does Staff's direct testimony not include all of the schedules usually contained in Staff's typical rate case testimony?

A. Once it was determined by Staff that TEP was not over-earning and that a rate decrease is not warranted, it became apparent that certain schedules and testimony would not be necessary. For example, rate design testimony is not necessary because Staff is not recommending any change to TEP's rates.

STAFF ADJUSTMENTS

Q. In order to determine if TEP was over-earning during the test year, did Staff make adjustments to test year revenues and expenses for purposes of its audit and analysis of the Company's filing?

A. Yes. Staff made several adjustments to the Company's rate base and adjusted test year operating income for purposes of its review in this case to determine if the Company is over-earning. Staff is not suggesting that the Company make these adjustments at this time. However, Staff intends to address these issues in subsequent future proceedings.

Q. Can you please summarize the adjustments?

A. Below is a description of Staff's rate base, capital structure, capital costs and certain operating revenue and expense adjustments.

Rate Base Adjustment No. 1 – Reversal of SFAS 143 Entries

Q. Please describe the Staff adjustment for SFAS 143.

A. On January 1, 2003, the Company recorded entries related to the implementation of Statement on Financial Accounting Standards ("SFAS") No. 143, entitled "Accounting for Asset Retirement Obligations". The Standard requires that all entities which have a legal[9] obligation to dispose of tangible long-lived assets record a liability for that obligation. For some plant and equipment, public utilities have a legal obligation to remove the asset at the end of the service life. These obligations are referred to as asset retirement obligations ("ARO").

[9] A legal obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.

When the liability is initially recorded, the entity should capitalize a cost by increasing the carrying amount of the related long-lived assets. Over time, the liability is adjusted to its present value by recognizing accretion expense as an operating expense, and the capitalized cost is depreciated over the useful life of the related asset.

Q. What was the effect on the Company's earnings to implement SFAS No. 143?

A. The cumulative effect of recording SFAS No. 143 was an increase of $67.5 million[10] to the Company's net income for the year 2003. The Company identified legal AROs of approximately $38 million, at the date of retirement. The present value of the AROs at January 1, 2003 was $1.1 million.

The Company also reversed $112.8 million of previously accumulated depreciation it had collected in its rates through the end of 2002. This amount reversed all non-legal AROs through the end of 2002.

Staff's position on this matter is that the amount of accumulated depreciation should have been recorded as a regulatory liability. The Company has been collecting decommissioning costs related to its generating assets for many years. Therefore, Staff's analysis found that this obligation should be recognized for regulatory purposes and the Company should reverse the approximate effects of recording SFAS 143. Therefore, Staff increased accumulated depreciation by $112.8 million, reduced accumulated deferred taxes by $44.7 million and increased the annual depreciation expense by $6 million to reflect the impacts of reversing SFAS 143 (Schedule JJD-3).

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[10] Tucson Electric Power Company, Federal Energy Regulatory Commission Form 1, 2003, page 117, column (c), line 73, "Extraordinary Items after Taxes".

The effect of Staff's adjustments on rate base and operating income are noted in Adjustment #1 on Schedule JJD-3 and Adjustment #11 on Schedule JJD-7.

Q. What is Staff's position with respect to recognizing AROs?

A. Recognition of a Company's legal obligations can be an important aspect in determining a Company's authorized rates. However, to the extent the recognition of such costs is speculative, Staff did not recognize SFAS 143 as proper for ratemaking purposes.

Q. Has the Commission dealt with this issue before?

A. Yes, it has. In Arizona Public Service Company's recent rate case SFAS 143 was not adopted for ratemaking purposes.[11]

Q. What did Staff determine on this issue?

A. Staff determined that the entry to record the cumulative effect of implementing SFAS No. 143 should be reversed for regulatory purposes. Staff's adjustment, in effect, recognizes a regulatory liability which is equal to the difference between the SFAS 143 liability and the accumulated deferred decommissioning cost previously and currently being collected from ratepayers (See Schedule JJD-3). In future rate cases, Staff will evaluate both legal and non-legal AROs on a case by case basis.

Rate Base Adjustment No. 2 - Plant Held for Future Use

Q. Does Staff have another rate base adjustment?

A. Yes, Staff excluded $576,000 of Plant Held for Future Use since it is not used and useful (Schedule JJD-3).

[11] Decision 67744, dated April 8, 2005. Docket No. E-01345A-03-0473, page 19.

Q. Is this typically how Plant Held for Future Use is treated by Staff?

A. Yes, Staff will generally exclude Plant Held for Future Use.

Q. Does that complete Staff's adjustments to rate base?

A. Yes, it does.

COST OF CAPITAL

TEP's Proposed Overall Rate of Return

Q. What is the Company proposing for capital structure, cost of debt, return on equity and overall rate of return?

A. The Company's proposed capital structure, cost of debt, return on equity and overall rate of return are presented in Table 1.

Table 1

	Weight	Cost	Weighted Cost
Long-term Debt	60.00%	6.97%	4.18%
Common Equity	40.00%	11.50%	4.60%
Cost of Capital/ROR			**8.78%**

TEP's filing reflects an overall rate of return of 8.78 percent on OCRB.

Cost of Debt Capital

Q. Please describe the methods used by the Company to determine its cost of debt.

A. For its debt rate, the Company used its embedded cost of debt for the test year which was 6.93 percent and adjusted it for the following factors:

1. It adjusted the variable debt rate to reflect a new credit facility.
2. It used the forward curve for short-term interest rates.

3. It adjusted its debt structure to reflect anticipated debt retirements associated with a proposed merger.[12]

4. It adjusted the amortization of debt discount and issuance costs and the loss on reacquired debt.

Q. Does Staff agree with the Company's methodology for determining debt cost?

A. Staff agrees that the cost of debt should reflect the amortization of debt discount and issuance costs and the loss on reacquired debt. However, Staff does object to using a forward curve for short-term interest rates. Also, the proposed merger was denied by the Commission and those estimated effects should be removed.

Q. What cost of debt did Staff find appropriate?

A. Staff determined that a 6.63 percent cost of debt is appropriate. In response to RUCO data request 5.7, TEP provided updated debt cost (including the effects of the debt discount, issuance cost and the reacquired debt loss amortizations) showing 6.63 percent as the cost of long-term debt as of May 2005. TEP also stated that it drew $25 million on its revolving credit facility on May 10, 2005. The cost for this short-term borrowing at that time was 6.00 percent, and its effect on the overall cost of debt is immaterial. Therefore, Staff used 6.63 percent for the cost of debt.

Cost of Common Equity Capital

Q. What methods did the Company use to determine its cost of equity?

A. The Company performed three analyses to support its cost of equity estimate. It performed a multi-stage discounted cash flow ("DCF") analysis of seven comparable

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[12] Denied in Commission Decision No. 67454.

electric utility companies, a capital asset pricing model ("CAPM") analysis for those same entities, and an equity risk premium analysis. TEP used the historical difference between authorized equity returns for other electric utilities in the United States and the prevailing yield to maturity on 30-year Treasury bonds to check the reasonableness of its cost of equity estimate.

Q. Did Staff prepare its own study of the cost of equity capital for TEP?

A. Staff initiated its normal cost of equity analysis when the Company's filing was deemed sufficient. However, when it became apparent to Staff that an unreasonably low estimate for return on equity would be required to produce a revenue decrease, an alternative analysis seemed prudent and was pursued.

Q. What did Staff conclude from its analysis of TEP's cost of equity analyses?

A. Although the DCF and CAPM analyses prepared by TEP use somewhat different methods than those normally used by Staff, an application of Staff's typical methodology would be expected to produce similar results. Accordingly, Staff used the cost of equity estimates for the sample companies resulting from TEP's DCF and CAPM analyses shown on Exhibits KPL-8 and KPL-9, respectively, of Mr. Larson's direct testimony for its own analysis.

Q. Specifically, how did Staff derive a cost of equity estimate?

A. Staff calculated the average DCF and CAPM cost of equity estimates for the seven sample companies as 10.6 percent (rounded upward) and 10.3 percent, respectively. Then Staff averaged those two rates [(10.6% + 10.3% / 2 = 10.5 percent (rounded upward)]. Staff determined a cost of equity estimate of 10.5 percent for TEP would be reasonable.

Q. Why is Staff's cost of equity estimate different than TEP's if Staff based its estimate on TEP's analysis?

A. TEP witness Mr. Larson's direct testimony (pp. 25-28) explains the Company's position that an equity risk premium estimated at 1.3 percent is appropriate because "TEP has higher debt leverage and lower credit ratings relative to the sample group." The Company's cost of equity estimate recognizes an equity risk premium whereas Staff's does not.

Q. Why doesn't Staff recognize an equity risk premium?

A. First, the Company's analysis requires assumptions regarding bond ratings and the relationship between bond premiums and equity premiums that render the analysis unreliable. Moreover, as presented below, in this case Staff is accepting the Company's proposed hypothetical capital structure that includes more equity than its actual capital structure. Since the cost of equity exceeds the cost of debt, acceptance of the hypothetical capital structure indirectly enhances the effective cost of equity recognized.

Capital Structure

Q. What was TEP's actual capital structure at the end of the test year?

A. Schedule D-1 of the Company's filing shows that the Company capital structure at the end of the test year, December 31, 2003, was composed of 73.6 percent debt and 26.4 percent equity.

Q. How does the Company's capital structure compare to the sample companies in the DCF and CAPM analyses?

A. Exhibit KPL-5 of Company witness Mr. Larson's testimony shows that the median debt level for his sample companies is 54.3 percent. This indicates that TEP's 73.6 percent test year debt is significantly higher than the debt of the comparable companies. This relatively high leverage represents additional financial risk that negatively affects TEP's bond ratings and, accordingly, increases its debt costs. Accordingly, TEP should be encouraged to continue increasing the equity portion of total capital.

Q. Does Staff's cost of capital analysis reflect a position that assists TEP to achieve a higher level of equity in its capital structure?

A. Yes. Staff's cost of capital analysis continues a practice from the prior rate case to adopt a hypothetical capital structure that recognizes a higher than actual percentage of equity as a portion of total equity. As noted previously, this practice effectively provides for a higher return on actual equity capital resulting in additional earnings available to further grow equity.

Staff's Overall Rate of Return Finding

Q. What is Staff's finding for capital structure, cost of debt, return on equity and overall rate of return?

A. Staff's capital structure, cost of debt, return on equity and overall rate of return findings are presented in Table 2.

Table 2

	Weight	Cost	Weighted Cost
Long-term Debt	60.00%	6.63%	3.98%
Common Equity	40.00%	10.50%	4.20%
Cost of Capital/ROR			**8.18%**

Staff's overall rate of return finding is 8.18 percent on OCRB.

ADJUSTED TEST YEAR INCOME STATEMENT

Q. What did TEP propose for test year operating income?

A. TEP proposed test year operating revenues of $622,431,000 and test year operating expenses of $598,127,000, resulting in a test year operating income of $24,304,000.

Q. What does Staff find for the adjusted test year operating income?

A. Staff finds adjusted test year operating revenues of $686,940,000 and adjusted test year operating expenses of $648,198,000, resulting in an adjusted test year operating income of $38,742,000. See Staff Schedule JJD-6 for details.

INCOME STATEMENT PRO FORMA ADJUSTMENTS

Q. What approach did Staff utilize in determining its operating revenue and expense adjustments related to the Company's non-jurisdictional revenues and expenses?

A. Staff reviewed TEP's calculations that allocate costs to its non-jurisdictional revenues. As indicated in Adjustment No. 1, TEP earned an operating margin of $14 million on revenues of $29.8 million. Staff utilized an approach to evaluate the Company's non-jurisdictional activity which obviated the need for Staff to determine if jurisdictional allocations made by the Company were appropriate.

Staff treated the non-jurisdictional activities as if they are jurisdictional. Thus, neither the Company nor the ratepayers will be affected by potential misallocation of costs or revenues. Therefore, in Adjustments No. 1 & 2, Staff is adding the Short-Term Sales for Resale and Wholesale Trading activity to both the jurisdictional revenues and expenses.

To adequately measure whether the Company is over-earning, this approach includes all of the Company's activities and will measure its total potential to over-earn. Therefore, Staff is reversing the Company's adjustments for non-jurisdictional activity.

Q. Please describe Staff Operating Income Adjustment No. 1.

A. TEP proposed a pro forma adjustment to remove "short-term sales for resale" from jurisdictional income. Staff adjusted "sales for resale" by adding back the $29,767,000 that TEP had removed. Staff adjusted "fuel expense" by adding back the $12,668,000 that TEP had removed. Staff adjusted "purchased power – energy" by adding back the $3,019,000 that TEP had removed. The net effect of these adjustments is an increase in test year operating income of $14,080,000. The effect of Staff's adjustment is to treat this income as jurisdictional.

Q. Please describe Staff Operating Income Adjustment No. 2.

A. TEP proposed a pro forma adjustment to remove "wholesale trading activity" from jurisdictional income. Staff adjusted "sales for resale" by adding back the $34,742,000 that TEP had removed. Staff adjusted "fuel expense" by adding back the $34,048,000 that TEP had removed. The net effect of these adjustments is an increase in test year operating income of $694,000. The effect of Staff's adjustment is to treat this income as jurisdictional.

Q. Please describe Staff Operating Income Adjustment No. 3.

A. TEP proposes a pro forma adjustment to add expenses from the Springerville Unit No. 1 power plant. Staff adjusted "other operations and maintenance expense" by removing the $12,799,000 that TEP had added to the expense. Staff adjusted "depreciation and amortization" by removing the $463,000 that TEP had added to the expense. Staff adjusted "taxes other than income taxes" by removing the $944,000 that TEP had added to the expense. The net effect of these adjustments is an increase in test year operating income of $14,206,000. TEP based its adjustment on an allowed expense cost basis of $25.67 per kilowatt - month. Staff believes that a more realistic cost basis would be $20.00 per kilowatt - month which would not have required any pro forma adjustment by TEP.

The Commission has historically used the rate of $15.00 per kilowatt – month. TEP has not presented any compelling reasons to reset the rate to a market level. Additionally, the contract TEP uses to establish market is an option to purchase power, not a firm power sales agreement and should be disregarded. Staff's adjustment eliminates TEP's pro forma adjustment. In effect, Staff's adjustment is approximately half way between TEP's market rate of $25.67 and the Commission adopted $15.00.

The proper treatment of the Springerville 1 Unit and whether the Company should be allowed a market rather than a fixed rate per kilowatt – month should be evaluated in its next rate filing.

Q. Please describe Staff Operating Income Adjustment No. 4.

A. TEP proposed a pro forma adjustment adding expenses to "incentive compensation expense." TEP's adjustment is based on a four-year average of this expense. Staff does not believe TEP's adjustment is correct or justified. Staff adjusted "other operations and maintenance expense" by removing the $641,000 that TEP added to the expense.

The actual test year amount is $3,714,533; however, Staff takes the position that employee incentives should be shared equally between ratepayers and shareholders. Therefore, Staff also removed 50 percent of the test year amount from this account which amounts to $1,857,000. The net effect of these adjustments is an increase in test year operating income of $2,498,000.

Q. Please describe Staff Operating Income Adjustment No. 5.

A. TEP proposed a pro forma adjustment to add expenses to "purchased power – demand" and "purchased power – energy." Staff adjusted "purchased power – demand" by removing $688,000 that TEP added to the expense. Staff adjusted "purchased power – energy" by removing $2,216,000 that TEP added to the expense. These amounts represent 50 percent of the adjustments TEP made to these accounts regarding purchased power costs from Southern California Edison. The net effect of these adjustments is an increase in test year operating income of $2,904,000. Staff concludes that TEP's adjustment is excessive and recommends recognition of 50 percent of the pro forma amounts.

The agreement with SoCal Edison diversity exchange agreement expired on February 28, 2005, which is 14 months outside of the test year and should be considered out-of-period.

It is improper to recognize cost outside the test year unless they are shown to be known and measurable. Staff has reduced by one half the Company's adjustment to acknowledge that some level of cost associated with the 110 MW capacity that expired with that agreement.

Q. Please describe Staff Operating Income Adjustment No. 6.

A. TEP proposed a pro forma adjustment adding expenses to "gasoline expense." Staff adjusted "other operations and maintenance expense" by removing $74,000 that TEP added to the expense. Staff found this adjustment by TEP to represent out-of-period expenses that are not allowable in the test year. The Company used current gas prices to adjust its gasoline costs. Other out-of-period costs associated with operating Company vehicles which may reduce costs were not considered by the Company.

Q. Please describe Staff Operating Income Adjustments Nos. 7, 8 and 9.

A. TEP proposed three pro forma adjustments adding expenses to "rate case expense", "meter reading expense", and "bad debt expense." Staff adjusted "other operations and maintenance expense" by $70,000; $76,000; and $81,000, which represents adjustment Nos. 7, 8 and 9, respectively. These amounts represent 50 percent of the TEP adjustments. Many of the expenses were out-of-period but Staff determined that 50 percent recognition would be reasonable and appropriate. Further evaluation would not produce material adjustments.

Q. Please describe Staff Operating Income Adjustment No. 10.

A. TEP proposed a $763,000 increase to test year operating expenses to adjust for its estimate of the annual costs related to complying with Sarbanes-Oxley Section 404

("SOX"). SOX requires that publicly-traded entities' external auditors attest to and report on management's assessment of the effectiveness of their internal controls and procedures. Companies were required to be in compliance with SOX as of December 31, 2004.

SOX has heightened awareness of the importance of maintaining effective internal financial controls. Such financial controls protect both the ratepayers and the shareholders. Accordingly, Staff believes an equal sharing between ratepayers and shareholders of the estimated incremental costs would be appropriate.

Q. Did TEP incur any SOX expenditures during the test year?

A. Yes, it incurred $14,389 in SOX expenditures.

Q. What was TEP's estimated total cost for complying with SOX at the time of its filing this case?

A. TEP estimated its total incremental costs would approximate $1,000,000 of which $762,863 is allocable to TEP and the remainder to its affiliates.

Q. Is this significant incremental increase in TEP's estimate of its SOX costs reasonable?

A. Yes, it is. Many of the companies subject to SOX have indicated that they significantly underestimated the initial cost of compliance.

Q. What has Staff determined regarding the Company proposed adjustment for SOX?

A. Staff's evaluation suggests that the proposed Company adjustment be modified for the following reasons:

1. Staff's evaluation of the SOX costs indicated that approximately 25 percent of the initial implementation costs should be treated as non-recurring. This is based upon numerous published articles published that report on and evaluate company surveys of their first year experience in implementing SOX. Many companies complained of over-zealous audit techniques, duplication of effort, and other implementation problems.
2. Staff believes that the cost of SOX compliance should be shared equally between ratepayers and shareholders. The improved internal controls benefit both groups by protecting ratepayers with improved compliance and protecting shareholder from management impropriety.
3. Therefore, Staff finds an annual allowance for SOX of $275,861 would be appropriate (Schedule JJD-8).

Staff's adjustment to adjusted test year expense is $487,000 ($762,863 less allowance of $275,861).

Q. Please describe Staff Operating Income Adjustment No. 11.

A. This adjustment correlates with my previous testimony on SFAS No. 143 which increases depreciation expense in the test year by $6,000,000, for plant depreciation not included in the test year.

Q. Please describe Staff Operating Income Adjustment No. 12.

A. This adjustment simply adjusts test year income taxes to reflect all of Staff's adjustments.

OTHER TEP MATTERS

Q. Are there other matters that Staff considered in its preparation of this testimony?

A. Yes. Previous Commission orders have deferred several matters for consideration in future Commission proceedings.

Q. Does Staff have a recommendation on the Fixed CTC?

A. Based on Staff's evaluation of the Fixed CTC, Staff recommends that the existing fixed rate of 0.93 cents per/kWh be continued. As of March 31, 2005, the unamortized balance is approximately $236.5 million. At its current rate of collection, and with the Company's estimated 2 percent growth, the balance should be collected at or near the end of the 1999 settlement period of December 31, 2008.

Any reasonable changes to the Fixed CTC mechanism would be very minor based on current projections and Staff does not recommend any changes at this time.

Q. Even if the change is small, why not recommend an adjustment?

A. Ratepayers are protected by the fact that once the Company has recovered its costs, the Fixed CTC average customer charge of 0.93 cents per kWh will be removed from customers bills. Also, the Company has indicated that current accounting requirements could require the Company to write off a portion of the deferred amount.

Q. Therefore, is Staff recommending continuation of the CTC?

A. Yes, it does. Staff recommends continuation of the existing Fixed CTC charge pursuant to the 1999 Settlement Agreement.

Q. How did Staff address TEP's jurisdictional allocations as referred to in Decision No. 59594?

A. Although Staff gave consideration to the concepts raised by the issue of jurisdictional allocations, Staff is not recommending any revenue adjustments based upon its review of TEP's jurisdictional allocations. During a case in which revenue requirements are to be changed, determinations of specific jurisdictional allocation factors serves the purpose of ensuring that retail customers bear responsibility for costs associated with providing retail service while wholesale customers bear responsibility for costs associated with providing wholesale service. Staff's review of jurisdictional allocations indicated that any reasonable changes made to the manner in which TEP's costs are allocated between jurisdictions would not result in a revenue adjustment sufficient to cause Staff to recommend a rate reduction in this case.

Q. In Decision No. 65751, the Commission ordered that the experimental partial requirements tariffs approved in that order be evaluated in the June 1, 2004 rate review to determine "if the Commission should order a true-up of revenues collected under the experimental tariffs." How did Staff address the issue of whether TEP's experimental Partial Requirements tariffs remain in the public interest and whether the Commission should consider a true up of revenues collected under the tariffs?

A. No customers have taken service on these experimental rates since their inception. Therefore, no revenues have been collected under these tariffs and there is no revenue to true up. Staff did not review the Partial Requirements tariff issue in this testimony.

Q. In Decision No. 65751, TEP was ordered to submit "in its next general rate case filing" a feasibility study and consolidation plan or a plan for consolidation of operations of "Unisource's proposed electric operating company subsidiary in Santa Cruz County with Tucson Electric Power." How did Staff address the issue of a possible consolidation plan for Unisource's operations in Santa Cruz County with TEP?

A. TEP has not submitted such a plan. Since Staff's evaluation in this testimony is focused on an assessment of whether the Company is over-earning, Staff did not pursue the issue of the consolidation plan in preparation for this testimony.

Q. The 1999 Settlement Agreement approved in Decision No. 62103 indicated that the low income programs included in TEP's System Benefits Charge "will be reviewed as part of TEP's June 1, 2004 filing." How did Staff address this issue in its review of this case?

A. Since the System Benefits Charge issue is tangential to the issue of whether the Company is over-earning, Staff has not addressed the issue in this testimony.

Q. Did Staff conduct a procurement review of TEP's fuel and purchased power costs as required by the Commission Order in Track B?[13]

A. No. Currently, there is no mechanism through which TEP can pass on to customers any imprudently incurred fuel or purchased power costs. Under these circumstances, if there were any imprudent fuel costs, they would be absorbed by TEP's shareholders. TEP does

[13] Commission Decision 65154, dated September 10, 2002.

not have a fuel and purchased power adjustment clause, nor was one requested by TEP's in this case.

CONCLUSIONS

Q. What are Staff's conclusions?

A. Staff concluded that no increase or decrease in TEP rates should be authorized in this proceeding.

Q. Does Staff have any suggestion regarding the submittal of a tariff that describes TEP's bill estimation procedures?

A. Yes. Staff suggests that TEP be required to submit a tariff to the Commission that describes the methodologies utilized to estimate energy, demand, and time-of-use within 60 days of a decision in this matter. Staff would also suggest that TEP be required to work with Staff in developing the format and content of the tariff prior to its submittal.

Q. Why does Staff believe that a tariff detailing TEP's billing estimation procedure is necessary?

A. The recent complaint filed by Avis Read against Arizona Public Service Company (Docket Nos. E-01345A-04-0657 and E-01345A-03-0775) and Staff's subsequent investigation has led Staff to believe that the lack of a detailed estimation tariff can lead to significant customer confusion.

Q. Does Staff have any comments regarding the timing of TEP's next rate case?

A. Yes. Staff suggests that TEP be required to file for new rates to be in effect when the current rate freeze ends. That would suggest that TEP should file its next rate case with a test period ending no later than June 30, 2007. Therefore, adequate evaluation time would be available to permit new rates to go into effect on January 1, 2009.

Q. Does this conclude your testimony?

A. Yes, it does.

WITNESS QUALIFICATIONS FOR JAMES J. DORF

ADDRESS: 1200 West Washington Street, Phoenix, AZ 85007

EDUCATION: Master of Science in Business Administration, specialization in Accounting, Northern Illinois University

Bachelor of Science, Accounting, Northern Michigan University

Certified Public Accountant

EXPERIENCE: Chief Accountant, Financial & Regulatory Analysis Section, Utilities Division, Arizona Corporation Commission, 2004 to present.

Adjunct Professor of Accounting, Western International University, 2002 to 2004.
Taught Introductory Accounting, Cost Accounting and developed and taught on-line Cost Accounting curriculum.

Chief Financial Officer, Vice President and Special Advisor to the President, Great Lakes Gas Transmission Company, 1978 to 2001.
Complete financial, regulatory, and tax compliance responsibilities for a $2 billion interstate natural gas pipeline system. Issued over $750 million in privately placed Senior Notes. Responsible for preparing numerous general rate and purchased gas adjustment filings for presentation to the Federal Regulatory Energy Commission.

Audit Supervisor, KPMG Peat Marwick, CPA's, 1973 to 1978.
Supervisory responsibility for audits of manufacturing, insurance, contracting and governmental and other entities. Computer audit specialist.
Income tax return preparation and compliance.

Appeared as expert witness or submitted written testimony in rate proceedings before the Federal Energy Regulatory Commission, on tax policy issues before legislative bodies and regulatory accounting issues and tax litigation in Minnesota and Michigan.
Member, American Institute of Certified Public Accountants
Member, National Association of Regulatory Commissioners, Staff Subcommittee on Accounting and Finance
Past member of the American Gas Association Accounting Committee
Past member of the Interstate Natural Gas Association of America Accounting and Tax Committees

Tuscon Electric Power Company
Docket No. E-01933A-04-0408
Test Year Ended December 31, 2003

Schedule JJD-1

REVENUE REQUIREMENT (Amount in Thousands of Dollars)

Line No.	Description	[A] Company Original Cost	[B] Company RCND	[C] Company Fair Value
1	Adjusted Rate Base	$ 1,042,088	$ 1,767,076	$ 1,404,582
2	Adjusted Operating Income	$ 24,304	$ 24,304	$ 24,304
3	Current Rate of Return (L2/L1)	2.33%	1.38%	1.73%
4	Required Rate of Return	8.78%	5.18%	6.52%
5	Required Operating Income	$ 91,527	$ 91,527	$ 91,527
6	Operating Income Deficiency (L5 - L2)	$ 67,223	$ 67,223	$ 67,223
7	Gross Revenue Conversion Factor	1.6612	1.6612	1.6612
8	**Increase in Gross Revenue (L6 x L7)**	**$ 111,670**	**$ 111,670**	**$ 111,670**
9	Adjusted Test Year Revenue	$ 622,431	$ 622,431	$ 622,431
10	Proposed Annual Revenue	$ 734,101	$ 734,101	$ 734,101
11	Required Increase in Revenue (%)	17.94%	17.94%	17.94%
		[D] Staff Original Cost	[E] Staff RCND	[F] Staff Fair Value
1	Adjusted Rate Base	$ 973,434	$ 1,698,422	$ 1,335,928
2	Adjusted Operating Income	$ 38,742	$ 38,742	$ 38,742
3	Current Rate of Return (L2/L1)	3.98%	2.28%	2.90%
4	Required Rate of Return	8.18%	4.69%	5.96%
5	Required Operating Income	$ 79,627	$ 79,627	$ 79,627
6	Operating Income Deficiency (L5-L2)	$ 40,885	$ 40,885	$ 40,885
7	Gross Revenue Conversion Factor	1.6364	1.6364	1.6364
8	**Increase in Gross Revenue (L6xL7)**	**$ 66,903**	**$ 66,904**	**$ 66,904**
9	Adjusted Test Year Revenue	$ 686,940	$ 686,940	$ 686,940
10	Proposed Annual Revenue	$ 753,843	$ 753,844	$ 753,844
11	Required Increase in Revenue (%)	9.74%	9.74%	9.74%

REFERENCES:
Columns [A], [B], and [C]: Company Schedules A-1 and C-1
Columns [D], [E], and [F]: Staff Schedules JJD-5 and JJD-6

Tuscon Electric Power Company
Docket No. E-01933A-04-0408
Test Year Ended December 31, 2003

Schedule JJD-2

SUMMARY OF ORIGINAL COST AND RCND RATE BASE
(Amount in Thousand Dollars)

Line No.	Description	[A] Company Adjusted OCRB	[B] Company RCND	[C] Staff Adjusted OCRB	[D] Staff RCND
1	Gross Utility Plant in Service	$ 2,498,313	$ 4,245,199	$ 2,498,313	$ 4,245,199
2	Less: Accumulated Depreciation	1,223,945	2,051,899	1,336,701	2,164,655
3	Net Utility Plant in Service	1,274,368	2,193,300	1,161,612	2,080,544
4	Plant Held for Future Use	576	576	0	-
5	**Total Net Utility Plant**	1,274,944	2,193,876	1,161,612	2,080,544
	DEDUCTIONS				
6	Customer Advances for Construction	(5,090)	(7,831)	(5,090)	(7,831)
7	Customer Deposits	(7,398)	(7,398)	(7,398)	(7,398)
8	Deferred Credit - Contributed Plant and Retirement Obligations	(3,727)	(3,727)	(3,727)	(3,727)
9	Accumulated Deferred Income Taxes	(275,478)	(466,681)	(230,799)	(422,002)
10	**Total Deductions**	(291,693)	(485,637)	(247,014)	(440,958)
	ADDITIONS				
11	Allowance For Working Capital	19,662	19,662	19,662	19,662
12	Regulatory Assets	39,174	39,174	39,174	39,174
13	**Total Additions**	58,836	58,836	58,836	58,836
14	**Total Original Cost Rate Base**	$ 1,042,087	$ 1,767,075	$ 973,434	1,698,422

REFERENCES:
Column [A]: Company Schedule B-1

Column [B]: Company Schedule B-1

Column [C]: Staff Tesimony
Staff Schedule JJD-3

Column [D]: Staff Tesimony
Staff Schedule JJD-3

Tuscon Electric Power Company
Docket No. E-01933A-04-0408
Test Year Ended December 31, 2003

Schedule JJD-3

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
(Amount in Thousand Dollars)

Line No.	Description	Company Adjusted OCRB	Adj. #1	Adj. #2	Staff Adjusted OCRB
1	Gross Utility Plant in Service	$ 2,498,313			$ 2,498,313
2	Less: Accumulated Depreciation	1,223,945	112,756		$ 1,336,701
3	Net Utility Plant in Service	1,274,368	(112,756)		1,161,612
4	Plant Held for Future Use	576		(576)	0
5	**Total Net Utility Plant**	1,274,944	(112,756)	(576)	1,161,612
	Deductions:				
6	Customer Advances for Construction	(5,090)			(5,090)
7	Customer Deposits	(7,398)			(7,398)
8	Deferred Credit - Contributed Plant and Retirement Obligations	(3,727)			(3,727)
9	Accumulated Deferred Income Taxes	(275,478)	44,679		(230,799)
10	**Total Deductions**	(291,693)	44,679		(247,014)
	Additions:				
11	Allowance For Working Capital	19,662			19,662
12	Regulatory Assets	39,174			39,174
	Total Additions	58,836			58,836
13	**Total Original Cost Rate Base**	$ 1,041,838	(68,077)	(576)	$ 973,434

REFERENCES:
Original Cost Rate Base Adjustment No. 1 - Reversal of FAS 143 Adjustment
Original Cost Rate Base Adjustment No. 2 - Plant Held for Future Use

Tuscon Electric Power Company
Docket No. E-01933A-04-0408
Test Year Ended December 31, 2003

Schedule JJD-4

SUMMARY OF RCND RATE BASE ADJUSTMENTS
(Amount in Thousand Dollars)

Line No.	Description	Company Adjusted RCND	Adj. #1	Adj. #2	Staff Adjusted OCRB
1	Gross Utility Plant in Service	$ 4,245,199			$ 4,245,199
2	Less: Accumulated Depreciation	2,051,899	112,756		2,164,655
3	Net Utility Plant in Service	2,193,300	(112,756)		2,080,544
4	Plant Held for Future Use	576		(576)	0
5	**Total Net Utility Plant**	2,193,876	(112,756)	(576)	2,080,544
	Deductions:				
6	Customer Advances for Construction	(7,831)			(7,831)
7	Customer Deposits	(7,398)			(7,398)
8	Deferred Credit - Contributed Plant and Retirement Obligations	(3,727)			(3,727)
9	Accumulated Deferred Income Taxes	(466,681)	44,679		(422,002)
10	**Total Deductions**	(485,637)	44,679		(440,958)
	Additions:				
11	Allowance For Working Capital	19,662			19,662
12	Regulatory Assets	39,174			39,174
	Total Additions	58,836			58,836
13	**Total Original Cost Rate Base**	$ 1,767,075	(68,077)	(576)	$ 1,698,422

REFERENCES:
RCND Rate Base Adjustment No. 1 - Reversal of FAS 143 Adjustment
RCND Rate Base Adjustment No. 2 - Plant Held for Future Use

Tucson Electric Power Company
Summary Cost of Capital
Test Year Ended December 31, 2003
(Thousands of Dollars)

Schedule JJD-5

Line No.	Capital Source*		Capitalization Amount	Capitalization Percent	Cost Rate (c)	Weighted Cost of Capital
	Adjusted - End of Test Period					
5	Short-Term Debt		N/A	N/A	N/A	N/A
6	Long-Term Debt - Net*	(a)	$ 844,534	60.00%	6.63%	3.98%
7	Common Stock Equity/(Deficit)		563,023	40.00%	10.50%	4.20%
8	Total Capital		$ 1,407,557	100.00%		8.18%

* Excludes Capital Lease Obligations

Supporting Schedules	Recap Schedules
(a) D-2	(c) A-3

Tucson Electric Power Company
Docket No. E-01933A-04-0408
Test Year Ended December 31, 2003

Schedule JJD-6

Adjusted Test Year Income Statement (in Thousands of Dollars)

Line No.	Description	Test Year Company Adjusted	Test Year Staff Adjusted
	Operating Revenues		
1	Electric Retail Revenues	$ 608,219	$ 608,219
2	Sales for Resale		$ 64,509
3	Other Operating Revenue	14,212	$ 14,212
4	Total Operating Revenues	622,431	$ 686,940
	Operating Expenses		
5	Fuel Expense	173,935	$ 220,651
6	Purchased Power - Demand	4,136	$ 3,448
7	Purchased Power - Energy	22,406	$ 23,209
8	Other Operations and Maintenance Expense	261,425	$ 245,340
9	Depreciation and Amortization	91,854	$ 97,391
10	Taxes Other than Income Taxes	40,982	$ 40,038
11	Income Taxes	3,388	$ 18,120
12	Total Operating Expenses	598,127	$ 648,198
13	Operating Income	$ 24,304	$ 38,742

Calculation of Synchronized Interest
Staff Adjusted Rate Base

Weighted Average Cost of Debt: (60% x 6.63%) 3.98%

Tucson Electric Power Company
Docket No. E-01933A-04-0408
Test Year Ended December 31, 2003

Schedule JJD-7

Income Statement Pro Forma Adjustments

(in Thousands of Dollars)

Line No.	Description	Company As Filed	Adj#1	Adj#2	Adj#3	Adj#4	Adj#5	Adj#6	Adj#7	Adj#8	Adj#9	Adj#10	Adj#11	Adj#12	Staff Adjusted
	Operating Revenues														
1	Electric Retail Revenues	$ 608,219													$608,219
2	Sales for Resale		29,767	34,742											$ 64,509
3	Other Operating Revenue	14,212													$ 14,212
4	Total Operating Revenues	622,431	29,767	34,742											$686,940
	Operating Expenses														
5	Fuel Expense	173,935	12,668	34,048											$220,651
6	Purchased Power - Demand	4,136					(688)								$ 3,448
7	Purchased Power - Energy	22,406	3,019				(2,216)								$ 23,209
8	Other Operations and Maintenance Expense	261,425			(12,799)	(2,498)		(74)	(70)	(76)	(81)	(487)			$245,340
9	Depreciation and Amortization	91,854			(463)								6,000		$ 97,391
10	Taxes Other than Income Taxes	40,982			(944)										$ 40,038
11	Income Taxes	3,388												14,732	$ 18,120
12	Total Operating Expenses	598,127	15,687	34,048	(14,206)	(2,498)	(2,904)	(74)	(70)	(76)	(81)	(487)	6,000	14,732	$648,198
13	Operating Income	$ 24,304	$ 14,080	$ 694	$ 14,206	$ 2,498	$ 2,904	$ 74	$ 70	$ 76	$ 81	$ 487	$ (6,000)	$(14,732)	$ 38,742

Recap Schedules
C-1

Tucson Electric Power Company
Summary Cost of Capital
Test Year Ended December 31, 2003
(Thousands of Dollars)

Schedule JJD-8

OPERATING INCOME ADJUSTMENT NO. 10 - SARBANES-OXLEY

Line No.	Description	Amount
1	TEP Estimated Incremental SOX Compliance Cost (1)	$ 1,000,000
2	Non-recurring Start-up Costs at 25 Percent (Staff's Estimate)	250,000
		750,000
3	Less: Shareholders' Share at 50 Percent	(375,000)
		375,000
4	Less: Allocable to Other Affiliates at 22.6 Percent (1)	(84,750)
		290,250
5	Less: Test Year Actual Expense (1)	(14,389)
6	Correct Adjustment to Test Year Expense	275,861
7	SOX Expenses as Filed by Company	762,863
8	Staff Adjustment to Operating Income	$ 487,002

(1) Data Request DWC-17, TEP page 3201