0000020465

EXHIBITS FOR E-01345A-03-0437

BARCODE 0000020465

STAFF 10-32
SWEEP 1-4
WRA 1-4

CONTINUED
PLEASE SEE BARCODES AS REFERENCED BELOW
FOR REMAINDER OF EXHIBITS

0000020460: ACPA 1-4, AECC 1, 2, AECC/PD/FEA/K 1-3, APS 1-4

0000020461: APS 5-27, APS 33-39

0000020462: APS-R 1-15

0000020463: APS-R 16-22, APS-SD 1-4, ASP-SR 1-3, AUIA, AUIA-S, AZCA 1-5 & 7-10 (6 NOT USED) CNE/SEL 1-5, DOME VALLEY, FEA 1 & 2, GLEASON 1, IBEW 1, KROGER 1, MESQUITE 1 & 2, MUNDELL 1

0000020464: PPL 1 & 2, RUCO 1-15, SOUTHWESTERN POWER 1 & 2 STAFF 1-9

EXHIBIT
ALL-STATE LEGAL®
S-10
Admitted

BEFORE THE STATE OF ARIZONA

ARIZONA CORPORATION COMMISSION

I/M/O THE APPLICATION OF	)
ARIZONA PUBLIC SERVICE COMPANY	)
FOR A HEARING TO DETERMINE THE FAIR	)
VALUE OF THE UTILITY PROPERTY OF THE	)
COMPANY FOR RATEMAKING PURPOSES,	)
TO FIX A JUST AND REASONABLE RATE OF	) DOCKET NO. E-01345A-03-0437
RETURN THEREON, TO APPROVE RATE	)
SCHEDULES DESIGNED TO DEVELOP SUCH	)
RETURN, AND FOR APPROVAL OF	)
PURCHASED POWER CONTRACT	)

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.
ON BEHALF OF THE
ARIZONA CORPORATION COMMISSION

VOLUME 1

DIRECT TESTIMONY
AND
EXHIBIT___(MJM-1) THROUGH EXHIBIT___(MJM-2)
EXHIBIT___(MJM-4) THROUGH EXHIBIT___(MJM-8)

Date: FEBRUARY 3, 2004

BEFORE THE STATE OF ARIZONA
ARIZONA CORPORATION COMMISSION

I/M/O THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	) DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.
ON BEHALF OF THE
ARIZONA CORPORATION COMMISSION

Date: FEBRUARY 3, 2004

Introduction

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

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

Q. Please describe Snavely King.

A. Snavely King was founded in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 11 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 33-year history, members of the firm have participated in more than 500 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

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

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

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the staff ("Staff") of the Arizona Corporation Commission ("ACC").

Q. What is the subject of your testimony?

A. Depreciation is the subject of my testimony.

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

A. Yes. I and other members of my firm specialize in the field of public utility depreciation. We have appeared as expert witnesses on this subject before the regulatory commissions of almost every state in the country. I have testified in over 100 proceedings on the subject of public utility depreciation and represented various clients in several other proceedings in which depreciation was an issue but was settled. I have also negotiated on behalf of clients in fifteen of the Federal Communications Commissions' ("FCC") Triennial Depreciation Represcription conferences.

Q. Does your experience specifically include electric company depreciation?

A. Yes. I have testified in thirty-one proceedings on the subject of electric company depreciation, and I have prepared testimony in seven electric proceedings in which depreciation was ultimately settled.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I have been asked to review the depreciation-related testimony and exhibits of Arizona Public Service Company ("APS" or "the Company"). I was asked to express an opinion regarding the reasonableness of the Company's depreciation expense proposal and, if warranted, make alternative recommendations. I will also address the Company's implementation of the Financial Accounting

Standards Board's ("FASB") Statement of Financial Accounting Standards No. 143 ("SFAS No. 143").

APS' Depreciation-Related Proposal

Q. Please summarize APS' proposal.

A. Company witness Ms. Laura Rockenberger sponsors the Company's depreciation study and the resulting depreciation claim. The study was actually conducted by Mr. John F. Wiedmayer of Gannett Fleming and results in revised depreciation rates and amortization schedules producing a $287.7 million depreciation and amortization expense based on APS' plant and accumulated depreciation balances as of December 31, 2002.[1] This, in turn, represents a $3.0 million depreciation expense increase. Mr. Wiedmayer also prepared an addendum to the depreciation study setting forth depreciation rates for certain Pinnacle West Energy Corporation ("PWEC") production assets for which APS is seeking rate base treatment.[2]

In addition to the Company's depreciation proposal, Ms. Rockenberger sponsors the Company's implementation of the Financial Accounting Standards Board's Statement of Financial Accounting Standards No. 143. In its initial adoption of SFAS No. 143 "APS recorded a liability of $219 million for its asset retirement obligations including accretion impacts; a $67 million increase in the book value of the associated assets; and a net reduction of $192 million in

[1] Direct Testimony of Laura Rockenberger ("Rockenberger"), page 18, lines 13-14.
[2] Rockenberger, page 14, lines 23-24 and page 15, lines 1-2.

accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs relating to these obligations. Additionally, APS recorded a regulatory liability of $40 million for its asset retirement obligations."[3] The $40 million liability represents the cumulative timing differences between the amounts previously recovered in regulated rates in excess of the amount calculated under SFAS No. 143."[4] The Company is requesting specific language in the Commission's decision in this case approving APS' request that the application of SFAS No. 143 be revenue neutral in the rate making process and that cost of removal for assets without an asset retirement obligation continue to be reflected in the depreciation accrual and accumulated depreciation.[5]

Current Rates

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

A. APS' present depreciation rates were approved in a February 14, 1995 letter from the Arizona Corporation Commission, responding to APS' request for proposed depreciation changes.[6] The submission for a change in depreciation rates was based on an update of a 1992 study by Gannett Fleming, approved by the ACC in Decision No. 58664, dated June 1, 1994.[7]

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[3] Rockenberger, page 21, lines 18–24.
[4] Rockenberger, page 21, lines 18–24.
[5] Id., page 22, lines 10-17.
[6] Response to MJM 1-45. February 14, 1995 letter from Gary Yaquinto, Director, Utilities Division, Arizona Corporation Commission to William T. Post, Chief Operating Officer, Arizona Public Service Company.
[7] Id.

Q. How are the present rates calculated?

A. The Company's present rates for the Production, Transmission and Distribution functions are straight-line remaining life rates.[8] They include a $5.6 million additional depreciation provision for nuclear plant accounts, which was intended to offset the reduction in expense caused by switching from the average service life method (prior to the 1995 letter) to the remaining-life method (as approved in the 1995 letter).[9]

Q. Is APS proposing to continue to collect the additional provision for nuclear plant depreciation in its proposal for this proceeding?

A. No.[10]

<u>Summary and Conclusions</u>

Q. What is your opinion regarding the Company's depreciation and SFAS No. 143 proposals?

A. In my opinion, the Company's depreciation proposal is unreasonable because the proposal produces an excessive depreciation expense which will, in turn, be charged to ratepayers. APS' SFAS No. 143 proposal is also unreasonable because it is inconsistent with the principles and fundamentals of SFAS No. 143 as well as the related accounting order of the Federal Energy Regulatory Commission ("FERC") in Docket No. RM02-7, ("Order No. 631.")

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[8] The rates for Nuclear account 325 and the General plant accounts are calculated using the average service life method.

[9] Id.

[10] Response to MJM 2-77.

Q. What do you recommend?

A. I recommend a $240.3 million depreciation and amortization expense which results in a $44.3 million decrease rather than APS' $3.0 million proposed increase.[11]

Q. Why do you disagree with the Company's depreciation proposal?

A. I have the following disagreements.

- The Company has overstated its recovery of production plant decommissioning costs.
- The Company's proposed incorporation of future net salvage values in its transmission, distribution and general depreciation rate calculations is unreasonable because they increase the depreciation rates for inflated estimates of costs that probably will not be incurred.
- Several of the Company's proposed lives in the transmission, distribution and general plant functions are too short, thereby overstating the associated depreciation expense.

Q. Why do you disagree with the Company's SFAS No. 143 proposal?

A. I disagree with the Company's SFAS No. 143 proposal because it has not properly reflected the net salvage allowance it is proposing to charge to ratepayers.

Q. Have you accepted any of the Company's parameters?

A. Yes, I have accepted several of the Company's proposed parameters.

[11] Exhibit___(MJM-3), Statement D, p. 1 of 1.

Q. Was your decision to accept these parameters passive or did you conduct analysis to arrive at your decision?

A. My decision to accept these parameters was not passive; I conducted substantial analysis as will be discussed in several later sections of my testimony. Where I have accepted the Company's proposals it was based on my own independent analysis.

Additional Studies

Q. Did you conduct any additional analyses or studies which are useful for purposes of this proceeding?

A. Yes. My firm prepared a nationwide study of the life spans of Steam Production units in excess of 50 MW. We also conducted a study of life spans relating to Other Production units. These studies, identified as Exhibit___(MJM-1) and (MJM-2), can be used along with other information, to judge the reasonableness of estimated production plant life spans.

Q. Do your testimony and the related exhibits constitute a depreciation study?

A. Yes, they do. Exhibit___(MJM-3) incorporates all of my analyses and calculations and recommendations. It is followed by several explanatory exhibits.

Depreciation Concepts

Q. What is depreciation expense?

A. In summary, depreciation expense is a charge to operating expense to reflect the recovery of a company's previously expended capital. Public utility depreciation expense is typically straight-line over service life which results in an equal share of the cost of assets being assigned to expense each year over the service life of the assets. A service life is the period of time during which depreciable plant [and equipment] is in service.[12] Annual depreciation expense is a cost included in a public utility's revenue requirement.

Q. How is the annual depreciation expense calculated?

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

Q. Is it true that depreciation is a non-cash expense?

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

Q. What is the accumulated depreciation account?

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

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

Q. Does the fact that depreciation is a non-cash expense render it any less legitimate than any other expense?

A. Depreciation is a legitimate expense. However, since it is based on a substantial amount of judgment and complex analytical procedures, the measurement of depreciation and the calculation of the expense warrant careful consideration.

Q. What is the objective of depreciation expense?

A. For public utilities, the objective of depreciation is straight-line capital recovery. As stated above, this is accomplished by allocating the original cost of assets to expense over the lives of those assets through the application of depreciation rates to plant balances.

Q. How does APS determine its annual depreciation rates?

A. APS' depreciation rates are founded upon three fundamental parameters: a service life, a dispersion pattern and a net salvage ratio. APS used the remaining life technique to compute its proposed rates.

Q. Would you please explain how the rates were calculated?

A. Yes. In order to understand remaining-life depreciation, it is useful to first address whole-life depreciation.

Q. Please explain the whole-life technique.

A. The following calculation shows a straight-line whole-life depreciation rate assuming a 10-year average service life and zero ("0") percent net salvage.

Table 1

Straight-Line Whole-Life Depreciation Rate
Assuming 10-Year Life and 0% Net Salvage

$$\frac{100\%-(0\%)}{10 \text{ yrs.}} = 10.0\%$$

Each year the 10.0 percent depreciation rate would be applied to plant in service to produce an annual depreciation expense.

Q. What happens if you include net salvage in the calculation?

A. I will use negative net salvage as an example. Negative net salvage is the net cost of removal of the asset after completion of its service life. For the remainder of the testimony I use the terms negative net salvage and cost of removal interchangeably. Assume a negative 5 percent (-5%) net salvage ratio. The equation above with a value for negative net salvage is as follows:

Table 2

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

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

Negative net salvage increases the resulting whole-life depreciation rate from 10.0% to 10.5%.

Q. Why does negative net salvage increase the depreciation rate?

A. It increases the depreciation rate because negative salvage is, in effect, added to the original cost of the plant. Instead of 100% (which represents the original cost of assets), the numerator becomes 105%. This is equivalent to capitalizing or adding the estimated cost of removal to the original cost of the asset.

Q. Please explain the remaining-life technique.

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

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

Table 3

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

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

Q. Please explain why the whole-life depreciation rate in Table 2 and the remaining life depreciation rate in Table 3 are both 10.5 percent?

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

Q. What would happen if either of these fundamental parameters were to change?

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

Q. Is there anything unique about public utility depreciation?

A. Yes. There are three unique factors driving public utility depreciation rates. First, public utility depreciation is based on a "group life" as opposed to the lives of individual assets. Second, the cost of removing or disposing of an asset that is retired from service is charged to the accumulated depreciation reserve, as opposed to being recognized as an operating cost in the year incurred. Third, the original cost of a retired asset is also recorded in the accumulated depreciation reserve, as opposed to being written off in the year of the asset's retirement/disposal. Each of these factors affect the depreciation rates that are ultimately determined for the group of assets that are recorded in plant accounts designated by the FERC Uniform System of Accounts ("USOA").

Q. Please explain the concept of group life depreciation.

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

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

These factors are necessarily estimates of the average service lives and average remaining lives of groups of assets. These estimates are in turn based on complex analytical procedures, which involve not only the age of existing and retired assets, but also retirement dispersion patterns called "Iowa curves."

I will discuss all of these in more detail later in my testimony. The important point to remember is that service life, average age and Iowa curves are all used in the estimation of an average service life and average remaining life of a group of assets and are ultimately used to calculate the depreciation rate for that group of assets.

Q. Would you please relate these fundamentals to the issues in this proceeding?

A. Yes. In depreciation analysis it is axiomatic that the shorter the life, the higher the resulting depreciation rate. Several of APS' proposed depreciation rates are too high because they are based on lives which are too short. The following table shows the impact of a shorter life.

<u>Table 4</u>

<u>Impact of Lives on Depreciation Rates</u>

30 year life = 100%/30 = 3.3%

10 year life = 100%/10 = 10.0%

The shorter the life, the higher the rate. If the life is too short, the resulting rate is obviously excessive.

Q. Is there any other reason that APS' depreciation rates are excessive?

A. Yes, most of APS' proposed depreciation rates contain negative net salvage allowances which collect too much for future cost of removal and thus are far too negative. They result in excessive depreciation rates. The next table shows the impact on depreciation rates of increasing the cost of removal ratio:

Table 5

Impact of Increasing Cost of Removal Ratio

-5% ratio = 100 %-(-5)/10 = 10.5 %

-50% ratio = 100 %-(-50)/10 = 15.0 %

Increasing a cost of removal ratio from -5% to -50% increases the depreciation rate from 10.5% to 15.0%. If the estimated -50% cost of removal ratio is not supportable; obviously, the resulting 15.0% depreciation rate is excessive. The combination of these two factors, i.e., understated lives and overstated cost of removal ratios, compounds the excessive depreciation rate problem.

Excessive Depreciation

Q. What is an excessive depreciation rate?

A. An excessive depreciation rate is one that produces depreciation expense which is more than necessary to return a company's capital investment over the life of the asset.

Q. Have any courts addressed the concept of excessive depreciation?

A. Yes, the concept of excessive depreciation was explained by the U.S. Supreme Court in a landmark 1934 decision, Lindheimer v. Illinois Bell Telephone Company, as follows:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating

> expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies of the ∀behavior of large groups∀ of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, [are] always present. The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience.[13]

Q. Are you providing this as a legal opinion?

A. No. I provide this to illustrate that the concept of an excessive depreciation rate is not new.

Q. What is the effect of an excessive depreciation rate?

A. Excessive depreciation rates produce excessive depreciation expense. In other

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

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

Q. Who pays for excessive depreciation rates?

A. Ratepayers pay for excessive depreciation rates.

Q. Why are APS' depreciation rates excessive?

A. As explained above, they are excessive for two fundamental reasons. First they are based on lives which are too short; and second, they have been increased to provide for an unsupportable allowance for future negative net salvage.

Q. How will you address these issues?

A. Ordinarily, I would discuss lives and life study approaches first. However, due to the magnitude of the negative net salvage difference between the Company and my analysis, I will discuss negative net salvage first.

<u>Net Salvage</u>

Q. Did Mr. Wiedmayer include net salvage ratios in his depreciation rate calculations?

A. Yes.

Q. Is net salvage a significant issue in this proceeding?

A. Yes, it is.

Q. Please explain why.

A. It is significant because Mr. Wiedmayer has bundled inappropriate cost of removal factors in his proposed depreciation rates. If those rates are approved, the result will be that current ratepayers will pay for future inflation to costs that will not be incurred. In order to fully address this issue, I will approach it in the following manner. First I will address SFAS No. 143 and asset retirement obligations. This will be followed by a discussion of FERC Order No. 631. Next, I will discuss production plant dismantlement costs. Finally, I will discuss the net salvage ratios included in Mr. Wiedmayer's transmission, distribution and general plant depreciation rates.

Financial Accounting Standards Board's Statement of Financial Accounting Standard No. 143

Q. What is the Financial Accounting Standards Board?

A. The Financial Accounting Standards Board ("FASB") is a standards-setting body for the public accounting profession.

Q. What is SFAS No. 143?

A. SFAS No. 143 is a recent FASB pronouncement concerning the appropriate accounting for long-lived assets. Pursuant to SFAS No. 143 all companies (including APS) must review all of their long-lived assets to determine whether or not they have actual legal obligations to remove retired assets. For some plant and equipment, public utilities have a legal obligation to remove the asset at the end of the service life. These legal obligations for future removal are called asset retirement obligations ("AROs"). For other assets, no such obligation exists.

If a company does have an ARO, the net present value of the future retirement cost is considered to be part of the original cost of the asset. It is therefore capitalized (included in the original cost) and depreciated over the life of the asset. Hence, for assets with AROs, the accumulated depreciation account would equal the plant balance at the end of the asset's life. In other words, when AROs exist total depreciation expense would incorporate the cost of future removal. Total depreciation would equal the total recorded cost of the end of the asset's life.

If, however, a company does not have such legal obligations, the future cost of removal will not be capitalized and will not be included in depreciation expense. Therefore, for assets without AROs, at the end of the asset's life, the accumulated depreciation account will equal the plant balance because only the original cost of the asset will have been depreciated. In other words, there is symmetry between assets with and without AROs. In both cases, the accumulated depreciation will equal the original cost of the asset at the end of its life.

Q. How are AROs measured?

A. AROs are measured at their net present value, not their inflated future value.

Q How are AROs recorded on the books?

A. As stated above, AROs are capitalized as a cost of the related asset and concomitantly recorded as a liability for those companies with a legal obligation to remove a retired asset. Each year, as the liability increases due to inflation, the increase is charged to accretion expense and credited to the liability, but the asset value remains the same. In other words, just as the original cost of the asset does not increase, neither does the capitalized asset retirement cost.

Q. What happens if a company does not have an asset retirement obligation pursuant to SFAS No. 143?

A. As explained above, if a company does not have such obligations, the future cost of removal is not considered as a cost of the asset, and therefore it will not be included in the company's depreciation expense on its general purpose financial statements. SFAS No. 143, therefore, unbundles net salvage from depreciation rates. It does this in two ways. Either by incorporating the net present value of an ARO in the cost of the asset, or by excluding non-AROs from the depreciation rate calculations.

Q. What is the accounting impact of SFAS No. 143 for electric utilities?

A. Under Generally Accepted Accounting Principles ("GAAP"), electric utilities will be required to review all of their assets to determine if they have any AROs. They will also be required to determine the amount of any prior cost of removal collections relating to non-AROs that is now included in their accumulated depreciation accounts. These latter amounts and any such future charges to ratepayers will be recorded as a regulatory liability to ratepayers.

Q. Has APS implemented SFAS No. 143?

A. Yes. The Company implemented SFAS No. 143 on January 1, 2003.[14]

[14] Rockenberger, page 19, line 4.

Q. Does the Company have any asset retirement obligations pursuant to SFAS No. 143?

A. Yes. Upon review, the Company found that the Palo Verde (including the Palo Verde sale leaseback), Four Corners, Navajo and Childs Irving generating plants had retirement obligations generally relating to final plant decommissioning or removal costs based on regulatory or contractual requirements as estimated and recorded as of January 1, 2003.[15] APS also has some AROs related to transmission and distribution plant, but as the timing of these obligations cannot be determined, no ARO has been recorded.[16]

Q. Has APS recorded any impacts related to SFAS No. 143 on its books?

A. Yes. As discussed above, "APS recorded a liability of $219 million for its asset retirement obligations including accretion impacts; a $67 million increase in the book value of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs relating to these obligations."[17]

APS also recorded a regulatory liability of $40 million for its asset retirement obligations, representing the cumulative timing differences between

[15] Rockenberger, page 19.
[16] Id., page 20.
[17] Id., page 21.

the amounts previously recovered in regulated rates in excess of the amount calculated under SFAS No. 143."[18]

Q. Why did APS record the $40 million regulatory liability?

A. According to Ms. Rockenberger, the purpose of the regulatory liability is "to make the implementation of the new standard revenue neutral, so that the timing differences in the accounting would not increase or decrease APS' overall revenue requirement."[19]

Q. Does the Company make any additional requests regarding the implementation of SFAS No. 143 for asset retirement obligations?

A. The Company has requested that the Commission insert the following specific language in its decision in this proceeding:

> The Commission approves APS' request that the application of SFAS No. 143 be revenue neutral in the rate making process and authorizes APS to place all impacts to its income statement caused by the adoption of SFAS No. 143 in regulatory accounts. Those impacts include the cumulative adjustment as of January 1, 2003 and ongoing expense recognition impacts.[20]

Q. Why would APS request such language?

A. In my opinion, APS is requesting this language because it is aware that it does not have AROs for a majority of its assets but it has a substantial amount future inflated cost of removal included in its accumulated depreciation account and in

[18] Rockenberger, page 21, lines 18–24.
[19] Rockenberger, page 22.
[20] Rockenberger, page 22.

its current and proposed depreciation rates. The elimination of this recovery in accordance with the principle SFAS No. 143 will lead to a significant reduction in APS' depreciation expense. Consequently, it seeks a revenue neutral application of SFAS No. 143.

Q. Do you agree with APS' request for revenue-neutral language?

A. No.

Q. Does the Company discuss its plans for the treatment of removal costs that are unrelated to asset retirement obligations?

A. Yes. The Company plans to continue to include these costs "in the calculation of the depreciation accrual and accumulated depreciation in the same manner as it was prior to January 1, 2003, consistent with current ratemaking treatment."[21] In fact, APS requests the Commission include specific language in its decision related to this issue, as such:

> The Commission also approves APS' request that removal costs for assets that do not have an asset retirement obligation continue to be reflected in the depreciation accrual and accumulated depreciation.[22]

Q. Do you agree with the Company's treatment of these types of removal costs?

A. No. The Company's proposal violates the principles and fundamentals of current Generally Accepted Accounting Principles ("GAAP") regarding cost, capital

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[21] Id., page 21.
[22] Id., page 22.

recovery, and cost of removal. APS' approach, which bundles future net salvage ratios in depreciation rates, results in the anomalous result of an accumulated depreciation account which exceeds the actual plant balance at the end of the plant life as I explained in the depreciation concepts section.

<u>FERC Reporting</u>

Q. Does APS file depreciation studies with FERC?

A. No. APS has not filed depreciation studies with FERC in the last ten years and [according to APS] there are no current FERC requirements to file depreciation studies with FERC.[23]

Q. Are there any differences between the depreciation rates the Company uses for FERC reporting and those it uses for ratemaking purposes?

A. No. According to the response to MJM 1-54, "the Company uses the same depreciation rates for FERC reporting and ratemaking purposes as it does for intrastate reporting and ratemaking purposes." [24]

<u>FERC Order No. 631</u>

Q. What is the impact of SFAS No. 143 on electric regulatory accounting?

A. The impact on regulatory accounting for electric utilities is that SFAS No. 143 evolved into FERC Order No. 631 in Docket RM02-7-000. FERC Order No. 631 resulted in changes to the USOA to incorporate the principle of SFAS No. 143.

Q. How did SFAS No. 143 evolve into FERC Order No. 631?

[23] Response to MJM 1-53.
[24] Response to MJM 1-54.

A. SFAS No. 143 was initiated in 1994 as a result of a request by the Edison Electric Institute. Subsequent to that initiation, the accounting community went through several iterations of proposals and comments to finally arrive at SFAS No. 143. FERC established Docket No. RM02-7-000 as a result of SFAS No. 143. This docket has included a Technical Conference, Comments, a Notice of Proposed Rulemaking ("NOPR"), Additional Comments and ultimately, Order No. 631, on April 9, 2003. Exhibit___(MJM-4) is a document I wrote to track the progress of SFAS No. 143 into FERC Order No. 631. It primarily addresses net salvage as it relates to non-ARO assets, since that is the subject in dispute.

Q. What is the thrust of Order No. 631?

A. Order No. 631 essentially adopts SFAS No. 143 and then integrates it into the Uniform System of Accounts.

Q. Does Order No. 631 require electric utilities to review their long-lived assets to determine whether they have any AROs?

A. Yes. Order No. 631 adopts SFAS No. 143, which already obligates electric utilities, among others, to review their long-lived assets to determine if they have any AROs.

Q. Is the Order No. 631 review the same as the review APS has already performed under SFAS No. 143 in which it determined that it has AROs for some of its production plant?

A. Yes, it is.

Q. What are the implications of Order No. 631 in situations where electric utilities do not have AROs?

A. FERC Order No. 631 defines cost of removal allowances for which there is no legal asset retirement obligation, as "non-legal retirement obligations." Past and future "non-legal AROs" must be specifically identified and accounted for separately in the depreciation studies, depreciation expense and the accumulated depreciation account.

In Order No. 631, FERC established new requirements for non-legal AROs, as follows:

> Instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in Parts 101, 201 and account 31, Accrued depreciation - Carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals.[25]

Q. Does FERC provide any additional insight as to the interpretation of these new rules?

A. Yes, FERC also states:

[25] FERC Docket No. RM02-7-000, Order No. 631, Issued April 9, 2003, Paragraph 38.

> Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations."[26]

Q. Does FERC make any policy calls concerning the appropriate treatment of the disposition of prior and future collections contained in these separate allowances?

A. No. FERC declines to make such calls on a policy basis. FERC will resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis. Specifically, FERC states:

> "The Commission will decline to make policy calls concerning regulatory certainty for disposition of transition costs, external funds for amounts collected in rates for asset retirement obligations, adjustments to book depreciation rates, and the exclusion of accumulated depreciation and accretion for asset retirement obligations from rate base; these are matters that

[26] Id., Paragraph 39.

> are not subject to a one size fits all approach and are better resolved on a case-by-case basis in rate proceedings. The Commission is of the view that utilities will have the opportunity to seek recovery of qualified costs for asset retirement obligations in individual rate proceedings. This rule should not be construed as pregranted authority for rate recovery in a rate proceeding."[27]

Q. Does FERC's Order require anything new or more with respect to its requirement for detailed depreciation studies?

A. No. FERC states:

> "Finally this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates.45." [28]

And footnote 45 states:

> "When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."[29]

Thus, FERC recognizes distinctions between legal and non-legal AROs just as

[27] Id., Paragraph 64. (Emphasis added.)
[28] Id., paragraph 65.
[29] Id., footnote 45.

SFAS No. 143 recognizes those distinctions. In fact, the amount resulting from Order No. 631's requirement to identify previous amounts collected for non-legal AROs should result in the same amounts as the SFAS No. 143 requirement to establish a regulatory liability to ratepayers. It is also clear, that on a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to include in rates.

Q. What is the most important aspect of Order No. 631?

A. The most important aspect of Order No. 631 is its requirement to separate or unbundle non-legal cost of removal allowances from depreciation rates.

Q. How much prior collections are included in APS' accumulated depreciation account?

A. APS' response to MJM-82 indicates that it has already collected $364.6 million from its customers for future cost of removal.

Q. Is APS proposing to include any additional future removal costs in its depreciation rates?

A. Yes. APS' depreciation rates are designed to collect an annual amount of about $31.6 million for future removal costs.[30] It would do this by bundling net salvage ratios in depreciation rates. This amount would fluctuate based on changes in plant balances.

Q. Does APS' proposal comply with FERC Order No. 631?

[30] Difference between APS' proposed depreciation expense with and without Gannett Fleming net salvage proposals.

A. APS' proposal does not comply with FERC Order No. 631. APS has already implemented SFAS No. 143. The removal costs it proposes to recover through depreciation rates are "non-legal AROs". Order No. 631 requires that these be accounted for separately as a specifically identifiable allowance. I have estimated these amounts, but they are not set forth in specifically identifiable allowances. They are bundled into depreciation rates.

Q. What is your reaction to APS' filing?

A. My reaction is that even though APS has implemented SFAS No. 143 and apparently Order No. 631, it is proposing to charge much more to its ratepayers for non-legal AROs than it would if it actually had legal obligations to remove these assets.

Q. Has APS been uniform in its approach to estimating these non-legal AROs?

A. No. APS' removal costs for the production plant units were based on site-specific estimates which Gannett Fleming then inflated to the anticipated retirement date of each unit.[31] The estimated removal costs for the transmission, distribution and general functions were based on historical summaries. First, I will discuss the production plant decommissioning estimates. Then, I will address the transmission, distribution and general net salvage estimates.

<u>Production Dismantlement Costs</u>

Q. Has APS built decommissioning costs for its production plant into its depreciation rates?

[31] Attachment LLR-4, page II-31.

A. Yes. APS has included negative net salvage ratios in its steam, nuclear and other production plant depreciation rates. While the Company does not include a net salvage ratio in its depreciation rates for hydraulic plant, it does request specific decommissioning costs related to this plant.

Q. Do you agree with APS' inclusion of these decommissioning costs in its depreciation rates?

A. I disagree with the Company's production plant decommissioning proposals for its steam, nuclear and other plant. The Company has already implemented SFAS No. 143 and recorded the impacts on its books. Any remaining decommissioning should be related to non-legal AROs, and as will be discussed below, should not be included in depreciation rates. Furthermore, as shown on Schedule 1 of Attachment LLR-4, the Company has included a net salvage component in the depreciation rates for plants it has identified as having AROs. This could indicate a double count of decommissioning costs for these plants.

Q. Please explain the Company's proposal for hydraulic plant.

A. In 1999 the Company entered into an agreement to decommission the Childs-Irving hydro plant and to restore the waters to Fossil Creek by 2004. Previously, APS had intended to renew the plants' operating licenses for an additional 30 years. As such, the Company did not include decommissioning costs in the previous depreciation study. APS took additional depreciation of over $8 million related to the decommissioning of these plants over the years 2000-2002. In the current case, APS requests that the difference between the estimated decommissioning cost of $13.2 million and the book reserve of $7.9 million be amortized over the upcoming two year period.[32] The resulting annual amount of $2.7 million is included in the depreciation study. No other depreciation expense is being collected for hydro plant.

Q. Do you agree with the Company's handling of the hydro decommissioning costs?

A. I do not agree with the Company's treatment of hydro decommissioning costs. It has AROs for the investment. I have, however, accepted the Company's amortization because I believe it approximates the amount that would result from the appropriate ARO treatment.

<u>Non-Production Plant Net Salvage Estimates</u>

Q. What is net salvage?

A. Plant and equipment is retired from service at the end of its useful life. Sometimes the retired plant and equipment may be physically removed and can be resold for value. This is called gross salvage. In more technical terms, gross salvage is the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property. Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant.[33] Net salvage is the difference between gross salvage and cost of removal.

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[32] Response to MJM 1-3.
[33] NARUC Manual, pages 320 and 317.

Q. Does APS propose to charge net salvage to ratepayers for its non-production plant accounts?

A. Yes. APS has included negative net salvage ratios in most of its proposed transmission and distribution plant depreciation rates, as well as the depreciation rate for one of its general plant accounts. As explained in the depreciation concepts sections of this testimony, negative future net salvage ratios increase depreciation rates.

Q. How did APS estimate its proposed future net salvage ratios?

A. Mr. Wiedmayer prepared summaries of annual retirements and net salvage, which he used as a basis for his future net salvage proposals. The following table is a hypothetical example of Mr. Wiedmayer's net salvage studies.

Table 6

Hypothetical Net Salvage Study

Year	Original Cost Retired Asset	Cost of Removal ($)	Cost of Removal (%)
(a)	(b)	(c)	(d)=(c)/(b)
1997	1,000	(500)	(50)%
1998	2,000	(1,500)	(75)
1999	2,500	(1,000)	(40)
2000	3,000	(2,500)	(83)
2001	4,000	(5,000)	(125)
Total	12,500	(10,500)	(84)%
3-year Avg.	3,167	(2,833)	(89)%
5-year Avg.	2,500	(2,100)	(84)%

Q. Please explain this table.

A. The years in column (a) are the years in which the assets in column (b) were retired. These assets had originally been placed in service several years before they were retired. In other words they were added to plant in service several years ago, they lived their service life, and then they were retired or withdrawn from service. The cost of removal amounts in column (c) are the costs incurred in connection with the retirement from service and the disposition of the assets. In other words, an asset that originally cost $4,000 several years earlier was retired from service in 2001. It cost $5,000 to retire and dispose of that asset in 2001. The ratios in column (d) are the cost of removal amount expressed as a percentage of the original cost of the assets.

Q. How did Mr. Wiedmayer use these figures to estimate his future net salvage ratios?

A. Mr. Wiedmayer considered rolling 3-year averages, the most recent 5-year average and overall average in making his decision. He also adjusted his net salvage estimates for some transmission and distribution plant accounts to account for reuse of materials.

Q. Why did Mr. Wiedmayer adjust his net salvage analysis to account for reuse of materials?

A. As described on page II-30 of Attachment LLR-4, "Many transmission and distribution plant accounts experience high levels of reuse salvage, i.e., materials returned to stores during the early portion of a group's life cycle." "However, as the group ages, the ability to reuse materials decreases and ultimately ceases."

"As a result of inflation, most of the original cost retired relates to relatively young plant which can be reused. Thus, the analysis of gross salvage provides an indication that only would be correct if such plant was capable of being reused throughout its life cycle."[34]

Q. How did Mr. Wiedmayer adjust his net salvage analysis for reuse salvage?

A. Mr. Wiedmayer estimated the age beyond which plant will not be reused, determined the percent surviving at that age and weighted the experienced gross salvage indication by 100 percent less the percent surviving, the percent retired.

Q. What was the effect of this adjustment?

A. The overall effect of the adjustment was to change the net salvage percent for each account adjusted from a positive figure to, in most cases, a negative figure and thus increase the depreciation rate. Mr. Wiedmayer then used judgment to assign a future net salvage percent to each of these accounts.[35]

Q. Do you agree with this adjustment?

A. I do not agree with the adjustment. To be intellectually consistent, Mr. Wiedmayer should have correspondingly lengthened the lives in these accounts. However, my disagreement is a moot point as I do not agree with Mr. Wiedmayer's net salvage analysis as a whole. As will be discussed below, Mr. Wiedmayer's approach results in a mismatch of dollars, leading to unreasonable net salvage ratios. Mr. Wiedmayer recognizes this mismatch in one area in his

[34] Attachment LLR-4, page II-30.
[35] Attachment LLR-4, page II-32.

decision to adjust his salvage analysis. Furthermore, Mr. Wiedmayer's chosen net salvage ratios do not reflect the results of his adjustment, in most cases they are far too negative.

Q. His reuse adjustment aside, does Mr. Wiedmayer's net salvage approach result in an increase to depreciation rates?

A. Yes, it does. Net salvage ratios developed in this fashion depend on the relationship of the cost of removal as a percentage of the original cost of the assets retired, as shown above. This relationship results in a negative net salvage ratio which is bundled into the depreciation rate calculation as shown in the concepts section of this testimony. Since the ratio is negative, <u>it increases the resulting depreciation rate</u>. This is also demonstrated in the concepts section.

Q. Is this approach problematic?

A. Yes. The hypothetical retirements shown above are in very old original cost dollars. This approach is problematic due to the mismatch in the value of dollars between the years the assets were installed and the years they are retired. For example, assume that the $4,000 of assets retired in 2001 were actually placed in service in 1951 or 50 years ago. The cost of removal in 2001 dollars is $5,000, or 125 percent, of the 1951 addition.

Q. Please explain what caused the result to be negative 125 percent.

A. The result is negative 125 percent because the $5,000 cost of removal has experienced 50 years of inflation. If we assume the inflation rate has been 5 percent annually, the cost of removal in 50-year old dollars is only $436 or 11 percent of the original $4,000 installation. Mr. Wiedmayer's approach, however, shows 125 percent as a result of this mismatch. The same disparity would be true for all other years in the example. There is a fundamental mismatch between the dollars associated with the installation dates of the assets and the dates they are removed from service.

Q. How would Mr. Wiedmayer use this ratio?

A. Mr. Wiedmayer would use a negative 125 percent ratio in the depreciation rate calculation. As I explained in the concepts section, this approach is equivalent to capitalizing 125 percent of the existing plant in service. The example above addresses only retirements. But at the same time, as explained in the concepts section, the actual plant balance has been growing for many reasons. The hypothetical company has been making additions every year due to growth, and these additions have also experienced inflation. Assume the current total plant balance in this account is $100,000,000. Mr. Wiedmayer would calculate depreciation rates designed to collect $225,000,000 from ratepayers, i.e. $125,000,000 more than the company spent on the plant, and this would be based on a $4,000 retirement.

Q. Do APS' net salvage studies suffer from this mismatch?

A. Yes, APS' net salvage studies suffer from a mismatch in the value of dollars between the installation and removal dates of their retired assets. This mismatch leads, and has lead in the past, to exorbitant current charges to current ratepayers for inflated future cost of removal. If such amounts are to be recovered, only the present value should be recovered from current ratepayers as is done for AROs.

Q. Is there a simple explanation for the exorbitant current charges?

A. Yes, APS' future net salvage ratios are <u>inflated</u>, but not reduced to their net present value. They result in excessive cost of removal charges because these inflated net salvage ratios are applied to current plant balances. Thus, current ratepayers pay for inflated removal costs that are not expected to occur.

Q. Is there a way to visualize this?

A. Yes, consider the examples in the depreciation concepts section of this testimony. If you recall, I showed the difference in depreciation rates resulting from a negative 5 percent net salvage ratio versus a negative 50 percent net salvage ratio. It increased the resulting rate substantially. If the actual cost of removal in today's dollars is only 5 percent, then the increased depreciation rate resulting from the inclusion of future inflation results in today's ratepayers being charged for inflation that has not even occurred. The proper approach is to use the negative 5 percent present value, not the negative 50 percent inflated value, of the cost of removal.

Q. How much future net salvage is incorporated in the Company's depreciation request?

A. Because the amount varies with changes in plant balances, it is difficult to determine the precise amount of net salvage. I estimate however, that there is a minimum of $31.6 million of annual **negative** net salvage charges included in APS' overall depreciation request.

Q. How much actual net salvage has the Company been experiencing?

A. Over the five years ending 2002 the Company has experienced $1.1 million in **positive** net salvage on average. This is shown in the net salvage section of Exhibit___(MJM-3).

Q. What do you make of the level of cost of removal in the Company's proposal?

A. The Company is proposing to collect approximately $31.6 million annually for a cost which averages to a **positive** $1.1 million annually. That is a substantial mismatch.

Q. Are you familiar with APS' approach?

A. Yes. In the past, many utilities have used this approach. Furthermore, it seems to be the recommended approach in the NARUC's 1996 Public Utilities Depreciation Practices Manual. On the other hand, the manual also states:

> "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."[36]

[36] NARUC Manual, page 157.

The NARUC depreciation manual further opines on the underlying rationale for treating removal cost as a current-period expense, instead of incorporating it in depreciation rates:

> "It is frequently the case that net salvage for a class of property is negative, that is, cost of removal exceeds gross salvage. This circumstance has increasingly become dominant over the past 20 to 30 years; in some cases negative net salvage even exceeds the original cost of plant. Today few utility plant categories experience positive net salvage; this means that most depreciation rates must be designed to recover more than the original cost of plant. The predominance of this circumstance is another reason why some utility commissions have switched to current-period accounting for gross salvage and, particularly, cost of removal."[37]

Setting aside ratemaking, one of the mechanical problems with this approach is that it can result in a depreciation reserve actually exceeding the gross plant balance. That is because, as I explained in the depreciation concepts section, the depreciation rate is more than necessary to fully depreciate the plant. Therefore, at the end of its life, the accumulated depreciation account exceeds the plant account balance. This is one of the reasons I believe that APS' approach is inconsistent with fundamentals and principles of current practices regarding cost, capital recovery, and cost of removal. The accumulated depreciation and depreciation expense should be designed to recover the

[37] Id., page 158.

original costs, not something more.

Separation

Q. What do you recommend?

A. First, since these are "non-legal" AROs, they must be accounted for as specifically identified allowances within depreciation expense and accumulated depreciation. In other words, they must be separated from other depreciation expenses.

Measurement

Q. How should these allowances be calculated?

A. I recommend the Pennsylvania Public Utility Commission's normalized net salvage allowance approach to determine the annual amount of the allowance. This is based on the average of the most recent 5 years worth of actual net salvage activity shown in APS' depreciation study. Net salvage is treated just as any other normalized expense, except that it is charged to accumulated depreciation. The Company is ensured full recovery of its annual costs, and ratepayers are not required to pay for estimated future inflation.

This approach has the added benefit that it is simple, straight-forward and easy to implement. It conforms to FERC Order No. 631 in that the net salvage allowance is a specifically identifiable amount that can be separately accounted for in depreciation expense and the accumulated depreciation account. Furthermore, it does not treat non-legal AROs as if they were legal AROs. Using the Company's data as reported in their FERC Form 1 reports, the normalized net salvage allowance amount would be positive $1.1 million. This is because APS actually experiences positive net salvage on average.

Q. How did you arrive at the positive $1.1 million annual net salvage allowance?

A. That is the average of the most recent 5-years worth of actual net salvage activity reported by the Company in their 1998 through 2002 FERC Form 1 reports[38], as shown in the Net Salvage Section of Exhibit___(MJM-3). The positive $1.1 million allowance is actually a normalized allowance.

Q. Do you recommend reducing the Company's depreciation expense by the $1.1 million net salvage allowance

A. No, I do not. While the Company has been experiencing positive net salvage on average for many years, it appears that a substantial portion of the positive net salvage is actually "reuse". For this reason, I am recommending a zero ("$0") net salvage allowance in this proceeding.

Q. Please summarize your net salvage recommendations.

A. First , I recommend rejecting APS' request to include $31.6 million of cost of removal in determining the depreciation rates for its plant accounts. The Company has already collected $346.6 million for removal costs it has not

[38] FERC Form 1 reports were used to get the most up-to-date information. Mr. Wiedmayer's net salvage data only covered up to 2001. The amounts for 1998-2001 do not match Mr. Wiedmayer's amounts exactly, but they are close.

incurred.[39] This resulted from the inclusion of inflated future net salvage ratios in prior depreciation rates.

Second, APS proposes to continue to collect $31.6 million more <u>each year</u> even though actual average expense is a positive $1.1 million. Again, this mismatch is caused by APS' request for additional inflated future net salvage ratios in its new proposed depreciation rates.

APS' net salvage request amount is not specifically identifiable; it can only be estimated, since it is bundled into APS' proposed depreciation rates, and it will change each year as plant balances change. Considering these numbers in light of SFAS No. 143 and FERC's Order No. 631, it is impossible to even rationalize APS' $31.6 million request.

As an alternative, I am recommending an unbundled specific identifiable net salvage allowance that can be included as a component of depreciation expense and recorded in accumulated depreciation. Due to the Company's collection of positive net salvage on average, this allowance should be $0. This approach will separately identify such information to facilitate external reporting, regulatory analysis, and for rate setting purposes. My recommendation is consistent with paragraphs 36 and 38 of the FERC's Order No. 631 in its Docket No. RM02-7-000, issued April 9, 2003.

Q. What significant numbers are involved in the net salvage issue?

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[39] Response to MJM 2-82.

A. In my opinion there are three very significant numbers. The first is the $354.6 million APS has already charged to customers. The second is the amount of inflated estimated future cost of removal bundled in Mr. Wiedmayer's depreciation rates for all functions, i.e., including production. The third is its actual recent experience. These amounts are listed below:

Table 7

Net Salvage Amounts	Annual Amount
Included in Depreciation Reserve	$ 354.6 million
Bundled in Wiedmayer Rates	$ 31.6 million
Actual Recent Experience	- $ 1.1 million

The Commission can use these three numbers to judge the reasonableness of the specific identifiable annual allowance it grants to the Company. In my opinion, the allowance should be $0. To grant the $31.6 million would be tantamount to providing APS with $31.6 million of additional before-tax return on equity each year.

Q. Does the 5-year average allowance approach you are recommending result in the abandonment of accrual accounting?

A. No. Accrual accounting is the recognition of revenue when earned and expenses when incurred. SFAS No. 143 and Order No. 631 preclude recording AROs for non-legal retirements because there is no legal obligation to incur such costs. Mr. Wiedmayer is attempting to accrue an expense for which APS has no liability. Consider that GAAP is founded upon accrual accounting, and SFAS No. 143 is GAAP.

Q. Have you made any similar recommendations in other proceedings?

A. Yes, in two recent cases the New Jersey Board of Public Utilities actually endorsed my testimony regarding SFAS No. 143. For example, in a recent case involving Rockland Electric Company the Administrative Law Judge accepted my position:

> 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.
>
> 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.[40]

[40] 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.

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.[41]
>
> 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.[42]

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

In a separate proceeding involving Jersey Central Power & Light Company, the Board agreed with my position:

> 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.[43]

Q. Have any other states adopted a 5-year net salvage allowance approach?

A. Yes. As I stated earlier the 5-year rolling net salvage allowance approach is used by the Pennsylvania Public Utility Commission.[44] This procedure was also recently adopted by the Missouri PSC in at least two cases in that state[45], and on a trial basis by the Kentucky PSC in two recent cases.[46] The net salvage allowance approach ensures that the Company recovers the net present value of its actual cost, but eliminates the inclusion of future inflation in depreciation rates.

Q. Does this conclude your discussion of net salvage?

A. Yes, I will now discuss life studies.

<u>Life Study Methods</u>

Q. Please describe life analysis and life estimation.

A. Life analysis is the process of estimating how long plant has lived in the past. Life estimation is the process of estimating how long the existing plant will live in the future. Mr. Wiedmayer used two basic methods: the life span method and the retirement-rate actuarial method. The life span method was used for the Production Plant functions and the retirement-rate method was used for the

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

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

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

[46] I/M/O The Application of Jackson Energy Cooperative for an Adjustment of Rates, Case No. 2000-373, Order Issued May 21, 2001; and I/M/O Adjustment of Rates of Fleming-Mason Cooperative, Case No. 2001-00244, Order Issued August 7, 2002.

Transmission, Distribution and General functions.

Q. What is the life span method?

A. The life span method is based on the premise that all plant within a property group will retire concurrently a specific number of years after the initial placement. There may be interim additions and retirements; however, all plant is assumed to be subject to a "final retirement."

Chapter X of the NARUC Manual addresses the life span method. It stresses that the final retirement date is the most important factor in the determination of a depreciation rate using the life span method.[47] The NARUC Manual requires consideration of several factors, including economic studies, retirement plans, forecasts, technological obsolescence, adequacy of capacity and competitive pressure in order to develop an informed estimate of the final retirement date.[48] The NARUC Manual elaborates on the need for the consideration of these factors as follows:

> **Economic Studies and Retirement Plans**
>
> Retirement plans for utility properties are supported by various kinds of studies, including economic analyses. It is critical that this vital information be considered; otherwise the [life span] study is analogous to a building which is structurally well built from the ground up but lacking a sound and proper foundation. Retirement decisions should be based on sound engineering and economic principles and practices so that management may be confident

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[47] NARUC Manual, p. 146.
[48] Id.

> that the planned retirement of existing plant and approval of new investment are the most economical actions.[49]

The relevance of this quotation will become evident in my discussion of the Company's steam production plant depreciation rates.

Q. What is the retirement rate method?

A. The retirement rate method is an actuarial technique used to study plant lives, much like the actuarial techniques used in the insurance industry to study human lives. It requires a record of the dates of placement (birth) and retirement (death) for each asset unit studied. It is the most sophisticated and reliable of the statistical life analysis methods in that it relies on the most refined level of data. Aged retirements and exposures data from a company's records are used to construct observed life tables ("OLT"). These are then smoothed and extended by fitting, using least-squares analysis, to a family of 31 predefined survivor curves ("Iowa Curves") using varying life assumptions. The process continues until a best fit life is found for each curve. Numerous interactive calculations are required for a retirement rate analysis.

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

Q. How did Mr. Wiedmayer calculate production plant depreciation rates?

A. Mr. Wiedmayer used the life span method.

Q. Please explain the life span method.

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49 <u>Id.</u> (Emphasis added).

A. The life span method is actually a procedure to calculate an average service life and average remaining life for a property group. It is based on the assumption that a property group is comprised of a small number of large units subject to concurrent terminal (final) retirement. The period between the original installation and the terminal retirement date is the life span. The period between the study date and the terminal retirement date is the remaining life span. The life span method also recognizes "interim" additions and retirements prior to the terminal date. Importantly, however, interim additions are not considered in the depreciation base or depreciation rate until they occur.[50] The life span method has obvious intuitive appeal. The method also has limitations and strenuous rules for its application.

Q. Do you agree with the Company's use of the life span method?

A. Not necessarily. However, I am not opposing the use of it in this proceeding.

Q. What terminal retirement years is the Company proposing for its production plant investment?

A. The Company's proposed terminal retirement years are shown on Statement E of Exhibit___(MJM-3), which is my depreciation study.

Q. Are these terminal retirement years important?

A. Yes. The terminal (final) retirement year is the most important factor in the determination of a depreciation rate using the life span method.

[50] Id., p. 142.

Q. Do you disagree with the terminal retirement years that Mr. Wiedmayer is proposing?

A. No. I have accepted Mr. Wiedmayer's terminal retirement years based on my own independent analysis. I am including this detailed discussion so that the Commission can understand my reasoning for accepting APS' proposal.

Q. What is the viewpoint of NARUC on the subject of terminal retirement years?

A. In August 1996, NARUC issued an updated version of its Public Utility Depreciation Practices Manual ("NARUC Depreciation Practices Manual"). Chapter X of the manual addresses the life span method. It stresses that the final retirement date is the <u>most</u> important factor in the determination of depreciation rate using the life span method. The NARUC Depreciation Practices Manual requires consideration of several factors, including: economic studies, retirement plans, forecasts, technological obsolescence, adequacy of capacity and competitive pressures, in order to develop an informed estimate of the final retirement date.[51] The NARUC Depreciation Practices Manual elaborates on the need for the consideration of these factors as follows:

> **Selecting Retirement Dates**
>
> As indicated in the above discussion, the final retirement date is the most important factor in the determination of a depreciation rate for life span properties. Therefore, an informed estimate of the final retirement date is essential to ensure adequate recognition of depreciation over the life of the property. Several factors are considered in selecting retirement dates, e.g.

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[51] NARUC Depreciation Practices Manual, page 146.

economic studies, retirement plans, forecasts, technological obsolescence, adequacy of capacity and competitive pressure.[52]

Q. What life spans is Mr. Wiedmayer proposing for his depreciation study?

A. The Terminal Retirement Years table in Exhibit___(MJM-3) also shows Mr. Wiedmayer's proposed life spans and remaining life spans. Mr. Wiedmayer proposed life spans range from 51 to 62 years for Steam Production units, 40 years for Nuclear Production units, 88 to 95 years for Hydraulic Production units and 45 to 55 for Other Production units. On average Mr. Wiedmayer proposes 56.5 years for the Steam Production plant.

Q. Does the Company have any of the studies, plans, or forecasts specified in the NARUC depreciation practices manual to support any of its terminal retirement year and life span estimates?

A. Data request MJM 1-11, attached as Exhibit___(MJM-5) addressed this issue. According to the Company, "APS does not maintain the information requested in the question in the form outlined in NARUC Public Utility Depreciation Practices."[53] The response goes on to note that the lives for Four Corners 1-3 and Navajo were tied to the underlying lease terms. The lives for Four Corners 4-5 were tied to the ARO probability for retirement of these units. Other steam production lives were extended based on engineers' estimates, or remained the same as the currently approved life. The life of the nuclear plant reflects the

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[52] Id.

[53] Response to MJM 1-11.

license period and the lives of the hydraulic plants reflect the scheduled decommissioning date of 2004.

Q. Did you independently test the reasonableness of the Company's life spans?

A. Yes. I relied on a National Study of U.S. Steam Generating Unit Lives – 50 MW and Greater ("National Study") conducted by my firm. This study, included as Exhibit___(MJM-1) uses analytical techniques generally accepted in the utility industry and a database maintained by the U.S. Department of Energy.[54] The study concludes that U.S. Steam Generating Units 50 MW or greater are experiencing average life spans of approximately 60 years and that these spans are lengthening almost on a year-to-year basis.

Q. Has your firm also conducted National Studies of other production unit retirements?

A. Yes. We have also studied national retirements of Other Production units. We employed Energy Information Administration Form 860 for all units designated as Jet Engine (JE), Combustion Turbine (CT), Gas Turbine (GT) and Internal Combustion (IC). The following table shows the composition of the database.

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

Table 8

Type of Peaking Unit

	JE	GT	IC	CT	TOTAL
Operable	129	1,354	2,814	107	4,407
Retired	1	,116	1,443	0	1,559
TOTAL	130	1,470	4,257	107	5,963

These technologies are in various stages of introduction as evidenced by the virtual lack of unit retirements in the JE and CT classifications. What they have in common, however, is the way that they are used. All are used primarily to meet short-term peaks in demand. Our study is included as Exhibit___(MJM-2). It indicates lives of approximately 46 years at a minimum which have lengthened in recent years to as long as 56 years.

Q. What are your conclusions based on your National Life Studies?

A. I conclude that Mr. Wiedmayer's proposed life spans for the Steam and Other Production functions are reasonable. This, combined with the Company's response to MJM 1-11 leads me to accept them, even though Mr. Wiedmayer states, "the estimated retirement dates should not be interpreted as commitments to retire these plants on these dates, but rather, as reasonable estimates subject to modification in the future as circumstances dictate."[55] Otherwise I would have recommended that the life span method not be used for APS. Had I done so, the resulting depreciation rates would have been substantially lower since there would not have been an assumed finite retirement date for each unit.

[55] Attachment LLR-4, page II-29.

Q. Have you addressed APS' nuclear depreciation rates?

A. No. Only to the extent of interim net salvage.

<u>Transmission, Distribution and General Functions</u>

Q. How did Mr. Wiedmayer determine his estimated service lives for these functions?

A. Typically, service life estimates start with actuarial or semi-actuarial studies of historical plant information. These studies provide a statistical expression of the average service lives and retirement patterns (dispersion) that have actually been experienced in the past.

Mr. Wiedmayer used the actuarial retirement rate approach to study plant history. This approach related aged retirement data to the amount of plant exposed to retirement during historical age intervals to calculate "retirement ratios." These retirement ratios are then used in a chain calculation to calculate an "observed life table" ("OLT"). The OLT is a series of percents surviving, by age, reflecting the actual [retirement] experience recorded in a band of mortality data.[56] The OLT can be smoothed and extended to zero using mathematical extrapolation or by fitting to a preexisting standardized survival pattern. Mr. Wiedmayer used Iowa curves, each with varying life assumptions to compare or fit to the OLT.

Q. What is an Iowa curve?

A. An Iowa curve is a surrogate or standardized OLT based on a specific pattern of retirements around an average service life. The Iowa curves were devised over 60 years ago at what is now Iowa State University. They provide a set of standard patterns of retirement dispersion. Retirement dispersion merely recognizes that accounts are comprised of individual assets or units having different lives. Retirement dispersion is the scattering of retirements by age for the individual assets around the average service life for the entire group assets. If one thinks in terms of a "bell shaped" curve, dispersion represents the scattering of events around the average.

There are left-skewed, symmetrical and right-skewed curves known, respectively, as the "L curves," "S curves" and "R curves."[57] A number identifies the range of dispersion. A low number represents a wide pattern and high number a narrow pattern. The combination of one letter and one number defines a dispersion pattern. The combination of an average service life with an Iowa curve provides a survivor curve depicting how a group of assets will survive, or conversely be retired, over the average service life.

Q. Can you provide an example of an Iowa curve?

A. Yes. The following table contains a 5 S0 and 10 S0 life and curve. I have included two combinations to demonstrate that these curves can be calculated with various alternative life assumptions. The percent surviving represents the

[56] National Association of Regulatory Utility Commissioners, Public Utility Depreciation Practices, August 1996 ("NARUC Manual"), p. 322.
[57] There is also a set of Origin Modal ("O") curves which are essentially negative exponential curves.

amount surviving at each age interval shown in the first column. Notice that the 5 S0 life and curve sums to the 5 year average service life which would be used in the depreciation calculations and the 10 S0 life and curve sums to a 10 year average service life.

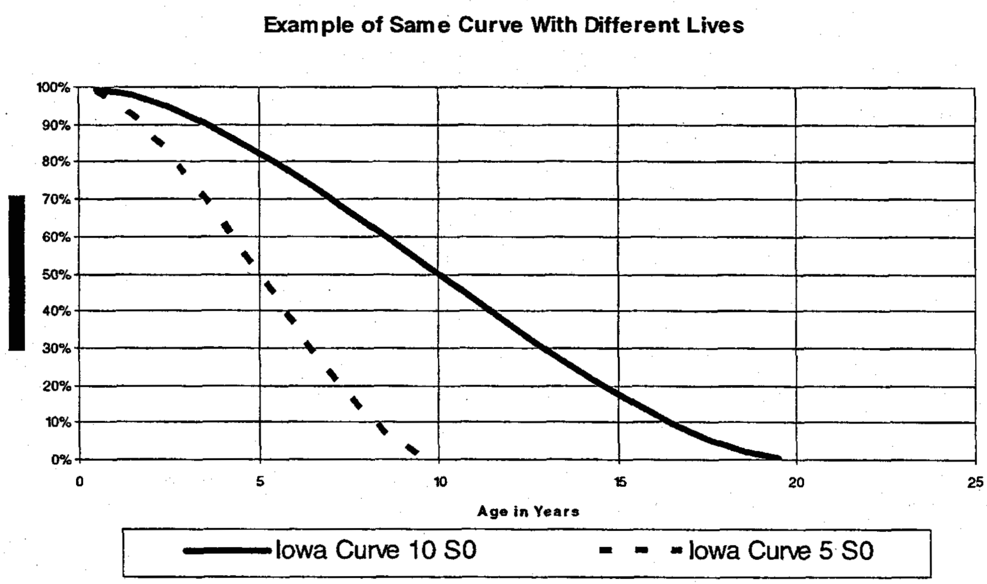
Table 9

	Survivor Curves	
	5 S0	10 S0
Age	Percent Surviving	Percent Surviving
0.5	0.99	1.00
1.5	0.92	0.98
2.5	0.83	0.94
3.5	0.70	0.90
4.5	0.57	0.85
5.5	0.43	0.80
6.5	0.30	0.74
7.5	0.17	0.67
8.5	0.08	0.60
9.5	0.01	0.53
10.5		0.47
11.5		0.40
12.5		0.33
13.5		0.26
14.5		0.20
15.5		0.15
16.5		0.10
17.5		0.06
18.5		0.02
19.5		0.00
Total	**5.00**	**10.00**

Q. Why do you call tables of numbers, such as the ones above, curves?

A. Because when they are plotted on charts with the x-axis representing "age" and the y-axis representing "percent surviving" they appear as curves as shown below:

Table 10



Q. Can you provide an example of how Mr. Wiedmayer used the actuarial retirement rate approach?

A. I will use account 355 – Poles and Fixtures, Wood as an example to explain Mr. Wiedmayer's approach and also to explain why I disagree with Mr. Wiedmayer's approach.

Q. What band of retirement experience did Mr. Wiedmayer use to analyze this account?

A. Mr. Wiedmayer used the 1973-2001 experience band to analyze the account. Mr. Wiedmayer's resulting OLT is attached as Exhibit___(MJM-6). This was obtained from Mr. Wiedmayer's study.

Q. Is there anything that the reader should make note of regarding this OLT?

A. Yes, note that on page 2 of Exhibit___(MJM-6), the OLT in the far right column goes to eight (8) percent surviving at the 78.5 age interval. The significance of this fact will become apparent later in my testimony.

Q. Please explain how to interpret Mr. Wiedmayer's chart

A. The series of "Xs" represents the OLT, and the smooth curve represents Mr. Wiedmayer's 48 R1.5 life and curve recommendation for this account.

Q. How did Mr. Wiedmayer arrive at his 48 R1.5 recommendation?

A. Mr. Wiedmayer states that for this account "The survivor curve estimate is based on the statistical indication for the period 1973 through 2001. The Iowa 48 R1.5 is an excellent fit of the significant portion of the original survivor curve."[58]

Q. How did Mr. Wiedmayer select a 48 R1.5 life and curve?

A. Mr. Wiedmayer selected a 48 R1.5 life and curve by fitting various Iowa curves to the OLT. Then he selected a 48 R1.5 and plotted it on the graph.

Q. How did Mr. Wiedmayer fit Iowa curves to the OLT?

A. "The original survivor curves [OLTs] shown in the Depreciation Study and Addendum are fit to the Iowa curves <u>visually</u> using a proprietary screen matching program."[59] In other words, Mr. Wiedmayer used an "eyeball" approach.

Q. Was Mr. Wiedmayer able to determine the statistical "best fit" to the OLTs using the visual approach?

[58] Attachment LLR-4, page II-25.

A. No.

Q. Is Mr. Wiedmayer's software capable of providing a statistical best fit?

A. Yes. "Gannett Fleming's software does produce statistical best fit Iowa curves for each plant account,"[60] however, Mr. Wiedmayer apparently did not refer to or rely upon this feature of his in-house software.

Q. Were you able to determine a best fit?

A. Yes. My software statistically fits Iowa curves to OLTs using least squared differences as the fit criteria. This is a fairly standard approach.

Q. Is Mr. Wiedmayer's 48 R1.5 recommendation the best fit to the OLT he shows on his chart?

A. No. The statistical best fit to the OLT shown on Mr. Wiedmayer's chart is a 70 L0 life and curve.

Q. How did Mr. Wiedmayer make such an error?

A. This error resulted from Mr. Wiedmayer's use of the visual method.

Q. What is your opinion of Mr. Wiedmayer's presentation from an analytical standpoint?

A. Mr. Wiedmayer's partial presentation is misleading from an analytical standpoint, particularly if a visual fitting approach is used. It is appropriate to see all of the data, before making any decisions concerning visual fits.

Q. How much of the complete OLT did Mr. Wiedmayer exclude from his chart?

A. Exhibit___(MJM-8) demonstrates the portion of the OLT from account 355 that

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[59] Response to MJM 1-18 (emphasis added).

Mr. Wiedmayer excluded.

Q. If Mr. Wiedmayer had not excluded a portion of the OLT for account 355 and also had obtained the best fit to all of the data, what would be the result?

A. The result is a 46 R2 life and curve, which is actually shorter than Mr. Wiedmayer's recommendation.

Q. Did Mr. Wiedmayer exclude substantial portions of the OLTs for other accounts?

A. Yes, Mr. Wiedmayer excluded substantial portions of the OLTs for several other accounts; for example, accounts 353, 362, 367, 371 and 397. Many of these are significant accounts in terms of dollars.

Q. What would have been the result if Mr. Wiedmayer had obtained a best fit to the complete OLTs for these accounts?

In general, the best fits to the complete OLTs for these accounts yield longer, not shorter, lives.

Q. Is that why you believe that Mr. Wiedmayer's approach is misleading?

A. Yes, in general Mr. Wiedmayer's approach excluded portions of the OLT which, if not excluded, would have resulted in longer life indications.

<u>**Alternative Recommendations**</u>

Q. Mr. Majoros, based on your identification of this problem in Mr. Wiedmayer's study, have your determined an alternative set of service lives

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[60] Response to MJM 2-71.

and Iowa curve recommendations?

A. Yes, I have.

Q. Did you conduct any independent analyses?

A. Yes. I conducted independent retirement rate analyses as described above. I used industry life data to set the upper and lower fitting parameters in my analyses. In other words, I obtained industry statistics to determine the shortest and longest life reported by the industry for each account. I set the parameters in my software to determine the best life fit for each Iowa curve within those upper and lower life boundaries. Therefore, even if the data would support a much longer life, the curve fitting process ends at the upper limit of the industry range.

Q. Is the industry data included in your study?

A. Yes, the industry data is included in the study, but the individual company names are not shown because the study, which is prepared by the Edison Electric Institute, is labeled as confidential.

Q. Did you consider any other information?

A. Yes. I propounded, and APS responded to, several data requests designed to learn more about the Company's life extension programs and other plans. These data requests were MJM 1-4, 1-5, 1-6, 1-7, 1-11, 1-12, 1-39, 1-40, 1-57, 1-58, 2-68, 2-69, and 2-76.

Q. How did you arrive at your alternative recommendations?

A. First, I grouped the accounts and subaccounts into the same study groups identified by Mr. Wiedmayer. The groups are:

Wiedmayer Study Groups

1. Mass accounts for which statistical analysis was primary basis for estimates.[61]

2. Life Span Accounts.[62]

3. Amortization accounts.[63]

4. Mass accounts based on judgments incorporating the nature of the plant and equipment, reviews of historical retirement data and general knowledge of service lives for similar equipment in other electric companies.[64]

Q. What was your next step?

A. Based on my acceptance of the Company's life spans, I eliminated the Life Span Account group from my study.

Q. Would you please list, by group, the remaining accounts you are addressing?

A. Yes, I will summarize and discuss each group individually. The first group is mass accounts for which statistical analysis was the primary basis for estimates.[65] This group contains the following accounts:

61 Attachment LLR-4, page II-24.
62 Id., page II-25.
63 Id., page II-29.
64 Id.
65 Id., page II-24.

Mass Accounts for Which Statistical Analysis
Was the Primary Basis for Mr. Wiedmayer's Estimates

Transmission Plant
353 – Station Equipment
355 – Poles and Fixtures – Wood

Distribution Plant
362 – Station Equipment
364 – Poles, Towers and Fixtures – Wood
365 – Overhead Conductors and Devices
366 – Underground Conduit
367 – Underground Conductors and Devices
368 – Line Transformers
370 – Meters
371 – Installations on Customers Premises
373 – Street Lighting and Signal Systems

General Plant
390 – Structures and Improvements
397 – Communication Equipment

Q. Do you have any general comments regarding these accounts?

A. Yes. In most cases, Mr. Wiedmayer excluded a substantial portion of the OLT for the accounts on his charts, and also, in most cases his recommended life and curve is inaccurate as result of his visual method.

Q. Did you conduct actuarial retirement rate studies for these accounts?

A. Yes, I did. These studies and the related charts are included in Exhibit___(MJM-3) which contains all of my actuarial analyses in chronological order by account number.

Q. Have you compared your results to Mr. Wiedmayer's proposals?

A. Yes. They are compared on Statement B of Exhibit___(MJM-3).

Q. What do you recommend?

A. I recommend the statistical best fit results based on full OLT data. These are the accounts that Mr. Wiedmayer designated as being most appropriate for statistical analysis, thus, I recommend the statistical best fit. Please refer to the individual account discussions in Exhibit___(MJM-3) for a more detailed description of my disagreements with Mr. Wiedmayer.

Q. What is the next group that you studied?

A. The next group consists of the accounts for which Mr. Wiedmayer exercised judgment. They are:

Mass Accounts for Which Mr. Wiedmayer
<u>Considered Statistical Analysis to be Inconclusive</u>

<u>Transmission Plant</u>
352 - Structures and Improvements
352.5 - Structures and Improvements - SCE 500 KV Line
353.5 - Station Equipment - SCE 500 KV Line
354 - Towers and Fixtures
354.5 - Towers and Fixtures - SCE 500 KV Line
355.1 - Poles and Fixtures - Steel
355.5 - Poles and Fixtures - SCE 500 KV Line
356 - Overhead Conductors and Devices
356.5 - Overhead Conductors and Devices - SCE 500 KV Line
357 - Underground Conduit
358 - Underground Conductors and Devices

<u>Distribution Plant</u>
361 - Structures and Improvements
364.1 - Poles and Fixtures - Steel
369 - Services
370.1 - Electronic Meters

Q. Did you review Mr. Wiedmayer's actuarial retirement rate studies for this group of accounts?

A. Yes.

Q. What did you find?

A. Again, Mr. Wiedmayer excluded substantial portions of the OLT for several accounts.

Q. Did you conduct actuarial retirement rate studies based on the full OLT data?

A. Yes, I did.

Q. What were your results?

A. Exhibit___(MJM-3) also shows the results of my actuarial analyses for these accounts.

Q. Do you also recommend that the best fit result be adopted for all of these accounts?

A. No. In fact, I accepted all of Mr. Wiedmayer's proposals for these accounts except for electronic meters. Mr. Wiedmayer proposed to reduce the life from 26 to 12 with no support for that account. I recommend retention of the existing 26 years.

Q. Does this conclude your discussion of your survivor curve recommendations?

A. Yes.

Q. What is the overall result?

A. I calculated remaining lives using my recommended survivor curves. These calculations were made using the same procedures as Mr. Wiedmayer and are included in Exhibit___(MJM-3).

<u>Depreciation Rate Calculations</u>

Q. Does APS maintain its book depreciation reserve by plant account?

A. No.[66]

Q. How did Mr. Wiedmayer calculate his estimated reserve for each plant account for purposes of calculating his proposed depreciation rate?

A. I am not sure how Mr. Wiedmayer estimated the reserve for each plant account. In Data Requests MJM 1-2 and MJM 3-85 I requested an electronic version of all of Mr. Wiedmayer's tabulations, with all formulae intact. While I was provided with an electronic version of Mr. Wiedmayer's rate calculations, the actual amounts are shown as hard coded amounts. Hence, I do not know how Mr. Wiedmayer estimated his reserve amounts.

Q. Have you reallocated the reserve amounts between plant accounts?

A. Yes. I allocated the reserves by function to plant accounts based on theoretical reserves developed using my recommended parameters. These amounts were then used to calculate my recommended remaining life depreciation rates.

Q. Have you calculated recommended depreciation rates for APS?

A. Yes. My depreciation rate calculations are shown on Statement A of Exhibit___(MJM-3).

<u>PWEC Depreciation Rates</u>

Q. Have you reviewed the Company's requested depreciation rates for the Pinnacle West assets?

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66 Response to MJM 1-30.

A. Yes I have. The Company's proposed rates for the PWEC assets are developed in the Depreciation Study Addendum portion of Attachment LLR-4. The plant in question consists of both Other Production and Transmission related plant. The proposed depreciation rates are straight-line remaining life rates.

Q. How did Mr. Wiedmayer analyze the PWEC Other Production plant accounts?

A. As with the APS production plant , Mr. Wiedmayer used the life span method.

Q. What life spans does Mr. Wiedmayer propose for these accounts?

A. Mr. Wiedmayer proposes a 32-year life span for Redhawk Combined Cycle Units 1 and 2, and 30-year life spans for West Phoenix Combined Cycle Unit 4 and Saguaro Combustion Turbine Unit 3.

Q. Do you agree with Mr. Wiedmayer's proposed life spans for this plant?

A. I do not agree with the life spans used by Mr. Wiedmayer for these units. They are too short. As discussed above, my National Study supports life spans of around 46 years for Other Production plant. Mr. Wiedmayer is proposing life spans of 30 and 32 years. The Company does not support these life spans. In fact, the Depreciation Study Addendum states, "The estimated retirement dates should not be interpreted as commitments to retire these plants on these dates, but rather, as reasonable estimates subject to modification in the future as circumstances dictate.[67]

Q. What life spans do you recommend?

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[67] Attachment LLR-4, Depreciation Study Addendum, page II-4.

A. Mr. Wiedmayer used a 55-year life span for combined cycle equipment in his study of APS, and a 45-year life span for combustion turbine equipment. To maintain consistency I recommend the same for the PWEC plant. My recommendations are compared to Mr. Wiedmayer's in Table 11 below.

Table 11

Other Production	**Company Proposed Life Span**	**Snavely King Recommended Life Span**
Redhawk CC Units 1 & 2	32 years	55 Years
West Phoenix CC Unit 4	30 years	45 Years
Saguaro CT Unit 3	30 years	55 Years

Q. Do the depreciation rates for the PWEC assets include a provision for net salvage?

A. No, they do not. As explained on page II-5 of the Depreciation Study Addendum portion of Attachment LLR-4, "PWEC will treat all removal costs as a current period expense as incurred consistent with SFAS 143. The treatment of cost of removal as an expense is a departure from the typical accounting treatment used for regulatory purposes. However, since these facilities are owned by PWEC, a company whose assets are not regulated by the Arizona Corporation Commission, the Company is compelled to adhere to SFAS 143."[68]

Q. What is the basis for Mr. Wiedmayer's proposed lives for the transmission

[68] Attachment LLR-4, Depreciation Study Addendum, page II-5.

plant accounts?

A. Mr. Wiedmayer's proposed service life estimates are based on judgment which considered a number of factors, including statistical analyses of historical and projected plant accounting data for Redhawk, current Company policies and outlook as determined during field reviews of the property, conversations with management, and survivor curve estimates from previous studies of this company and other electric companies.[69]

Q. On an account by account basis, how do Mr. Wiedmayer's proposed life estimates compare with those he proposed for the APS plant?

A. Mr. Wiedmayer is proposing the same lives and curves for the PWEC assets as he is proposing for the APS assets. Table 12 below summarizes that comparison:

Table 12

	Wiedmayer	
Account	PWEC Proposal	APS Proposal
353 – Station Equipment	42-R3	42-R3
355 – Poles & Fixtures, Steel	55-R3	55-R3
356 – Overhead Conductors & Devices	55-R3	55-R3

Q. How do these lives compare with your recommendations for the APS plant accounts?

[69] Id., page II-3.

A. I have agreed with Mr. Wiedmayer's selected life and curve for accounts 355 and 356. However, I have recommended a 57-R1.5 life and curve for APS' account 353.

Q. What do you recommend for the PWEC transmission assets?

A. Consistent with my recommendations for APS plant, I recommend a 57-R1.5 life and curve for account 353. I accept Mr. Wiedmayer's 55-R3 life and curve for accounts 355 and 356 as I did in the APS study.

<u>SUMMARY</u>

Q. Please summarize your recommendations.

A. My recommendations are individually discussed in my testimony above and in my exhibits. In general:

- I have addressed the Company's SFAS No. 143 proposal, and found that its depreciation study results in higher charges to ratepayers than would result if APS had actual legal obligations for a majority of its plant.
- APS proposal is inconsistent with the principles of SFAS No. 143 and FERC Order No. 631.
- I have removed net salvage as a component of the Company's depreciation rates.
- I have identified and recommended a specifically identifiable net salvage allowance in conformance with FERC Order No. 631, based on a five-year average of actual experience. Due to the Company's experience, on average, of positive net salvage, I recommend this allowance to be $0.

- I have accepted the Company's life spans for its production plant functions.
- I have performed actuarial analysis of APS' transmission, distribution and general plant and have calculated new depreciation rates based on my findings.
- I have reviewed the Company's proposal regarding the PWEC assets and conformed the life proposals to the APS proposals.

My recommendations result in a $240.3 million depreciation expense accrual. This is $47.4 million less than the Company's proposal. My recommendations also result in a $27.8 million expense for the PWEC which is $13.7 million less than the Company's request.

Q. Does this conclude your testimony?

A. Yes, it does.

Experience

Snavely King Majoros O'Connor & Lee, Inc.

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

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

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

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

Handling Equipment Sales Company, Inc.

Treasurer (1976-1978)

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

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

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

University of Baltimore - *(1971-1973)*

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

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

Central Savings Bank, *(1969-1971)*

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

Education

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

Professional Affiliations

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

Publications, Papers, and Panels

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

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

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

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

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

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

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

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

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

Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities
2003	FCC 52/	03-173	All LECs
State Regulatory Agencies			
1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Electric Power Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.

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1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.
1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan

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1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa
1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel

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2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy
2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service
2003	Nova Scotia, CN 49/	EMO NSPI	Nova Scotia Power, Inc.
2003	Kentucky 36/	2003-00252	Union Light Heat & Power
2003	Alaska 44/	U-96-89	ACS Communications, Inc.
2003	Indiana 29/	42359	PSI Energy, Inc.
2003	Kansas 20/ 40/	03-ATMG-1036-RTS	Atmos Energy
2003	Florida 50/	030001-E1	Tampa Electric Company
2003	Maryland 51/	8960	Washington Gas Light

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

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

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

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

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

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

Database

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

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

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

Analysis

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

Expanded Full Band Analysis

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

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

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

Rolling Band Analysis

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

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

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

Shrinking Band Analysis

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

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

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

Snavely King Majoros O'Connor & Lee, Inc.
National Study of U.S. Other Production Unit Lives

Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King") performed a study of U.S. Other Production Units Lives using analytical techniques generally accepted in the utility industry and a database maintained by the U.S. Department of Energy ("DOE"). Snavely King concludes that U.S. Other Production Units are experiencing average life spans of approximately 46.5 years at a minimum, and that these spans have lengthened in recent years to as long as 56.5 years.

Database

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

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

Various sorts were made to refine the data and to remove bad data. For example, plant with in-service dates of 1900 apparently had a Y2K problem. Some units listed as retired had no retirement dates indicated, etc.

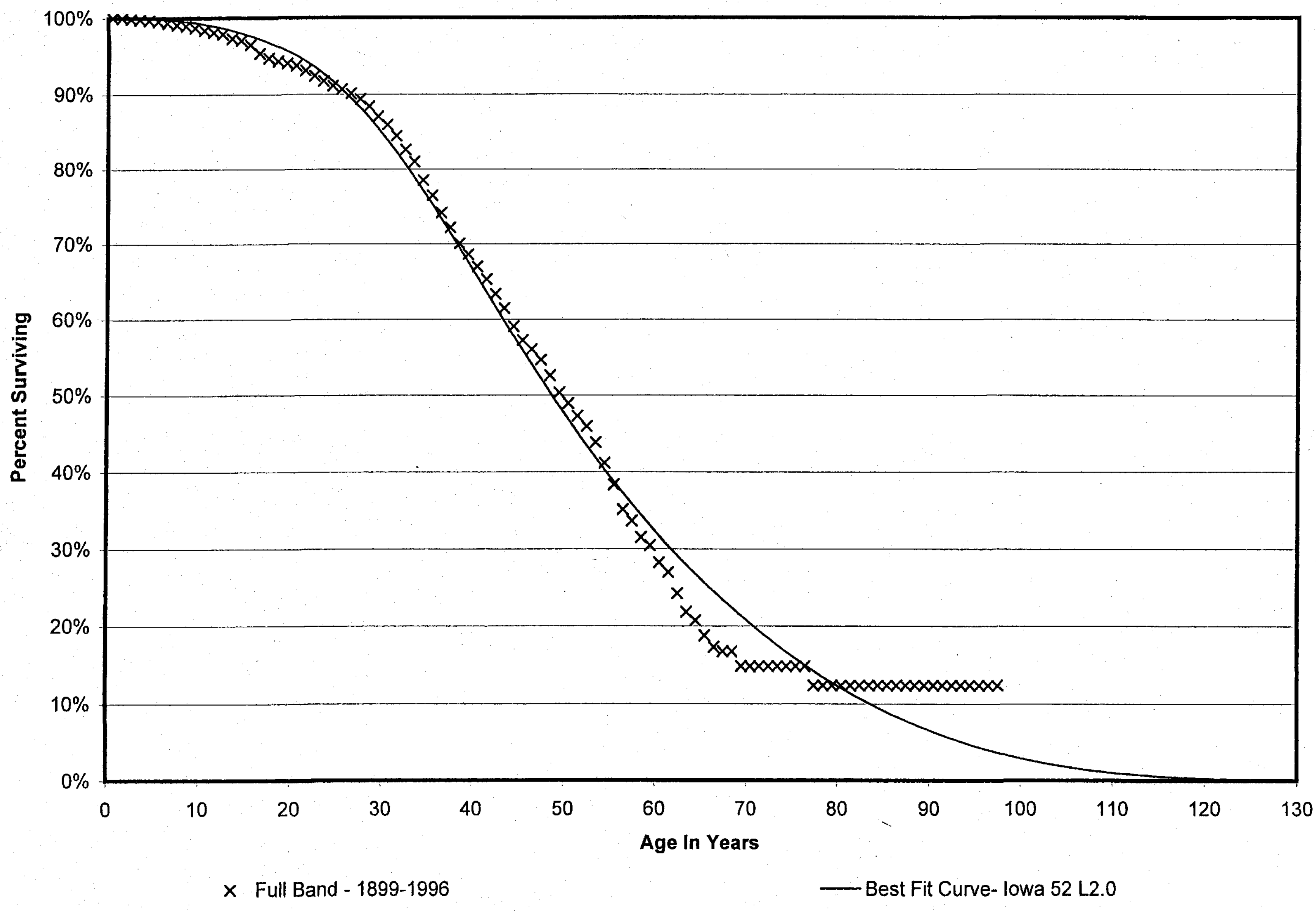
Analysis

Snavely King performed an analysis of the full band (1899-1996) and a "shrinking band" analysis, in which the final year (1996) was held constant and the bands were continually shrunk. The results are discussed and set forth in tabular form below.

Band	Width	Life	Curve Type
1899-96	Full	52.0	L2.0
1977-96	20 years	46.5	L1.5
1982-96	15 years	47.5	L1.5
1987-96	10 years	52.5	L1.5
1992-96	5 years	56.5	L2.0

As the analysis indicates, the average life span for Other Production Units has lengthened in recent years.

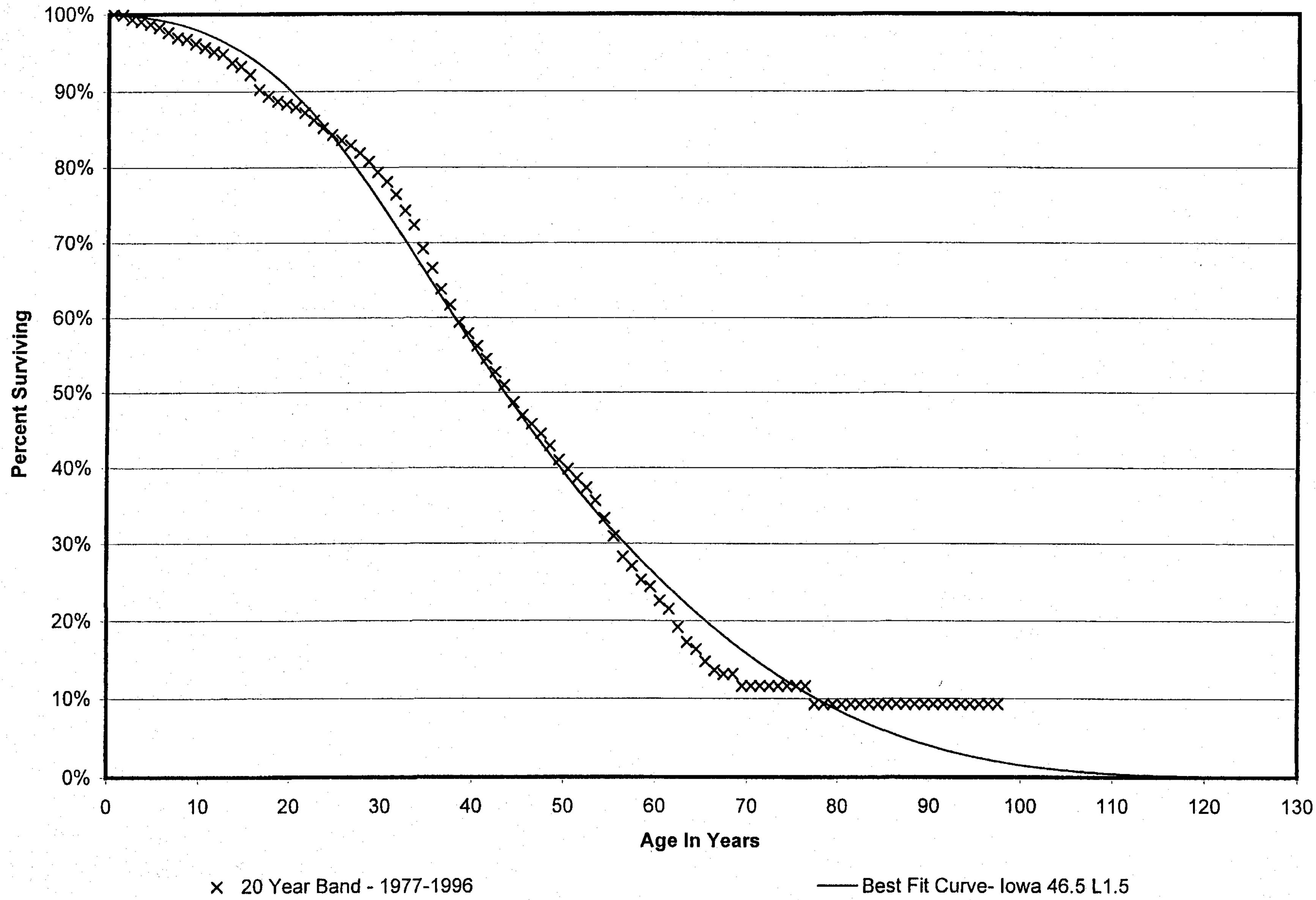
Observed Life Table and Best Fit Iowa Curve
All U.S. Other Production Units: Band 1899-1996



qqvqal ACTUARIAL ANALYSIS
CURVE FITTING RESULTS
ACCOUNT: 888000
BAND: 1899,1996

RANK	IOWA CURVE	AVERAGE SERVICE LIFE	SUM OF SQUARED DEVIATIONS
1	L2	52.00	1121.66
2	L1.5	52.00	1749.96
3	S1	50.50	2419.96
4	S0.5	50.50	2669.22
5	S1.5	50.50	2698.74
6	L3	52.00	2749.26
7	R1.5	49.50	3195.03
8	L1	51.50	3379.00
9	R2	49.50	3507.07
10	S2	50.50	3825.60
11	S0	50.00	3863.70
12	R1	49.00	4179.53
13	R2.5	50.00	4402.90
14	L0.5	51.50	5336.07
15	R0.5	49.00	6092.86
16	S-0.5	49.50	6182.28
17	R3	50.00	6439.15
18	S3	50.50	7381.55
19	L0	52.00	8110.19
20	L4	51.00	8858.58
21	O1	49.00	10014.22
22	O2	52.50	10310.85
23	R4	50.50	11604.03
24	S4	50.50	14100.69
25	L5	51.00	16336.66
26	O3	64.50	19846.15
27	R5	50.50	19875.93
28	S5	50.50	22178.08
29	O4	84.50	24972.86
30	S6	50.50	30361.29
31	SQ	49.50	49189.21

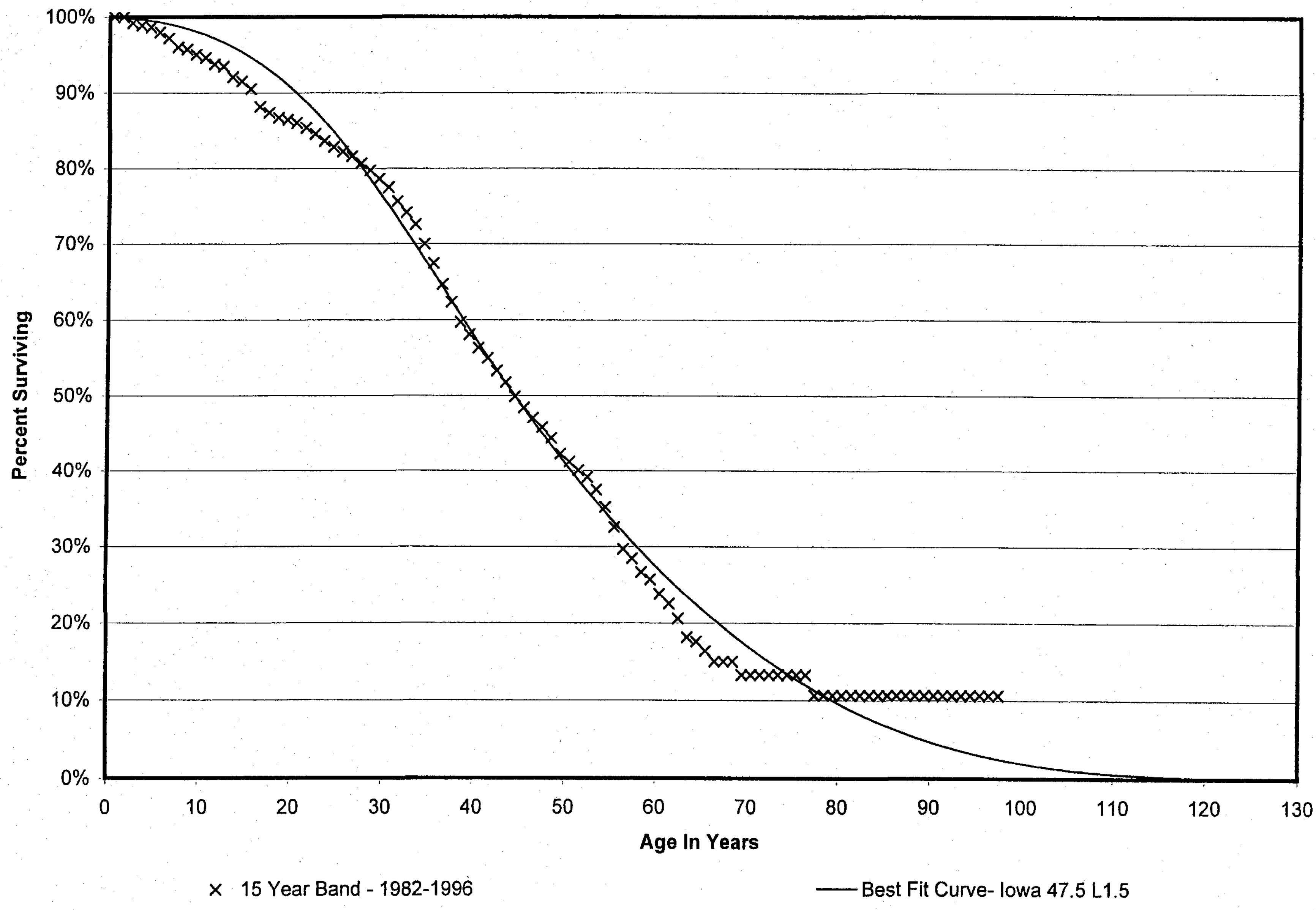
Observed Life Table and Best Fit Iowa Curve
All U.S. Other Production Units: Band 1977-1996



qqvqal ACTUARIAL ANALYSIS
CURVE FITTING RESULTS
ACCOUNT: 888000
BAND: 1977,1996

RANK	IOWA CURVE	AVERAGE SERVICE LIFE	SUM OF SQUARED DEVIATIONS
1	L1.5	46.50	890.79
2	L2	47.00	1214.63
3	L1	46.50	1486.82
4	S0.5	45.50	1738.92
5	S0	45.00	2068.88
6	S1	45.50	2241.00
7	R1	44.50	2310.87
8	R1.5	45.00	2352.97
9	L0.5	46.50	2528.51
10	R0.5	44.00	3224.10
11	S1.5	46.00	3260.10
12	S-0.5	44.50	3341.13
13	R2	45.00	3538.36
14	L3	46.50	4347.48
15	L0	46.00	4364.76
16	S2	46.00	5031.07
17	R2.5	45.50	5342.66
18	O1	43.50	5904.40
19	O2	47.00	5941.92
20	R3	45.50	8187.31
21	S3	46.00	9683.67
22	L4	46.00	11527.50
23	R4	46.00	14611.97
24	O3	55.50	15077.92
25	S4	46.00	17390.95
26	L5	46.00	19723.73
27	O4	71.00	20738.40
28	R5	45.50	23700.81
29	S5	45.50	25950.52
30	S6	45.00	34082.54
31	SQ	43.50	51072.33

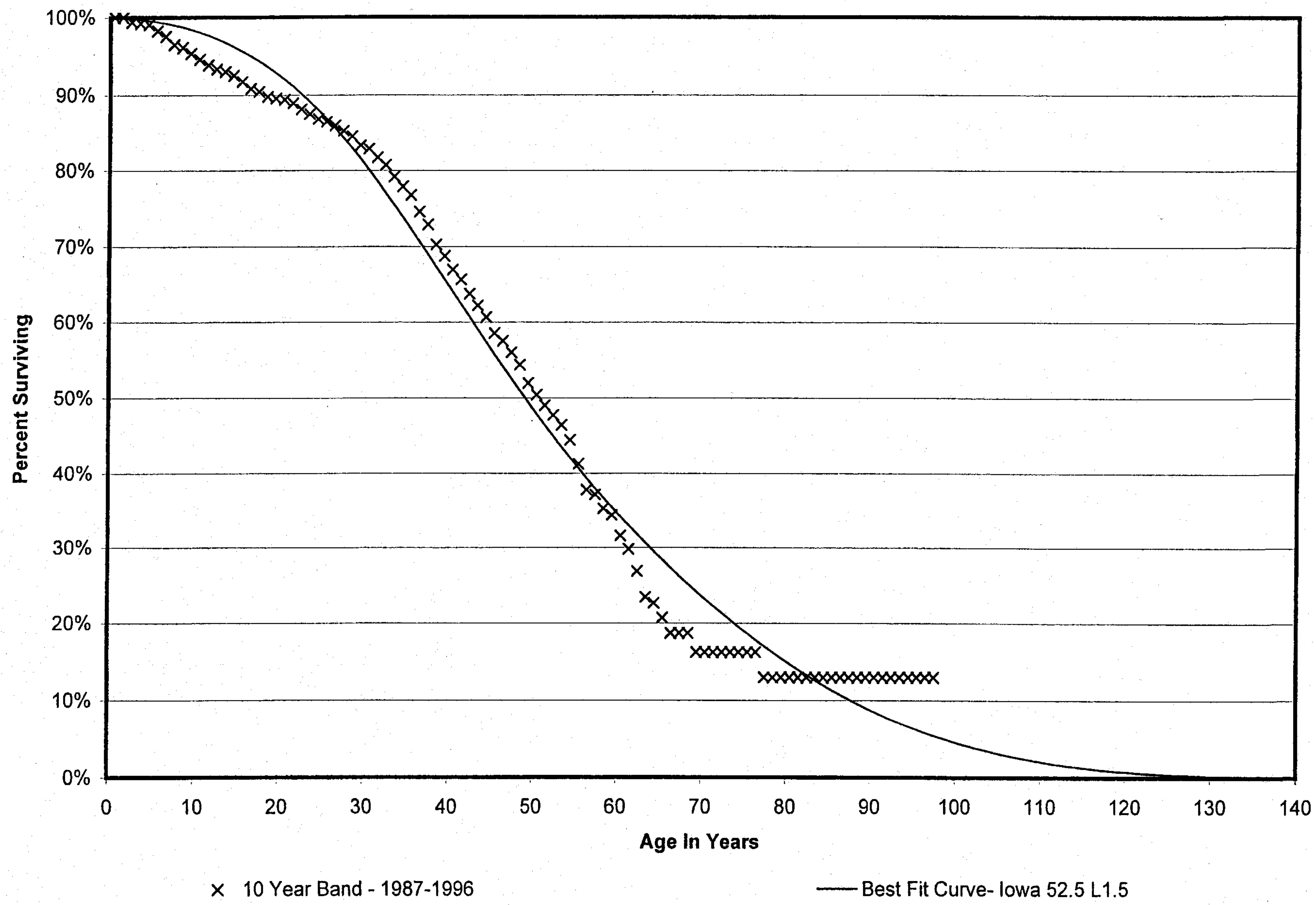
Observed Life Table and Best Fit Iowa Curve
All U.S. Other Production Units: Band 1982-1996



qqvqal ACTUARIAL ANALYSIS
CURVE FITTING RESULTS
ACCOUNT: 888000
BAND: 1982,1996

RANK	IOWA CURVE	AVERAGE SERVICE LIFE	SUM OF SQUARED DEVIATIONS
1	L1.5	47.50	1118.69
2	L1	47.00	1318.91
3	L2	47.50	1853.33
4	L0.5	47.00	1966.71
5	S0	45.50	2208.91
6	S0.5	46.00	2224.03
7	R1	45.00	2547.78
8	R0.5	45.00	2945.64
9	R1.5	45.50	2965.67
10	S-0.5	45.00	3009.49
11	S1	46.50	3108.92
12	L0	47.00	3414.09
13	S1.5	46.50	4424.84
14	R2	45.50	4572.63
15	O2	48.00	4679.77
16	O1	44.50	5155.09
17	L3	47.50	5743.41
18	S2	46.50	6521.74
19	R2.5	46.00	6682.54
20	R3	46.00	9867.68
21	S3	46.50	11638.85
22	O3	56.50	12805.77
23	L4	47.00	13606.64
24	R4	46.50	16728.92
25	O4	72.00	17949.21
26	S4	46.50	19745.52
27	L5	46.50	22185.46
28	R5	46.50	26233.52
29	S5	46.50	28609.65
30	S6	46.00	36996.22
31	SQ	43.50	54451.44

Observed Life Table and Best Fit Iowa Curve
All U.S. Other Production Units: Band 1987-1996



qqvqal ACTUARIAL ANALYSIS

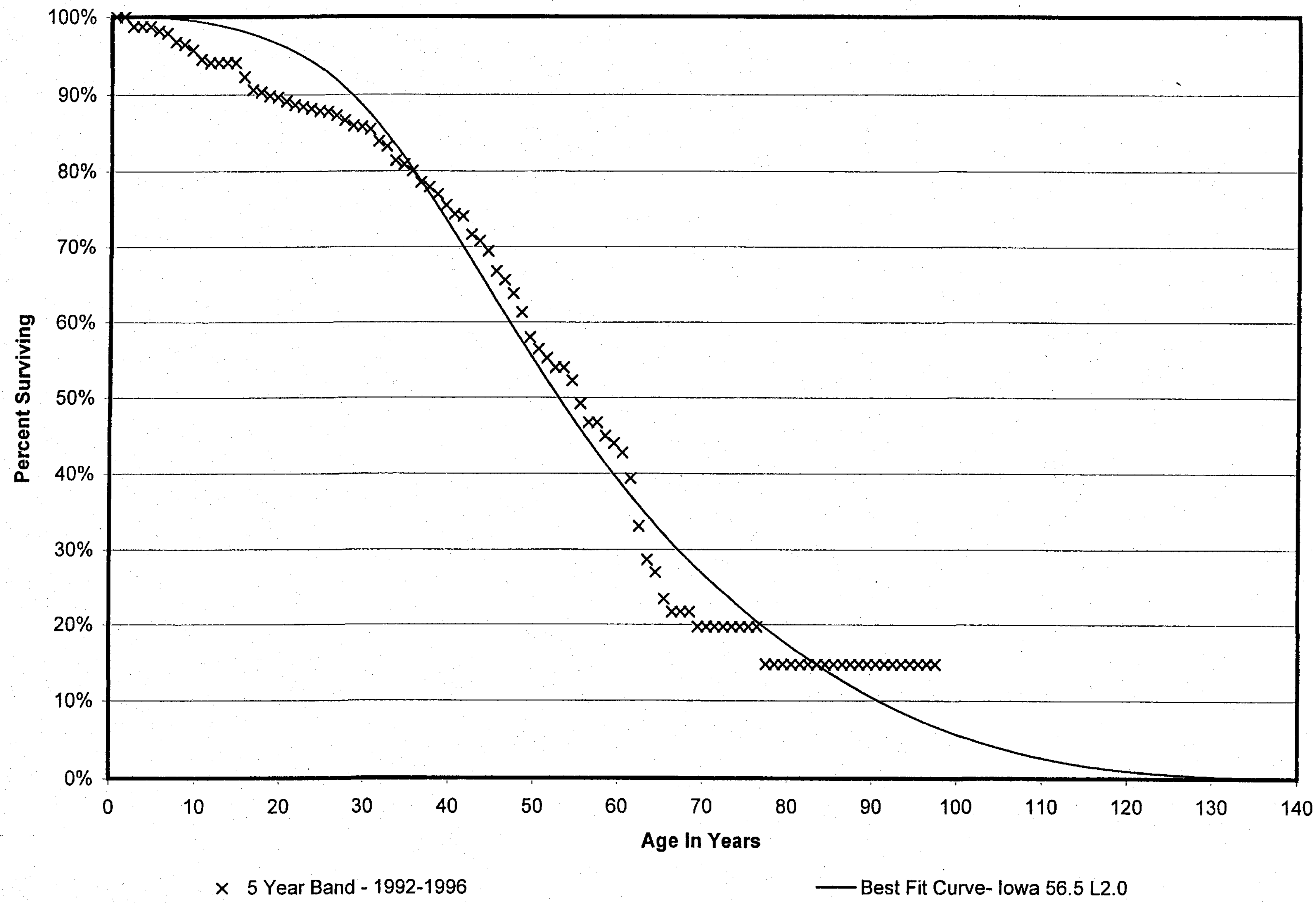
CURVE FITTING RESULTS

ACCOUNT: 888000

BAND: 1987,1996

RANK	IOWA CURVE	AVERAGE SERVICE LIFE	SUM OF SQUARED DEVIATIONS
1	L1.5	52.50	1425.50
2	L2	53.00	1586.31
3	S0.5	51.00	2147.43
4	L1	52.00	2278.64
5	S0	51.00	2621.18
6	S1	51.50	2637.51
7	R1.5	50.00	2640.16
8	R1	50.00	2825.25
9	L0.5	52.00	3495.25
10	S1.5	51.50	3519.27
11	R2	50.50	3766.24
12	R0.5	50.00	3818.13
13	S-0.5	50.00	3976.92
14	L3	52.50	4389.92
15	S2	51.50	5265.97
16	R2.5	50.50	5346.45
17	L0	52.50	5528.59
18	O1	49.50	6832.53
19	O2	53.50	7079.00
20	R3	51.00	8082.98
21	S3	51.50	9724.13
22	L4	52.00	11469.84
23	R4	51.50	14229.10
24	O3	65.00	15496.68
25	S4	51.50	17216.77
26	L5	52.00	19617.66
27	O4	84.50	20112.98
28	R5	51.50	23315.78
29	S5	51.50	25784.65
30	S6	51.50	34306.98
31	SQ	51.00	53468.24

Observed Life Table and Best Fit Iowa Curve
All U.S. Other Production Units: Band 1992-1996



qqvqal ACTUARIAL ANALYSIS
CURVE FITTING RESULTS
ACCOUNT: 888000
BAND: 1992,1996

RANK	IOWA CURVE	AVERAGE SERVICE LIFE	SUM OF SQUARED DEVIATIONS
1	L2	56.50	1969.77
2	L1.5	56.50	2071.53
3	S0.5	54.50	2306.61
4	R1.5	54.00	2576.68
5	S1	55.00	2598.77
6	R1	53.50	2994.95
7	S0	54.50	2997.49
8	L1	56.00	3221.35
9	S1.5	55.50	3327.10
10	R2	54.00	3563.95
11	L3	56.50	4092.86
12	R0.5	53.00	4401.13
13	L0.5	56.50	4661.40
14	S-0.5	53.50	4690.56
15	R2.5	54.50	4934.77
16	S2	55.50	4969.21
17	L0	56.50	6913.56
18	R3	54.50	7577.41
19	O1	52.50	7870.18
20	O2	57.50	8545.85
21	S3	55.50	9191.79
22	L4	56.00	10671.21
23	R4	55.00	13409.13
24	S4	55.50	16328.33
25	O3	72.00	16639.12
26	L5	56.00	18620.55
27	O4	94.50	20709.27
28	R5	55.50	22110.83
29	S5	55.50	24596.04
30	S6	56.00	33193.13
31	SQ	55.00	52932.29

Summary and Analysis of SFAS No. 143 and FERC Order No. 631
As They Relate to Non-Legal Asset Retirement Obligations
By Michael J. Majoros, Jr.
June 9, 2003

Introduction

This summary and analysis provides the background required to understand the accounting and ratemaking implications of FERC Order No. 631 Accounting, Financial Reporting and Rate Filing Requirements for Asset Retirement Obligations as it relates to assets for which asset retirement obligations *do not* exist. It was prepared by Michael J. Majoros, Jr. who has closely followed and testified about the issue. Mr. Majoros attended the FERC Commission staff's May 7, 2002 Technical Conference on the subject and in conjunction with his partner Charles W. King prepared the Comments of the National Association of State Utility Consumer Advocates ("NASUCA") in FERC Docket No. RM02-7-000 which is manifested in FERC Order No. 631.

Background

In June 1994, at the request of the Edison Electric Institute ("EEI"), the Financial Accounting Standards Board ("FASB" or "Board") added an agenda project to focus on accounting for decommissioning costs of nuclear power plants. The original scope of the project related to the legal costs of decommissioning a nuclear power plant imposed by the Nuclear Regulatory Commission. Subsequently, the scope was expanded to include (a) similar legal obligations in other industries and (b) constructive obligations. In February 1996, the Board issued an Exposure Draft, *Accounting for Certain Liabilities Related to Closure or Removal of Long-Lived Assets.*[1]

SFAS No. 143

After two Exposure Drafts and several rounds of comments, FASB issued, in June 2001, its resulting Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 applies to all entities [including public utilities] and "components of transmission and distribution systems (utility poles) etc," are specifically not excluded. (SFAS No. 143, paragraph B17, footnote 22.)

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[1] FASB Accounting for Obligations Associated with the Retirement of Long-Lived Assets. Staff summary of Board decisions, http://www.rutgers.edu/Accounting/raw/fasb/project/aro

It applies to *unambiguous* legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and (or) the normal operation of a long-lived asset, except for certain obligations of lessees. As used in SFAS No. 143, a legal obligation is an 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.[2] SFAS No. 143 is effective for all financial statements issued for fiscal years beginning after June 15, 2002.

As indicated, SFAS No. 143 establishes accounting standards for recognition and measurement of a liability for an *asset retirement obligation* ("ARO") and the associated *asset retirement cost* ("ARC"). An asset retirement obligation refers to an obligation associated with the retirement of a tangible long-lived asset. The term asset retirement cost refers to the amount capitalized that increases the carrying amount of the long-lived asset <u>when a liability for an asset retirement obligation is recognized</u>.[3]

In general, SFAS No. 143 requires all entities to conduct reviews of their long-lived assets to determine whether they have AROs based on the legal standards summarized above. If an ARO exists, the entity must measure the ARC and <u>record a liability</u> for the amount and capitalize it as part of the original cost of the asset.

In explaining why it adopted this approach, the FASB stated that "paragraph 37 of [its] Statement 19 states that 'estimated dismantlement, restoration, and abandonment costs [future cost of removal]...shall be taken into account in determining amortization and depreciation rates.' Application of that paragraph has the effect of accruing an expense irrespective of the requirements for liability recognition in FASB Concepts Statements. In doing so, it results in [the anomalous] recognition of accumulated depreciation that can exceed the historical cost of a long-lived asset. The Board concluded that an entity should be precluded from including an amount for an asset retirement obligation in the depreciation base of a long-lived asset unless that amount also meets the recognition criteria in this Statement [SFAS No. 143]. When an entity recognizes a liability for an asset retirement obligation, it also will recognize an increase in the carrying amount of the related long-lived asset. Consequently, <u>depreciation of that asset will not result in the recognition of accumulated depreciation in excess of the historical cost of a long-lived asset</u>."[4]

Paragraph 37 eliminates any doubt as to the FASB's intent regarding the application of SFAS No. 143. All companies must review their long-lived assets to determine whether they have unambiguous legal asset retirement obligations associated with those assets. If they do have such obligations, then the estimated ARC (which is based on its estimated present value and updated annually following the rules in the Statement) is capitalized as part off the cost of the asset. Thus, at the end of the asset's

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[2] SFAS No. 143, Summary, and Paragraph 2, and Appendix A, Paragraph A3.
[3] Id., Paragraph 1 and Footnote 1.
[4] Id., Paragraph B22. Emphasis added.

life, the accumulated depreciation account will be equal to the historical plant balance. In no case, may entities in general, include estimated future cost of removal in depreciation rates. Although SFAS No. 143 does not specifically state what to do with removal costs for assets which are not AROs, it is intuitively well accepted that concepts in the AICPA's SOP on Property, Plant and Equipment will eventually be adopted, and at least will not be objectionable. Those concepts would support expensing as incurred, or capitalization as a cost of the replacement.

Regardless of these overall principles and concepts, SFAS No. 143 recognizes that historically, many public utility depreciation rates contained a component for future cost of removal in the rate calculation. It deals with this issue as follows. "Many rate-regulated entities currently provide for the costs related to asset retirement obligations in their financial statements and recover those amounts in rates charged to their customers. Some of those costs relate to asset retirement obligations within the scope of this Statement; others are not within the scope of this Statement and, therefore, cannot be recognized as liabilities under its provisions. The objective of including those amounts in rates currently charged to customers is to allocate costs to customers over the lives of those assets. The amount charged to customers is adjusted periodically to reflect the excess or deficiency of the amounts charged over the amounts incurred for the retirement of long-lived assets. The Board concluded that if asset retirement costs are charged to customers of rate-regulated entities but no liability is recognized, a regulatory liability should be recognized if the requirements of SFAS No. 71 are met."[5]

Thus if the utility has included future net salvage in the past for which it has no ARO, then it will recognize and record a Regulatory Liability to ratepayers for that amount on its financial books and records. Presumably, if the utility continues to include future cost of removal in its depreciation rates, the Regulatory Liability to Ratepayers will also continue to grow.

In summary, SFAS No. 143 precludes the inclusion of future net salvage in depreciation rates for all entities in general, based on the principles and concepts included therein. However, recognizing the unique aspects of rate-regulated entities, SFAS No. 143 requires that those unique aspects be accounted for in a Regulatory Liability to Ratepayers.

FERC Docket No. RM02-7-000

On March 29, 2002, the FERC Commission staff announced that it would hold a technical conference to discuss the financial accounting, reporting and ratemaking implications related to asset retirement obligations associated with the retirement of tangible long-lived assets.[6] "The main purpose for convening this technical conference is to afford an opportunity for the electric, natural gas and oil pipeline industries and other

[5] Id., Paragraph B72.
[6] Federal Energy Regulatory Commission, Docket No. RM02-7-000, Notice of Informal Technical Conference, Agenda and Request for Comments, (March 29, 2002). ("Notice".)

interested parties to discuss with the Commission staff issues related to the implementation of accounting requirements for asset retirement obligations. The goal of the conference is to identify how recognition of asset retirement obligations may affect the Commission's existing accounting and rate regulations."[7] The FERC Notice also requested comments on the subject.

Several comments were received and the Technical Conference was held at the FERC in Washington, D.C. on May 7, 2002. Several parties attended, and several panels were heard, followed by a question and answer session. The subjects of ARO's and SFAS No. 143 were intertwined through virtually all comments. Subsequently, on October 30, 2002, the FERC Issued a Notice of Proposed Rulemaking ("NOPR") in Docket RM02-7-000. The FERC proposed to revise its regulations to update the accounting and reporting requirements for liabilities for asset retirement obligations under its Uniform Systems of Accounts for public utilities, licensees, natural gas companies, and oil pipeline companies.[8]

The NOPR stated that "the proposed accounting for asset retirement obligations is consistent with the accounting and reporting requirement that jurisdictional entities will use [SFAS No. 143] in their general purpose financial statements provided to shareholders and the Securities and Exchange Commission. (e.g., companies will separately account and report the liability for asset retirement obligations, capitalize the asset costs, and charge earnings for depreciation of the asset and operating expense for the accretion of the liability)."[9]

The NOPR went on to say "the recognition and measurement of legal liabilities associated with the retirement and decommissioning of long-lived assets by various entities, including Commission jurisdictional entities, has been inconsistent over the years. The usefulness of consistently recognizing and measuring asset retirement obligations in the financial statements resulted in Financial Accounting Standards Board (FASB) issuing a new accounting pronouncement affecting the manner in which legal obligations are measured and reported in the financial statements applicable to entities in general.6" The NOPR's footnotes 6 to 12 then cited to various paragraphs and concepts contained in SFAS No. 143. The NOPR generally proposed to adopt and integrate SFAS No. 143 into its Uniform System of Accounts, and Reporting Requirements and then established certain ratemaking standards.

Regarding non-legal retirement obligations the NOPR stated "the Commission is aware that a number of natural gas companies are currently collecting an allowance in jurisdictional rates to cover the future cost of retiring and removing facilities. This allowance is referred to as a negative salvage allowance. The Commission believes that these negative salvage allowances do not necessarily reflect the existence of a legal asset

[7] Notice page 3.
[8] FERC Docket No. RM02-7-000, Notice of Proposed Rulemaking, Issued October 30, 2002, ("NOPR"), page 1.
[9] Id., Paragraph I.2.

retirement obligation. Therefore, the Commission will require that negative net salvage allowances that are not established due to an asset retirement obligation be identified for ratemaking purposes separately from asset retirement obligation allowances. The current rate change filing requirements for natural gas companies at 154.312(d), Statement D, requires that any authorized negative salvage must be maintained in a separate subaccount of account 108, Accumulated provision for depreciation of gas utility plant. The Commission proposes to amend this section to ensure that this subaccount must not include any amounts related to asset retirement obligations."[10] The NOPR did not specifically identify electric utilities in this regard. Again, comments were requested and received, and on April 9, 2003 the FERC issued its Final Rule, i.e. Docket No. RM02-7-000, Order No. 631.

Order No. 631

Order No. 631 states "instead, we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in parts 101, 201 and account 31, Accrued depreciation-carrier property, in Part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals."[11]

"Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accumulated removal costs for other than legal retirement obligations as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations."[12]

Order No. 631 also states "the Commission will decline to make policy calls concerning regulatory certainty for disposition of transition costs, external funds for amounts collected in rates for asset retirement obligations, adjustments to book depreciation rates, and the exclusion of accumulated depreciation and accretion for asset retirement obligations from rate base; these are matters that are not subject to a one size fits all approach and are better resolved on a case-by-case basis in rate proceedings. The

[10] Id., Paragraph III 45.
[11] FERC Docket No. RM02-7-000, Order No. 631, Issued April 9, 2003, Paragraph 39.
[12] Id., Paragraph 39.

Commission is of the view that utilities will have the opportunity to seek recovery of qualified costs for asset retirement obligations in individual rate proceedings. This rule should not be construed as pregranted authority for rate recovery in a rate proceeding."[13]

Order No. 631 goes on to say "finally this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost of removal, and salvage estimates in rates.45." [14] And footnote 45 states "when an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate."[15]

Thus, it seems clear that the FERC recognizes distinctions between legal and non-legal AROs just as SFAS No. 143 recognizes those distinctions. In fact, the amount resulting from Order No. 631's requirement to identify previous amounts collected for non-legal ARO's should result in the same amount as the SFAS NO. 143 requirement to establish a regulatory liability to ratepayers for the same amounts. It is also clear, that on a going-forward basis, jurisdictional entities must be prepared to specifically identify and justify any non-legal AROs that they propose to be included in their rates.

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[13] Id., Paragraph 64. (Emphasis added.)
[14] Id., Paragraph 65.
[15] Id., footnote 45.

SNAVELY MAJOROS O'CONNOR & LEE, INC.'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT E-01345A-03-0437

MJM 1-11 For all accounts and locations for which Mr. Wiedmayer is proposing the life span method, provide the following information to support the final retirement dates. Please respond to each item.

a. Economic studies. (NARUC, p. 146)
b. Retirement plans. (NARUC, p. 146)
c. Forecasts. (NARUC, p. 146)
d. Studies of technological obsolescence. (NARUC, p. 146)
e. Studies of adequacy of capacity. (NARUC, p. 146)
f. Studies of competitive pressure. (NARUC, p. 146)
g. Relationship of type of construction to remaining life span.
h. Relationship of attained age to remaining life span.
i. Relationship of observed features and conditions at the time of field visits to remaining life span.
j. Relationship of specific plans of management to remaining life span.

RESPONSE:

The life-span method is proposed for Production Accounts 311 through 346. APS does not maintain the information requested in the question in the form outlined in NARUC Public Utility Depreciation Practices. For these accounts in the current depreciation study, the changes to the prior approved retirement dates either increases the expected lives or reflect actual retirements or planned retirements. These changes were based primarily on engineers' estimates of remaining life for the specific assets in question.

For steam production plants, the lives were generally increased from the prior approved lives. Four Corners 1-3 and Navajo were tied to the underlying lease terms. Four Corners 4-5 was tied to the ARO probability for retirement of such units, and lives of such units were extended from 50 to 62 years. The lives for the Cholla units were increased by five years from the prior approved lives, based on engineers' estimates. The lives for Octollo and Saguaro are the same as in the prior approved study. The West Phoenix steam units were retired.

For Palo Verde, the retirement dates are unchanged from the prior approved depreciation study, and reflects the license period. The retirement dates for the Childs-Irving hydro units reflect the scheduled decommissioning date of 2004. The retirement dates for the combustion turbines are based on a 45 year life, which APS believes is a very conservative estimate of plant life from a depreciation standpoint.

APS evaluated the proposed retirement dates for each of its units and determined that they were at the high end of industry averages, and thus believes that they are reasonable for purposes of the depreciation study. See the response to MJM 1-44, RC01212 (Estimated Remaining Life of Generating Plants).

Witness: Laura Rockenberger

ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355 POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	164,144,540	72,225	0.0004	0.9996	100.00
0.5	144,644,782	232,894	0.0016	0.9984	99.96
1.5	138,212,981	135,623	0.0010	0.9990	99.80
2.5	126,925,913	566,143	0.0045	0.9955	99.70
3.5	121,289,304	179,349	0.0015	0.9985	99.25
4.5	118,257,352	423,955	0.0036	0.9964	99.10
5.5	111,116,631	733,488	0.0066	0.9934	98.74
6.5	103,873,355	391,905	0.0038	0.9962	98.09
7.5	103,190,689	375,260	0.0036	0.9964	97.72
8.5	98,795,154	727,875	0.0074	0.9926	97.37
9.5	93,284,501	926,023	0.0099	0.9901	96.65
10.5	88,484,348	301,393	0.0034	0.9966	95.69
11.5	83,762,665	375,454	0.0045	0.9955	95.36
12.5	70,956,713	239,637	0.0034	0.9966	94.93
13.5	61,276,994	423,298	0.0069	0.9931	94.61
14.5	53,894,621	300,091	0.0056	0.9944	93.96
15.5	35,846,557	383,474	0.0107	0.9893	93.43
16.5	33,410,021	405,775	0.0121	0.9879	92.43
17.5	31,151,992	259,907	0.0083	0.9917	91.31
18.5	29,918,742	340,405	0.0114	0.9886	90.55
19.5	24,578,628	956,734	0.0389	0.9611	89.52
20.5	22,937,606	101,462	0.0044	0.9956	86.04
21.5	20,959,452	628,733	0.0300	0.9700	85.66
22.5	19,361,241	201,739	0.0104	0.9896	83.09
23.5	18,187,504	165,740	0.0091	0.9909	82.23
24.5	17,021,507	128,025	0.0075	0.9925	81.48
25.5	16,384,336	145,652	0.0089	0.9911	80.87
26.5	16,159,138	150,341	0.0093	0.9907	80.15
27.5	15,820,483	173,327	0.0110	0.9890	79.40
28.5	14,774,755	172,932	0.0117	0.9883	78.53
29.5	14,142,799	78,693	0.0056	0.9944	77.61
30.5	12,492,043	116,246	0.0093	0.9907	77.18
31.5	12,941,075	158,676	0.0123	0.9877	76.46
32.5	11,719,099	120,094	0.0102	0.9898	75.52
33.5	11,129,314	86,059	0.0077	0.9923	74.75
34.5	10,974,824	120,950	0.0110	0.9890	74.17
35.5	10,742,451	100,214	0.0093	0.9907	73.35
36.5	9,406,763	64,275	0.0068	0.9932	72.67
37.5	8,986,755	106,205	0.0118	0.9882	72.18
38.5	8,852,247	105,849	0.0120	0.9880	71.33

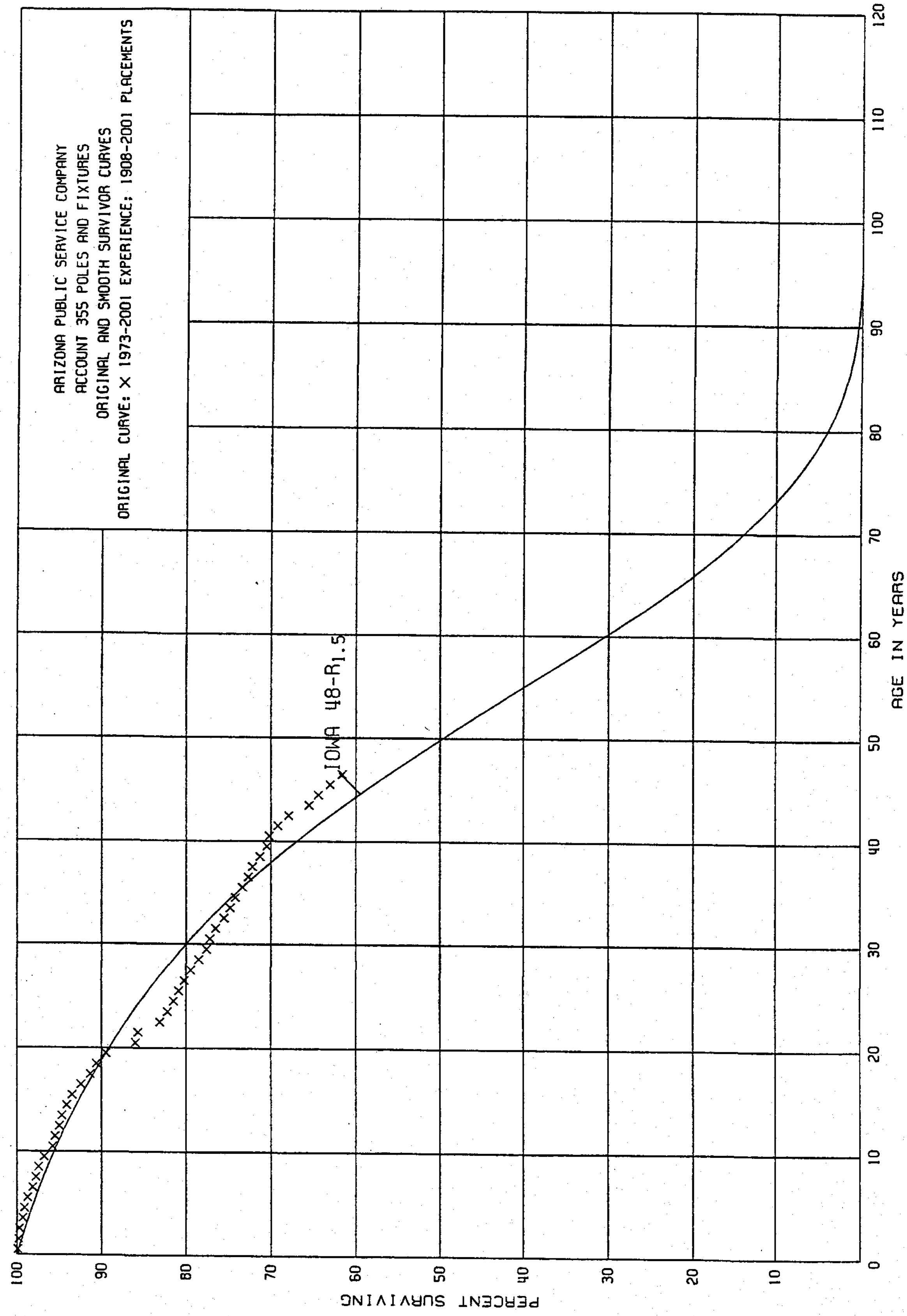
ARIZONA PUBLIC SERVICE COMPANY

ACCOUNT 355 POLES AND FIXTURES

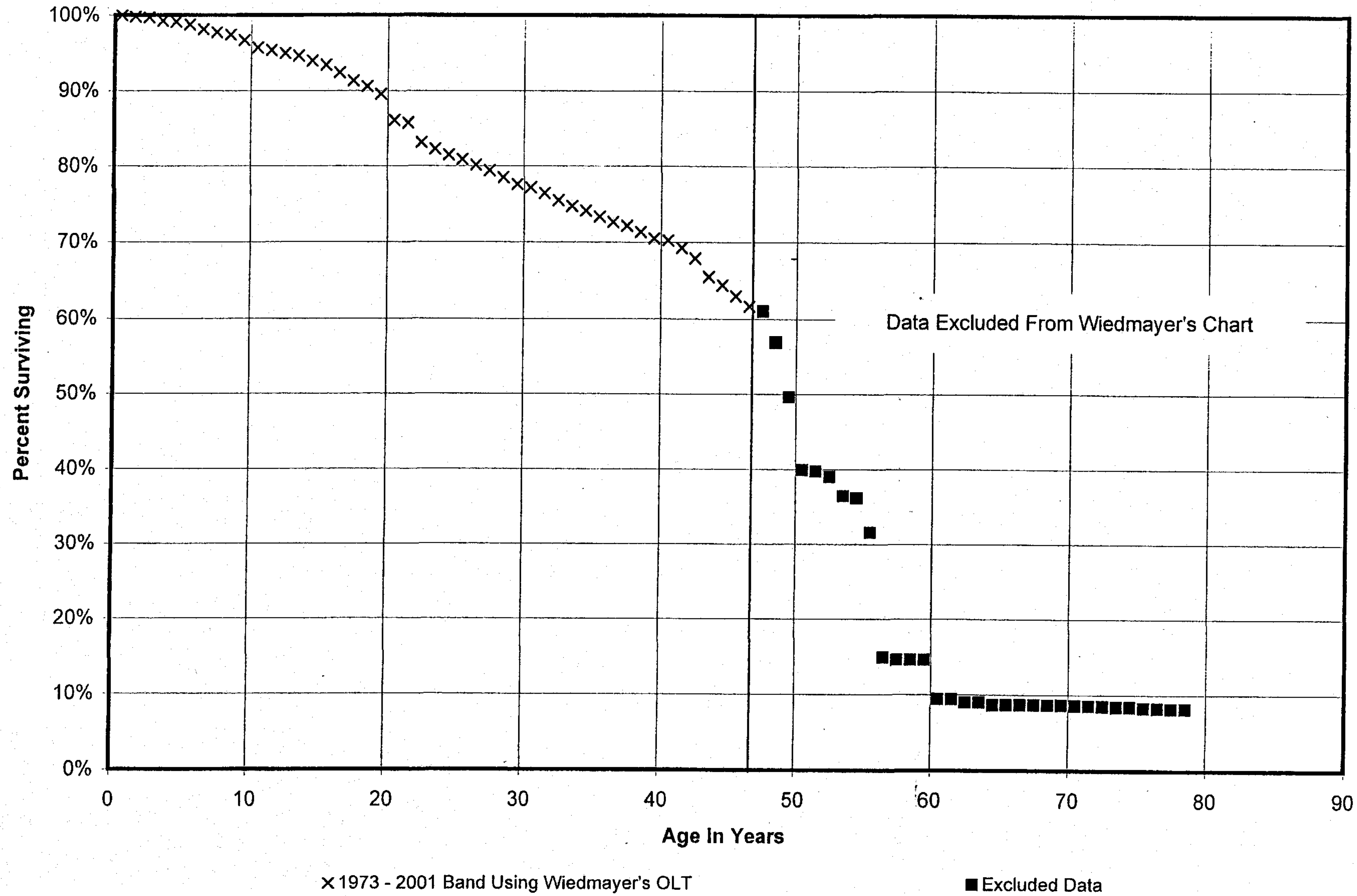
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2001 EXPERIENCE BAND 1973-2001

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,608,626	29,539	0.0034	0.9966	70.47
40.5	5,523,642	78,333	0.0142	0.9858	70.23
41.5	5,380,260	104,272	0.0194	0.9806	69.23
42.5	5,062,293	180,505	0.0357	0.9643	67.89
43.5	2,555,869	41,059	0.0161	0.9839	65.47
44.5	2,346,574	52,793	0.0225	0.9775	64.42
45.5	2,134,195	45,287	0.0212	0.9788	62.97
46.5	1,481,506	15,216	0.0103	0.9897	61.64
47.5	1,408,839	96,415	0.0684	0.9316	61.01
48.5	544,385	69,920	0.1284	0.8716	56.84
49.5	415,478	80,678	0.1942	0.8058	49.54
50.5	334,800	1,432	0.0043	0.9957	39.92
51.5	333,368	6,158	0.0185	0.9815	39.75
52.5	315,819	20,390	0.0646	0.9354	39.01
53.5	97,778	810	0.0083	0.9917	36.49
54.5	96,968	12,433	0.1282	0.8718	36.19
55.5	4,734	2,496	0.5272	0.4728	31.55
56.5	2,382	48	0.0202	0.9798	14.92
57.5	2,334		0.0000	1.0000	14.62
58.5	2,334		0.0000	1.0000	14.62
59.5	2,334	830	0.3556	0.6444	14.62
60.5	1,504		0.0000	1.0000	9.42
61.5	1,504	68	0.0452	0.9548	9.42
62.5	1,669		0.0000	1.0000	8.99
63.5	34,899	1,292	0.0370	0.9630	8.99
64.5	34,444		0.0000	1.0000	8.66
65.5	34,444		0.0000	1.0000	8.66
66.5	34,444	25	0.0007	0.9993	8.66
67.5	34,419	148	0.0043	0.9957	8.65
68.5	34,271		0.0000	1.0000	8.61
69.5	34,271	208	0.0061	0.9939	8.61
70.5	34,063	110	0.0032	0.9968	8.56
71.5	33,953	144	0.0042	0.9958	8.53
72.5	33,809	406	0.0120	0.9880	8.49
73.5	33,403		0.0000	1.0000	8.39
74.5	33,403	553	0.0166	0.9834	8.39
75.5	32,850	127	0.0039	0.9961	8.25
76.5	32,723	284	0.0087	0.9913	8.22
77.5	32,439		0.0000	1.0000	8.15
78.5	32,439		0.0000	1.0000	8.15


ARIZONA PUBLIC SERVICE COMPANY
ACCOUNT 355 POLES AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES
ORIGINAL CURVE: X 1973-2001 EXPERIENCE; 1908-2001 PLACEMENTS
IOWA 48-R1.5
PERCENT SURVIVING
AGE IN YEARS
0
10
20
30
40
50
60
70
80
90
100
110
120

Arizona Public Service Company
Account 355 - Poles and Fixtures



EXHIBIT

ALL-STATE LEGAL®

BEFORE THE STATE OF ARIZONA

ARIZONA CORPORATION COMMISSION

I/M/O THE APPLICATION OF	)	
ARIZONA PUBLIC SERVICE COMPANY	)	
FOR A HEARING TO DETERMINE THE FAIR	)	
VALUE OF THE UTILITY PROPERTY OF THE	)	
COMPANY FOR RATEMAKING PURPOSES,	)	
TO FIX A JUST AND REASONABLE RATE OF	)	DOCKET NO. E-01345A-03-0437
RETURN THEREON, TO APPROVE RATE	)	
SCHEDULES DESIGNED TO DEVELOP SUCH	)	
RETURN, AND FOR APPROVAL OF	)	
PURCHASED POWER CONTRACT	)	

DIRECT TESTIMONY OF MICHAEL J. MAJOROS, JR.
ON BEHALF OF THE
ARIZONA CORPORATION COMMISSION

VOLUME 2

EXHIBIT___(MJM-3)

Date: FEBRUARY 3, 2004

Exhibit___(MJM-3)

Snavely King Majoros O'Connor & Lee, Inc.

Depreciation Study
of
Arizona Public Service Company

Analyses, Calculations & Quantifications

Arizona Public Service Company

Exhibit___(MJM-3)

Index

Arizona Public Service Company
Estimated Survivor Curve, Net Salvage, Original Cost, Book Reserve and
Calculated Annual Depreciation Accruals Related to Electric Plant in Service as of December 31, 2002
SNAVELY KING RECOMMENDATION

Depreciable Group (1)	Probable Retirement Date (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/2002 (5)	SK Allocated Book Reserve at 12/31/2002 (6)	Future Book Accruals (7)=(5)-(6)	Average Remaining Life (8)	Annual Amount (9)=(7)/(8)	Accrual Rate (10)=(9)/(5)
PLANT IN SERVICE									
STEAM PRODUCTION PLANT									
311 Structure and Improvements									
Cholla Unit 1	06-2017	75-S1.5	0	2,144,789	1,841,738	303,051	14.0	21,646	1.01%
Cholla Unit 2	06-2033	75-S1.5	0	5,022,179	2,101,615	2,920,564	29.0	100,709	2.01%
Cholla Unit 3	06-2035	75-S1.5	0	9,583,277	5,184,966	4,398,311	29.9	147,101	1.53%
Cholla Common	06-2035	75-S1.5	0	36,234,550	19,318,431	16,916,119	29.9	565,756	1.56%
Four Corners Units 1-3	06-2016	75-S1.5	0	15,972,927	10,628,079	5,344,848	13.3	401,868	2.52%
Four Corners Units 4-5	06-2031	75-S1.5	0	9,195,585	5,124,992	4,070,593	26.8	151,888	1.65%
Four Corners Common	06-2031	75-S1.5	0	3,946,871	2,227,796	1,719,075	26.8	64,145	1.63%
Navajo Units 1-3	06-2026	75-S1.5	0	27,152,517	12,197,389	14,955,128	22.8	655,927	2.42%
Ocotillo Units 1-2	06-2020	75-S1.5	0	3,787,972	2,084,288	1,703,684	17.1	99,631	2.63%
Saguaro Units 1-2	06-2014	75-S1.5	0	2,446,832	1,989,759	457,073	11.3	40,449	1.65%
Yucca Unit 1	06-2016	75-S1.5	0	462,567	452,608	9,959	13.1	760	0.16%
Total Account 311				**115,950,066**	**63,151,660**	**52,798,406**		**2,249,880**	**1.94%**
312 Boiler Plant Equipment									
Cholla Unit 1	06-2017	48-L2	0	26,431,681	17,605,653	8,826,028	13.4	658,659	2.49%
Cholla Unit 2	06-2033	48-L2	0	140,612,492	86,692,363	53,920,129	22.0	2,450,915	1.74%
Cholla Unit 3	06-2035	48-L2	0	100,448,965	60,203,467	40,245,498	22.9	1,757,445	1.75%
Cholla Common	06-2035	48-L2	0	22,626,051	11,328,185	11,297,866	24.8	455,559	2.01%
Four Corners Units 1-3	06-2016	48-L2	0	197,139,757	115,304,816	81,834,941	12.7	6,443,696	3.27%
Four Corners Units 4-5	06-2031	48-L2	0	111,591,873	64,306,071	47,285,802	22.1	2,139,629	1.92%
Four Corners Common	06-2031	48-L2	0	3,290,391	2,152,160	1,138,231	22.8	49,922	1.52%
Navajo Units 1-3	06-2026	48-L2	0	149,350,243	69,950,378	79,399,865	20.6	3,854,362	2.58%
Ocotillo Units 1-2	06-2020	48-L2	0	24,152,351	17,905,382	6,246,969	15.2	410,985	1.70%
Saguaro Units 1-2	06-2014	48-L2	0	24,387,712	16,566,160	7,821,552	11.1	704,644	2.89%
Total Account 312				**800,031,516**	**462,014,635**	**338,016,881**		**18,925,817**	**2.37%**
314 Turbogenerator Units									
Cholla Unit 1	06-2017	65-R2	0	10,417,373	7,459,687	2,957,686	14.0	211,263	2.03%
Cholla Unit 2	06-2033	65-R2	0	28,551,889	15,518,951	13,032,938	27.5	473,925	1.66%
Cholla Unit 3	06-2035	65-R2	0	39,626,197	16,959,280	22,666,917	29.7	763,196	1.93%
Cholla Common	06-2035	65-R2	0	631,278	335,591	295,687	29.0	10,196	1.62%
Four Corners Units 1-3	06-2016	65-R2	0	36,412,926	24,829,283	11,583,643	13.1	884,248	2.43%
Four Corners Units 4-5	06-2031	65-R2	0	14,488,238	7,086,302	7,401,936	26.3	281,442	1.94%
Four Corners Common	06-2031	65-R2	0	1,726,164	1,349,968	376,196	23.3	16,146	0.94%
Navajo Units 1-3	06-2026	65-R2	0	24,387,110	14,479,672	9,907,438	22.0	450,338	1.85%
Ocotillo Units 1-2	06-2020	65-R2	0	15,517,601	11,437,238	4,080,363	16.8	242,879	1.57%
Saguaro Units 1-2	06-2014	65-R2	0	16,259,698	13,244,927	3,014,771	11.2	269,176	1.66%
Total Accounts 314				**188,018,474**	**112,700,899**	**75,317,575**		**3,602,809**	**1.92%**

Arizona Public Service Company
Estimated Survivor Curve, Net Salvage, Original Cost, Book Reserve and
Calculated Annual Depreciation Accruals Related to Electric Plant in Service as of December 31, 2002
SNAVELY KING RECOMMENDATION

Depreciable Group (1)	Probable Retirement Date (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/2002 (5)	SK Allocated Book Reserve at 12/31/2002 (6)	Future Book Accruals (7)=(5)-(6)	Average Remaining Life (8)	Annual Amount (9)=(7)/(8)	Accrual Rate (10)=(9)/(5)
315 Accessory Electric Equipment									
Cholla Unit 1	06-2017	60-R2.5	0	4,756,906	3,592,717	1,164,189	13.9	83,755	1.76%
Cholla Unit 2	06-2033	60-R2.5	0	42,235,618	25,070,631	17,164,987	26.8	640,485	1.52%
Cholla Unit 3	06-2035	60-R2.5	0	29,917,206	16,267,820	13,649,386	28.5	478,926	1.60%
Cholla Common	06-2035	60-R2.5	0	4,476,001	2,380,788	2,095,213	28.7	73,004	1.63%
Four Corners Units 1-3	06-2016	60-R2.5	0	16,353,282	9,525,599	6,827,683	13.2	517,249	3.16%
Four Corners Units 4-5	06-2031	60-R2.5	0	9,183,206	5,039,778	4,143,428	25.9	159,978	1.74%
Four Corners Common	06-2031	60-R2.5	0	2,596,719	2,104,631	492,088	21.0	23,433	0.90%
Navajo Units 1-3	06-2026	60-R2.5	0	20,226,194	11,727,970	8,498,224	22.0	386,283	1.91%
Ocotillo Units 1-2	06-2020	60-R2.5	0	2,407,622	2,023,821	383,801	16.3	23,546	0.98%
Saguaro Units 1-2	06-2014	60-R2.5	0	2,654,661	2,355,021	299,640	11.2	26,754	1.01%
Total Account 315				**134,807,415**	**80,088,777**	**54,718,638**		**2,413,411**	**1.79%**
316 Miscellaneous Power Plant Equipment									
Cholla Unit 1	06-2017	40-R2	0	2,315,189	1,189,333	1,125,856	13.5	83,397	3.60%
Cholla Unit 2	06-2033	40-R2	0	4,846,431	2,631,492	2,214,939	22.1	100,223	2.07%
Cholla Unit 3	06-2035	40-R2	0	4,138,531	1,990,199	2,148,332	23.8	90,266	2.18%
Cholla Common	06-2035	40-R2	0	7,096,069	2,439,747	4,656,322	25.8	180,478	2.54%
Four Corners Units 1-3	06-2016	40-R2	0	4,330,612	925,502	3,405,110	13.1	259,932	6.00%
Four Corners Units 4-5	06-2031	40-R2	0	3,304,340	1,402,561	1,901,779	23.0	82,686	2.50%
Four Corners Common	06-2031	40-R2	0	8,133,224	3,483,659	4,649,565	23.2	200,412	2.46%
Navajo Units 1-3	06-2026	40-R2	0	11,805,250	5,248,830	6,556,420	20.2	324,575	2.75%
Ocotillo Units 1-2	06-2020	40-R2	0	3,711,192	1,301,603	2,409,589	16.2	148,740	4.01%
Saguaro Units 1-2	06-2014	40-R2	0	3,191,024	1,340,385	1,850,639	10.9	169,783	5.32%
Yucca Unit 1	06-2016	40-R2	0	452,868	359,801	93,067	12.2	7,628	1.68%
Total Account 316				**53,324,730**	**22,313,113**	**31,011,617**		**1,648,121**	**3.09%**
TOTAL STEAM PRODUCTION PLANT				**1,292,132,201**	**740,269,083**	**551,863,118**		**28,840,038**	**2.23%**
NUCLEAR PRODUCTION PLANT									
321 Structures and Improvements									
Palo Verde Unit 1	12-2204	65-R2.5	0	161,039,432	69,557,944	91,481,488	21.2	4,315,165	2.68%
Palo Verde Unit 2	12-2025	65-R2.5	0	88,415,270	38,859,061	49,556,209	22.0	2,252,555	2.55%
Palo Verde Unit 3	03-2027	65-R2.5	0	159,591,077	63,133,223	96,457,854	23.3	4,139,822	2.59%
Palo Verde Water Reclamation	03-2027	65-R2.5	0	125,593,913	51,122,827	74,471,086	23.2	3,209,961	2.56%
Palo Verde Common	03-2027	65-R2.5	0	98,127,309	39,316,906	58,810,403	23.2	2,534,931	2.58%
Total Account 321				**632,767,001**	**261,989,962**	**370,777,039**		**16,452,433**	**2.60%**
322 *Reactor Plant Equipment*									
Palo Verde Unit 1	12-2204	70-R1	0	359,545,213	153,616,828	205,928,385	20.6	9,996,524	2.78%
Palo Verde Unit 2	12-2025	70-R1	0	176,362,235	72,582,559	103,779,676	21.5	4,826,962	2.74%
Palo Verde Unit 3	03-2027	70-R1	0	322,750,700	121,218,479	201,532,221	22.6	8,917,355	2.76%
Palo Verde Water Reclamation	03-2027	70-R1	0	123,313	7,176	116,137	23.0	5,049	4.09%
Palo Verde Common	03-2027	70-R1	0	26,449,873	9,583,436	16,866,437	22.6	746,303	2.82%
Total Account 322				**885,231,334**	**357,008,478**	**528,222,856**		**24,492,192**	**2.77%**
322.1 Reactor Plant Equipment - Steam Generators									
Palo Verde Unit 1	12-2005	Square	0	30,722,375	27,569,149	3,153,226	3.0	1,051,075	3.42%
Palo Verde Unit 2	12-2003	Square	0	15,870,053	15,868,635	1,418	1.0	1,418	0.01%
Palo Verde Unit 3	12-2007	Square	0	25,413,317	20,039,935	5,373,382	5.0	1,074,676	4.23%
Total Account 322.1				**72,005,745**	**63,477,719**	**8,528,026**		**2,127,170**	**2.95%**

Arizona Public Service Company
Estimated Survivor Curve, Net Salvage, Original Cost, Book Reserve and
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SNAVELY KING RECOMMENDATION

Depreciable Group	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/2002	SK Allocated Book Reserve at 12/31/2002	Future Book Accruals	Average Remaining Life	Annual Amount	Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)	(10)=(9)/(5)
323 Turbogenerator Units									
Palo Verde Unit 1	12-2024	60-S0	0	117,808,078	51,570,896	66,237,182	19.9	3,328,502	2.83%
Palo Verde Unit 2	12-2025	60-S0	0	76,754,224	32,432,468	44,321,756	20.8	2,130,854	2.78%
Palo Verde Unit 3	03-2027	60-S0	0	142,895,088	55,838,987	87,056,101	21.8	3,993,399	2.79%
Palo Verde Water Reclamation	03-2027	60-S0	0	217,707	76,585	141,122	22.0	6,415	2.95%
Palo Verde Common	03-2027	60-S0	0	1,223,879	346,554	877,325	22.2	39,519	3.23%
Total Account 323				**338,898,976**	**140,265,491**	**198,633,485**		**9,498,688**	**2.80%**
324 Accessory Electric Equipment									
Palo Verde Unit 1	12-2024	45-R3	0	115,495,170	53,444,066	62,051,104	20.0	3,102,555	2.69%
Palo Verde Unit 2	12-2025	45-R3	0	50,119,388	21,982,186	28,137,202	20.9	1,346,278	2.69%
Palo Verde Unit 3	03-2027	45-R3	0	89,143,623	36,343,481	52,800,142	22.1	2,389,147	2.68%
Palo Verde Common	03-2027	45-R3	0	17,918,193	7,299,463	10,618,730	22.0	482,670	2.69%
Total Account 324				**272,676,374**	**119,069,196**	**153,607,178**		**7,320,649**	**2.68%**
325 Miscellaneous Power Plant Equipment									
Palo Verde Unit 1	12-2024	35-R0.5	0	29,671,405	11,770,905	17,900,500	17.7	1,011,328	3.41%
Palo Verde Unit 2	12-2025	35-R0.5	0	26,389,406	8,702,844	17,686,562	18.7	945,805	3.58%
Palo Verde Unit 3	03-2027	35-R0.5	0	27,284,046	9,445,478	17,838,568	19.2	929,092	3.41%
Palo Verde Water Reclamation	03-2027	35-R0.5	0	88,819	27,706	61,113	19.5	3,134	3.53%
Palo Verde Common	03-2027	35-R0.5	0	48,459,510	15,382,218	33,077,292	19.4	1,705,015	3.52%
Total Account 325				**131,893,186**	**45,329,152**	**86,564,034**		**4,594,374**	**3.48%**
TOTAL NUCLEAR PRODUCTION PLANT				**2,333,472,616**	**987,139,997**	**1,346,332,619**		**64,485,507**	**2.76%**
HYDRO PRODUCTION PLANT									
331 Structures and Improvements	12-2024	200-SQ	0	100,878	100,878	0		0	0.00%
332 Reservoirs, Dams, and Waterways	12-2004	200-SQ	0	991,936	1,105,086	(113,150)		0	0.00%
333 Water Wheels, Turbines, and Generators	12-2004	200-SQ	0	157,196	157,196	0		0	0.00%
334 Accessory Electric Equipment	12-2004	200-SQ	0	627,611	627,611	0		0	0.00%
335 Miscellaneous Power Plant Equipment	12-2004	200-SQ	0	126,018	126,018	0		0	0.00%
336 Roads, Railroads, and Bridges	12-2004	200-SQ	0	77,427	77,427	0		0	0.00%
Hydro Decommissioning Costs					7,864,531	5,335,469	2.0	2,667,735 1/	
TOTAL HYDRO PRODUCTION PLANT				**2,081,066**	**10,058,747**	**5,222,319**		**2,667,735**	

Arizona Public Service Company
Estimated Survivor Curve, Net Salvage, Original Cost, Book Reserve and
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SNAVELY KING RECOMMENDATION

Depreciable Group (1)	Probable Retirement Date (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/2002 (5)	SK Allocated Book Reserve at 12/31/2002 (6)	Future Book Accruals (7)=(5)-(6)	Average Remaining Life (8)	Annual Amount (9)=(7)/(8)	Accrual Rate (10)=(9)/(5)
OTHER PRODUCTION									
341 Structures and Improvements									
Douglas CT	06-2017	80-S1	0	4,562	4,148	414	13.9	30	0.65%
Ocotillo CT 1-2	06-2017	80-S1	0	328,749	230,819	97,930	14.5	6,754	2.05%
Saguaro CT	06-2017	80-S1	0	1,288,525	466,971	821,554	14.4	57,052	4.43%
Solar Unit 1		12-SQ	0	375,512	383,809	(8,297)	3.6	-2,305	-0.61%
West phoenix CT 1-2	06-2017	80-S1	0	510,951	419,492	91,459	14.2	6,441	1.26%
West Phoenix Combined Cycle 1-3	06-2031	80-S1	0	6,706,722	2,438,522	4,268,200	28.1	151,893	2.26%
Yucca CT 1-4	06-2016	80-S1	0	452,751	222,815	229,936	13.4	17,159	3.79%
Total Account 341				**9,667,772**	**4,166,575**	**5,501,197**		**237,025**	**2.45%**
342 Fuel Holders, Products and Accessories									
Douglas CT	06-2017	70-S1	0	137,759	100,065	37,694	14.0	2,692	1.95%
Ocotillo CT 1-2	06-2017	70-S1	0	719,859	517,984	201,875	14.0	14,420	2.00%
Saguaro CT	06-2017	70-S1	0	1,304,977	1,019,500	285,477	14.0	20,391	1.56%
West phoenix CT 1-2	06-2017	70-S1	0	1,437,533	1,123,270	314,263	14.0	22,447	1.56%
West Phoenix Combined Cycle 1-3	06-2031	70-S1	0	19,343,993	2,649,135	16,694,858	27.7	602,702	3.12%
Yucca CT 1-4	06-2016	70-S1	0	3,232,217	2,859,228	372,989	12.9	28,914	0.89%
Total Account 342				**26,176,338**	**8,269,181**	**17,907,157**		**691,567**	**2.64%**
343 Prime Movers									
Douglas CT	06-2017	70-L1.5	0	1,101,449	999,227	102,222		0	0.00%
Ocotillo CT 1-2	06-2017	70-L1.5	0	6,679,324	5,679,469	999,855	14.1	70,912	1.06%
Saguaro CT	06-2017	70-L1.5	0	8,102,651	6,657,234	1,445,417	13.8	104,740	1.29%
West phoenix CT 1-2	06-2017	70-L1.5	0	8,802,636	6,220,272	2,582,364	14.2	181,857	2.07%
Yucca CT 1-4	06-2016	70-L1.5	0	7,920,584	7,302,457	618,127		0	0.00%
Total Account 343				**32,606,644**	**26,858,659**	**5,747,985**		**357,509**	**1.10%**
344 Generators and Devices									
Douglas CT	06-2017	37-R3	0	551,765	542,840	8,925	9.7	920	0.17%
Ocotillo CT 1-2	06-2017	37-R3	0	6,402,044	3,500,409	2,901,635	13.6	213,356	3.33%
Saguaro CT	06-2017	37-R3	0	4,185,247	2,504,957	1,680,290	13.0	129,253	3.09%
Solar Unit 1		12-SQ	0	6,933,081	3,289,918	3,643,163	7.8	467,072	6.74%
West phoenix CT 1-2	06-2017	37-R3	0	4,115,901	3,202,560	913,341	12.3	74,255	1.80%
West Phoenix Combined Cycle 1-3	06-2031	37-R3	0	81,920,222	11,983,119	69,937,103	26.2	2,669,355	3.26%
Yucca CT 1-4	06-2016	37-R3	0	5,395,818	4,370,148	1,025,670	11.6	88,420	1.64%
Total Account 344				**109,504,078**	**29,393,951**	**80,110,127**		**3,642,631**	**3.33%**

Arizona Public Service Company
Estimated Survivor Curve, Net Salvage, Original Cost, Book Reserve and
Calculated Annual Depreciation Accruals Related to Electric Plant In Service as of December 31, 2002
SNAVELY KING RECOMMENDATION

Depreciable Group	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/2002	SK Allocated Book Reserve at 12/31/2002	Future Book Accruals	Average Remaining Life	Annual Amount	Accrual Rate	
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)-(6)	(8)	(9)=(7)/(8)	(10)=(9)/(5)	
345 Accessory Electric Equipment										
Douglas CT	06-2017	50-S2	0	353,277	313,549	39,728	13.1	3,033	0.86%	
Ocotillo CT 1-2	06-2017	50-S2	0	1,494,636	1,281,843	212,793	13.2	16,121	1.08%	
Saguaro CT	06-2017	50-S2	0	1,715,774	1,389,500	326,274	13.4	24,349	1.42%	
Solar Unit 1		12-SQ	0	169,527	40,179	129,348	9.9	13,065	7.71%	
West phoenix CT 1-2	06-2017	50-S2	0	1,557,744	1,315,426	242,318	13.2	18,357	1.18%	
West Phoenix Combined Cycle 1-3	06-2031	50-S2	0	11,925,645	2,562,942	9,362,703	27.8	336,788	2.82%	
Yucca CT 1-4	06-2016	50-S2	0	2,166,526	1,817,969	348,557	13.0	26,812	1.24%	
Total Account 345				**19,383,129**	**8,721,408**	**10,661,721**		**438,525**	**2.26%**	
346 Miscellaneous Power Plant Equipment										
Douglas CT	06-2017	70-L1	0	40,913	30,160	10,753	13.8	779	1.90%	
Ocotillo CT 1-2	06-2017	70-L1	0	553,173	418,696	134,477	14.0	9,605	1.74%	
Saguaro CT	06-2017	70-L1	0	790,906	410,357	380,549	14.1	26,989	3.41%	
West phoenix CT 1-2	06-2017	70-L1	0	957,431	508,533	448,898	14.1	31,837	3.33%	
West Phoenix Combined Cycle 1-3	06-2031	70-L1	0	2,608,877	895,856	1,713,021	26.6	64,399	2.47%	
Yucca CT 1-4	06-2016	70-L1	0	427,175	357,633	69,542	13.2	5,268	1.23%	
Total Account 346				**5,378,475**	**2,621,236**	**2,757,239**		**138,878**	**2.58%**	
TOTAL OTHER PRODUCTION PLANT				**202,716,436**	**80,031,011**	**122,685,425**		**5,506,135**	**2.72%**	
TRANSMISSION PLANT										
352 Structures and Improvements		50-R4	0	27,618,299	12,484,016	15,134,283	35.2	429,951	1.56%	
352.5 Structures and Improvements - SCE 500 KV Line			0	409,725	424,897	(15,172)		13,316	3.25%	b
353 Station Equipment		57-R1.5	0	428,736,305	130,140,054	298,596,251	45.7	6,538,127	1.52%	
353.5 Station Equipment - SCE 500 KV Line			0	7,747,282	7,349,363	397,919		251,787	3.25%	b
354 Towers and Fixtures		60-R3	0	83,464,531	46,097,366	37,367,165	38.3	975,644	1.17%	
354.5 Towers and Fixtures - SCE 500 KV Line		.	0	13,752,584	17,477,965	(3,725,381)		446,959	3.25%	b
355 Poles and Fixtures - Wood		48-R1.5	0	91,126,939	27,541,958	63,584,981	38.5	1,651,558	1.81%	
355.1 Poles and Fixtures - Steel		55-R3	0	83,067,888	22,833,440	60,234,448	45.1	1,335,575	1.61%	
355.5 Poles and Fixtures - SCE 500 KV Line			0	930,308	692,575	237,733		30,235	3.25%	b
356 Overhead Conductors and Devices		55-R3	0	205,771,417	94,269,666	111,501,751	38.5	2,896,149	1.41%	
356.5 Overhead Conductors and Devices - SCE 500 KV Line			0	22,653,515	28,947,611	(6,294,096)		736,239	3.25%	b
357 Underground Conduit		48-S1.5	0	10,444,362	4,087,064	6,357,298	35.7	178,076	1.70%	
358 Underground Conductors and Devices		40-R3	0	18,551,254	9,702,854	8,848,400	26.3	336,441	1.81%	
TOTAL TRANSMISSION PLANT				**994,274,409**	**402,048,830**	**592,225,579**		**15,820,057**	**1.59%**	

Arizona Public Service Company
Estimated Survivor Curve, Net Salvage, Original Cost, Book Reserve and
Calculated Annual Depreciation Accruals Related to Electric Plant in Service as of December 31, 2002
SNAVELY KING RECOMMENDATION

Depreciable Group (1)	Probable Retirement Date (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/2002 (5)	SK Allocated Book Reserve at 12/31/2002 (6)	Future Book Accruals (7)=(5)-(6)	Average Remaining Life (8)	Annual Amount (9)=(7)/(8)	Accrual Rate (10)=(9)/(5)
DISTRIBUTION PLANT									
361 Structures and Improvements		45-R2.5	0	25,815,042	10,429,908	15,385,134	33.1	464,808	1.80%
362 Station Equipment		44-L0.5	0	212,357,577	52,722,295	159,635,282	36.9	4,332,029	2.04%
364 Poles and Fixtures - Wood		38-R0.5	0	284,200,711	81,128,434	203,072,277	30.9	6,571,918	2.31%
364.1 Poles and Fixtures - Steel		50-R3	0	53,919,651	5,601,820	48,317,831	46.6	1,036,863	1.92%
365 Overhead Conductors and Devices		53-O1	0	218,856,780	33,437,453	185,419,327	47.7	3,887,198	1.78%
366 Underground Conduit		86-O1	0	425,723,116	26,924,767	398,798,349	82.4	4,837,438	1.14%
367 Underground Conductors and Devices		29-L1	0	805,505,783	258,865,205	546,640,578	22.9	23,870,768	2.96%
368 Line Transformers		36-R3	0	486,837,053	235,537,009	251,300,044	24.6	10,215,449	2.10%
369 Services		37-S2	0	242,404,812	91,086,515	151,318,297	27.9	5,423,595	2.24%
370 Meters		29-L0	0	91,330,710	34,836,184	56,494,526	21.8	2,596,256	2.84%
370.1 Electronic Meters		26 R1.5	0	54,691,249	8,612,961	46,078,288	23.3	1,975,913	3.61%
371 Installations On Customer Premises		50-O2	0	25,335,831	3,863,126	21,472,705	45.0	477,065	1.88%
373 Street Lighting and Signal Systems		35-R2	0	57,185,737	22,716,125	34,469,612	25.9	1,330,873	2.33%
TOTAL DISTRIBUTION PLANT				**2,984,164,052**	**865,761,801**	**2,118,402,251**		**67,020,172**	**2.25%**
GENERAL PLANT									
390 Structures and Improvements		39-R1	0	96,667,435	24,085,116	72,582,319	30.7	2,364,245	2.45%
391 Office Furniture and Equipment - Furniture		20-SQ	0	19,919,640	11,543,613	8,376,027	10.1	829,310	4.16%
Reserve Variance Amortization							2/		
391.1 Office Furniture and Equipment - Pc Equip		8-R3	0	38,654,946	15,103,632	23,551,314	5.3	4,418,633	11.43%
Reserve Variance Amortization							2/		
391.2 Office Furniture and Equipment - Equipment		22-R4	0	7,652,923	2,932,191	4,720,732	14.8	318,968	4.17%
Reserve Variance Amortization							2/		
393 Stores Equipment		20-SQ	0	1,227,371	1,235,746	(8,375)	2.8	-2,991	-0.24%
Reserve Variance Amortization							D		
394 Tools, Shop and Garage Equipment		20-SQ	0	12,673,031	4,673,542	7,999,489	13.7	583,904	4.61%
Reserve Variance Amortization							2/		
395 Laboratory Equipment		20-L1	0	1,350,583	531,270	819,313	12.0	68,504	5.07%
Reserve Variance Amortization							2/		
397 Communication Equipment		19-S1.5	0	94,309,691	40,677,647	53,632,044	12.0	4,469,337	4.74%
398 Miscellaneous Equipment		24-S1	0	1,336,404	481,755	854,649	16.6	51,454	3.85%
Reserve Variance Amortization							2/		
TOTAL GENERAL PLANT				**273,792,024**	**101,264,511**	**172,527,513**		**13,101,364**	**4.79%**
TOTAL DEPRECIABLE PLANT STUDIED				**8,082,632,804**	**3,186,573,980**	**4,909,258,824**		**197,441,008**	**2.44%**
NET SALVAGE ALLOWANCE								-	
TOTAL DEPRECIATION								**197,441,008**	

\b Assets Related to the 500 KV SCE Transmission Line are Depreciated at a 3.25 rate

*/ Change from Company proposed in SK analysis
1/ SK accepts Company proposal because amount approximates the ARO expense per response to RC00759_ARO Childs Irving, Childs Irving Summary
2/ Reserve Variances Related to General Plant Amortization Accounts are not used in SK Recommendation

Arizona Public Service Company
Comparison of Parameters, Rates and Accruals
Related to Electric Plant in Service as of December 31, 2002

	Existing Rates						Company Proposed					Snavely King Recommended				
Depreciable Group	Original Cost at 12/31/2001	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
PLANT IN SERVICE																
STEAM PRODUCTION PLANT																
311 Structure and Improvements																
Cholla Unit 1	2,144,789	06-2012	80-S1	(20)			06-2017	75-S1.5	(20)	2.03%	43,523	06-2017	75-S1.5	0	1.01%	21,646
Cholla Unit 2	5,022,179	06-2028	80-S1	(20)			06-2033	75-S1.5	(20)	2.52%	126,743	06-2033	75-S1.5	0	2.01%	100,709
Cholla Unit 3	9,583,277	06-2028	80-S1	(20)			06-2035	75-S1.5	(20)	1.88%	180,314	06-2035	75-S1.5	0	1.53%	147,101
Cholla Common	36,234,550	06-2029	80-S1	(20)			06-2035	75-S1.5	(20)	1.89%	685,872	06-2035	75-S1.5	0	1.56%	565,756
Four Corners Units 1-3	15,972,927	06-2013	80-S1	(20)			06-2016	75-S1.5	(20)	5.55%	885,732	06-2016	75-S1.5	0	2.52%	401,868
Four Corners Units 4-5	9,195,585	06-2019	80-S1	(20)			06-2031	75-S1.5	(20)	2.35%	216,098	06-2031	75-S1.5	0	1.65%	151,888
Four Corners Common	3,946,871	06-2019	80-S1	(20)			06-2031	75-S1.5	(20)	1.84%	72,563	06-2031	75-S1.5	0	1.63%	64,145
Navajo Units 1-3	27,152,517	06-2025	80-S1	(20)			06-2026	75-S1.5	(20)	3.42%	929,321	06-2026	75-S1.5	0	2.42%	655,927
Ocotillo Units 1-2	3,787,972	06-2020	80-S1	(20)			06-2020	75-S1.5	(20)	4.11%	155,535	06-2020	75-S1.5	0	2.63%	99,631
Saguaro Units 1-2	2,446,832	06-2014	80-S1	(20)			06-2014	75-S1.5	(20)	3.34%	81,704	06-2014	75-S1.5	0	1.65%	40,449
Yucca Unit 1	462,567	06-2019	80-S1	(20)			06-2016	75-S1.5	(20)	1.38%	6,405	06-2016	75-S1.5	0	0.16%	760
Total Account 311	**115,950,066**				**2.80**	**3,246,602**				**2.92%**	**3,383,810**				**1.94%**	**2,249,880**
312 Boiler Plant Equipment																
Cholla Unit 1	26,431,681	06-2012	70-L1	(20)			06-2017	48-L2	(20)	4.06%	1,074,426	06-2017	48-L2	0	2.49%	658,659
Cholla Unit 2	140,612,492	06-2028	70-L1	(20)			06-2033	48-L2	(20)	2.41%	3,393,069	06-2033	48-L2	0	1.74%	2,450,915
Cholla Unit 3	100,448,965	06-2028	70-L1	(20)			06-2035	48-L2	(20)	2.49%	2,500,521	06-2035	48-L2	0	1.75%	1,757,445
Cholla Common	22,626,051	06-2029	70-L1	(20)			06-2035	48-L2	(20)	2.71%	613,196	06-2035	48-L2	0	2.01%	455,559
Four Corners Units 1-3	197,139,757	06-2013	70-L1	(20)			06-2016	48-L2	(20)	5.85%	11,533,490	06-2016	48-L2	0	3.27%	6,443,696
Four Corners Units 4-5	111,591,873	06-2019	70-L1	(20)			06-2031	48-L2	(20)	2.98%	3,320,980	06-2031	48-L2	0	1.92%	2,139,629
Four Corners Common	3,290,391	06-2019	70-L1	(20)			06-2031	48-L2	(20)	1.55%	50,863	06-2031	48-L2	0	1.52%	49,922
Navajo Units 1-3	149,350,243	06-2025	70-L1	(20)			06-2026	48-L2	(20)	3.70%	5,528,022	06-2026	48-L2	0	2.58%	3,854,362
Ocotillo Units 1-2	24,152,351	06-2020	70-L1	(20)			06-2020	48-L2	(20)	2.76%	665,415	06-2020	48-L2	0	1.70%	410,985
Saguaro Units 1-2	24,387,712	06-2014	70-L1	(20)			06-2014	48-L2	(20)	4.36%	1,062,280	06-2014	48-L2	0	2.89%	704,644
Total Account 312	**800,031,516**				**2.88**	**23,040,908**				**3.72%**	**29,742,262**				**2.37%**	**18,925,817**
314 Turbogenerator Units																
Cholla Unit 1	10,417,373	06-2012	65-R2	(20)			06-2017	65-R2	(20)	2.95%	307,127	06-2017	65-R2	0	2.03%	211,263
Cholla Unit 2	28,551,889	06-2028	65-R2	(20)			06-2033	65-R2	(20)	2.01%	574,578	06-2033	65-R2	0	1.66%	473,925
Cholla Unit 3	39,626,197	06-2028	65-R2	(20)			06-2035	65-R2	(20)	2.34%	929,156	06-2035	65-R2	0	1.93%	763,196
Cholla Common	631,278	06-2029	65-R2	(20)			06-2035	65-R2	(20)	2.01%	12,687	06-2035	65-R2	0	1.62%	10,196
Four Corners Units 1-3	36,412,926	06-2013	65-R2	(20)			06-2016	65-R2	(20)	3.92%	1,427,354	06-2016	65-R2	0	2.43%	884,248
Four Corners Units 4-5	14,488,238	06-2019	65-R2	(20)			06-2031	65-R2	(20)	2.45%	355,319	06-2031	65-R2	0	1.94%	281,442
Four Corners Common	1,726,164	06-2019	65-R2	(20)			06-2031	65-R2	(20)	0.26%	4,559	06-2031	65-R2	0	0.94%	16,146
Navajo Units 1-3	24,387,110	06-2025	65-R2	(20)			06-2026	65-R2	(20)	2.60%	632,931	06-2026	65-R2	0	1.85%	450,338
Ocotillo Units 1-2	15,517,601	06-2020	65-R2	(20)			06-2020	65-R2	(20)	1.94%	300,851	06-2020	65-R2	0	1.57%	242,879
Saguaro Units 1-2	16,259,698	06-2014	65-R2	(20)			06-2014	65-R2	(20)	3.62%	588,188	06-2014	65-R2	0	1.66%	269,176
Total Accounts 314	**188,018,474**				**2.34**	**4,399,632**				**2.73%**	**5,132,750**				**1.92%**	**3,602,809**
315 Accessory Electric Equipment																
Cholla Unit 1	4,756,906	06-2012	45-R3	(20)			06-2017	60-R2.5	(20)	3.28%	156,073	06-2017	60-R2.5	0	1.76%	83,755
Cholla Unit 2	42,235,618	06-2028	45-R3	(20)			06-2033	60-R2.5	(20)	1.84%	778,409	06-2033	60-R2.5	0	1.52%	640,485
Cholla Unit 3	29,917,206	06-2028	45-R3	(20)			06-2035	60-R2.5	(20)	1.98%	591,676	06-2035	60-R2.5	0	1.60%	478,926
Cholla Common	4,476,001	06-2029	45-R3	(20)			06-2035	60-R2.5	(20)	2.00%	89,341	06-2035	60-R2.5	0	1.63%	73,004
Four Corners Units 1-3	16,353,282	06-2013	45-R3	(20)			06-2016	60-R2.5	(20)	5.99%	978,802	06-2016	60-R2.5	0	3.16%	517,249
Four Corners Units 4-5	9,183,206	06-2019	45-R3	(20)			06-2031	60-R2.5	(20)	2.42%	222,550	06-2031	60-R2.5	0	1.74%	159,978
Four Corners Common	2,596,719	06-2019	45-R3	(20)			06-2031	60-R2.5	(20)	0.17%	4,503	06-2031	60-R2.5	0	0.90%	23,433
Navajo Units 1-3	20,226,194	06-2025	45-R3	(20)			06-2026	60-R2.5	(20)	2.58%	521,434	06-2026	60-R2.5	0	1.91%	386,283
Ocotillo Units 1-2	2,407,622	06-2020	45-R3	(20)			06-2020	60-R2.5	(20)	1.38%	33,220	06-2020	60-R2.5	0	0.98%	23,546
Saguaro Units 1-2	2,654,661	06-2014	45-R3	(20)			06-2014	60-R2.5	(20)	1.97%	52,354	06-2014	60-R2.5	0	1.01%	26,754
Total Account 315	**134,807,415**				**2.73**	**3,680,242**				**2.54%**	**3,428,362**				**1.79%**	**2,413,411**

Arizona Public Service Company
Comparison of Parameters, Rates and Accruals
Related to Electric Plant In Service as of December 31, 2002

	Existing Rates						Company Proposed					Snavely King Recommended				
Depreciable Group	Original Cost at 12/31/2001	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
316 Miscellaneous Power Plant																
Cholla Unit 1	2,315,189	06-2012	34-R4	(20)			06-2017	40-R2	(20)	6.17%	142,907	06-2017	40-R2	0	3.60%	83,397
Cholla Unit 2	4,846,431	06-2028	34-R4	(20)			06-2033	40-R2	(20)	2.68%	129,898	06-2033	40-R2	0	2.07%	100,223
Cholla Unit 3	4,138,531	06-2028	34-R4	(20)			06-2035	40-R2	(20)	2.79%	115,595	06-2035	40-R2	0	2.18%	90,266
Cholla Common	7,096,069	06-2029	34-R4	(20)			06-2035	40-R2	(20)	3.27%	232,179	06-2035	40-R2	0	2.54%	180,478
Four Corners Units 1-3	4,330,612	06-2013	34-R4	(20)			06-2016	40-R2	(20)	8.20%	354,982	06-2016	40-R2	0	6.00%	259,932
Four Corners Units 4-5	3,304,340	06-2019	34-R4	(20)			06-2031	40-R2	(20)	3.24%	107,103	06-2031	40-R2	0	2.50%	82,686
Four Corners Common	8,133,224	06-2019	34-R4	(20)			06-2031	40-R2	(20)	3.31%	269,374	06-2031	40-R2	0	2.46%	200,412
Navajo Units 1-3	11,805,250	06-2025	34-R4	(20)			06-2026	40-R2	(20)	3.76%	444,171	06-2026	40-R2	0	2.75%	324,575
Ocotillo Units 1-2	3,711,192	06-2020	34-R4	(20)			06-2020	40-R2	(20)	5.66%	210,098	06-2020	40-R2	0	4.01%	148,740
Saguaro Units 1-2	3,191,024	06-2014	34-R4	(20)			06-2014	40-R2	(20)	8.08%	257,730	06-2014	40-R2	0	5.32%	169,783
Yucca Unit 1	452,868	06-2019	34-R4	(20)			06-2016	40-R2	(20)	3.46%	15,667	06-2016	40-R2	0	1.68%	7,628
Total Account 316	**53,324,730**				**3.94**	**2,100,994**				**4.28%**	**2,279,704**				**3.09%**	**1,648,121**
TOTAL STEAM PRODUCTION	**1,292,132,201**				**2.82**	**36,468,379**				**3.40%**	**43,966,888**				**2.23%**	**28,840,038**
NUCLEAR PRODUCTION PLANT																
321 Structures and Improvements																
Palo Verde Unit 1	161,039,432	12-2024	65-R3	0			12-2024	65-R2.5	0	2.72%	4,384,691	12-2024	65-R2.5	0	2.68%	4,315,165
Palo Verde Unit 2	88,415,270	12-2025	65-R3	0			12-2025	65-R2.5	0	2.64%	2,331,149	12-2025	65-R2.5	0	2.55%	2,252,555
Palo Verde Unit 3	159,591,077	03-2027	65-R3	0			03-2027	65-R2.5	0	2.63%	4,195,723	03-2027	65-R2.5	0	2.59%	4,139,822
Palo Verde Water Reclamation	125,593,913	03-2027	65-R3	0			03-2027	65-R2.5	0	2.57%	3,225,203	03-2027	65-R2.5	0	2.56%	3,209,961
Palo Verde Common	98,127,309	03-2027	65-R3	0			03-2027	65-R2.5	0	2.64%	2,586,955	03-2027	65-R2.5	0	2.58%	2,534,931
Total Account 321	**632,767,001**				2.57	**16,262,112**				**2.64%**	**16,723,721**				**2.60%**	**16,452,433**
322 Reactor Plant Equipment																
Palo Verde Unit 1	359,545,213	12-2024	100-O1	(1)			12-2024	70-R1	(2)	2.99%	10,760,567	12-2024	70-R1	0	2.78%	9,996,524
Palo Verde Unit 2	176,362,235	12-2025	100-O1	(1)			12-2025	70-R1	(2)	3.05%	5,377,429	12-2025	70-R1	0	2.74%	4,826,962
Palo Verde Unit 3	322,750,700	03-2027	100-O1	(1)			03-2027	70-R1	(2)	2.89%	9,331,561	03-2027	70-R1	0	2.76%	8,917,355
Palo Verde Water Reclamation	123,313		(a)				03-2027	70-R1	(2)	4.26%	5,251	03-2027	70-R1	0	4.09%	5,049
Palo Verde Common	26,449,873	03-2027	100-O1	(1)			03-2027	70-R1	(2)	2.88%	760,717	03-2027	70-R1	0	2.82%	746,303
Total Account 322	**885,231,334**				3.03	**26,822,509**				**2.96%**	**26,235,525**				**2.77%**	**24,492,192**
322.1 Reactor Plant Equipment - Steam																
Palo Verde Unit 1	30,722,375	06-2006	100-O1	(68)			12-2005	Square	(17)	4.53%	1,393,021	12-2005	Square	0	3.42%	1,051,075
Palo Verde Unit 2	15,870,053	06-2006	100-O1	(68)			12-2003	Square	(17)	4.10%	650,838	12-2003	Square	0	0.01%	1,418
Palo Verde Unit 3	25,413,317	06-2006	100-O1	(68)			12-2007	Square	(17)	4.83%	1,227,246	12-2007	Square	0	4.23%	1,074,676
Total Account 322.1	**72,005,745**				3.03	**2,181,774**				**4.54%**	**3,271,105**				**2.95%**	**2,127,170**
323 Turbogenerator Units																
Palo Verde Unit 1	117,808,078	12-2024	65-R2	(1)			12-2024	60-S0	(2)	2.95%	3,471,147	12-2024	60-S0	0	2.83%	3,328,502
Palo Verde Unit 2	76,754,224	12-2025	65-R2	(1)			12-2025	60-S0	(2)	3.01%	2,307,463	12-2025	60-S0	0	2.78%	2,130,854
Palo Verde Unit 3	142,895,088	03-2027	65-R2	(1)			03-2027	60-S0	(2)	2.89%	4,123,870	03-2027	60-S0	0	2.79%	3,993,399
Palo Verde Water Reclamation	217,707	03-2027	65-R2	(1)			03-2027	60-S0	(2)	3.50%	7,629	03-2027	60-S0	0	2.95%	6,415
Palo Verde Common	1,223,879	03-2027	65-R2	(1)			03-2027	60-S0	(2)	5.08%	62,190	03-2027	60-S0	0	3.23%	39,519
Total Account 323	**338,898,976**				2.78	**9,421,392**				**2.94%**	**9,972,299**				**2.80%**	**9,498,688**

Arizona Public Service Company
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	Existing Rates							Company Proposed					Snavely King Recommended				
Depreciable Group	Original Cost at 12/31/2001	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $		Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $
(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
324 Accessory Electric Equipment																	
Palo Verde Unit 1	115,495,170	12-2024	45-R3	(1)			L	12-2024	45-R3	(2)	2.85%	3,292,508	12-2024	45-R3	0	2.69%	3,102,555
Palo Verde Unit 2	50,119,388	12-2025	45-R3	(1)			L	12-2025	45-R3	(2)	2.93%	1,470,132	12-2025	45-R3	0	2.69%	1,346,278
Palo Verde Unit 3	89,143,623	03-2027	45-R3	(1)			L	03-2027	45-R3	(2)	2.78%	2,475,838	03-2027	45-R3	0	2.68%	2,389,147
Palo Verde Common	17,918,193	03-2027	45-R3	(1)			L	03-2027	45-R3	(2)	2.76%	495,396	03-2027	45-R3	0	2.69%	482,670
Total Account 324	**272,676,374**				2.87	**7,825,812**						**7,733,874**				**2.68%**	**7,320,649**
325 Miscellaneous Power Plant																	
Palo Verde Unit 1	29,671,405	12-2024	34-R4	(2)			L	12-2024	35-R0.5	(2)	2.41%	716,211	12-2024	35-R0.5	0	3.41%	1,011,328
Palo Verde Unit 2	26,389,406	12-2025	34-R4	(2)			L	12-2025	35-R0.5	(2)	2.74%	722,783	12-2025	35-R0.5	0	3.58%	945,805
Palo Verde Unit 3	27,284,046	03-2027	34-R4	(2)			L	03-2027	35-R0.5	(2)	2.43%	663,956	03-2027	35-R0.5	0	3.41%	929,092
Palo Verde Water Reclamation	88,819	03-2027	34-R4	(2)			L	03-2027	35-R0.5	(2)	2.55%	2,261	03-2027	35-R0.5	0	3.53%	3,134
Palo Verde Common	48,459,510	03-2027	34-R4	(2)			L	03-2027	35-R0.5	(2)	3.00%	1,453,065	03-2027	35-R0.5	0	3.52%	1,705,015
Total Account 325	**131,893,186**				5.56	**7,333,261**					**2.70%**	**3,558,276**				**3.48%**	**4,594,374**
TOTAL NUCLEAR PRODUCTION	**2,333,472,618**				**2.99**	**69,846,860**					2.89%	**67,494,800**				**2.76%**	**64,485,507**
HYDRO PRODUCTION PLANT																	
331 Structures and Improvements	100,878	06-2024	120-R2	(10)	0.28	282	L	12-2004	Square	0	0.00%	0	12-2004	200-SQ	0	0.00%	0
332 Reservoirs, Dams, and Waterways	991,936	06-2024	200-SQ	(10)	0.90	8,927	L	12-2004	Square	0	0.00%	0	12-2004	200-SQ	0	0.00%	0
333 Water Wheels, Turbines, and	157,196	06-2024	200-SQ	(10)	0.73	1,148	L	12-2004	Square	0	0.00%	0	12-2004	200-SQ	0	0.00%	0
334 Accessory Electric Equipment	627,611	06-2024	200-SQ	(10)	2.67	16,757	L	12-2004	Square	0	0.00%	0	12-2004	200-SQ	0	0.00%	0
335 Miscellaneous Power Plant	126,018	06-2024	200-SQ	(10)	2.48	3,125	L	12-2004	Square	0	0.00%	0	12-2004	200-SQ	0	0.00%	0
336 Roads, Railroads, and Bridges	77,427	06-2024	200-SQ	(10)	0.28	217	L	12-2004	Square	0	0.00%	0	12-2004	200-SQ	0	0.00%	0
Hydro Decommissioning Costs						2,667,735						2,667,735					2,667,735
TOTAL HYDRO PRODUCTION	**2,081,066**					**2,698,191**						**2,667,735**					**2,667,735**
OTHER PRODUCTION																	
341 Structures and Improvements																	
Douglas CT	4,562	06-2012	80-S1	(5)			L	06-2017	80-S1	(5)	2.17%	99	06-2017	80-S1	0	0.65%	30
Ocotillo CT 1-2	328,749	06-2012	80-S1	(5)			L	06-2017	80-S1	(5)	0.74%	2,439	06-2017	80-S1	0	2.05%	6,754
Saguaro CT	1,288,525	06-2012	80-S1	(5)			L	06-2017	80-S1	(5)	5.36%	69,056	06-2017	80-S1	0	4.43%	57,052
Solar Unit 1	375,512		(a)						12-SQ	0	10.13%	38,056		12-SQ	0	-0.61%	-2,305
West phoenix CT 1-2	510,951	06-2012	80-S1	(5)			L	06-2017	80-S1	(5)	0.85%	4,328	06-2017	80-S1	0	1.26%	6,441
West Phoenix Combined Cycle 1-3	6,706,722	06-2001	80-S1	(5)			L	06-2031	80-S1	(5)	1.64%	110,243	06-2031	80-S1	0	2.26%	151,893
Yucca CT 1-4	452,751	06-2011	80-S1	(5)			L	06-2016	80-S1	(5)	5.29%	23,962	06-2016	80-S1	0	3.79%	17,159
Total Account 341	**9,667,772**				2.84	**274,565**					**2.57%**	**248,183**				**2.45%**	**237,025**
342 Fuel Holders, Products and																	
Douglas CT	137,759	06-2012	80-S1	(5)			L	06-2017	70-S1	(5)	3.68%	5,063	06-2017	70-S1	0	1.95%	2,692
Ocotillo CT 1-2	719,859	06-2012	80-S1	(5)			L	06-2017	70-S1	(5)	3.92%	28,225	06-2017	70-S1	0	2.00%	14,420
Saguaro CT	1,304,977	06-2012	80-S1	(5)			L	06-2017	70-S1	(5)	3.11%	40,547	06-2017	70-S1	0	1.56%	20,391
West phoenix CT 1-2	1,437,533	06-2012	80-S1	(5)			L	06-2017	70-S1	(5)	3.33%	47,921	06-2017	70-S1	0	1.56%	22,447
West Phoenix Combined Cycle 1-3	19,343,993	06-2001	80-S1	(5)			L	06-2031	70-S1	(5)	3.23%	624,716	06-2031	70-S1	0	3.12%	602,702
Yucca CT 1-4	3,232,217	06-2011	80-S1	(5)			L	06-2016	70-S1	(5)	1.64%	52,931	06-2016	70-S1	0	0.89%	28,914
Total Account 342	**26,176,338**				2.81	**735,555**					**3.05%**	**799,403**				**2.64%**	**691,567**

Arizona Public Service Company
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Depreciable Group	Existing Rates: Original Cost at 12/31/2001	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $		Company Proposed: Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Snavely King Recommended: Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $
(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
343 Prime Movers																	
Douglas CT	1,101,449	06-2012	70-L1.5	0			L	06-2017	70-L1.5	0	0.00%	0	06-2017	70-L1.5	0	0.00%	0
Ocotillo CT 1-2	6,679,324	06-2012	70-L1.5	0			L	06-2017	70-L1.5	0	0.59%	39,158	06-2017	70-L1.5	0	1.06%	70,912
Saguaro CT	8,102,651	06-2012	70-L1.5	0			L	06-2017	70-L1.5	0	1.48%	120,086	06-2017	70-L1.5	0	1.29%	104,740
West phoenix CT 1-2	8,802,636	06-2012	70-L1.5	0			L	06-2017	70-L1.5	0	1.90%	167,290	06-2017	70-L1.5	0	2.07%	181,857
Yucca CT 1-4	7,920,584	06-2011	70-L1.5	0			L	06-2016	70-L1.5	0	0.00%	0	06-2016	70-L1.5	0	0.00%	0
Total Account 343	**32,606,644**				1.51	**492,360**					**1.00%**	**326,534**				**1.10%**	**357,509**
344 Generators and Devices																	
Douglas CT	551,765	06-2012	40-S2	0			L	06-2017	37-R3	0	0.10%	549	06-2017	37-R3	0	0.17%	920
Ocotillo CT 1-2	6,402,044	06-2012	40-S2	0			L	06-2017	37-R3	0	4.63%	296,448	06-2017	37-R3	0	3.33%	213,356
Saguaro CT	4,185,247	06-2012	40-S2	0			L	06-2017	37-R3	0	4.10%	171,743	06-2017	37-R3	0	3.09%	129,253
Solar Unit 1	6,933,081		(a)						12-SQ	0	7.18%	498,118		12-SQ	0	6.74%	467,072
West phoenix CT 1-2	4,115,901	06-2012	40-S2	0			L	06-2017	37-R3	0	3.38%	138,912	06-2017	37-R3	0	1.80%	74,255
West Phoenix Combined Cycle 1-3	81,920,222	06-2001	40-S2	0			L	06-2031	37-R3	(2)	3.38%	2,765,872	06-2031	37-R3	0	3.26%	2,669,355
Yucca CT 1-4	5,395,818	06-2011	40-S2	0			L	06-2016	37-R3	0	2.63%	141,655	06-2016	37-R3	0	1.64%	88,420
Total Account 344	**109,504,078**				2.27	**2,485,743**					**3.66%**	**4,013,297**				**3.33%**	**3,642,631**
345 Accessory Electric Equipment																	
Douglas CT	353,277	06-2012	40-S2	0			L	06-2017	50-S2	0	1.23%	4,339	06-2017	50-S2	0	0.86%	3,033
Ocotillo CT 1-2	1,494,636	06-2012	40-S2	0			L	06-2017	50-S2	0	1.70%	25,401	06-2017	50-S2	0	1.08%	16,121
Saguaro CT	1,715,774	06-2012	40-S2	0			L	06-2017	50-S2	0	2.54%	43,562	06-2017	50-S2	0	1.42%	24,349
Solar Unit 1	169,527		(a)						12-SQ	0	9.36%	15,865		12-SQ	0	7.71%	13,065
West phoenix CT 1-2	1,557,744	06-2012	40-S2	0			L	06-2017	50-S2	0	2.32%	36,163	06-2017	50-S2	0	1.18%	18,357
West Phoenix Combined Cycle 1-3	11,925,645	06-2001	40-S2	0			L	06-2031	50-S2	0	2.47%	293,998	06-2031	50-S2	0	2.82%	336,788
Yucca CT 1-4	2,166,526	06-2011	40-S2	0			L	06-2016	50-S2	0	1.24%	26,820	06-2016	50-S2	0	1.24%	26,812
Total Account 345	**19,383,129**				2.28	**441,935**					**2.30%**	**446,148**				**2.26%**	**438,525**
346 Miscellaneous Power Plant																	
Douglas CT	40,913	06-2012	50-L1	0			L	06-2017	70-L1	0	1.95%	798	06-2017	70-L1	0	1.90%	779
Ocotillo CT 1-2	553,173	06-2012	50-L1	0			L	06-2017	70-L1	0	1.20%	6,650	06-2017	70-L1	0	1.74%	9,605
Saguaro CT	790,906	06-2012	50-L1	0			L	06-2017	70-L1	0	3.60%	28,508	06-2017	70-L1	0	3.41%	26,989
West phoenix CT 1-2	957,431	06-2012	50-L1	0			L	06-2017	70-L1	0	3.54%	33,908	06-2017	70-L1	0	3.33%	31,837
West Phoenix Combined Cycle 1-3	2,608,877	06-2001	50-L1	0			L	06-2031	70-L1	0	1.29%	33,618	06-2031	70-L1	0	2.47%	64,399
Yucca CT 1-4	427,175	06-2011	50-L1	0			L	06-2016	70-L1	0	0.27%	1,166	06-2016	70-L1	0	1.23%	5,268
Total Account 346	**5,378,475**				3.48	**187,171**	b				**1.95%**	**104,648**				**2.58%**	**138,878**
TOTAL OTHER PRODUCTION	**202,716,436**				2.28	**4,617,329**					**2.93%**	**5,938,213**				**2.72%**	**5,506,135**

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(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
TRANSMISSION PLANT																	
352 Structures and Improvements	27,618,299		50-R4	(5)	2.07	571,699	J		50-R4	(5)	2.15%	592,619		50-R4	0	1.56%	429,951
352.5 Structures and Improvements - SCE	409,725				3.25	13,316	Jc				3.25%	13,316			0	3.25%	13,316
353 Station Equipment	428,736,305		35-S1	7	2.09	8,960,589	S		42-R3	0	1.91%	8,167,649		57-R1.5	0	1.52%	6,538,127
353.5 Station Equipment - SCE 500 KV Line	7,747,282				3.25	251,787	Jc				3.25%	251,787			0	3.25%	251,787
354 Towers and Fixtures	83,464,531		60-R3	(30)	1.99	1,660,944	J		60-R3	(35)	2.28%	1,899,472		60-R3	0	1.17%	975,644
354.5 Towers and Fixtures - SCE 500 KV	13,752,584				3.25	446,959	Jc				3.25%	446,959			0	3.25%	446,959
355 Poles and Fixtures - Wood	91,126,939		43-R1	(30)	2.73	2,487,765	Sb		48-R1.5	(35)	2.55%	2,321,504		48-R1.5	0	1.81%	1,651,558
355.1 Poles and Fixtures - Steel	83,067,888		(a)		2.73	2,267,753	Jb		55-R3	(15)	1.96%	1,625,822		55-R3	0	1.61%	1,335,575
355.5 Poles and Fixtures - SCE 500 KV	930,308				3.25	30,235	Jc				3.25%	30,235			0	3.25%	30,235
356 Overhead Conductors and Devices	205,771,417		55-R3	(30)	2.16	4,444,663	J		55-R3	(35)	2.62%	5,391,852		55-R3	0	1.41%	2,896,149
356.5 *Overhead Conductors and Devices - SCE 500 KV Line*	22,653,515				3.25	736,239	J				3.25%	736,239			0	3.25%	736,239
357 Underground Conduit	10,444,362		50-R3	(5)	2.20	229,776	J		48-S1.5	(10)	2.28%	237,777		48-S1.5	0	1.70%	178,076
358 Underground Conductors and	18,551,254		50-R3	(5)	1.85	343,198	J		40-R3	(10)	2.88%	534,608		40-R3	0	1.81%	336,441
TOTAL TRANSMISSION PLANT	**994,274,409**				**2.26**	**22,444,923**					**2.24%**	**22,249,839**				**1.59%**	**15,820,057**
DISTRIBUTION PLANT																	
361 Structures and Improvements	25,815,042		40-R2.5	(15)	3.00	774,451	J		45-R2.5	(10)	2.41%	623,356		45-R2.5	0	1.80%	464,808
362 Station Equipment	212,357,577		26-R0.5	0	3.49	7,411,279	S		38-S0	0	2.10%	4,456,837		44-L0.5	0	2.04%	4,332,029
364 Poles and Fixtures - Wood	284,200,711		37-R0.5	(10)	2.68	7,616,579	S		38-R0.5	(10)	2.49%	7,076,374		38-R0.5	0	2.31%	6,571,918
364.1 Poles and Fixtures - Steel	53,919,651		(a)		2.68	1,445,047	J		50-R3	(5)	2.05%	1,105,404		50-R3	0	1.92%	1,036,863
365 Overhead Conductors and Devices	218,856,780		53-R1	(10)	1.77	3,873,765	S		53-O1	(10)	1.74%	3,810,605		53-O1	0	1.78%	3,887,198
366 Underground Conduit	425,723,116		60-R2	(10)	1.77	7,535,299	S		55-R1.5	(5)	1.88%	8,009,076		86-O1	0	1.14%	4,837,438
367 Underground Conductors and	805,505,783		27-R2	(10)	4.42	35,603,356	S		29-L1	(5)	3.36%	27,036,316		29-L1	0	2.96%	23,870,768
368 Line Transformers	486,837,053		Various		3.39	16,503,776	S		36-R3	(5)	2.70%	13,147,552		36-R3	0	2.10%	10,215,449
369 Services	242,404,812		30-R2	(3)	4.60	11,150,621	J		37-S2	(10)	2.67%	6,463,178		37-S2	0	2.24%	5,423,595
370 Meters	91,330,710		26-R1.5	0	4.54	4,146,414	S		23-R1	0	4.47%	4,086,660		29-L0	0	2.84%	2,596,256
370.1 Electronic Meters	54,691,249		26-R1.5	0	4.54	2,482,983	J		12-S2	0	9.12%	4,987,610		26 R1.5	0	3.61%	1,975,913
371 Installations On Customer Premises	25,335,831		30-R0.5	(30)	3.49	884,221	S		30-R1	(20)	3.73%	945,981		50-O2	0	1.88%	477,065
373 Street Lighting and Signal Systems	57,185,737		32-R1.5	(20)	3.92	2,241,681	S		35-R2	(20)	3.31%	1,890,534		35-R2	0	2.33%	1,330,873
TOTAL DISTRIBUTION PLANT	**2,984,164,052**				**3.41**	**101,669,472**					**2.80%**	**83,639,483**				**2.25%**	**67,020,172**

Arizona Public Service Company
Comparison of Parameters, Rates and Accruals
Related to Electric Plant in Service as of December 31, 2002

	Existing Rates						Company Proposed					Snavely King Recommended				
Depreciable Group	Original Cost at 12/31/2001	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Accrual Rate	Annual Amount $
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
GENERAL PLANT																
390 Structures and Improvements	96,667,435		30-R1	(5)	3.50	3,383,360 S		39-R1	(15)	2.71%	2,624,392		39-R1	0	2.45%	2,364,245
391 Office Furniture and Equipment -	19,919,640		25-O1	1	3.96	788,818 A		20-SQ	0		994,570		20-SQ	0	4.16%	829,310
Reserve Variance Amortization											0 D					
											994,570					
391.1 Office Furniture and Equipment - Pc	38,654,946		8-R3	0	12.50	4,831,868 A		5-SQ	0		6,467,368 *		8-R3	0	11.43%	4,418,633
Reserve Variance Amortization											2,351,998 D					
										22.82%	**8,819,366**					
391.2 Office Furniture and Equipment -	7,652,923		14-S2	1	7.07	541,062 A		10-SQ	0		461,909 *		22-R4	0	4.17%	318,968
Reserve Variance Amortization											0 D					
										6.04%	**461,909**					
393 Stores Equipment	1,227,371		40-R3	0	2.50	30,684 A		20-SQ	0		29,921		20-SQ	0	-0.24%	-2,991
Reserve Variance Amortization											101,325 D					
										10.69%	**131,246**					
394 Tools, Shop and Garage Equipment	12,673,031		25-R3	0	4.00	506,921 A		20-SQ	0		633,652		20-SQ	0	4.61%	583,904
Reserve Variance Amortization											230,228 D					
										6.82%	**863,880**					
395 Laboratory Equipment	1,350,583		15-R3	0	6.67	90,084 A		15-SQ	0		75,200 *		20-L1	0	5.07%	68,504
Reserve Variance Amortization											12,780 D					
										6.51%	**87,980**					
397 Communication Equipment	94,309,691		21-R3	0	4.76	4,489,141 S		19-S1.5	0	5.10%	4,811,742		19-S1.5	0	4.74%	4,469,337
398 Miscellaneous Equipment	1,336,404		20-R3	0	5.00	66,820 A		20-SQ	0		65,276 *		24-S1	0	3.85%	51,454
Reserve Variance Amortization									0		(20,959) D					
										3.32%	**44,317**					
TOTAL GENERAL PLANT	**273,792,024**					**14,728,759**					**18,839,402**				**4.79%**	**13,101,364**
TOTAL PLANT STUDIED	**8,082,632,804**					**252,473,913**					**244,796,360**				**2.44%**	**197,441,008**
5-YEAR AVERAGE NET SALVAGE ALLOWANCE																-
TOTAL DEPRECIATION																**197,441,008**

(a) No Existing Service Life Parameters. Composite rate applied to this Account/Subaccount
(b) Composite Rate Applied to one or More Accounts/Subaccounts
(c) Assets Related to the 500 KV SCE Transmission Line are Depreciated at a 3.25 rate

A/ Amortization
L/ Life Span
S/ Statistical Analysis
J/ Judgment Analysis
D/ Reserve Variances Related to General Plant Amortization Accounts are not used in SK Recommendation

Arizona Public Service Company
Calculation of Theoretical Reserve and Allocation of Book Reserve
Related to Electric Plant in Service at December 31, 2002

Depreciable Group (1)	Original Cost at 12/31/2002 (2)	Probable Retirement Date (3)	Average Service Life (4)	Iowa Curve Type (5)	Net Salvage Percent (6)	Average Remaining Life (7)	SK Theoretical Reserve (8)	SK Allocated Book Reserve (9)	Company Adjusted Book Reserve at 12/31/2002 (10)
PLANT IN SERVICE									
STEAM PRODUCTION PLANT									
311 Structure and Improvements									
Cholla Unit 1	2,144,789	06-2017	75	S1.5	0	14.0	1,389,907	1,841,738	1,964,146
Cholla Unit 2	5,022,179	06-2033	75	S1.5	0	29.0	1,586,028	2,101,615	2,346,306
Cholla Unit 3	9,583,277	06-2035	75	S1.5	0	29.9	3,912,944	5,184,966	6,113,726
Cholla Common	36,234,550	06-2035	75	S1.5	0	29.9	14,579,063	19,318,431	22,949,841
Four Corners Units 1-3	15,972,927	06-2016	75	S1.5	0	13.3	8,020,704	10,628,079	7,395,910
Four Corners Units 4-5	9,195,585	06-2031	75	S1.5	0	26.8	3,867,683	5,124,992	5,253,259
Four Corners Common	3,946,871	06-2031	75	S1.5	0	26.8	1,681,253	2,227,796	2,790,814
Navajo Units 1-3	27,152,517	06-2026	75	S1.5	0	22.8	9,205,018	12,197,389	11,359,467
Ocotillo Units 1-2	3,787,972	06-2020	75	S1.5	0	17.1	1,572,952	2,084,288	1,882,068
Saguaro Units 1-2	2,446,832	06-2014	75	S1.5	0	11.3	1,501,613	1,989,759	2,011,377
Yucca Unit 1	462,567	06-2016	75	S1.5	0	13.1	341,570	452,608	471,080
Total Account 311	**115,950,066**						**47,658,735**	**63,151,660**	**64,537,994**
312 Boiler Plant Equipment									
Cholla Unit 1	26,431,681	06-2017	48	L2	0	13.4	13,286,478	17,605,653	17,353,280
Cholla Unit 2	140,612,492	06-2033	48	L2	0	22.0	65,424,224	86,692,363	93,979,314
Cholla Unit 3	100,448,965	06-2035	48	L2	0	22.9	45,433,819	60,203,467	63,309,215
Cholla Common	22,626,051	06-2035	48	L2	0	24.8	8,549,054	11,328,185	11,951,401
Four Corners Units 1-3	197,139,757	06-2016	48	L2	0	12.7	87,017,217	115,304,816	90,637,620
Four Corners Units 4-5	111,591,873	06-2031	48	L2	0	22.1	48,529,936	64,306,071	60,671,520
Four Corners Common	3,290,391	06-2031	48	L2	0	22.8	1,624,173	2,152,160	2,787,122
Navajo Units 1-3	149,350,243	06-2026	48	L2	0	20.6	52,789,532	69,950,378	65,220,188
Ocotillo Units 1-2	24,152,351	06-2020	48	L2	0	15.2	13,512,675	17,905,382	18,891,592
Saguaro Units 1-2	24,387,712	06-2014	48	L2	0	11.1	12,502,003	16,566,160	17,510,312
Total Account 312	**800,031,516**						**348,669,111**	**462,014,635**	**442,311,564**
314 Turbogenerator Units									
Cholla Unit 1	10,417,373	06-2017	65	R2	0	14.0	5,629,611	7,459,687	8,187,222
Cholla Unit 2	28,551,889	06-2033	65	R2	0	27.5	11,711,704	15,518,951	18,457,272
Cholla Unit 3	39,626,197	06-2035	65	R2	0	29.7	12,798,679	16,959,280	19,942,381
Cholla Common	631,278	06-2035	65	R2	0	29.0	253,261	335,591	389,822
Four Corners Units 1-3	36,412,926	06-2016	65	R2	0	13.1	18,737,943	24,829,283	24,997,649
Four Corners Units 4-5	14,488,238	06-2031	65	R2	0	26.3	5,347,828	7,086,302	8,049,950
Four Corners Common	1,726,164	06-2031	65	R2	0	23.3	1,018,782	1,349,968	1,965,225
Navajo Units 1-3	24,387,110	06-2026	65	R2	0	22.0	10,927,391	14,479,672	15,363,242
Ocotillo Units 1-2	15,517,601	06-2020	65	R2	0	16.8	8,631,353	11,437,238	13,579,702
Saguaro Units 1-2	16,259,698	06-2014	65	R2	0	11.2	9,995,564	13,244,927	12,946,682
Total Accounts 314	**188,018,474**						**85,052,116**	**112,700,899**	**123,879,147**

Arizona Public Service Company
Calculation of Theoretical Reserve and Allocation of Book Reserve
Related to Electric Plant in Service at December 31, 2002

Depreciable Group (1)	Original Cost at 12/31/2002 (2)	Probable Retirement Date (3)	Average Service Life (4)	Iowa Curve Type (5)	Net Salvage Percent (6)	Average Remaining Life (7)	SK Theoretical Reserve (8)	SK Allocated Book Reserve (9)	Company Adjusted Book Reserve at 12/31/2002 (10)
315 Accessory Electric Equipment									
Cholla Unit 1	4,756,906	06-2017	60	R2.5	0	13.9	2,711,320	3,592,717	3,537,479
Cholla Unit 2	42,235,618	06-2033	60	R2.5	0	26.8	18,920,082	25,070,631	29,787,215
Cholla Unit 3	29,917,206	06-2035	60	R2.5	0	28.5	12,276,854	16,267,820	18,952,154
Cholla Common	4,476,001	06-2035	60	R2.5	0	28.7	1,796,712	2,380,788	2,804,488
Four Corners Units 1-3	16,353,282	06-2016	60	R2.5	0	13.2	7,188,695	9,525,599	6,735,295
Four Corners Units 4-5	9,183,206	06-2031	60	R2.5	0	25.9	3,803,375	5,039,778	5,249,818
Four Corners Common	2,596,719	06-2031	60	R2.5	0	21.0	1,588,304	2,104,631	3,017,438
Navajo Units 1-3	20,226,194	06-2026	60	R2.5	0	22.0	8,850,761	11,727,970	12,812,227
Ocotillo Units 1-2	2,407,622	06-2020	60	R2.5	0	16.3	1,527,319	2,023,821	2,349,290
Saguaro Units 1-2	2,654,661	06-2014	60	R2.5	0	11.2	1,777,267	2,355,021	2,598,693
Total Account 315	**134,807,415**						**60,440,688**	**80,088,777**	**87,844,097**
316 Miscellaneous Power Plant Equipment									
Cholla Unit 1	2,315,189	06-2017	40	R2	0	13.5	897,555	1,189,333	849,777
Cholla Unit 2	4,846,431	06-2033	40	R2	0	22.1	1,985,911	2,631,492	2,942,292
Cholla Unit 3	4,138,531	06-2035	40	R2	0	23.8	1,501,946	1,990,199	2,218,283
Cholla Common	7,096,069	06-2035	40	R2	0	25.8	1,841,207	2,439,747	2,519,563
Four Corners Units 1-3	4,330,612	06-2016	40	R2	0	13.1	698,450	925,502	557,644
Four Corners Units 4-5	3,304,340	06-2031	40	R2	0	23.0	1,058,473	1,402,561	1,499,998
Four Corners Common	8,133,224	06-2031	40	R2	0	23.2	2,629,017	3,483,659	3,516,915
Navajo Units 1-3	11,805,250	06-2026	40	R2	0	20.2	3,961,141	5,248,830	5,178,470
Ocotillo Units 1-2	3,711,192	06-2020	40	R2	0	16.2	982,283	1,301,603	1,047,634
Saguaro Units 1-2	3,191,024	06-2014	40	R2	0	10.9	1,011,550	1,340,385	1,012,665
Yucca Unit 1	452,868	06-2016	40	R2	0	12.2	271,532	359,801	353,040
Total Account 316	**53,324,730**						**16,839,063**	**22,313,113**	**21,696,281**
TOTAL STEAM PRODUCTION PLANT	**1,292,132,201**						**558,659,713**	**740,269,083**	**740,269,083**
NUCLEAR PRODUCTION PLANT									
321 Structures and Improvements									
Palo Verde Unit 1	161,039,432	12-2204	65	R2.5	0	21.2	65,592,046	69,557,944	68,224,238
Palo Verde Unit 2	88,415,270	12-2025	65	R2.5	0	22.0	36,643,483	38,859,061	37,058,726
Palo Verde Unit 3	159,591,077	03-2027	65	R2.5	0	23.3	59,533,635	63,133,223	62,020,595
Palo Verde Water Reclamation	125,593,913	03-2027	65	R2.5	0	23.2	48,208,021	51,122,827	50,775,392
Palo Verde Common	98,127,309	03-2027	65	R2.5	0	23.2	37,075,223	39,316,906	38,045,036
Total Account 321	**632,767,001**						**247,052,408**	**261,989,962**	**256,123,987**
322 Reactor Plant Equipment									
Palo Verde Unit 1	359,545,213	12-2204	70	R1	0	20.6	144,858,250	153,616,828	144,992,453
Palo Verde Unit 2	176,362,235	12-2025	70	R1	0	21.5	68,444,210	72,582,559	64,407,419
Palo Verde Unit 3	322,750,700	03-2027	70	R1	0	22.6	114,307,117	121,218,479	118,393,045
Palo Verde Water Reclamation	123,313	03-2027	70	R1	0	23.0	6,767	7,176	5,190
Palo Verde Common	26,449,873	03-2027	70	R1	0	22.6	9,037,029	9,583,436	9,772,755
Total Account 322	**885,231,334**						**336,653,373**	**357,008,478**	**337,570,862**

Arizona Public Service Company
Calculation of Theoretical Reserve and Allocation of Book Reserve
Related to Electric Plant in Service at December 31, 2002

Depreciable Group (1)	Original Cost at 12/31/2002 (2)	Probable Retirement Date (3)	Average Service Life (4)	Iowa Curve Type (5)	Net Salvage Percent (6)	Average Remaining Life (7)	SK Theoretical Reserve (8)	SK Allocated Book Reserve (9)	Company Adjusted Book Reserve at 12/31/2002 (10)
322.1 Reactor Plant Equipment - Steam Generators									
Palo Verde Unit 1	30,722,375	12-2005		Square	0	3.0	25,997,274	27,569,149	31,766,117
Palo Verde Unit 2	15,870,053	12-2003		Square	0	1.0	14,963,873	15,868,635	17,917,124
Palo Verde Unit 3	25,413,317	12-2007		Square	0	5.0	18,897,343	20,039,935	23,597,351
Total Account 322.1	**72,005,745**						**59,858,489**	**63,477,719**	**73,280,592**
323 Turbogenerator Units									
Palo Verde Unit 1	117,808,078	12-2024	60	S0	0	19.9	48,630,543	51,570,896	50,929,473
Palo Verde Unit 2	76,754,224	12-2025	60	S0	0	20.8	30,583,307	32,432,468	30,390,765
Palo Verde Unit 3	142,895,088	03-2027	60	S0	0	21.8	52,655,285	55,838,987	55,717,208
Palo Verde Water Reclamation	217,707	03-2027	60	S0	0	22.0	72,219	76,585	54,310
Palo Verde Common	1,223,879	03-2027	60	S0	0	22.2	326,795	346,554	(131,408)
Total Account 323	**338,898,976**						**132,268,149**	**140,265,491**	**136,960,348**
324 Accessory Electric Equipment									
Palo Verde Unit 1	115,495,170	12-2024	45	R3	0	20.0	50,396,913	53,444,066	51,830,648
Palo Verde Unit 2	50,119,388	12-2025	45	R3	0	20.9	20,728,855	21,982,186	20,346,865
Palo Verde Unit 3	89,143,623	03-2027	45	R3	0	22.1	34,271,330	36,343,481	36,276,331
Palo Verde Common	17,918,193	03-2027	45	R3	0	22.0	6,883,278	7,299,463	7,373,717
Total Account 324	**272,676,374**						**112,280,376**	**119,069,196**	**115,827,561**
325 Miscellaneous Power Plant Equipment									
Palo Verde Unit 1	29,671,405	12-2024	35	R0.5	0	17.7	11,099,778	11,770,905	17,609,436
Palo Verde Unit 2	26,389,406	12-2025	35	R0.5	0	18.7	8,206,645	8,702,844	13,408,579
Palo Verde Unit 3	27,284,046	03-2027	35	R0.5	0	19.2	8,906,937	9,445,478	15,083,087
Palo Verde Water Reclamation	88,819	03-2027	35	R0.5	0	19.5	26,126	27,706	46,552
Palo Verde Common	48,459,510	03-2027	35	R0.5	0	19.4	14,505,189	15,382,218	21,228,993
Total Account 325	**131,893,186**						**42,744,676**	**45,329,152**	**67,376,647**
TOTAL NUCLEAR PRODUCTION PLANT	**2,333,472,616**						**930,857,471**	**987,139,997**	**987,139,997**
HYDRO PRODUCTION PLANT									
331 Structures and Improvements	100,878	12-2024	200	SQ	0			100,878	100,878
332 Reservoirs, Dams, and Waterways	991,936	12-2004	200	SQ	0			1,105,086	1,105,086
333 Water Wheels, Turbines, and Generators	157,196	12-2004	200	SQ	0			157,196	157,196
334 Accessory Electric Equipment	627,611	12-2004	200	SQ	0			627,611	627,611
335 Miscellaneous Power Plant Equipment	126,018	12-2004	200	SQ	0			126,018	126,018
336 Roads, Railroads, and Bridges	77,427	12-2004	200	SQ	0			77,427	77,427
Hydro Decommissioning Costs						2.0		7,864,531	7,864,531
TOTAL HYDRO PRODUCTION PLANT	**2,081,066**							**10,058,747**	**10,058,747**

Arizona Public Service Company
Calculation of Theoretical Reserve and Allocation of Book Reserve
Related to Electric Plant in Service at December 31, 2002

Depreciable Group (1)	Original Cost at 12/31/2002 (2)	Probable Retirement Date (3)	Average Service Life (4)	Iowa Curve Type (5)	Net Salvage Percent (6)	Average Remaining Life (7)	SK Theoretical Reserve (8)	SK Allocated Book Reserve (9)	Company Adjusted Book Reserve at 12/31/2002 (10)
OTHER PRODUCTION									
341 Structures and Improvements									
Douglas CT	4,562	06-2017	80	S1	0	13.9	3,077	4148	3,417
Ocotillo CT 1-2	328,749	06-2017	80	S1	0	14.5	171,245	230819	309,919
Saguaro CT	1,288,525	06-2017	80	S1	0	14.4	346,446	466971	360,293
Solar Unit 1	375,512		12	SQ	0	3.6	284,748	383809	237,890
West phoenix CT 1-2	510,951	06-2017	80	S1	0	14.2	311,221	419492	475,096
West Phoenix Combined Cycle 1-3	6,706,722	06-2031	80	S1	0	28.1	1,809,141	2438522	3,949,614
Yucca CT 1-4	452,751	06-2016	80	S1	0	13.4	165,307	222815	155,293
Total Account 341	**9,667,772**						**3,091,184**	**4,166,575**	**5,491,522**
342 Fuel Holders, Products and Accessories									
Douglas CT	137,759	06-2017	70	S1	0	14.0	74,238	100065	73,566
Ocotillo CT 1-2	719,859	06-2017	70	S1	0	14.0	384,292	517984	359,329
Saguaro CT	1,304,977	06-2017	70	S1	0	14.0	756,368	1019500	804,476
West phoenix CT 1-2	1,437,533	06-2017	70	S1	0	14.0	833,354	1123270	840,769
West Phoenix Combined Cycle 1-3	19,343,993	06-2031	70	S1	0	27.7	1,965,394	2649135	2,978,088
Yucca CT 1-4	3,232,217	06-2016	70	S1	0	12.9	2,121,263	2859228	2,710,284
Total Account 342	**26,176,338**						**6,134,910**	**8,269,181**	**7,766,512**
343 Prime Movers									
Douglas CT	1,101,449	06-2017	70	L1.5	0		741,327	999227	1,102,406
Ocotillo CT 1-2	6,679,324	06-2017	70	L1.5	0	14.1	4,213,601	5679469	6,127,017
Saguaro CT	8,102,651	06-2017	70	L1.5	0	13.8	4,939,005	6657234	6,441,288
West phoenix CT 1-2	8,802,636	06-2017	70	L1.5	0	14.2	4,614,823	6220272	6,428,854
Yucca CT 1-4	7,920,584	06-2016	70	L1.5	0		5,417,696	7302457	8,796,851
Total Account 343	**32,606,644**						**19,926,452**	**26,858,659**	**28,896,416**
344 Generators and Devices									
Douglas CT	551,765	06-2017	37	R3	0	9.7	402,733	542840	546,431
Ocotillo CT 1-2	6,402,044	06-2017	37	R3	0	13.6	2,596,955	3500409	2,369,080
Saguaro CT	4,185,247	06-2017	37	R3	0	13.0	1,858,429	2504957	1,954,137
Solar Unit 1	6,933,081		12	Sq	0	7.8	2,440,792	3289918	3,041,951
West phoenix CT 1-2	4,115,901	06-2017	37	R3	0	12.3	2,375,981	3202560	2,407,953
West Phoenix Combined Cycle 1-3	81,920,222	06-2031	37	R3	0	26.2	8,890,281	11983119	11,064,493
Yucca CT 1-4	5,395,818	06-2016	37	R3	0	11.6	3,242,215	4370148	3,751,109
Total Account 344	**109,504,078**						**21,807,386**	**29,393,951**	**25,135,154**
345 Accessory Electric Equipment									
Douglas CT	353,277	06-2017	50	S2	0	13.1	232,622	313549	296,417
Ocotillo CT 1-2	1,494,636	06-2017	50	S2	0	13.2	951,000	1281843	1,158,282
Saguaro CT	1,715,774	06-2017	50	S2	0	13.4	1,030,871	1389500	1,133,530
Solar Unit 1	169,527		12	SQ	0	9.9	29,809	40179	12,853
West phoenix CT 1-2	1,557,744	06-2017	50	S2	0	13.2	975,915	1315426	1,079,614
West Phoenix Combined Cycle 1-3	11,925,645	06-2031	50	S2	0	27.8	1,901,448	2562942	3,758,130
Yucca CT 1-4	2,166,526	06-2016	50	S2	0	13.0	1,348,752	1817969	1,818,547
Total Account 345	**19,383,129**						**6,470,417**	**8,721,408**	**9,257,373**

Arizona Public Service Company
Calculation of Theoretical Reserve and Allocation of Book Reserve
Related to Electric Plant in Service at December 31, 2002

Depreciable Group (1)	Original Cost at 12/31/2002 (2)	Probable Retirement Date (3)	Average Service Life (4)	Iowa Curve Type (5)	Net Salvage Percent (6)	Average Remaining Life (7)	SK Theoretical Reserve (8)	SK Allocated Book Reserve (9)	Company Adjusted Book Reserve at 12/31/2002 (10)
346 Miscellaneous Power Plant Equipment									
Douglas CT	40,913	06-2017	70	L1	0	13.8	22,376	30160	29,882
Ocotillo CT 1-2	553,173	06-2017	70	L1	0	14.0	310,631	418696	460,255
Saguaro CT	790,906	06-2017	70	L1	0	14.1	304,444	410357	388,367
West phoenix CT 1-2	957,431	06-2017	70	L1	0	14.1	377,281	508533	479,217
West Phoenix Combined Cycle 1-3	2,608,877	06-2031	70	L1	0	26.6	664,636	895856	1,714,480
Yucca CT 1-4	427,175	06-2016	70	L1	0	13.2	265,328	357633	411,833
Total Account 346	**5,378,475**						**1,944,696**	**2,621,236**	**3,484,034**
TOTAL OTHER PRODUCTION PLANT	**202,716,436**						**59,375,045**	**80,031,011**	**80,031,011**
TRANSMISSION PLANT									
352 Structures and Improvements	27,618,299		50	R4	0	35.2	8,175,017	12,484,016	8,135,201
352.5 Structures and Improvements - SCE 500 KV Line	409,725				0		278,239	424,897	296,895
353 Station Equipment	428,736,305		57	R1.5	0	45.7	85,220,743	130,140,054	173,966,733
353.5 Station Equipment - SCE 500 KV Line	7,747,282				0		4,812,647	7,349,363	6,464,972
354 Towers and Fixtures	83,464,531		60	R3	0	38.3	30,186,339	46,097,366	39,991,439
354.5 Towers and Fixtures - SCE 500 KV Line	13,752,584				0		11,445,248	17,477,965	13,542,259
355 Poles and Fixtures - Wood	91,126,939		48	R1.5	0	38.5	18,035,540	27,541,958	33,590,493
355.1 Poles and Fixtures - Steel	83,067,888		55	R3	0	45.1	14,952,220	22,833,440	22,282,935
355.5 Poles and Fixtures - SCE 500 KV Line	930,308				0		453,525	692,575	341,908
356 Overhead Conductors and Devices	205,771,417		55	R3	0	38.5	61,731,425	94,269,666	70,439,236
356.5 Overhead Conductors and Devices - SCE 500 KV Line	22,653,515				0		18,956,016	28,947,611	23,670,862
357 Underground Conduit	10,444,362		48	S1.5	0	35.7	2,676,368	4,087,064	2,989,523
358 Underground Conductors and Devices	18,551,254		40	R3	0	26.3	6,353,804	9,702,854	6,336,374
TOTAL TRANSMISSION PLANT	**994,274,409**						**263,277,130**	**402,048,830**	**402,048,830**
DISTRIBUTION PLANT									
361 Structures and Improvements	25,815,042		45	R2.5	0	33.1	6,826,644	10,429,908	7,749,290
362 Station Equipment	212,357,577		44	L0.5	0	36.9	34,508,106	52,722,295	70,802,963
364 Poles and Fixtures - Wood	284,200,711		38	R0.5	0	30.9	53,100,659	81,128,434	94,139,326
364.1 Poles and Fixtures - Steel	53,919,651		50	R3	0	46.6	3,666,536	5,601,820	5,138,171
365 Overhead Conductors and Devices	218,856,780		53	O1	0	47.7	21,885,678	33,437,453	58,922,434
366 Underground Conduit	425,723,116		86	O1	0	82.4	17,622,957	26,924,767	51,496,065
367 Underground Conductors and Devices	805,505,783		29	L1	0	22.9	169,433,975	258,865,205	227,200,974
368 Line Transformers	486,837,053		36	R3	0	24.6	154,165,067	235,537,009	188,298,226
369 Services	242,404,812		37	S2	0	27.9	59,618,481	91,086,515	86,204,425
370 Meters	91,330,710		29	L0	0	21.8	22,801,184	34,836,184	36,185,262
370.1 Electronic Meters	54,691,249		26	R1.5	0	23.3	5,637,406	8,612,961	11,298,055
371 Installations On Customer Premises	25,335,831		50	O2	0	45.0	2,528,516	3,863,126	8,708,344
373 Street Lighting and Signal Systems	57,185,737		35	R2.5	0	25.9	14,868,292	22,716,125	19,618,266
TOTAL DISTRIBUTION PLANT	**2,984,164,052**						**566,663,501**	**865,761,801**	**865,761,801**

Arizona Public Service Company
Calculation of Theoretical Reserve and Allocation of Book Reserve
Related to Electric Plant in Service at December 31, 2002

Depreciable Group (1)	Original Cost at 12/31/2002 (2)	Probable Retirement Date (3)	Average Service Life (4)	Iowa Curve Type (5)	Net Salvage Percent (6)	Average Remaining Life (7)	SK Theoretical Reserve (8)	SK Allocated Book Reserve (9)	Company Adjusted Book Reserve at 12/31/2002 (10)
GENERAL PLANT									
390 Structures and Improvements	96,667,435		39	R1	0	30.7	20,572,813	24,085,116	30,654,079
391 Office Furniture and Equipment - Furniture	19,919,640		20	SQ	0	10.1	9,860,222	11,543,613	9,897,448
Reserve Variance Amortization									
391.1 Office Furniture and Equipment - Pc Equip	38,654,946		8	R3	0	5.3	12,901,088	15,103,632	14,227,354
Reserve Variance Amortization									
391.2 Office Furniture and Equipment - Equipment	7,652,923		22	R4	0	14.8	2,504,593	2,932,191	4,070,284
Reserve Variance Amortization									
393 Stores Equipment	1,227,371		20	SQ	0	2.8	1,055,539	1,235,746	838,588
Reserve Variance Amortization									
394 Tools, Shop and Garage Equipment	12,673,031		20	SQ	0	13.7	3,992,005	4,673,542	3,298,597
Reserve Variance Amortization									
395 Laboratory Equipment	1,350,583		20	L1	0	13.3	453,796	531,270	1,043,823
Reserve Variance Amortization									
397 Communication Equipment	94,309,691		19	S1.5	0	12.0	34,745,676	40,677,647	36,587,109
398 Miscellaneous Equipment	1,336,404		24	S1.5	0	16.6	411,501	481,755	647,229
Reserve Variance Amortization									
TOTAL GENERAL PLANT	**273,792,024**						**86,497,233**	**101,264,511**	**101,264,511**
TOTAL DEPRECIABLE PLANT STUDIED	**8,082,632,804**						**2,465,330,093**	**3,186,573,980**	**3,186,573,980**
5-YEAR AVERAGE NET SALVAGE ALLOWANCE									
TOTAL DEPRECIATION									

Note: SK Theoretical Reserve for Production plant is Company Theoretical Reserve from Attachment LLR-4, less the net salvage component.

ARIZONA PUBLIC SERVICE COMPANY
Depreciation and Amortization Expense
Comparison of Company Proposal and Snavely King Recommendation
For the Year Ended December 31, 2002
(Thousands of Dollars)

Line No			Company Proposal			Snavely King Recommendation		
			Actual YTD 2002	Projected 2003	Difference	Projected 2003		Difference
1	PRODUCTION DEPRECIATION/AMORTIZATION							
2	Production							
3	Steam		$ 36,510	$ 43,967	$ 7,457	28,840	1/	(7,670)
4	Steam - Navajo Depreciation adjustment (a)		(378)	(378)	-	(378)	2/	-
5	Nuclear		74,657	67,495	(7,162)	64,486	1/	(10,171)
6	Nuclear - Leased Property Amortized		562	562	-	562	2/	-
7	Nuclear - Decommissioning		11,443	11,443	-	11,443	2/	-
7	Hydro (b)		3,262	2,668	(594)	2,668	2/	(594)
9	Hydro - Limited Term Land Rights		13	13	-	13	2/	-
10	Other		7,550	5,938	(1,612)	5,506	1/	(2,044)
11	TOTAL PRODUCTION DEPRECIATION	[Total Lines 3 - 11]	133,619	131,708	(1,911)	113,139		(20,480)
12	TRANSMISSION DEPRECIATION/AMORTIZATION							
13	Transmission Depreciation SCE 500 kV Line - Limited Term Land Rights		129	129	-	129	2/	-
14	Transmission Depreciation SCE 500 kV Line		1,413	1,479	66	1,479	2/	66
15	Transmission Depreciation All Other - Limited Term Land Rights		914	914	-	914	2/	-
16	Transmission Depreciation All Other		19,000	20,771	1,771	14,342	1/	(4,659)
17	TOTAL TRANSMISSION	[Total Lines 14-17]	21,456	23,293	1,837	16,863		(4,593)
18	DISTRIBUTION DEPRECIATION/AMORTIZATION							
19	Distribution Depreciation		98,904	83,639	(15,265)	67,020	1/	(31,884)
20	Distribution Depreciation All Other - Limited Term Land Rights		38	38	-	38	2/	-
21	Distribution - Leased Property Amortized		9	9	-	9	2/	-
22	TOTAL DISTRIBUTION	[Total Lines 20-22]	98,951	83,686	(15,265)	67,067		(31,884)
23	GENERAL AND INTANGIBLE DEPRECIATION/AMORTIZATION							
24	Intangible Amortization		17,935	21,620	3,685	21,620	2/	3,685
25	Intangible - Leased Property Amortization		17	17	-	17	2/	-
26	TOTAL INTANGIBLE AMORTIZATION	[Total Lines 24-25]	17,952	21,637	3,685	21,637		3,685
27	General Depreciation and Amortization							
28	390 Structures and Improvements		2,085	2,624	539	2,364	1/	279
29	390 Structures and Improvements - Leased Property Amortized		1,253	1,253	-	1,253	2/	-
30	391 Office Furniture		675	995	320	829	1/	154
31	3911 Office Furniture and Equipment-PC Equipment		2,870	6,467	3,597	4,419	1/	1,549
32	C391 Office Furniture and Equip-PC Equipment Capital Leases		752	1,978	1,226	1,978	2/	1,227
33	3911A Office Furniture and Equip-Reserve Variance Amortization		-	2,352	2,352	-	1/	-
34	3912 Office Equipment		378	462	84	319	1/	(59)
35	392 Transportation Equipment		515	777	262	777	2/	262
36	C392 Transportation Equipment - Capital Leases		-	3,315	3,315	3,315	2/	3,315
37	392.1 Transportation Equipment- Leased Vehicles Purchased		63	405	342	405	2/	341
38	393 Stores Equipment		32	30	(2)	(3)	1/	(35)
39	3931A Stores Equipment-Reserve Variance Amortization		-	101	101	-	1/	-
40	394 Tools, Shop and Garage Equipment		468	634	166	584	1/	116
41	3941A Tools, Shop & Garage Equip-Reserve Variance Amortization		-	230	230	-	1/	-
42	395 Laboratory Equipment		90	75	(15)	69	1/	(21)
43	3951A Laboratory Equipment-Reserve Variance Amortization		-	13	13	-	1/	-
44	396 Power Operated Equipment		596	787	191	787	2/	191
45	397 Communication Equipment		2,837	4,812	1,975	4,469	1/	1,632
46	397 Communication Equipment - Leased Property Amortized		9	9	-	9	2/	-
47	398 Miscellaneous Equipment		59	65	6	51	1/	(8)
48	3981A Misc. Equipment-Reserve Variance Amortization		-	(21)	(21)	-	1/	-
49	TOTAL GEN AND INTANG DEPR. AND AMORT.	[Total Lines 28 - 48]	12,682	27,363	14,681	21,625		8,942
50	5-Year Average Net Salvage Allowance					-		-
51	TOTAL DEPRECIATION AND AMORTIZATION EXPENSE (Accounts 403 & 404)		$ 284,660	$ 287,687	$ 3,027	$ 240,331		(44,329)
52	Amortization of Electric Plant Acquisition Adjustment (Account 406)		15,443	(c)				
53	Amortization of Property losses, Unrecovered Plant, and regulatory study costs (Account 4(		99,537	(c)				
54	Total		$ 399,640					

NOTE: 1/ From Snavely King Depreciation Study.
2/ No Snavely King challenge to Company proposal.
(a) - Navajo Railroad Depreciation expense reclassified to Fuel inventory (Account 151).
(b) - Includes Hydro Decommissioning only.
(c) - Refer to Pro-Forma adjustment on regulatory asset amortization schedule C2, Page 8 for Projected amount.

Arizona Public Service Company

Production Plant as of 12/31/2002

Company Proposed Terminal Retirement Years and Life Spans

Depreciable Group	Year In Service	Probable Retirement Year	Life Span	Remaining Life Span
Steam Production Plant				
Chollo Unit 1	1962	2017	55	15
Chollo Unit 2	1978	2033	55	31
Chollo Unit 3	1980	2035	55	33
Chollo Common	1978	2035	57	33
Four Corners Units 1-3	1963	2016	53	14
Four Corners Units 4-5	1969	2031	62	29
Navajo Units 1-3	1975	2026	51	24
Ocotillo Units 1-2	1960	2020	60	18
Saguaro Units 1-3	1954	2014	60	12
Yucca Unit 1	1959	2016	57	14
Nuclear Production Plant				
Palo Verde Unit 1	1986	2024	40	22
Palo Verde Unit 2	1986	2025	40	23
Palo Verde Unit 3	1988	2027	40	25
Palo Verde Water Reclamation	1986	2027	40	25
Palo Verde Common	1986	2027	40	25
Hydraulic Production Plant				
Childs	1909	2004	95	2
Irving	1916	2004	88	2
Other Production Plant				
Douglas	1972	2017	45	15
Ocotillo Turbines 1-2	1972	2017	45	15
Saguaro Turbines 1-2	1972	2017	45	15
West Phoenix Turbines 1-2	1972	2017	45	15
West Phoenix Combined Cycle 1-2	1976	2031	55	29
Yucca Turbines 1-4	1971	2016	45	14

Source: Attachment LLR-4, page II-28.
Note: Nuclear lifespan based on license period.

Arizona Public Service Company

Section SP

Production Plant

Arizona Public Service Company

Steam Production Plant

311.00 - Structures and Improvements

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Steam Production Plant - Structures and Improvements

Account	311 - Structures and Improvements	
Depreciable Balance	$115,950,066	
	APS	Snavely King
Depreciable Reserve	$64,537,994	$63,151,660
Reserve Percent	55.7%	54.5%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	80-S1	75-S1.5	75-S1.5
Remaining Life (Yrs.)			
Net Salvage (%)	(20)	(20)	0
Accrual ($)	3,246,602	3,383,810	2,249,880
Rate (%)	2.80%	2.92%	1.94%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 311 - Structures and Improvements

Age	Cumulative Survivors
	1948-2010
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	0.9986
5.5	0.9986
6.5	0.9983
7.5	0.9980
8.5	0.9969
9.5	0.9961
10.5	0.9948
11.5	0.9948
12.5	0.9946
13.5	0.9939
14.5	0.9938
15.5	0.9937
16.5	0.9932
17.5	0.9920
18.5	0.9905
19.5	0.9901
20.5	0.9852
21.5	0.9846
22.5	0.9846
23.5	0.9799
24.5	0.9797
25.5	0.9789
26.5	0.9767
27.5	0.9723
28.5	0.9617
29.5	0.9603
30.5	0.9603
31.5	0.9596
32.5	0.9231
33.5	0.9231
34.5	0.9227
35.5	0.9221
36.5	0.9213
37.5	0.9213
38.5	0.9213
39.5	0.8847
40.5	0.7501
41.5	0.5607
42.5	0.5475
43.5	0.5475
44.5	0.5475

Observed Life Table Results
Arizona Public Service Company
Account: 311 - Structures and Improvements

Age	Cumulative Survivors
45.5	0.4936
46.5	0.3482
47.5	0.3482
48.5	0.3087
49.5	0.3087
50.5	0.3087
51.5	0.3087
52.5	0.3087
53.5	0.3087
54.5	0.3087
55.5	0.3087
56.5	0.3087
57.5	0.3087
58.5	0.3087
59.5	0.3087
60.5	0.3087
61.5	0.3087
	1973 - 2010
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	0.9985
5.5	0.9985
6.5	0.9983
7.5	0.9979
8.5	0.9967
9.5	0.9963
10.5	0.9951
11.5	0.9950
12.5	0.9949
13.5	0.9941
14.5	0.9941
15.5	0.9939
16.5	0.9934
17.5	0.9922
18.5	0.9907
19.5	0.9903
20.5	0.9853
21.5	0.9848
22.5	0.9848
23.5	0.9801
24.5	0.9799
25.5	0.9790
26.5	0.9768
27.5	0.9725

Observed Life Table Results
Arizona Public Service Company
Account: 311 - Structures and Improvements

Age	Cumulative Survivors
28.5	0.9619
29.5	0.9604
30.5	0.9604
31.5	0.9597
32.5	0.9233
33.5	0.9233
34.5	0.9228
35.5	0.9222
36.5	0.9214
37.5	0.9214
38.5	0.9214
39.5	0.8848
40.5	0.7502
41.5	0.5608
42.5	0.5476
43.5	0.5476
44.5	0.5476
45.5	0.4937
46.5	0.3483
47.5	0.3483
48.5	0.3087
49.5	0.3087
50.5	0.3087
51.5	0.3087
52.5	0.3087
53.5	0.3087
54.5	0.3087
55.5	0.3087
56.5	0.3087
57.5	0.3087
58.5	0.3087
59.5	0.3087
60.5	0.3087
61.5	0.3087

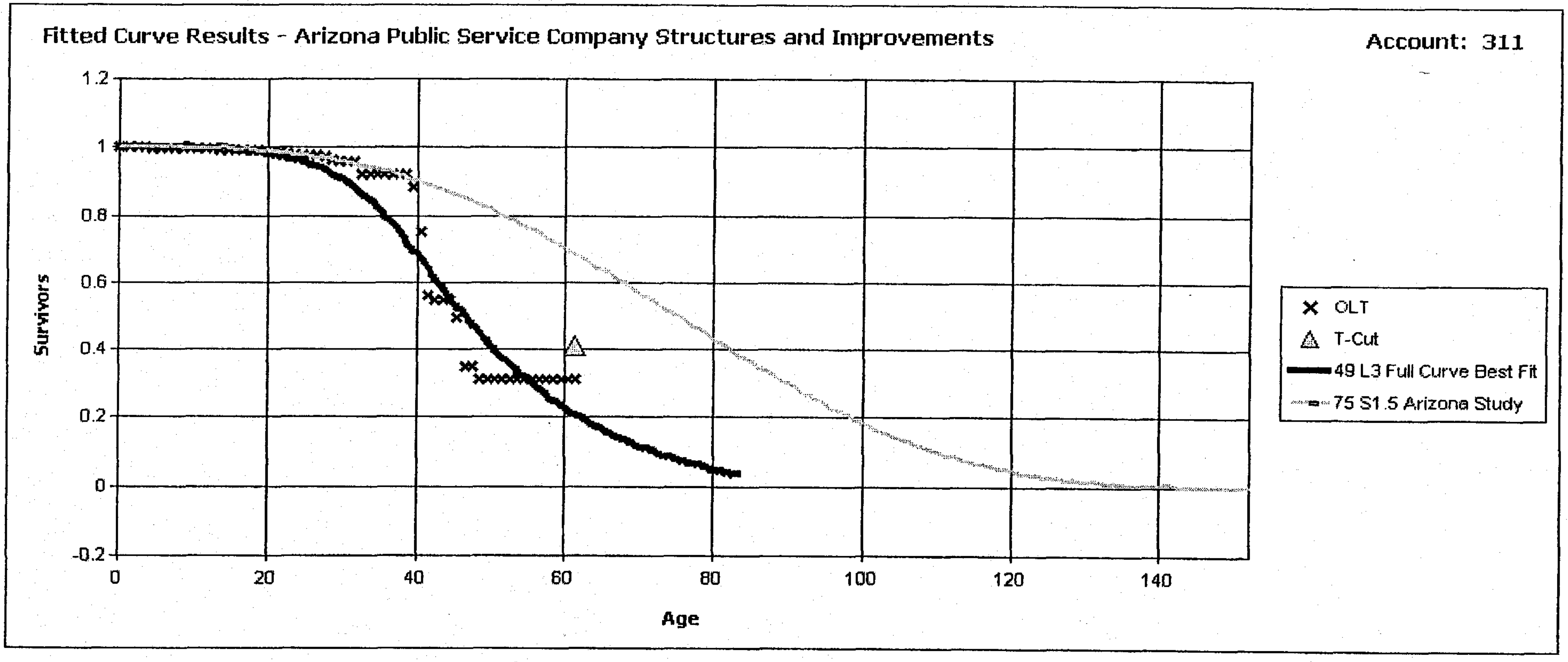
Best Fit Curve Results
Arizona Public Service Company
Account: 311 - Structures and Improvements

Curve	Life	Sum of Squared Differences
BAND	1973 - 2010	
L3	49.0	3,116.966
L4	47.0	3,208.758
S3	47.0	3,721.212
S2	48.0	4,396.967
R3	47.0	4,890.446
R2.5	47.0	5,454.272
S1.5	48.0	5,497.234
S4	47.0	5,512.058
L5	47.0	5,954.329
R4	47.0	6,035.324
L2	51.0	6,053.772
R2	47.0	6,790.014
S1	49.0	7,114.635
L1.5	52.0	8,278.239
R1.5	47.0	8,874.673
S0.5	49.0	9,072.909
R5	46.0	9,288.876
S5	46.0	9,524.832
L1	54.0	11,058.666
S0	50.0	11,508.013
R1	47.0	11,672.793
L0.5	56.0	13,387.113
S6	45.0	13,903.523
S-0.5	51.0	14,887.096
R0.5	49.0	15,216.336
L0	58.0	16,028.491
O1	54.0	18,827.055
O2	61.0	18,847.029
O3	86.0	21,113.142
O4	100.0	23,497.563
SQ	45.0	27,554.624

Analytical Parameters

OLT Placement Band:	1948 - 2010
OLT Experience Band:	1973 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	61.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1948 - 2010
OLT Experience Band:	1973 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	61.5

Arizona Public Service Company

Steam Production Plant

312.00 - Boiler Plant Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Steam Production Plant - Boiler Plant Equipment

Account 312 - Boiler Plant Equipment

Depreciable Balance $800,031,516

	APS	Snavely King
Depreciable Reserve	$442,311,564	$462,014,635
Reserve Percent	55.3%	57.7%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year	2012	2017	2017
Iowa Curve	70-L1	48-L2	48-L2
Remaining Life (Yrs.)		17.4	18.9
Net Salvage (%)	(20)	(20)	0
Accrual ($)	23,040,908	29,742,262	18,925,817
Rate (%)	2.88%	3.72%	2.37%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 312 - Boiler Plant Equipment

Age	Cumulative Survivors
BAND	1948-2010
0	1.0000
0.5	1.0000
1.5	0.9997
2.5	0.9988
3.5	0.9980
4.5	0.9926
5.5	0.9919
6.5	0.9908
7.5	0.9897
8.5	0.9859
9.5	0.9841
10.5	0.9818
11.5	0.9784
12.5	0.9750
13.5	0.9740
14.5	0.9731
15.5	0.9715
16.5	0.9692
17.5	0.9663
18.5	0.9649
19.5	0.9557
20.5	0.9528
21.5	0.9417
22.5	0.9397
23.5	0.9348
24.5	0.9257
25.5	0.9231
26.5	0.8938
27.5	0.8572
28.5	0.8425
29.5	0.7989
30.5	0.7661
31.5	0.7360
32.5	0.7182
33.5	0.7018
34.5	0.6903
35.5	0.6747
36.5	0.6730
37.5	0.6496
38.5	0.6380
39.5	0.5807
40.5	0.5702
41.5	0.5437
42.5	0.4544
43.5	0.3912
44.5	0.3050

Observed Life Table Results
Arizona Public Service Company
Account: 312 - Boiler Plant Equipment

Age	Cumulative Survivors
45.5	0.2866
46.5	0.2369
47.5	0.2100
48.5	0.1960
49.5	0.1883
50.5	0.1859
51.5	0.1859
52.5	0.1859
53.5	0.1835
54.5	0.1815
55.5	0.1815
56.5	0.1815
57.5	0.1815
58.5	0.1815
59.5	0.1815
60.5	0.1815
61.5	0.1815
BAND	**1973 - 2010**
0	1.0000
0.5	1.0000
1.5	0.9997
2.5	0.9987
3.5	0.9979
4.5	0.9921
5.5	0.9913
6.5	0.9902
7.5	0.9890
8.5	0.9848
9.5	0.9833
10.5	0.9810
11.5	0.9775
12.5	0.9740
13.5	0.9729
14.5	0.9721
15.5	0.9705
16.5	0.9681
17.5	0.9652
18.5	0.9638
19.5	0.9546
20.5	0.9517
21.5	0.9406
22.5	0.9386
23.5	0.9337
24.5	0.9246
25.5	0.9220
26.5	0.8927
27.5	0.8562

Observed Life Table Results
Arizona Public Service Company
Account: 312 - Boiler Plant Equipment

Age	Cumulative Survivors
28.5	0.8415
29.5	0.7979
30.5	0.7652
31.5	0.7352
32.5	0.7173
33.5	0.7010
34.5	0.6894
35.5	0.6739
36.5	0.6722
37.5	0.6489
38.5	0.6372
39.5	0.5800
40.5	0.5695
41.5	0.5431
42.5	0.4538
43.5	0.3907
44.5	0.3046
45.5	0.2863
46.5	0.2366
47.5	0.2098
48.5	0.1958
49.5	0.1880
50.5	0.1857
51.5	0.1857
52.5	0.1857
53.5	0.1833
54.5	0.1813
55.5	0.1813
56.5	0.1813
57.5	0.1813
58.5	0.1813
59.5	0.1813
60.5	0.1813
61.5	0.1813

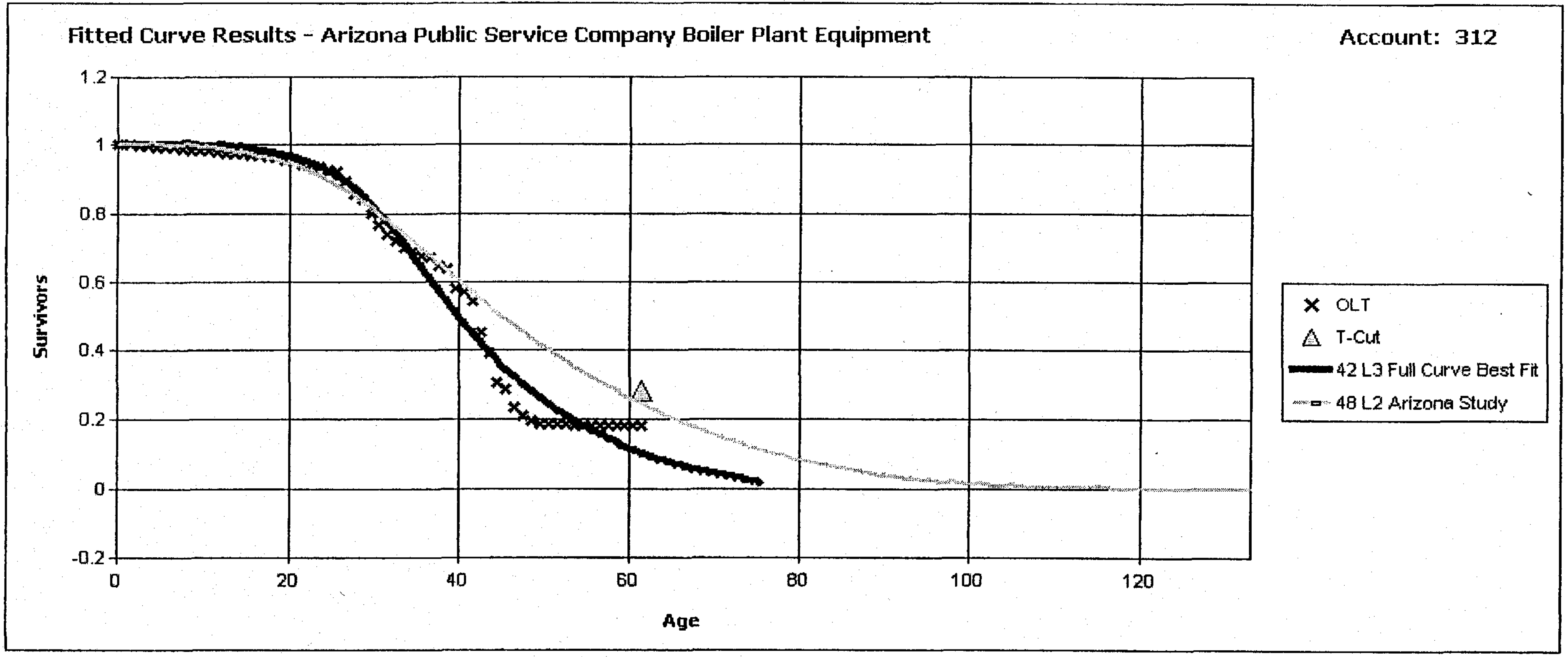
Best Fit Curve Results
Arizona Public Service Company
Account: 312 - Boiler Plant Equipment

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2010**	
L3	42.0	1,076.038
S2	41.0	1,456.100
S1.5	41.0	1,732.614
R2.5	40.0	1,838.285
R3	40.0	2,281.798
S3	41.0	2,284.511
R2	40.0	2,314.769
L2	43.0	2,561.788
S1	41.0	2,628.036
L4	42.0	2,647.777
R1.5	40.0	3,473.918
S0.5	41.0	4,006.420
L1.5	43.0	4,127.384
R4	41.0	4,234.110
S4	41.0	5,349.328
R1	39.0	5,506.529
S0	40.0	5,969.379
L5	42.0	6,320.393
L1	43.0	6,399.368
R5	41.0	8,194.846
L0.5	43.0	8,548.834
R0.5	39.0	8,648.869
S-0.5	40.0	8,948.648
S5	41.0	9,595.672
L0	44.0	11,147.996
O1	40.0	12,863.222
O2	45.0	13,230.810
S6	42.0	14,235.060
O3	61.0	18,100.057
O4	82.0	20,069.940
SQ	42.0	26,717.483

Analytical Parameters

OLT Placement Band:	1948 - 2010
OLT Experience Band:	1973 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	61.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1948 - 2010
OLT Experience Band:	1973 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	61.5

Arizona Public Service Company

Steam Production Plant

314.00 - Turbogenerator Units

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Steam Production Plant - Turbogenerator Units

Account 314 - Turbogenerator Units

Depreciable Balance $188,018,474

	APS	Snavely King
Depreciable Reserve	$123,879,147	$112,700,899
Reserve Percent	65.9%	59.9%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	65-R2	65-R2	65-R2
Remaining Life (Yrs.)			
Net Salvage (%)	(20)	(20)	0
Accrual ($)	4,399,632	5,132,750	3,602,809
Rate (%)	2.34%	2.73%	1.92%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 314 - Turbogenerator Units

Age	Cumulative Survivors
	1948-2010
0	1.0000
0.5	0.9998
1.5	0.9986
2.5	0.9986
3.5	0.9957
4.5	0.9957
5.5	0.9957
6.5	0.9894
7.5	0.9888
8.5	0.9888
9.5	0.9834
10.5	0.9826
11.5	0.9823
12.5	0.9823
13.5	0.9795
14.5	0.9786
15.5	0.9786
16.5	0.9763
17.5	0.9737
18.5	0.9714
19.5	0.9713
20.5	0.9708
21.5	0.9473
22.5	0.9468
23.5	0.9448
24.5	0.9365
25.5	0.9347
26.5	0.9270
27.5	0.9098
28.5	0.9053
29.5	0.9003
30.5	0.8964
31.5	0.8958
32.5	0.8933
33.5	0.8863
34.5	0.8859
35.5	0.8855
36.5	0.8842
37.5	0.8800
38.5	0.8522
39.5	0.8301
40.5	0.8234
41.5	0.8015
42.5	0.7877
43.5	0.7811
44.5	0.7525

Observed Life Table Results
Arizona Public Service Company
Account: 314 - Turbogenerator Units

Age	Cumulative Survivors
45.5	0.7084
46.5	0.7046
47.5	0.6992
48.5	0.6814
49.5	0.6814
50.5	0.6814
51.5	0.6814
52.5	0.6814
53.5	0.6814
54.5	0.6814
55.5	0.6814
56.5	0.6814
57.5	0.6814
58.5	0.6814
59.5	0.6814
60.5	0.6814
61.5	0.6814
	1973 - 2010
0	1.0000
0.5	0.9997
1.5	0.9983
2.5	0.9983
3.5	0.9945
4.5	0.9945
5.5	0.9945
6.5	0.9863
7.5	0.9855
8.5	0.9855
9.5	0.9782
10.5	0.9774
11.5	0.9770
12.5	0.9770
13.5	0.9740
14.5	0.9730
15.5	0.9730
16.5	0.9706
17.5	0.9679
18.5	0.9655
19.5	0.9654
20.5	0.9649
21.5	0.9416
22.5	0.9410
23.5	0.9390
24.5	0.9308
25.5	0.9290
26.5	0.9214
27.5	0.9042

Observed Life Table Results
Arizona Public Service Company
Account: 314 - Turbogenerator Units

Age	Cumulative Survivors
28.5	0.8998
29.5	0.8948
30.5	0.8909
31.5	0.8904
32.5	0.8879
33.5	0.8809
34.5	0.8805
35.5	0.8802
36.5	0.8789
37.5	0.8747
38.5	0.8471
39.5	0.8250
40.5	0.8184
41.5	0.7966
42.5	0.7829
43.5	0.7763
44.5	0.7480
45.5	0.7041
46.5	0.7003
47.5	0.6950
48.5	0.6773
49.5	0.6773
50.5	0.6773
51.5	0.6773
52.5	0.6773
53.5	0.6773
54.5	0.6773
55.5	0.6773
56.5	0.6773
57.5	0.6773
58.5	0.6773
59.5	0.6773
60.5	0.6773
61.5	0.6773

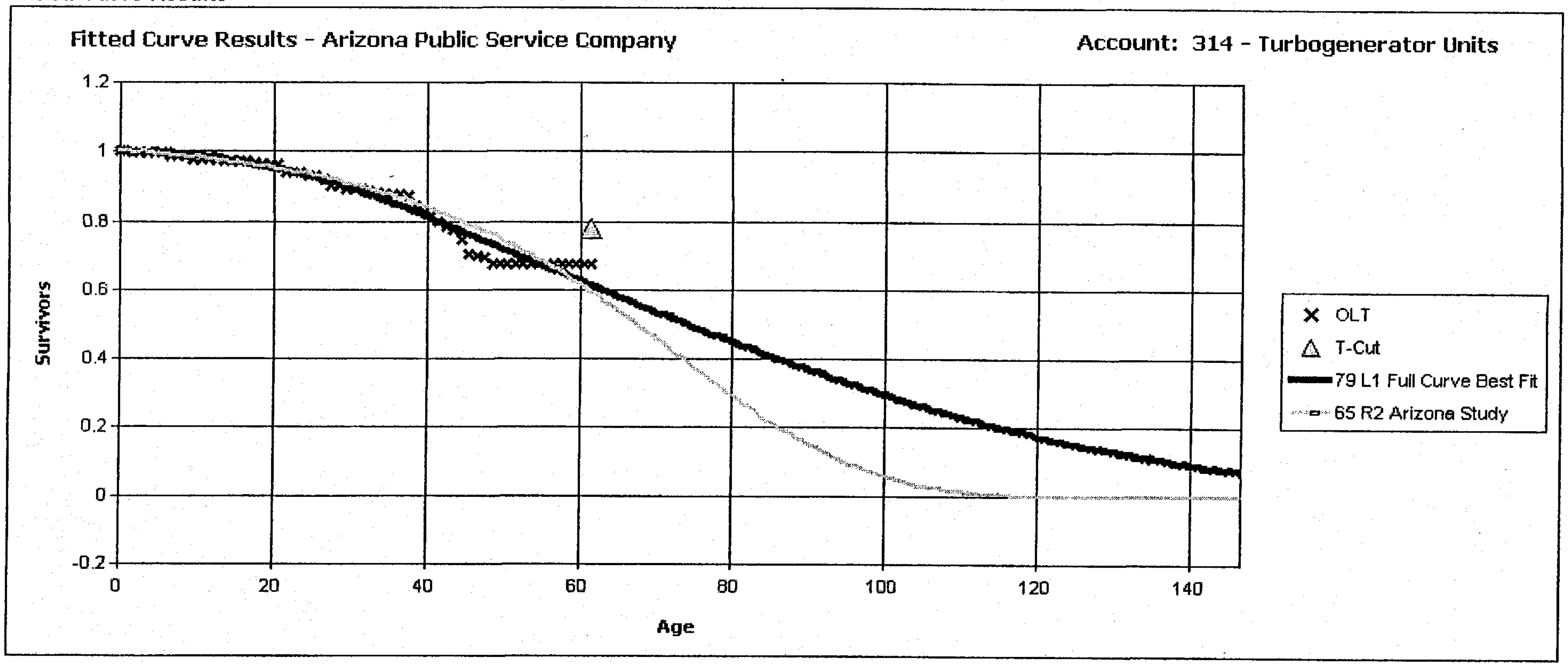
Best Fit Curve Results
Arizona Public Service Company
Account: 314 - Turbogenerator Units

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2010**	
L1	79.0	351.768
S0.5	71.0	424.530
S0	76.0	431.005
L0.5	86.0	452.274
L1.5	74.0	534.731
R1.5	68.0	560.321
R2	64.0	635.991
S1	67.0	642.710
L0	96.0	690.982
R1	73.0	731.767
S-0.5	84.0	784.137
L2	70.0	1,052.774
R0.5	83.0	1,057.320
S1.5	65.0	1,059.290
R2.5	62.0	1,065.435
O1	98.0	1,307.194
O2	100.0	1,524.200
S2	63.0	1,767.799
R3	61.0	1,888.693
L3	65.0	2,823.283
S3	61.0	3,687.200
R4	59.0	4,175.310
L4	62.0	5,415.623
S4	60.0	7,088.422
O3	100.0	7,216.441
R5	60.0	8,802.536
L5	61.0	8,897.391
S5	60.0	11,088.729
S6	61.0	14,900.344
O4	100.0	20,433.347
SQ	62.0	21,942.338

Analytical Parameters

OLT Placement Band:	1948 - 2010
OLT Experience Band:	1973 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	61.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1948 - 2010
OLT Experience Band:	1973 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	61.5

Arizona Public Service Company

Steam Production Plant

315.00 - Accessory Electric Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Steam Production Plant - Accessory Electric Equipment

Account 315 - Accessory Electric Equipment

Depreciable Balance $134,807,415

	APS	Snavely King
Depreciable Reserve	$87,844,097	$80,088,777
Reserve Percent	65.2%	59.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	45-R3	60-R2.5	60-R2.5
Remaining Life (Yrs.)			
Net Salvage (%)	(20)	(20)	0
Accrual ($)	3,680,242	3,428,362	2,413,411
Rate (%)	2.73%	2.54%	1.79%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 315 - Accessory Electric Equipment

Age BAND	Cumulative Survivors 1973 - 2001
0	1.0000
0.5	1.0000
1.5	0.9999
2.5	0.9999
3.5	0.9999
4.5	0.9999
5.5	0.9986
6.5	0.9986
7.5	0.9985
8.5	0.9866
9.5	0.9866
10.5	0.9841
11.5	0.9752
12.5	0.9744
13.5	0.9740
14.5	0.9740
15.5	0.9739
16.5	0.9723
17.5	0.9708
18.5	0.9667
19.5	0.9620
20.5	0.9574
21.5	0.9492
22.5	0.9465
23.5	0.9429
24.5	0.9385
25.5	0.9364
26.5	0.9364
27.5	0.9333
28.5	0.9318
29.5	0.9314
30.5	0.9228
31.5	0.9043
32.5	0.9043
33.5	0.9018
34.5	0.8967
35.5	0.8935
36.5	0.8935
37.5	0.8935
38.5	0.8924
39.5	0.8873
40.5	0.8873
41.5	0.8873
42.5	0.8873
43.5	0.8873
44.5	0.8873

Observed Life Table Results
Arizona Public Service Company
Account: 315 - Accessory Electric Equipment

Age	Cumulative Survivors
45.5	0.8873
46.5	0.8873
47.5	0.8873

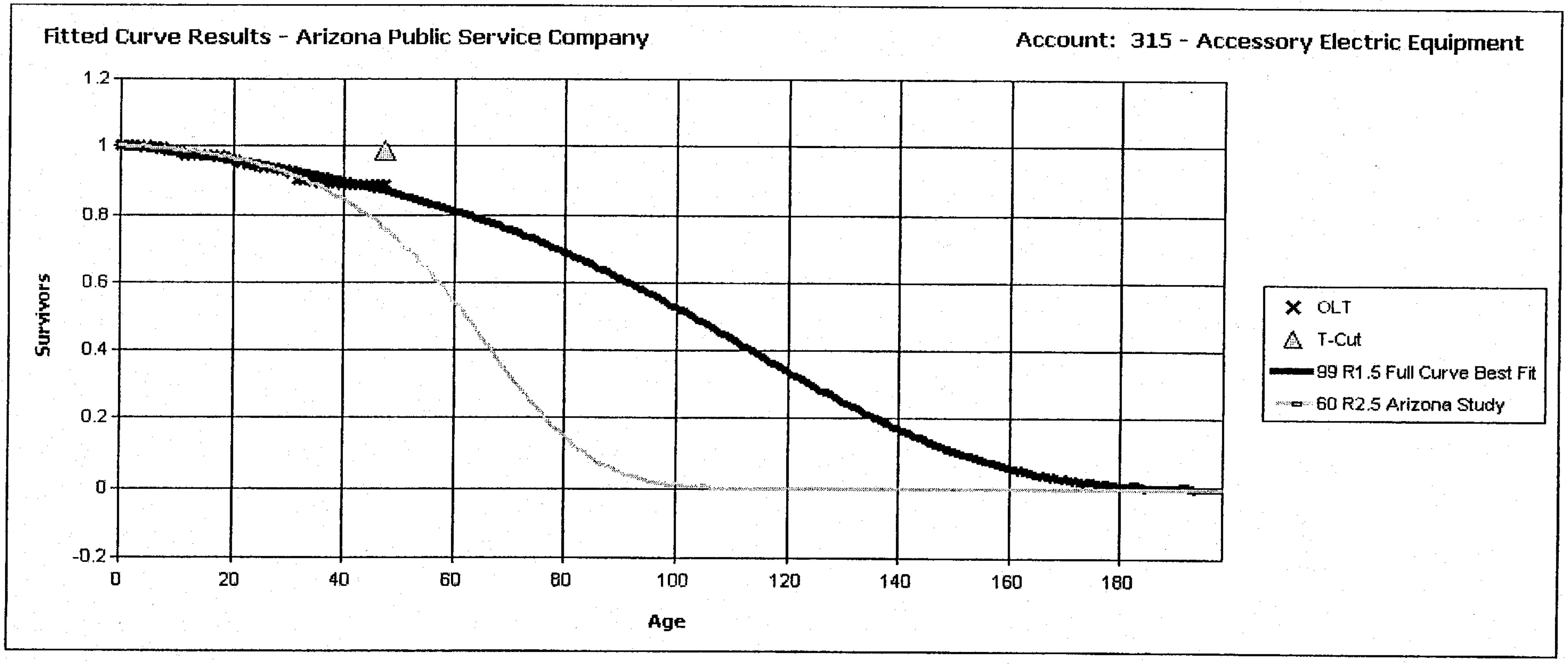
Best Fit Curve Results
Arizona Public Service Company
Account: 315 - Accessory Electric Equipment

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R1.5	99.0	10,036.043
R2	82.0	10,057.670
S0.5	93.0	10,083.079
S0	100.0	10,089.188
R2.5	72.0	10,111.259
L1	100.0	10,115.095
L1.5	91.0	10,136.762
S1	81.0	10,184.055
R1	100.0	10,219.771
R3	65.0	10,248.726
S1.5	74.0	10,263.707
L2	80.0	10,279.512
S2	68.0	10,437.765
L0.5	100.0	10,509.839
L3	67.0	10,542.621
R4	58.0	10,614.319
S-0.5	100.0	10,751.273
S3	61.0	10,753.195
L4	59.0	10,816.652
R0.5	100.0	10,988.289
S4	56.0	11,186.426
R5	53.0	11,223.756
L5	55.0	11,260.199
S5	53.0	11,565.321
L0	100.0	11,578.870
S6	51.0	11,857.508
O1	100.0	12,352.752
SQ	48.0	12,360.967
O2	100.0	13,636.815
O3	100.0	20,944.684
O4	100.0	33,190.213

Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	47.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	47.5

Arizona Public Service Company

Steam Production Plant

316.00 - Miscellaneous Power Plant Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Steam Production Plant

Account 316 - Miscellaneous Power Plant Equipment

Depreciable Balance $53,324,730

	APS	Snavely King
Depreciable Reserve	$21,696,281	$22,313,113
Reserve Percent	40.7%	41.8%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	34-R4	40-R2	40-R2
Remaining Life (Yrs.)			
Net Salvage (%)	(20)	(20)	0
Accrual ($)	2,100,994	2,279,704	1,648,121
Rate (%)	3.94%	4.28%	3.09%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 316 - Power Plant Equipment

Age	Cumulative Survivors
0	1.0000
0.5	0.9996
1.5	0.9995
2.5	0.9994
3.5	0.9987
4.5	0.9962
5.5	0.9920
6.5	0.9896
7.5	0.9808
8.5	0.9695
9.5	0.9659
10.5	0.9616
11.5	0.9578
12.5	0.9540
13.5	0.9469
14.5	0.9463
15.5	0.9107
16.5	0.9056
17.5	0.9002
18.5	0.8977
19.5	0.8934
20.5	0.8929
21.5	0.8883
22.5	0.8821
23.5	0.8725
24.5	0.8723
25.5	0.8425
26.5	0.8300
27.5	0.7806
28.5	0.7404
29.5	0.7385
30.5	0.7336
31.5	0.7288
32.5	0.7288
33.5	0.6818
34.5	0.6818
35.5	0.6818
36.5	0.6818
37.5	0.6818
38.5	0.6818
39.5	0.6774
40.5	0.6774
41.5	0.6774
42.5	0.6774
43.5	0.6774
44.5	0.6774
45.5	0.6774
46.5	0.6774
47.5	0.6774

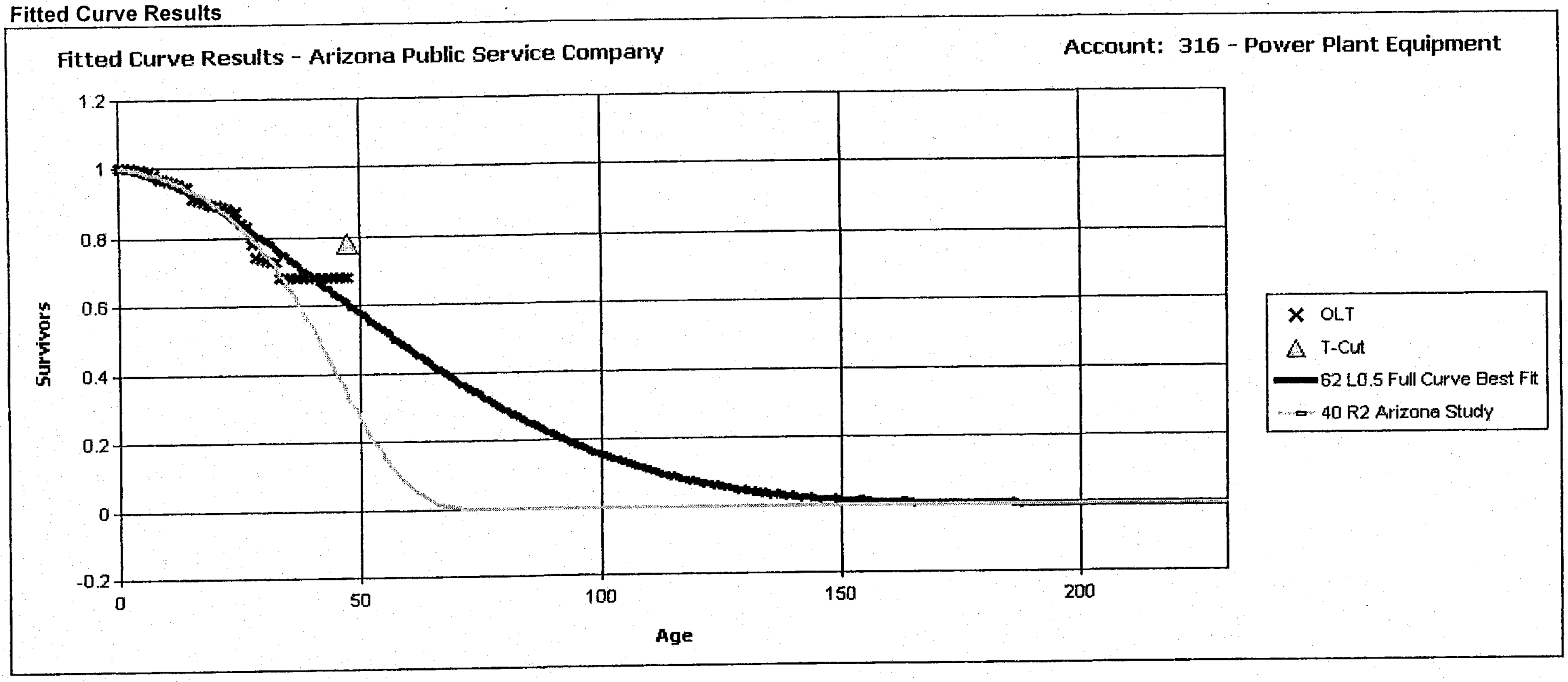
Best Fit Curve Results
Arizona Public Service Company
Account: 316 - Power Plant Equipment

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
L0.5	62.0	10,413.651
L0	69.0	10,415.937
S0	55.0	10,473.608
S-0.5	60.0	10,486.870
R1	53.0	10,563.560
L1	58.0	10,570.930
R0.5	60.0	10,617.739
R1.5	50.0	10,707.711
S0.5	52.0	10,724.905
O2	77.0	10,725.977
O1	69.0	10,727.158
O3	100.0	10,948.876
L1.5	55.0	11,030.021
R2	48.0	11,132.352
S1	50.0	11,205.571
L2	52.0	11,845.342
R2.5	47.0	11,849.506
S1.5	49.0	11,858.145
S2	48.0	12,786.040
R3	46.0	12,920.478
L3	49.0	14,022.289
O4	100.0	14,588.613
S3	47.0	15,004.161
R4	46.0	15,464.760
L4	47.0	16,691.583
S4	46.0	18,388.010
R5	46.0	19,835.744
L5	47.0	19,955.272
S5	46.0	21,873.053
S6	47.0	24,787.631
SQ	48.0	30,285.698

Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	47.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	47.5

Arizona Public Service Company

Nuclear Production Plant

321.00 - Structures and Improvements

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Nuclear Production Plant

Account 321 - Structures and Improvements

Depreciable Balance $632,767,001

	APS	Snavely King
Depreciable Reserve	$256,123,987	$261,989,962
Reserve Percent	40.5%	41.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	65-R3	65-R2.5	65-R2.5
Remaining Life (Yrs.)		22.5	22.9
Net Salvage (%)	0	0	0
Accrual ($)	16,262,112	16,723,721	16,452,433
Rate (%)	2.57%	2.64%	2.60%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 321 - Structures and Improvements

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	0.9997
3.5	0.9945
4.5	0.9939
5.5	0.9932
6.5	0.9923
7.5	0.9908
8.5	0.9897
9.5	0.9894
10.5	0.9888
11.5	0.9881
12.5	0.9814
13.5	0.9808
14.5	0.9805
15.5	0.9803
16.5	0.9803
17.5	0.9795
18.5	0.9788
19.5	0.9776
20.5	0.9719
21.5	0.9678
22.5	0.9528
23.5	0.9472

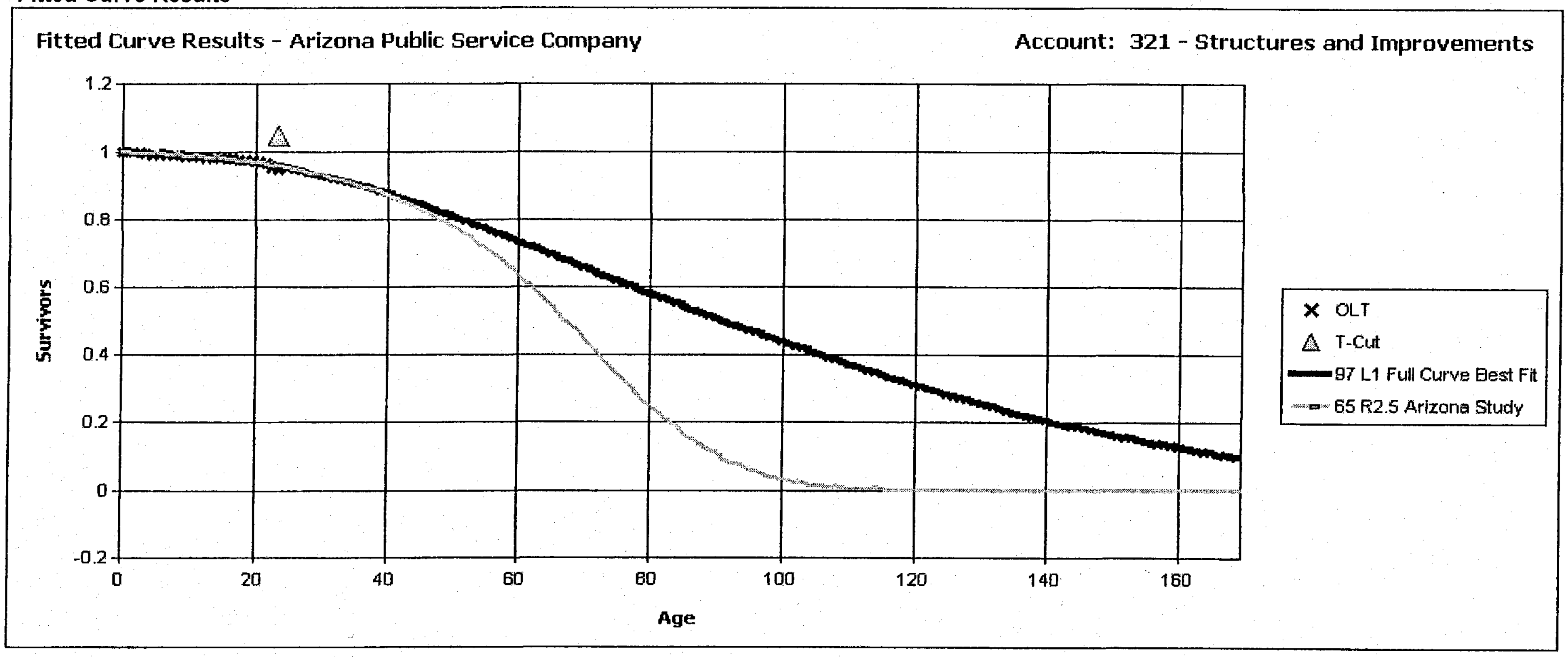
Best Fit Curve Results
Arizona Public Service Company
Account: 321 - Structures and Improvements

Curve	Life	Sum of Squared Differences
BAND	**1986 - 2010**	
L1	97.0	4.084
R2.5	66.0	4.118
L1.5	78.0	4.508
S0.5	86.0	4.749
R3	50.0	4.754
R2	88.0	5.135
S1	66.0	7.108
L2	60.0	7.275
S1.5	56.0	7.914
S0	100.0	8.574
L3	44.0	12.922
S2	47.0	13.169
R4	37.0	13.573
S3	38.0	21.423
R1.5	100.0	22.462
L4	36.0	24.150
R5	30.0	33.810
S4	32.0	34.300
L5	31.0	37.794
S5	29.0	50.539
L0.5	100.0	52.276
S6	27.0	68.404
R1	100.0	97.541
SQ	24.0	108.302
S-0.5	100.0	170.961
L0	100.0	211.042
R0.5	100.0	286.750
O1	100.0	578.733
O2	100.0	796.958
O3	100.0	2,068.629
O4	100.0	4,352.348

Analytical Parameters

OLT Placement Band:	1986 - 2010
OLT Experience Band:	1986 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	23.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1986 - 2010
OLT Experience Band:	1986 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	23.5

Arizona Public Service Company

Nuclear Production Plant

322.00 - Reactor Plant Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Nuclear Production Plant

Account 322 - Reactor Plant Equipment

Depreciable Balance $885,231,334

	APS	Snavely King
Depreciable Reserve	$337,570,862	$357,008,478
Reserve Percent	38.1%	40.3%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	100-O1	70-R1	70-R1
Remaining Life (Yrs.)		21.5	22.4
Net Salvage (%)	(1)	(2)	0
Accrual ($)	26,822,509	26,235,525	24,492,192
Rate (%)	3.03%	2.96%	2.77%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 322 - Reactor Life Table

Age	Cumulative Survivors
0	1.0000
0.5	0.9978
1.5	0.9973
2.5	0.9914
3.5	0.9893
4.5	0.9818
5.5	0.9744
6.5	0.9684
7.5	0.9620
8.5	0.9566
9.5	0.9516
10.5	0.9510
11.5	0.9496
12.5	0.9478
13.5	0.9465
14.5	0.9462
15.5	0.9428
16.5	0.9411
17.5	0.9325
18.5	0.9199
19.5	0.9097
20.5	0.9052
21.5	0.9024
22.5	0.9000
23.5	0.8957

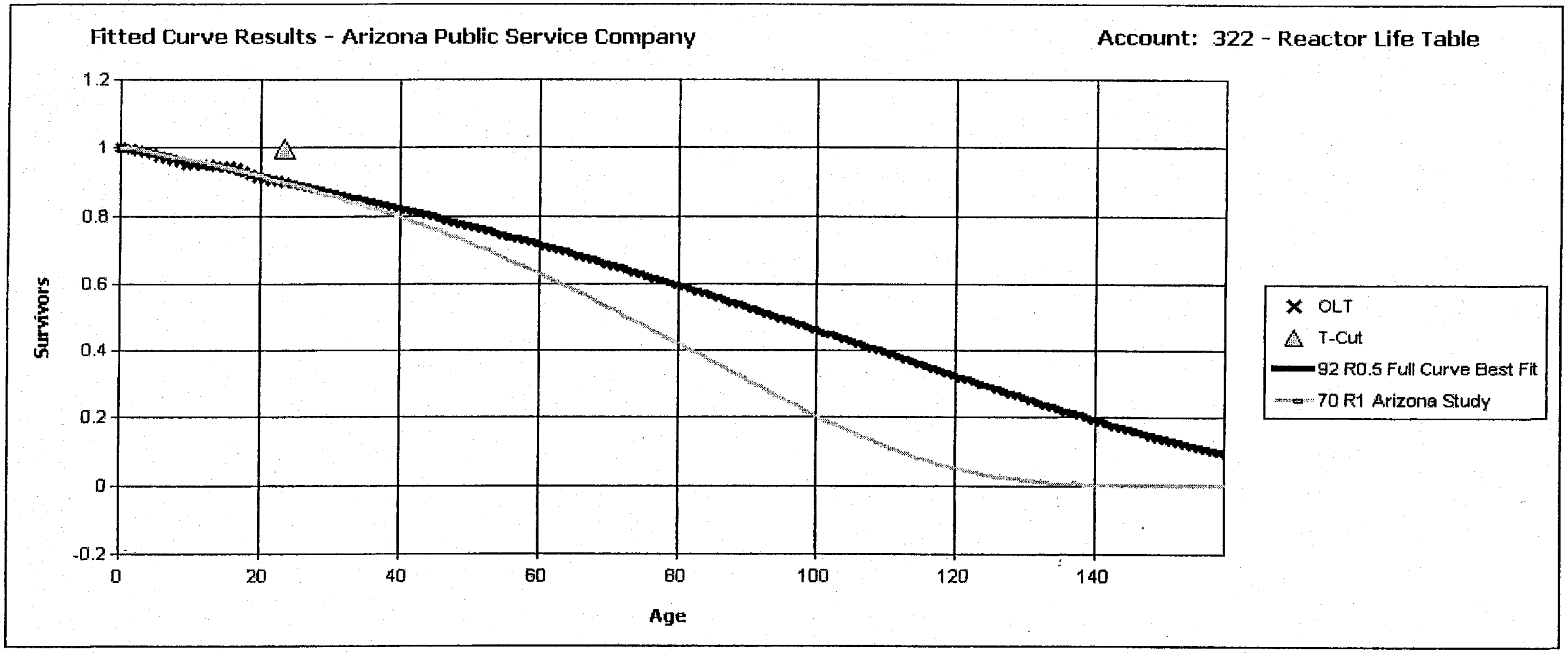
Best Fit Curve Results
Arizona Public Service Company
Account: 322 - Reactor Life Table

Curve	Life	Sum of Squared Differences
BAND	**1986 - 2010**	
R0.5	92.0	7.138
R1	70.0	7.685
S-0.5	82.0	8.879
R1.5	56.0	10.238
L0	88.0	16.187
L0.5	71.0	22.037
R2	45.0	24.384
O1	100.0	28.828
S0	60.0	33.290
R2.5	39.0	46.825
L1	57.0	48.927
S0.5	51.0	49.907
L1.5	49.0	67.738
O2	100.0	85.406
S1	44.0	95.661
R3	34.0	103.737
L2	42.0	120.366
S1.5	39.0	122.240
S2	36.0	184.682
L3	35.0	209.342
R4	30.0	231.503
S3	32.0	285.918
L4	30.0	302.258
S4	29.0	426.374
R5	27.0	427.870
L5	28.0	443.625
S5	27.0	551.983
S6	26.0	671.767
O3	100.0	690.354
SQ	24.0	865.354
O4	100.0	2,182.882

Analytical Parameters

OLT Placement Band:	1986 - 2010
OLT Experience Band:	1986 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	23.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1986 - 2010
OLT Experience Band:	1986 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	23.5

Arizona Public Service Company

Nuclear Production Plant

322.10 - Reactor Plant Equipment - Steam Generators

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Nuclear Production Plant

Account 322.1 - Reactor Plant Equipment - Steam Generators

Depreciable Balance $72,005,745

	APS	Snavely King
Depreciable Reserve	$73,280,592	$63,477,719
Reserve Percent	101.8%	88.2%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	100-O1	Square	Square
Remaining Life (Yrs.)		3.4	
Net Salvage (%)	(68)	(17)	0
Accrual ($)	2,181,774	3,271,105	2,127,170
Rate (%)	3.03%	4.54%	2.95%

****

Comment:

Arizona Public Service Company

Nuclear Production Plant

323.00 - Turbogenerator Units

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Nuclear Production Plant

Account 323 - Turbogenerator Units

Depreciable Balance $338,898,976

	APS	Snavely King
Depreciable Reserve	$136,960,348	$140,265,491
Reserve Percent	40.4%	41.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	65-R2	60-S0	60-S0
Remaining Life (Yrs.)			
Net Salvage (%)	(1)	(2)	0
Accrual ($)	9,421,392	9,972,299	9,498,688
Rate (%)	2.78%	2.94%	2.80%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 323 - Turbogenerator Units

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	0.9989
3.5	0.9976
4.5	0.9963
5.5	0.9948
6.5	0.9865
7.5	0.9854
8.5	0.9842
9.5	0.9799
10.5	0.9781
11.5	0.9779
12.5	0.9672
13.5	0.9656
14.5	0.9636
15.5	0.9582
16.5	0.9550
17.5	0.9269
18.5	0.9126
19.5	0.8745
20.5	0.8732
21.5	0.8724
22.5	0.8712
23.5	0.8698

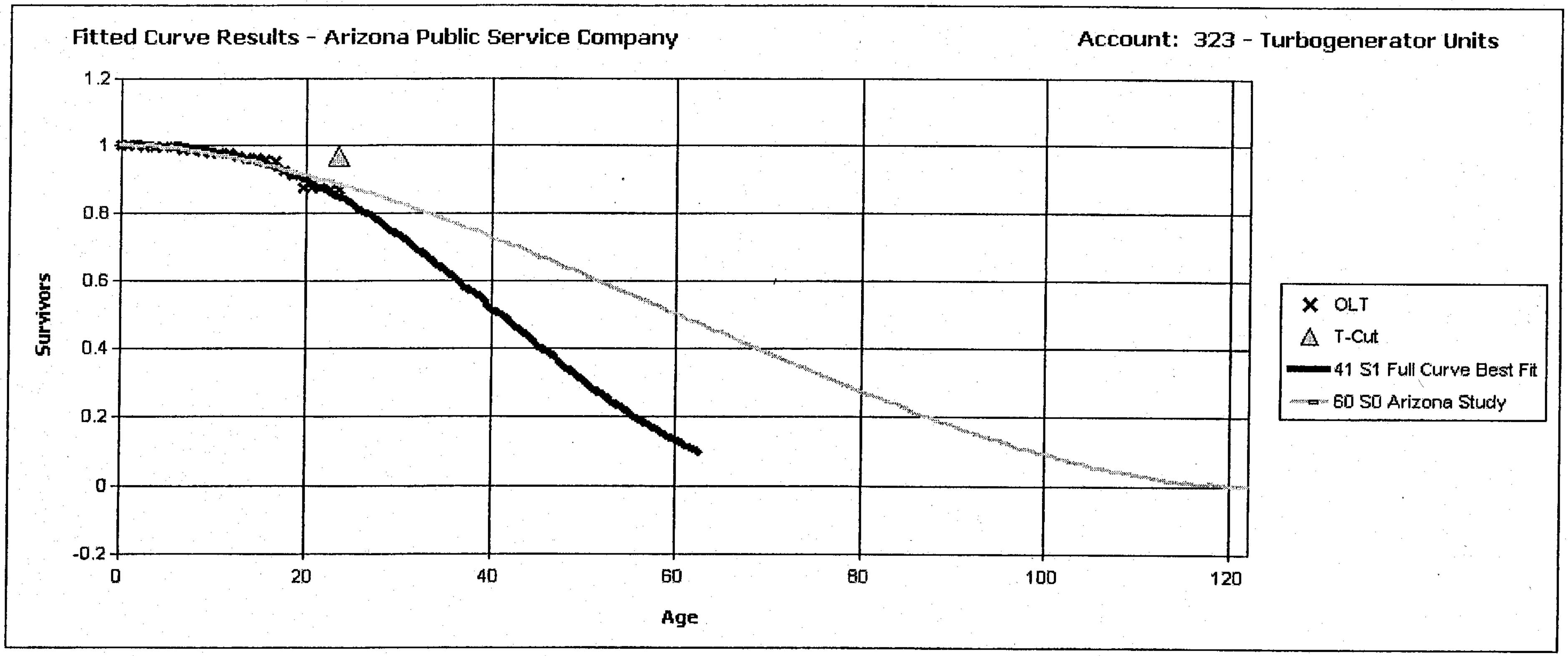
Best Fit Curve Results
Arizona Public Service Company
Account: 323 - Turbogenerator Units

Curve	Life	Sum of Squared Differences
BAND	**1986 - 2010**	
S1	41.0	25.280
L1.5	46.0	26.806
S1.5	37.0	30.505
L1	54.0	31.537
R3	33.0	31.949
R2.5	37.0	32.883
S0.5	48.0	32.958
L2	40.0	33.223
S0	57.0	46.575
R2	42.0	50.073
S2	34.0	55.919
L0.5	67.0	58.063
L0	84.0	73.136
R1.5	53.0	84.740
L3	33.0	86.354
S-0.5	78.0	96.769
R4	29.0	104.017
R1	67.0	104.989
R0.5	88.0	121.110
S3	30.0	139.226
O1	100.0	142.112
L4	29.0	161.273
O2	100.0	190.872
S4	28.0	311.393
R5	26.0	336.960
L5	27.0	338.374
S5	26.0	505.416
S6	25.0	694.875
O3	100.0	769.821
SQ	24.0	1,040.598
O4	100.0	2,237.777

Analytical Parameters

OLT Placement Band:	1986 - 2010
OLT Experience Band:	1986 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	23.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1986 - 2010
OLT Experience Band:	1986 - 2010
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	23.5

Arizona Public Service Company

Nuclear Production Plant

324.00 - Accessory Electric Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Nuclear Production Plant

Account 324 - Accessory Electric Equipment

Depreciable Balance $272,676,374

	APS	Snavely King
Depreciable Reserve	$115,827,561	$119,069,196
Reserve Percent	42.5%	43.7%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	45-R3	45-R3	45-R3
Remaining Life (Yrs.)			
Net Salvage (%)	(1)	(2)	0
Accrual ($)	7,825,812	7,733,874	7,320,649
Rate (%)	2.87%	2.84%	2.68%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 324 - Accessory Electric Equipment

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	0.9990
3.5	0.9976
4.5	0.9956
5.5	0.9951
6.5	0.9931
7.5	0.9927
8.5	0.9925
9.5	0.9914
10.5	0.9912
11.5	0.9912
12.5	0.9884
13.5	0.9884
14.5	0.9884
15.5	0.9884

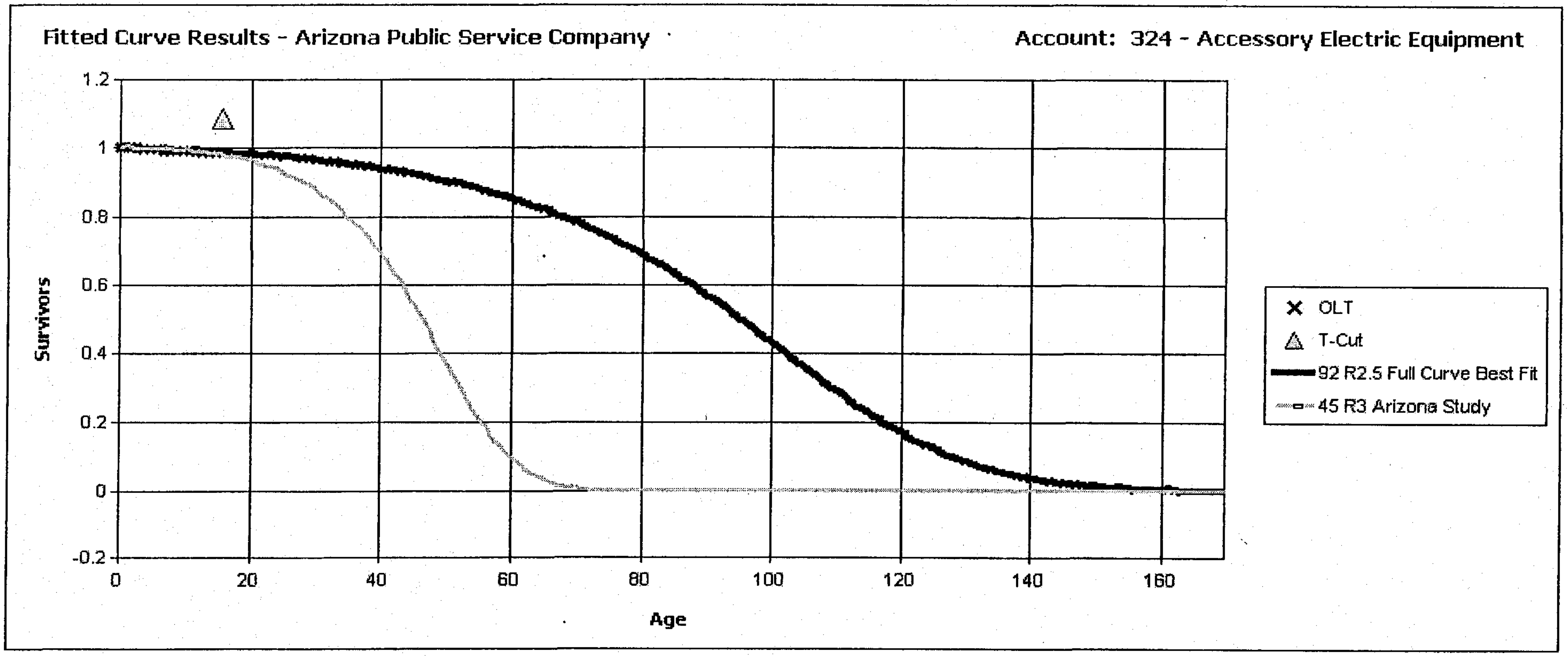
Best Fit Curve Results
Arizona Public Service Company
Account: 324 - Accessory Electric Equipment

Curve	Life	Sum of Squared Differences
BAND	**1986 - 2001**	
R2.5	92.0	10,000.149
L1.5	89.0	10,000.373
S0.5	100.0	10,000.436
R3	54.0	10,000.442
S1	67.0	10,001.108
L2	60.0	10,001.177
S1.5	55.0	10,001.244
L1	100.0	10,001.411
R4	32.0	10,001.985
R2	100.0	10,002.006
S2	42.0	10,002.256
L3	39.0	10,002.308
S3	31.0	10,003.479
L4	29.0	10,004.090
S0	100.0	10,004.800
R5	23.0	10,004.986
S4	24.0	10,005.079
L5	23.0	10,005.640
S5	21.0	10,006.126
S6	19.0	10,007.110
SQ	16.0	10,008.398
R1.5	100.0	10,019.329
L0.5	100.0	10,023.406
R1	100.0	10,054.863
L0	100.0	10,073.589
S-0.5	100.0	10,077.507
R0.5	100.0	10,132.256
O1	100.0	10,243.248
O2	100.0	10,319.500
O3	100.0	10,755.442
O4	100.0	11,529.349

Analytical Parameters

OLT Placement Band:	1986 - 2001
OLT Experience Band:	1986 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	15.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1986 - 2001
OLT Experience Band:	1986 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	15.5

Arizona Public Service Company

Nuclear Production Plant

325.00 - Miscellaneous Power Plant Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Nuclear Production Plant

Account 325 - Miscellaneous Power Plant Equipment

Depreciable Balance $131,893,186

	APS	Snavely King
Depreciable Reserve	$67,376,647	$45,329,152
Reserve Percent	51.1%	34.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	34-R4	35-R0.5	35-R0.5
Remaining Life (Yrs.)			
Net Salvage (%)	(2)	(2)	0
Accrual ($)	7,333,261	3,558,276	4,594,374
Rate (%)	5.56%	2.70%	3.48%

****

Comment:

Arizona Public Service Company

Hydro Production Plant

331 - Structures and Improvements

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Hydro Production Plant

Account 331 - Structures and Improvements

Depreciable Balance $100,878

	APS	Snavely King
Depreciable Reserve	$100,878	$100,878
Reserve Percent	100.0%	100.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	2024	2004	2004
Iowa Curve	120-R2	200-SQ	200-SQ
Remaining Life (Yrs.)		0.0	0.0
Net Salvage (%)	-10	0	0
Accrual ($)	282	0	0
Rate (%)	0.28%	0.00%	0.00%

****

Comment:

Arizona Public Service Company

Hydro Production Plant

332 - Reservoirs, Dams, and Waterways

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Hydro Production Plant

Account 332 - Reservoirs, Dams, and Waterways

Depreciable Balance $991,936

	APS	Snavely King
Depreciable Reserve	$1,105,086	$1,105,086
Reserve Percent	111.4%	111.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	2024	2004	2004
Iowa Curve	200-SQ	200-SQ	200-SQ
Remaining Life (Yrs.)		0.0	0.0
Net Salvage (%)	-10	0	0
Accrual ($)	8,927	0	0
Rate (%)	0.00%	0.00%	0.00%

****

Comment:

Arizona Public Service Company

Hydro Production Plant

333 - Water Wheels, Turbines, and Generators

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Hydro Production Plant

Account 333 - Water Wheels, Turbines, and Generators

Depreciable Balance $157,196

	APS	Snavely King
Depreciable Reserve	$157,196	$157,196
Reserve Percent	100.0%	100.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	2024	2004	2004
Iowa Curve	200-SQ	200-SQ	200-SQ
Remaining Life (Yrs.)		0.0	0.0
Net Salvage (%)	-10	0	0
Accrual ($)	1,148	0	0
Rate (%)	0.73%	0.00%	0.00%

****

Comment:

Arizona Public Service Company

Hydro Production Plant

334 - Accessory Electric Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Hydro Production Plant

Account 334 - Accessory Electric Equipment

Depreciable Balance $627,611

	APS	Snavely King
Depreciable Reserve	$627,611	$627,611
Reserve Percent	100.0%	100.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	2024	2004	2004
Iowa Curve	200-SQ	200-SQ	200-SQ
Remaining Life (Yrs.)		0.0	0.0
Net Salvage (%)	-10	0	0
Accrual ($)	16,757	0	0
Rate (%)	2.67%	0.00%	0.00%

****

Comment:

Arizona Public Service Company

Hydro Production Plant

335 - Miscellaneous Power Plant Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Hydro Production Plant

Account 335 - Miscellaneous Power Plant Equipment

Depreciable Balance $126,018

	APS	Snavely King
Depreciable Reserve	$126,018	$126,018
Reserve Percent	100.0%	100.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	2024	2004	2004
Iowa Curve	200-SQ	200-SQ	200-SQ
Remaining Life (Yrs.)		0.0	0.0
Net Salvage (%)	-10	0	0
Accrual ($)	3,125	0	0
Rate (%)	2.48%	0.00%	0.00%

****

Comment:

Arizona Public Service Company

Hydro Production Plant

336 - Roads, Railroads, and Bridges

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Hydro Production Plant

Account 336 - Roads, Railroads, and Bridges

Depreciable Balance $77,427

	APS	Snavely King
Depreciable Reserve	$77,427	$77,427
Reserve Percent	100.0%	100.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	2024	2004	2004
Iowa Curve	200-SQ	200-SQ	200-SQ
Remaining Life (Yrs.)		0.0	0.0
Net Salvage (%)	-10	0	0
Accrual ($)	217	0	0
Rate (%)	0.28%	0.00%	0.00%

****

Comment:

Arizona Public Service Company

Other Production Plant

341.00 - Structures and Improvements

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Other Production Plant - Structures and Improvements

Account 341 - Structures and Improvements

Depreciable Balance $9,667,772

	APS	Snavely King
Depreciable Reserve	$5,491,522	$8,269,181
Reserve Percent	56.8%	85.5%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)	(5)	(5)	0
Accrual ($)	274,565	248,183	237,025
Rate (%)	2.84%	2.57%	2.45%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 341 - Structures and Improvements

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	0.9953
4.5	0.9953
5.5	0.9902
6.5	0.9902
7.5	0.9901
8.5	0.9881
9.5	0.9881
10.5	0.9881
11.5	0.9881
12.5	0.9863
13.5	0.9863
14.5	0.9863
15.5	0.9863
16.5	0.9863
17.5	0.9863
18.5	0.9863
19.5	0.9852
20.5	0.9852
21.5	0.9852
22.5	0.9852
23.5	0.9852
24.5	0.9852
25.5	0.9825
26.5	0.9825
27.5	0.9825
28.5	0.9825
29.5	0.9825
30.5	0.9825
31.5	0.9825
32.5	0.9825
33.5	0.9825
34.5	0.9825
35.5	0.9825
36.5	0.9825
37.5	0.9825
38.5	0.9825

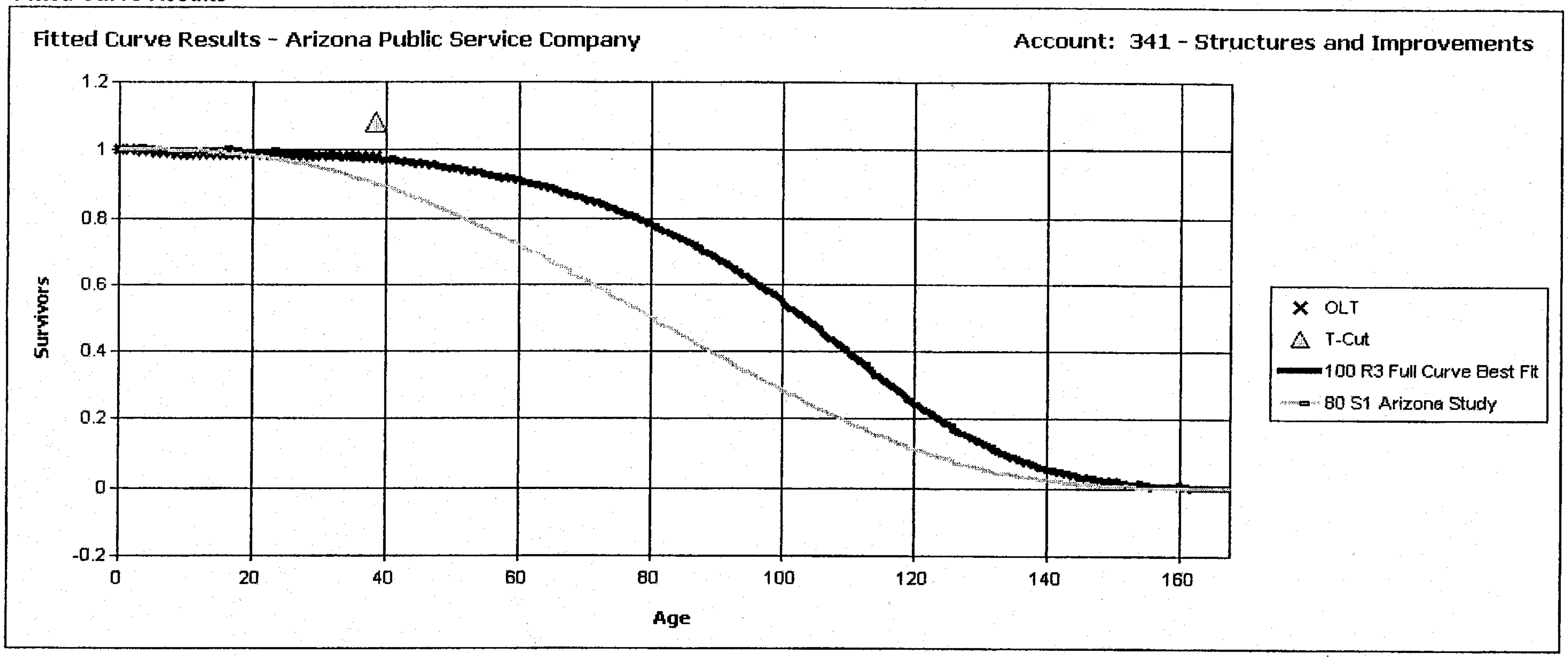
Best Fit Curve Results
Arizona Public Service Company
Account: 341 - Structures and Improvements

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R3	100.0	10,016.838
S1.5	100.0	10,032.421
R4	70.0	10,033.828
L3	84.0	10,034.626
S2	90.0	10,034.802
S3	71.0	10,044.716
L2	100.0	10,046.085
L4	66.0	10,048.380
R5	54.0	10,055.244
S4	57.0	10,055.419
R2.5	100.0	10,057.466
L5	55.0	10,058.723
S5	50.0	10,062.755
S6	45.0	10,067.381
SQ	39.0	10,075.100
S1	100.0	10,085.364
R2	100.0	10,200.588
L1.5	100.0	10,211.486
S0.5	100.0	10,313.125
L1	100.0	10,567.927
R1.5	100.0	10,604.181
S0	100.0	10,747.052
R1	100.0	11,242.424
L0.5	100.0	11,424.898
S-0.5	100.0	11,958.740
R0.5	100.0	12,358.042
L0	100.0	12,718.431
O1	100.0	13,836.493
O2	100.0	14,991.687
O3	100.0	20,933.150
O4	100.0	30,321.055

Analytical Parameters

OLT Placement Band:	1912 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	38.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1912 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	38.5

Arizona Public Service Company

Other Production Plant

342.00 - Fuel Holders, Products and Accessories

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Other Production Plant - Fuel Holders, Products and Accessories

Account 342 - Fuel Holders, Products and Accessories

Depreciable Balance $26,176,338

	APS	Snavely King
Depreciable Reserve	$7,766,512	$8,269,189
Reserve Percent	29.7%	31.6%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	80-S1	70-S1	70-S1
Remaining Life (Yrs.)			
Net Salvage (%)	(5)	(5)	0
Accrual ($)	735,555	799,403	691,567
Rate (%)	2.81%	3.05%	2.64%

****

Observed Life Table Results
Arizona Public Service Company
Account: 342 - Fuel Holders, Products and Accessories

Age	Cumulative Survivors
0	1.0000
0.5	0.9997
1.5	0.9995
2.5	0.9995
3.5	0.9995
4.5	0.9995
5.5	0.9995
6.5	0.9995
7.5	0.9979
8.5	0.9979
9.5	0.9979
10.5	0.9979
11.5	0.9979
12.5	0.9979
13.5	0.9979
14.5	0.9970
15.5	0.9970
16.5	0.9970
17.5	0.9907
18.5	0.9907
19.5	0.9578
20.5	0.9512
21.5	0.9396
22.5	0.9361
23.5	0.9361
24.5	0.9361
25.5	0.9361
26.5	0.9361
27.5	0.9361
28.5	0.9361
29.5	0.9361
30.5	0.9361

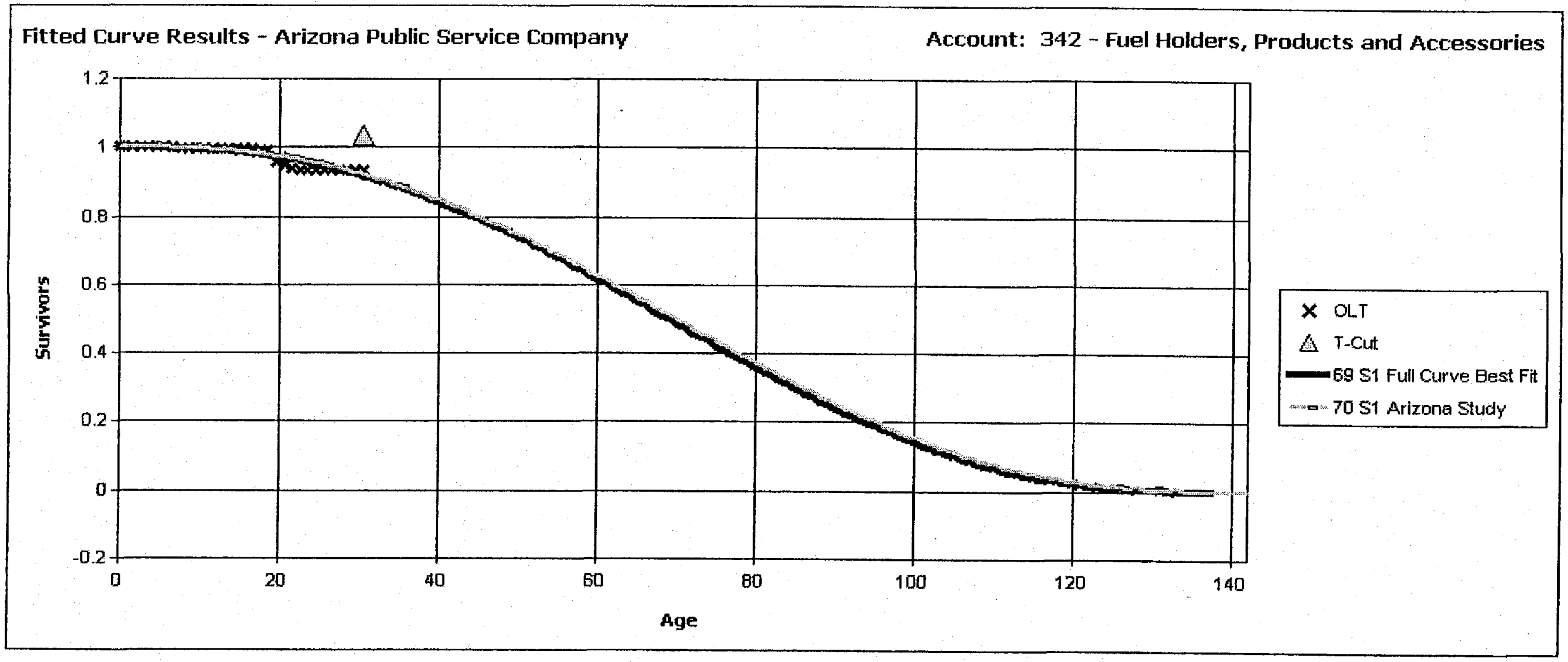
Best Fit Curve Results
Arizona Public Service Company
Account: 342 - Fuel Holders, Products and Accessories

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
S1	69.0	10,035.753
S1.5	60.0	10,038.370
L2	64.0	10,039.461
L1.5	79.0	10,040.516
R3	53.0	10,041.001
S0.5	86.0	10,043.103
L1	96.0	10,046.090
R2.5	65.0	10,051.339
S2	53.0	10,051.588
S0	100.0	10,054.310
L3	50.0	10,058.006
R2	81.0	10,062.472
R4	43.0	10,070.129
R1.5	100.0	10,088.646
S3	45.0	10,095.324
L4	42.0	10,100.183
L0.5	100.0	10,154.398
R5	37.0	10,174.840
S4	39.0	10,176.448
L5	38.0	10,190.040
R1	100.0	10,215.923
S5	36.0	10,253.441
S6	34.0	10,310.367
S-0.5	100.0	10,369.943
SQ	31.0	10,407.086
L0	100.0	10,500.623
R0.5	100.0	10,563.091
O1	100.0	11,112.813
O2	100.0	11,545.556
O3	100.0	14,064.844
O4	100.0	18,534.087

Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Arizona Public Service Company

Other Production Plant

343.0 - Prime Movers

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Other Production Plant - Prime Movers

Account 343 - Prime Movers

Depreciable Balance $32,606,644

	APS	Snavely King
Depreciable Reserve	$28,896,416	$26,858,659
Reserve Percent	88.6%	82.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve	70-L1.5	70-L1.5	70-L1.5
Remaining Life (Yrs.)			
Net Salvage (%)	0	0	0
Accrual ($)	492,360	326,534	357,509
Rate (%)	1.51%	1.00%	1.10%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 343 - Prime Movers

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	0.9977
4.5	0.9869
5.5	0.9756
6.5	0.9729
7.5	0.9729
8.5	0.9729
9.5	0.9729
10.5	0.9729
11.5	0.9729
12.5	0.9729
13.5	0.9729
14.5	0.9729
15.5	0.9729
16.5	0.9729
17.5	0.9729
18.5	0.9729
19.5	0.9431
20.5	0.9431
21.5	0.9431
22.5	0.9431
23.5	0.9431
24.5	0.9431
25.5	0.9431
26.5	0.9414
27.5	0.9397
28.5	0.9324
29.5	0.9172
30.5	0.9172
32.5	0.9100
33.5	0.9100
34.5	0.9100
35.5	0.9100
36.5	0.9100
37.5	0.9100
38.5	0.9100
BAND	
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	0.9973

4.5	0.9846
5.5	0.9713
6.5	0.9681
7.5	0.9681
8.5	0.9681
9.5	0.9681
10.5	0.9681
11.5	0.9681
12.5	0.9681
13.5	0.9681
14.5	0.9681
15.5	0.9681
16.5	0.9681
17.5	0.9681
18.5	0.9681
19.5	0.9293
20.5	0.9293
21.5	0.9293
22.5	0.9293
23.5	0.9293
24.5	0.9293
25.5	0.9293
26.5	0.9273
27.5	0.9254
28.5	0.9177
29.5	0.9100
30.5	0.9100
31.5	0.9100
32.5	0.9100
33.5	0.9100
34.5	0.9100
35.5	0.9100
36.5	0.9100
37.5	0.9100
38.5	0.9100

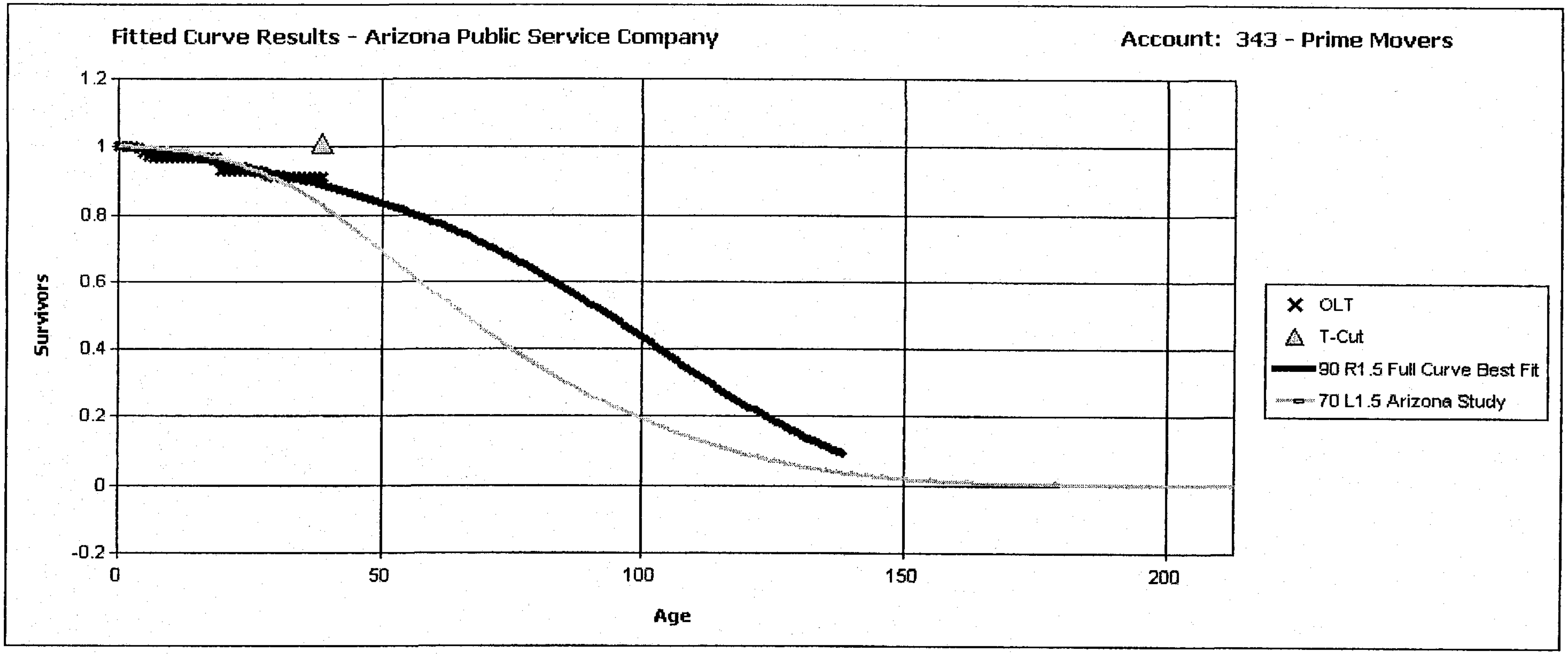
Best Fit Curve Results
Arizona Public Service Company
Account: 343 - Prime Movers

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R1.5	98.0	10,017.403
R2	73.0	10,021.041
S0	98.0	10,029.220
R2.5	61.0	10,029.477
L1	90.0	10,033.628
S0.5	80.0	10,036.647
L1.5	75.0	10,043.570
R3	51.0	10,058.752
S1	66.0	10,063.005
L0.5	100.0	10,063.497
L2	62.0	10,071.156
R1	100.0	10,072.616
S1.5	58.0	10,075.968
S2	52.0	10,114.287
L3	49.0	10,120.729
R4	42.0	10,135.002
S3	44.0	10,174.224
L4	42.0	10,183.386
S-0.5	100.0	10,189.338
R5	37.0	10,255.287
S4	39.0	10,255.790
L5	37.0	10,270.926
L0	100.0	10,317.156
R0.5	100.0	10,323.055
S5	36.0	10,326.914
S6	34.0	10,384.148
SQ	31.0	10,514.785
O1	100.0	10,776.048
O2	100.0	11,153.892
O3	100.0	13,443.861
O4	100.0	17,638.070

Analytical Parameters

OLT Placement Band:	1971 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1971 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Arizona Public Service Company

Other Production Plant

344.00 - Generators and Devices

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Other Production Plant - Generators and Devices

Account 344 - Generators and Devices

Depreciable Balance $109,504,078

	APS	Snavely King
Depreciable Reserve	$25,135,154	$29,393,951
Reserve Percent	23.0%	26.8%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)	0	0	0
Accrual ($)	2,485,743	4,013,297	3,642,631
Rate (%)	2.27%	3.66%	3.33%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 344 - Generators and Devices

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	0.9984
2.5	0.9984
3.5	0.9984
4.5	0.9983
5.5	0.9929
6.5	0.9899
7.5	0.9885
8.5	0.9853
9.5	0.9834
10.5	0.9829
11.5	0.9819
12.5	0.9712
13.5	0.9712
14.5	0.9688
15.5	0.9642
16.5	0.9642
17.5	0.9605
18.5	0.9605
19.5	0.9540
20.5	0.9465
21.5	0.8933
22.5	0.8595
23.5	0.8595
24.5	0.8595
25.5	0.8366
26.5	0.8366
27.5	0.8366
28.5	0.8366
29.5	0.8366
30.5	0.7140

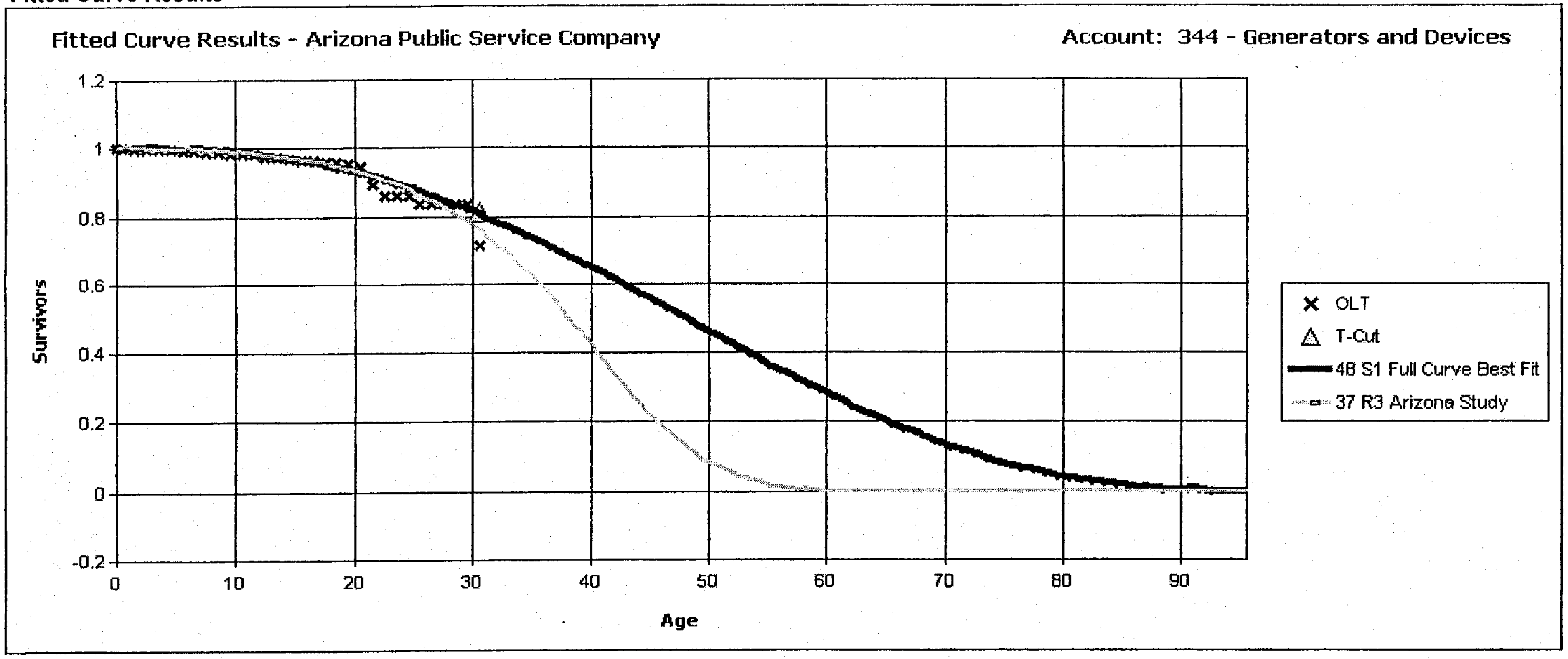
Best Fit Curve Results
Arizona Public Service Company
Account: 344 - Generators and Devices

Curve	Life	Sum of Squared Differences
BAND	1973 - 2001	
S1	48.0	10,073.486
S1.5	44.0	10,079.329
L1.5	54.0	10,080.331
L2	48.0	10,087.699
R3	39.0	10,090.291
L1	62.0	10,093.566
R2.5	43.0	10,093.603
S0.5	55.0	10,098.757
S2	41.0	10,120.473
R2	48.0	10,128.547
S0	63.0	10,133.672
L0.5	74.0	10,155.603
L0	91.0	10,196.206
L3	40.0	10,198.975
R1.5	57.0	10,205.056
R4	35.0	10,227.936
S-0.5	83.0	10,242.292
R1	71.0	10,257.316
S3	37.0	10,277.602
R0.5	92.0	10,298.117
L4	36.0	10,352.580
O1	100.0	10,360.375
O2	100.0	10,479.167
S4	34.0	10,629.770
R5	33.0	10,693.605
L5	34.0	10,720.500
S5	33.0	11,044.672
S6	32.0	11,442.235
O3	100.0	11,746.994
SQ	31.0	12,188.047
O4	100.0	14,780.278

Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1948 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Arizona Public Service Company

Other Production Plant

345.00 - Accessory Electric Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Other Production Plant - Accessory Electric Equipment

Account 345 - Accessory Electric Equipment

Depreciable Balance $19,383,129

	APS	Snavely King
Depreciable Reserve	$9,257,373	$8,721,408
Reserve Percent	47.8%	45.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)	0	0	0
Accrual ($)	441,935	446,148	438,525
Rate (%)	2.28%	2.30%	2.26%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 345 - Accessory Electric Equipment

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	1.0000
5.5	0.9935
6.5	0.9935
7.5	0.9935
8.5	0.9924
9.5	0.9924
10.5	0.9924
11.5	0.9924
12.5	0.9836
13.5	0.9836
14.5	0.9824
15.5	0.9824
16.5	0.9824
17.5	0.9824
18.5	0.9713
19.5	0.9694
20.5	0.9694
21.5	0.9675
22.5	0.9570
23.5	0.9570
24.5	0.9570
25.5	0.9505
26.5	0.9505
27.5	0.9505
28.5	0.9505
29.5	0.9505
30.5	0.9505

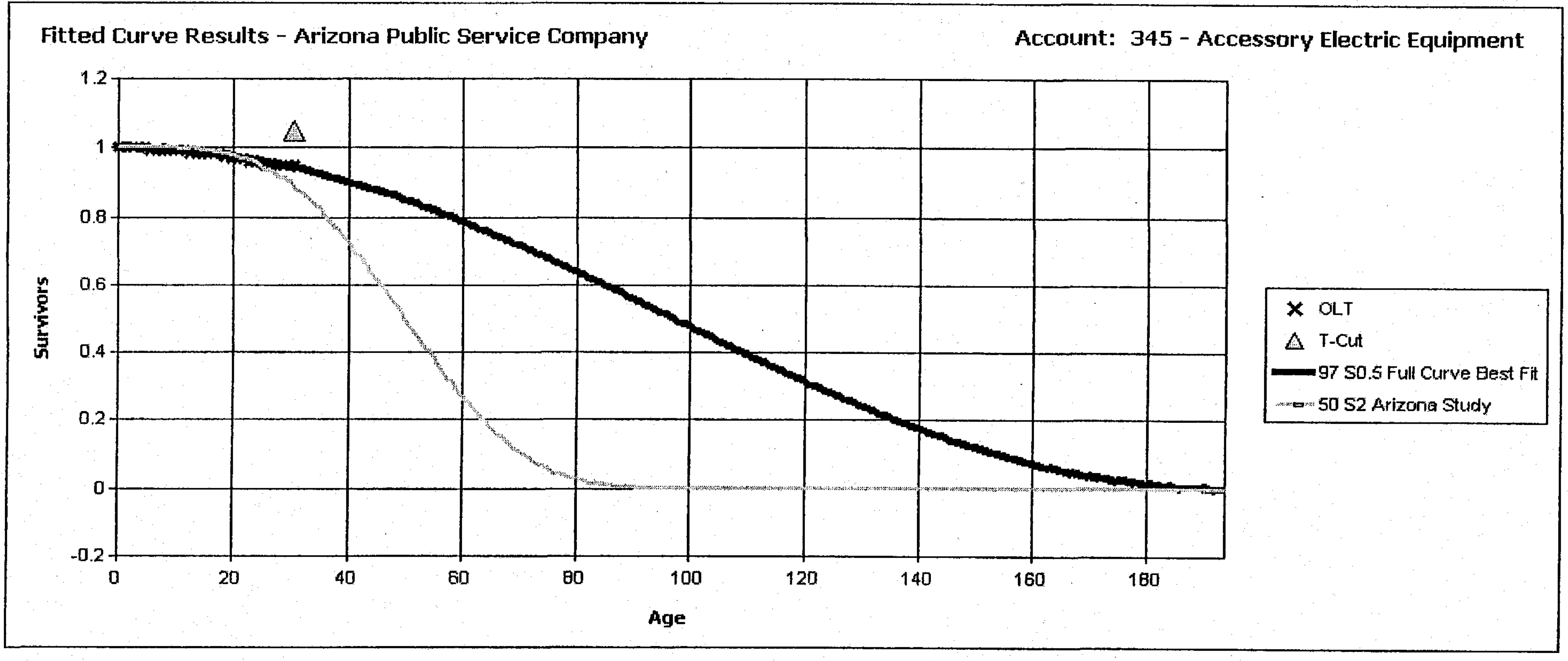
Best Fit Curve Results
Arizona Public Service Company
Account: 345 - Accessory Electric Equipment

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
S0.5	97.0	10,003.481
R2.5	73.0	10,003.986
L1.5	88.0	10,004.752
R2	94.0	10,005.547
R3	58.0	10,008.380
S1	76.0	10,009.715
L1	100.0	10,009.735
L2	70.0	10,011.528
S1.5	66.0	10,014.061
S2	57.0	10,030.735
L3	53.0	10,031.811
S0	100.0	10,038.339
R4	45.0	10,039.511
R1.5	100.0	10,053.225
S3	47.0	10,060.900
L4	44.0	10,067.063
R5	38.0	10,105.473
S4	40.0	10,108.335
L5	39.0	10,115.079
S5	37.0	10,149.853
L0.5	100.0	10,180.534
S6	34.0	10,183.249
R1	100.0	10,224.297
SQ	31.0	10,236.857
S-0.5	100.0	10,418.599
L0	100.0	10,591.328
R0.5	100.0	10,623.919
O1	100.0	11,226.094
O2	100.0	11,694.048
O3	100.0	14,349.111
O4	100.0	18,968.905

Analytical Parameters

OLT Placement Band:	1953 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1953 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Arizona Public Service Company

Other Production Plant

346.00 - Miscellaneous Power Plant Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Other Production Plant - Miscellaneous Power Plant Equipment

Account 346 - Miscellaneous Power Plant Equipment

Depreciable Balance $5,378,475

	APS	Snavely King
Depreciable Reserve	$3,484,034	$2,621,236
Reserve Percent	64.8%	48.7%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Probable Retirement Year			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)	0	0	0
Accrual ($)	187,171	104,648	138,878
Rate (%)	3.48%	1.95%	2.58%

****

Comment:

Observed Life Table Results
Arizona Public Service Company
Account: 346 - Miscellaneous Power Plant Equipment

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	1.0000
5.5	0.9957
6.5	0.9957
7.5	0.9905
8.5	0.9905
9.5	0.9905
10.5	0.9493
11.5	0.9493
12.5	0.9493
13.5	0.9493
14.5	0.9493
15.5	0.9449
16.5	0.9420
17.5	0.9376
18.5	0.9376
19.5	0.9376
20.5	0.9323
21.5	0.9323
22.5	0.9323
23.5	0.9323
24.5	0.9323
25.5	0.9203
26.5	0.9203
27.5	0.9203
28.5	0.9203
29.5	0.9203
30.5	0.9203

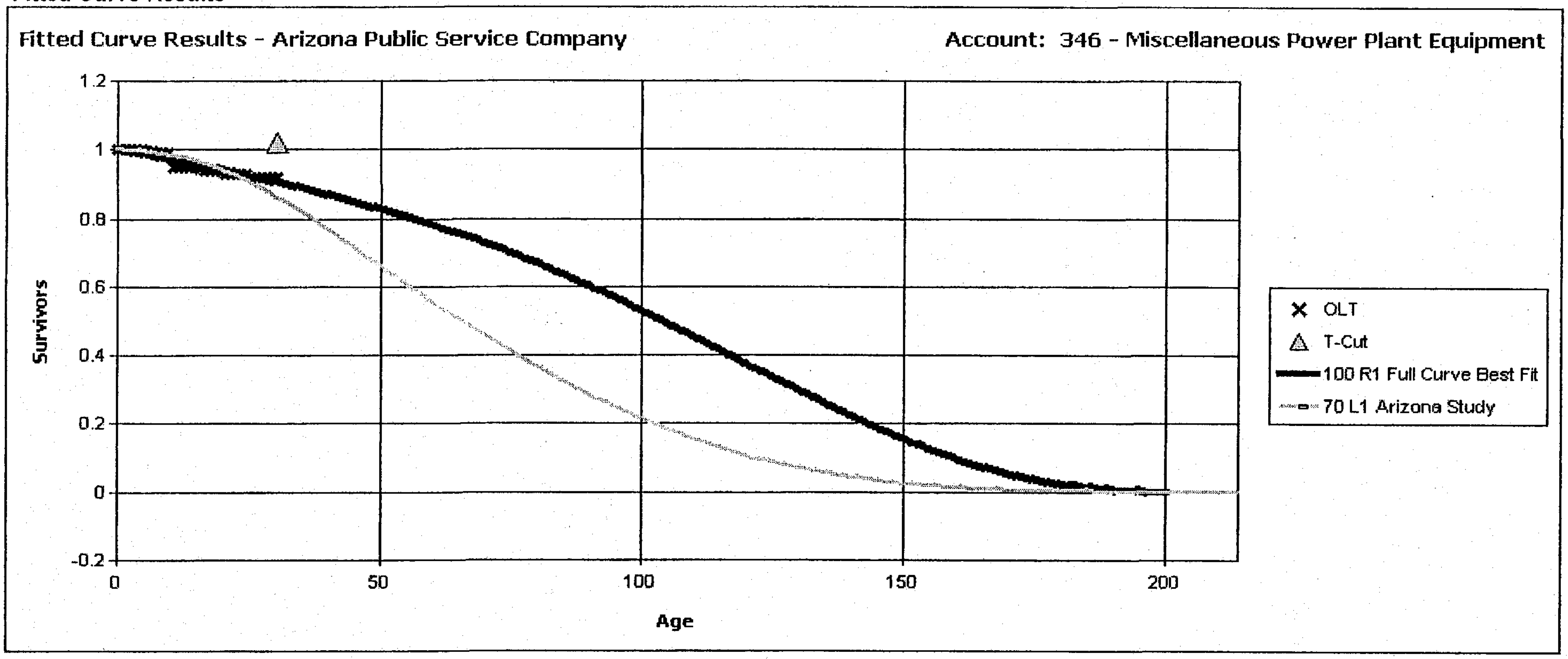
Best Fit Curve Results
Arizona Public Service Company
Account: 346 - Miscellaneous Power Plant Equipment

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R1	100.0	10,034.968
R1.5	81.0	10,037.228
L0.5	100.0	10,047.232
R2	63.0	10,053.360
S0	84.0	10,057.911
S0.5	71.0	10,078.518
R2.5	54.0	10,078.920
S-0.5	100.0	10,079.177
L1	80.0	10,080.501
L1.5	68.0	10,101.277
S1	60.0	10,133.922
R3	47.0	10,143.724
R0.5	100.0	10,154.781
L0	100.0	10,155.045
L2	58.0	10,161.148
S1.5	54.0	10,166.359
S2	49.0	10,245.298
L3	47.0	10,265.664
R4	40.0	10,296.979
S3	43.0	10,363.502
L4	40.0	10,381.812
O1	100.0	10,477.146
S4	38.0	10,503.302
R5	36.0	10,504.623
L5	37.0	10,522.869
S5	35.0	10,618.716
S6	34.0	10,715.320
O2	100.0	10,775.292
SQ	31.0	10,859.184
O3	100.0	12,743.247
O4	100.0	16,562.434

Analytical Parameters

OLT Placement Band:	1943 - 2000
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	30.5

Fitted Curve Results



Analytical Parameters	
OLT Placement Band:	1943 - 2000
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	30.5

Arizona Public Service Company

Section T

Transmission Plant

Arizona Public Service Company

Transmission Plant

352 - Structures and Improvements

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 352.0 - Structures and Improvements

Depreciable Balance $27,618,299

	APS	Snavely King
Depreciable Reserve	$8,135,201	$12,484,016
Reserve Percent	29.5%	45.2%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	50.0	50.0	50.0
Iowa Curve	R4	R4	R4
Remaining Life (Yrs.)		35.2	35.2
Net Salvage (%)	-5	-5	0
Accrual ($)	571,699	592,619	429,951
Rate (%)	2.07%	2.15%	1.56%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept this judgment because there is no change to the current parameter and there is insufficient data to conduct a meaningful statistical analysis.

Observed Life Table Results
Arizona Public Service Company
Account: 352 - Structures and Improvements

Age	Cumulative Survivors
BAND	1973 - 2001
0	1.0000
0.5	1.0000
1.5	0.9997
2.5	0.9997
3.5	0.9997
4.5	0.9997
5.5	0.9997
6.5	0.9992
7.5	0.9992
8.5	0.9992
9.5	0.9986
10.5	0.9986
11.5	0.9971
12.5	0.9971
13.5	0.9951
14.5	0.9948
15.5	0.9947
16.5	0.9942
17.5	0.9929
18.5	0.9827
19.5	0.9815
20.5	0.9764
21.5	0.9744
22.5	0.9744
23.5	0.9743
24.5	0.9737
25.5	0.9736
26.5	0.9718
27.5	0.9718
28.5	0.9615
29.5	0.9615
30.5	0.9615
31.5	0.9614
32.5	0.9613
33.5	0.9613
34.5	0.9613
35.5	0.9628
36.5	0.9628
37.5	0.9628
38.5	0.9297
39.5	0.9297
40.5	0.9293
41.5	0.9293
42.5	0.9293
43.5	0.8830
44.5	0.8830

Observed Life Table Results
Arizona Public Service Company
Account: 352 - Structures and Improvements

Age	Cumulative Survivors
45.5	0.8830
46.5	0.8830
47.5	0.8830
48.5	0.8830
49.5	0.8830
50.5	0.8830
51.5	0.8830
52.5	0.8830
53.5	0.8830
54.5	0.8830
55.5	0.8830
56.5	0.8830
57.5	0.8830
58.5	0.8830
59.5	0.8830
60.5	0.8830
61.5	0.8830
62.5	0.8830
63.5	0.8830
64.5	0.8830
65.5	0.8830
66.5	0.8830
67.5	0.8830
68.5	0.8830
69.5	0.8830
70.5	0.8830
71.5	0.8830
72.5	0.8830

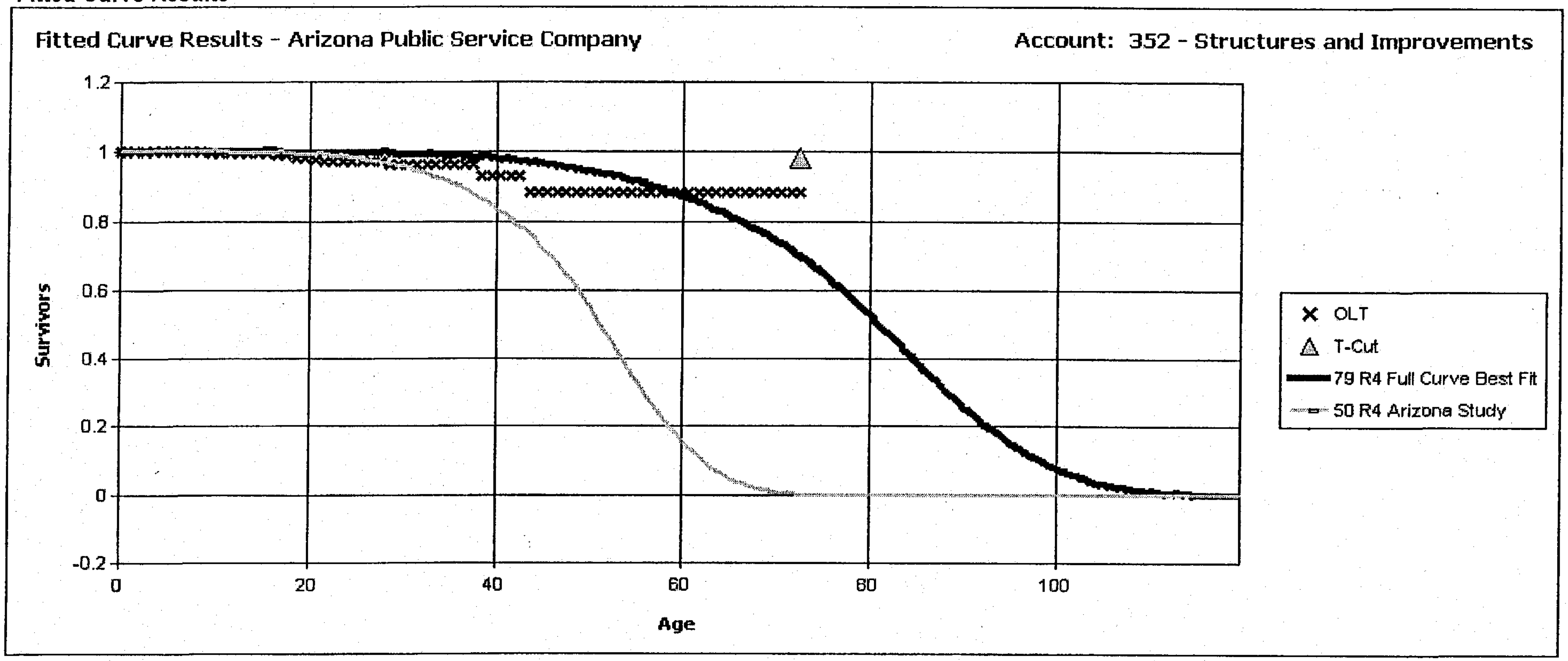
Best Fit Curve Results
Arizona Public Service Company
Account: 352 - Structures and Improvements

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R4	79.0	12,164.508
R5	79.0	12,578.253
L5	79.0	12,946.181
S5	79.0	13,158.403
S4	79.0	13,185.073
R3	79.0	13,215.696
S6	77.0	13,609.194
L4	79.0	13,660.056
S3	79.0	14,160.194
SQ	73.0	14,427.771
R2.5	79.0	14,566.251
S2	79.0	16,160.740
R2	79.0	16,667.800
S1.5	79.0	17,722.573
L3	79.0	18,115.626
R1.5	79.0	19,618.248
S1	79.0	19,943.315
S0.5	79.0	22,580.824
R1	79.0	23,497.371
L2	79.0	23,875.401
S0	79.0	25,968.860
L1.5	79.0	26,887.460
R0.5	79.0	29,523.132
S-0.5	79.0	30,813.957
L1	79.0	30,948.370
L0.5	79.0	35,536.664
O1	79.0	36,915.592
L0	79.0	41,068.474
O2	79.0	46,949.951
O3	79.0	80,609.628
O4	79.0	118,780.464

Analytical Parameters

OLT Placement Band:	1929 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	79
Life Increment Parameter:	1
Max Age (T-Cut):	72.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1929 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	79
Life Increment Parameter:	1
Max Age (T-Cut):	72.5

Arizona Public Service Company

Transmission Plant

352.5 - Structures and Improvements - SCE 500 KV Line

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 352.5- Structures and Improvements - SCE 500 KV Line

Depreciable Balance $409,725

	APS	Snavely King
Depreciable Reserve	$296,895	$424,897
Reserve Percent	72.5%	103.7%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)			
Accrual ($)	13,316	13,316	13,316
Rate (%)	3.25%	3.25%	3.25%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept the proposal to retain the existing depreciation rates.

Arizona Public Service Company

Transmission Plant

353.00 - Station Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 353 - Station Equipment

Depreciable Balance $428,736,305

	APS	Snavely King
Depreciable Reserve	$173,966,733	$130,140,054
Reserve Percent	40.6%	30.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	35.0	42.0	57.0
Iowa Curve	S1	R3	R1.5
Remaining Life (Yrs.)		31.2	45.7
Net Salvage (%)	7	0	0
Accrual ($)	8,960,589	8,167,649	6,538,127
Rate (%)	2.09%	1.91%	1.52%

****

Comment: Mr. Wiedmayer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) However, Mr. Wiedmayer's statistical study was deficient and incomplete because he excluded a substantial portion of the OLT. The complete statistical analysis results is a 57 R1.5 life and curve.

Observed Life Table Results
Arizona Public Service Company
Account: 353 - Station Equipment

Age	Cumulative Survivors
BAND	1973 - 2001
0	1.0000
0.5	1.0000
1.5	0.9996
2.5	0.9981
3.5	0.9935
4.5	0.9929
5.5	0.9919
6.5	0.9908
7.5	0.9887
8.5	0.9867
9.5	0.9830
10.5	0.9789
11.5	0.9766
12.5	0.9743
13.5	0.9718
14.5	0.9675
15.5	0.9631
16.5	0.9604
17.5	0.9590
18.5	0.9465
19.5	0.9437
20.5	0.9381
21.5	0.9339
22.5	0.9293
23.5	0.9183
24.5	0.9098
25.5	0.9011
26.5	0.8923
27.5	0.8819
28.5	0.8707
29.5	0.8546
30.5	0.8133
31.5	0.7926
32.5	0.7871
33.5	0.7766
34.5	0.7757
35.5	0.7726
36.5	0.7683
37.5	0.7598
38.5	0.7561
39.5	0.7524
40.5	0.7486
41.5	0.7389
42.5	0.7362
43.5	0.7332
44.5	0.7332

Observed Life Table Results
Arizona Public Service Company
Account: 353 - Station Equipment

Age	Cumulative Survivors
45.5	0.7326
46.5	0.7288
47.5	0.7287
48.5	0.7232
49.5	0.7216
50.5	0.7060
51.5	0.7048
52.5	0.7048
53.5	0.7047
54.5	0.7046
55.5	0.5175
56.5	0.4430
57.5	0.4154
58.5	0.4154
59.5	0.4154
60.5	0.4154
61.5	0.4154
62.5	0.4154
63.5	0.4154
64.5	0.4154
65.5	0.3907
66.5	0.3907
67.5	0.3907
68.5	0.3907
69.5	0.3907
70.5	0.3907
71.5	0.3907
72.5	0.3907

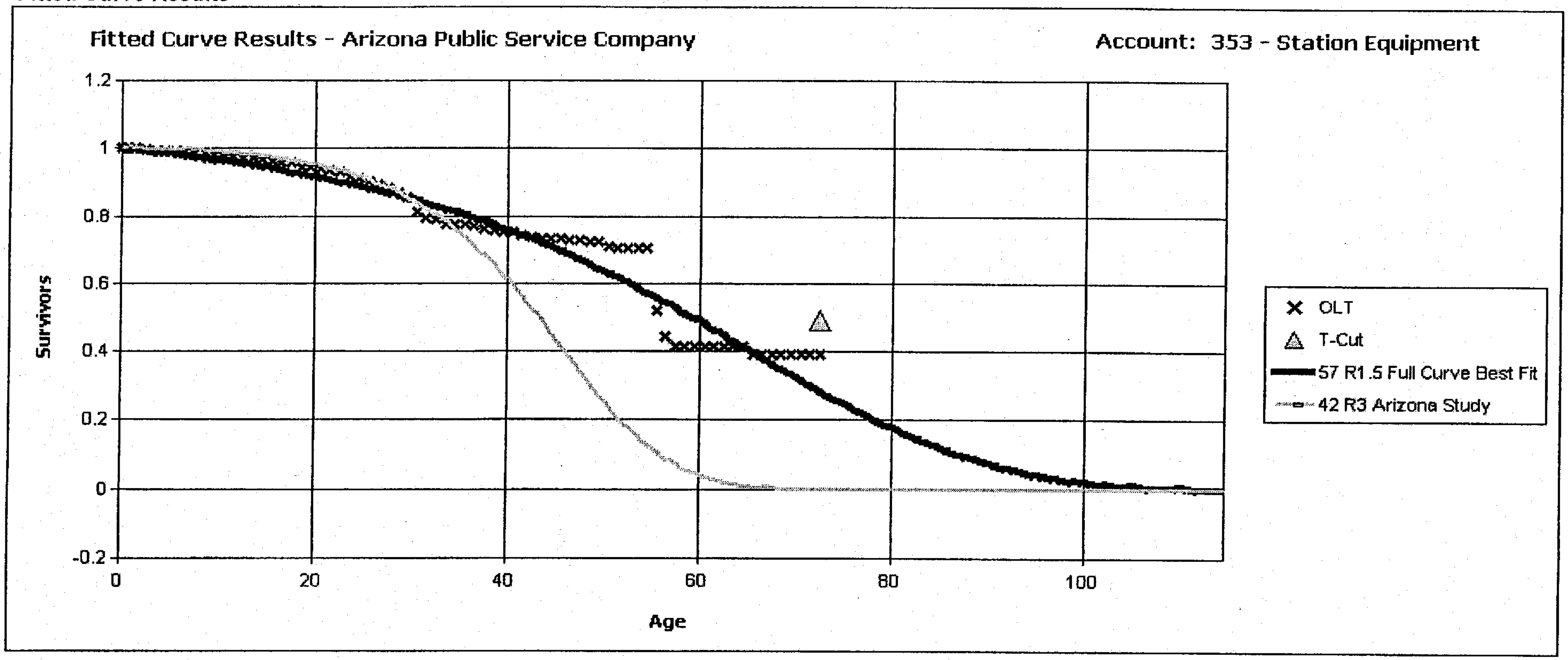
Best Fit Curve Results
Arizona Public Service Company
Account: 353 - Station Equipment

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R1.5	57.0	11,861.187
R2	57.0	11,951.137
S1	57.0	12,480.539
S0.5	57.0	12,538.842
R1	57.0	12,576.435
R2.5	57.0	12,958.691
S1.5	57.0	12,990.393
S0	57.0	13,220.725
S2	57.0	14,103.033
R0.5	57.0	14,528.483
L1.5	57.0	14,711.569
R3	57.0	14,806.067
L2	57.0	14,818.095
S-0.5	57.0	14,891.179
L1	57.0	15,452.300
L3	57.0	16,480.181
L0.5	57.0	17,174.965
O1	57.0	17,543.437
S3	57.0	17,667.058
L0	57.0	19,591.199
L4	57.0	20,352.594
R4	57.0	20,409.292
O2	57.0	22,771.487
S4	57.0	24,432.585
L5	57.0	27,005.888
R5	57.0	30,117.175
S5	57.0	32,607.259
S6	57.0	40,287.065
O3	57.0	42,478.185
SQ	57.0	55,590.951
O4	57.0	67,201.270

Analytical Parameters

OLT Placement Band:	1919 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	57
Life Increment Parameter:	1
Max Age (T-Cut):	72.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1919 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	57
Life Increment Parameter:	1
Maximum Age (T-Cut):	72.5

Arizona Public Service Company

353 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 57 R1.5

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	45,622,655	57.00	56.59	800,397	45,291,769
2001	1.5	25,075,008	57.00	55.77	439,912	24,531,921
2000	2.5	12,254,988	57.00	54.95	215,000	11,813,867
1999	3.5	15,636,588	57.00	54.13	274,326	14,850,638
1998	4.5	17,354,374	57.00	53.33	304,463	16,235,707
1997	5.5	-	57.00	52.52	-	-
1996	6.5	46,591,401	57.00	51.72	817,393	42,275,445
1995	7.5	4,052,181	57.00	50.92	71,091	3,620,147
1994	8.5	2,768,114	57.00	50.13	48,563	2,434,479
1993	9.5	992,039	57.00	49.34	17,404	858,747
1992	10.5	2,814,458	57.00	48.56	49,376	2,397,562
1991	11.5	7,395,784	57.00	47.78	129,751	6,198,998
1990	12.5	11,517,106	57.00	47.00	202,054	9,496,534
1989	13.5	11,845,846	57.00	46.23	207,822	9,607,165
1988	14.5	19,545,737	57.00	45.46	342,908	15,588,582
1987	15.5	9,235,173	57.00	44.70	162,021	7,241,695
1986	16.5	38,589,436	57.00	43.94	677,008	29,745,324
1985	17.5	3,012,910	57.00	43.18	52,858	2,282,482
1984	18.5	11,051,702	57.00	42.43	193,890	8,226,809
1983	19.5	4,034,244	57.00	41.68	70,776	2,950,216
1982	20.5	7,393,573	57.00	40.94	129,712	5,310,598
1981	21.5	14,426,831	57.00	40.20	253,102	10,175,811
1980	22.5	19,059,867	57.00	39.47	334,384	13,198,736
1979	23.5	7,842,832	57.00	38.74	137,594	5,330,941
1978	24.5	27,968,778	57.00	38.02	490,680	18,656,363
1977	25.5	2,966,492	57.00	37.30	52,044	1,941,462
1976	26.5	4,388,156	57.00	36.59	76,985	2,817,101
1975	27.5	13,534,989	57.00	35.89	237,456	8,521,468
1974	28.5	3,810,669	57.00	35.19	66,854	2,352,310
1973	29.5	4,212,069	57.00	34.49	73,896	2,548,802
1972	30.5	2,651,631	57.00	33.80	46,520	1,572,538
1971	31.5	5,919,728	57.00	33.12	103,855	3,439,836
1970	32.5	2,289,745	57.00	32.45	40,171	1,303,380
1969	33.5	1,821,456	57.00	31.78	31,955	1,015,453
1968	34.5	481,896	57.00	31.12	8,454	263,058

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2002	0.5	45,622,655	57.00	56.59	800,397	45,291,769
2001	1.5	25,075,008	57.00	55.77	439,912	24,531,921
2000	2.5	12,254,988	57.00	54.95	215,000	11,813,867
1967	35.5	388,653	57.00	30.46	6,818	207,692
1966	36.5	506,829	57.00	29.81	8,892	265,080
1965	37.5	553,908	57.00	29.17	9,718	283,479
1964	38.5	266,708	57.00	28.54	4,679	133,534
1963	39.5	6,062,058	57.00	27.91	106,352	2,968,565
1962	40.5	3,149,040	57.00	27.29	55,246	1,507,919
1961	41.5	192,338	57.00	26.68	3,374	90,043
1960	42.5	1,940,121	57.00	26.08	34,037	887,786
1959	43.5	1,165,484	57.00	25.49	20,447	521,173
1958	44.5	1,052,541	57.00	24.90	18,466	459,850
1957	45.5	615,610	57.00	24.33	10,800	262,725
1956	46.5	241,417	57.00	23.76	4,235	100,622
1955	47.5	1,488,882	57.00	23.20	26,121	605,934
1954	48.5	1,535,823	57.00	22.65	26,944	610,177
1953	49.5	308,467	57.00	22.10	5,412	119,618
1952	50.5	371,456	57.00	21.57	6,517	140,568
1951	51.5	-	57.00	21.05	-	-
1950	52.5	224,911	57.00	20.53	3,946	81,008
1949	53.5	259,509	57.00	20.02	4,553	91,164
1948	54.5	62,397	57.00	19.53	1,095	21,376
1947	55.5	-	57.00	19.04	-	-
1946	56.5	8,672	57.00	18.56	152	2,824
1945	57.5	88,531	57.00	18.09	1,553	28,098
1944	58.5	-	57.00	17.63	-	-
1943	59.5	-	57.00	17.18	-	-
1942	60.5	-	57.00	16.74	-	-
1941	61.5	-	57.00	16.30	-	-
1940	62.5	1,302	57.00	15.88	23	363
1939	63.5	58,601	57.00	15.47	1,028	15,900
1938	64.5	3,775	57.00	15.06	66	997
1937	65.5	4,788	57.00	14.66	84	1,232
1936	66.5	3,198	57.00	14.27	56	801
1935	67.5	-	57.00	13.89	-	-
1934	68.5	-	57.00	13.52	-	-
1933	69.5	-	57.00	13.15	-	-
1932	70.5	-	57.00	12.79	-	-
1931	71.5	-	57.00	12.44	-	-
1930	72.5	-	57.00	12.10	-	-
1929	73.5	22,830	57.00	11.76	401	4,710

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	45,622,655	57.00	56.59	800,397	45,291,769
2001	1.5	25,075,008	57.00	55.77	439,912	24,531,921
2000	2.5	12,254,988	57.00	54.95	215,000	11,813,867
		428,736,305			7,521,690	343,509,176

AVERAGE SERVICE LIFE	57.00
AVERAGE REMAINING LIFE	45.67

Arizona Public Service Company

Transmission Plant

353.5 - Station Equipment - SCE 500 KV Line

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 353.5 - Station Equipment - SCE 500 KV Line

Depreciable Balance $7,747,282

	APS	Snavely King
Depreciable Reserve	$6,464,972	$7,349,363
Reserve Percent	83.4%	94.9%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)			
Accrual ($)	251,787	251,787	251,787
Rate (%)	3.25%	3.25%	3.25%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept the proposal to retain the existing depreciation rates.

Arizona Public Service Company

Transmission Plant

354 - Towers & Fixtures

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 354 - Towers & Fixtures

Depreciable Balance $83,464,531

	APS	Snavely King
Depreciable Reserve	$39,991,439	$46,097,366
Reserve Percent	47.9%	55.2%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	60.0	60.0	60.0
Iowa Curve	R3	R3	R3
Remaining Life (Yrs.)		38.3	38.3
Net Salvage (%)	-30	-35	0
Accrual ($)	1,660,944	1,899,472	975,644
Rate (%)	1.99%	2.28%	1.17%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept this judgment because there is no change to the current parameter and there is insufficient data to conduct a meaningful statistical analysis.

Observed Life Table Results
Arizona Public Service Company
Account: 354 - Towers and Fixtures

Age	Cumulative Survivors
BAND	1973 - 2001
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	1.0000
5.5	1.0000
6.5	1.0000
7.5	1.0000
8.5	1.0000
9.5	1.0000
10.5	1.0000
11.5	0.9997
12.5	0.9997
13.5	0.9997
14.5	0.9997
15.5	0.9997
16.5	0.9997
17.5	0.9987
18.5	0.9987
19.5	0.9987
20.5	0.9835
21.5	0.9835
22.5	0.9781
23.5	0.9745
24.5	0.9745
25.5	0.9745
26.5	0.9655
27.5	0.9564
28.5	0.9564
29.5	0.9564
30.5	0.9564
31.5	0.9558
32.5	0.9558
33.5	0.9557
34.5	0.9556
35.5	0.9555
36.5	0.9555
37.5	0.9555
38.5	0.9555

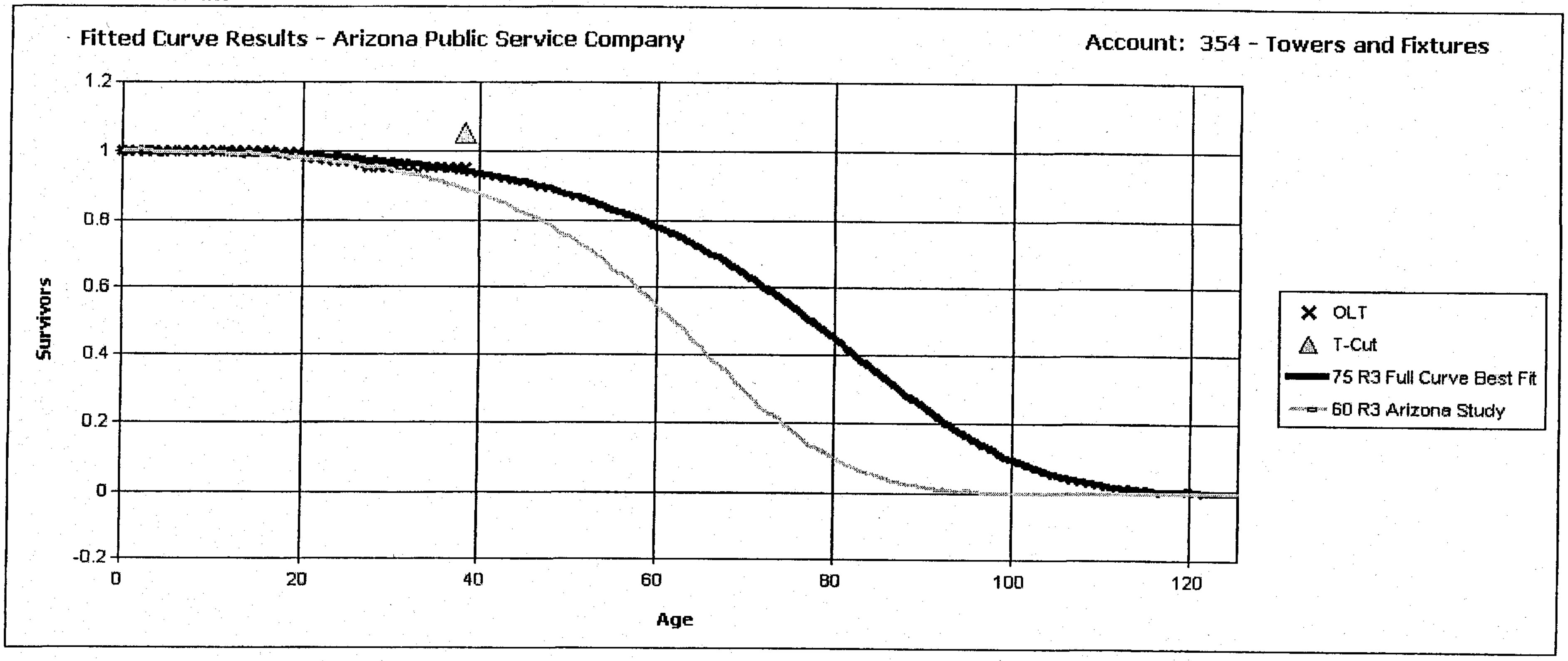
Best Fit Curve Results
Arizona Public Service Company
Account: 354 - Towers and Fixtures

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R3	75.0	10,019.681
S1.5	85.0	10,020.145
L2	86.0	10,025.261
S2	73.0	10,033.953
L3	68.0	10,034.690
R2.5	86.0	10,040.102
R4	58.0	10,044.144
S1	86.0	10,061.705
S3	60.0	10,066.834
L4	57.0	10,073.627
R5	49.0	10,119.322
S4	51.0	10,121.453
L5	49.0	10,131.945
S5	47.0	10,168.429
R2	86.0	10,185.653
S6	43.0	10,203.309
L1.5	86.0	10,230.008
SQ	39.0	10,255.564
S0.5	86.0	10,341.863
R1.5	86.0	10,650.831
L1	86.0	10,736.270
S0	86.0	10,895.883
R1	86.0	11,413.866
L0.5	86.0	11,826.002
S-0.5	86.0	12,354.907
R0.5	86.0	12,759.378
L0	86.0	13,436.709
O1	86.0	14,554.053
O2	86.0	16,019.013
O3	86.0	23,433.520
O4	86.0	34,846.681

Analytical Parameters

OLT Placement Band:	1909 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	86
Life Increment Parameter:	1
Max Age (T-Cut):	38.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1909 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	86
Life Increment Parameter:	1
Maximum Age (T-Cut):	38.5

Arizona Public Service Company

Transmission Plant

354.5 - Towers & Fixtures -SCE 500 KV Line

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 354.5 - Towers & Fixtures -SCE- 500 KV Line

Depreciable Balance $13,752,584

	APS	Snavely King
Depreciable Reserve	$13,542,259	$17,477,965
Reserve Percent	98.5%	127.1%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)			
Accrual ($)	446,959	446,959	446,959
Rate (%)	3.25%	3.25%	3.25%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept the proposal to retain the existing depreciation rates.

Arizona Public Service Company

Transmission Plant

355.00 - Poles and Fixtures - Wood

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 355 - Poles & Fixtures Wood

Depreciable Balance $91,126,939

	APS	Snavely King
Depreciable Reserve	$33,590,493	$27,541,958
Reserve Percent	36.9%	30.2%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	43.0	48.0	48.0
Iowa Curve	R1	R1.5	R1.5
Remaining Life (Yrs.)		38.5	38.5
Net Salvage (%)	-30	-35	0
Accrual ($)	2,487,765	2,321,504	1,651,558
Rate (%)	2.73%	2.55%	1.81%

****

Comment: Mr. Wiedmayer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) Mr. Wiedmayer's statistical study approximates the best fit results determined by SK (46-R2).

Observed Life Table Results
Arizona Public Service Company
Account: 355 - Poles and Fixtures

Age	Cumulative Survivors
BAND	1973 - 2001
0	1.0000
0.5	0.9996
1.5	0.9980
2.5	0.9970
3.5	0.9925
4.5	0.9910
5.5	0.9874
6.5	0.9809
7.5	0.9772
8.5	0.9737
9.5	0.9665
10.5	0.9569
11.5	0.9536
12.5	0.9493
13.5	0.9461
14.5	0.9396
15.5	0.9343
16.5	0.9243
17.5	0.9131
18.5	0.9055
19.5	0.8952
20.5	0.8604
21.5	0.8566
22.5	0.8309
23.5	0.8223
24.5	0.8148
25.5	0.8087
26.5	0.8015
27.5	0.7940
28.5	0.7853
29.5	0.7761
30.5	0.7718
31.5	0.7646
32.5	0.7552
33.5	0.7475
34.5	0.7417
35.5	0.7335
36.5	0.7267
37.5	0.7218
38.5	0.7133
39.5	0.7047
40.5	0.7023
41.5	0.6923
42.5	0.6789
43.5	0.6547
44.5	0.6442

Observed Life Table Results
Arizona Public Service Company
Account: 355 - Poles and Fixtures

Age	Cumulative Survivors
45.5	0.6297
46.5	0.6164
47.5	0.6101
48.5	0.5684
49.5	0.4954
50.5	0.3992
51.5	0.3975
52.5	0.3901
53.5	0.3649
54.5	0.3619
55.5	0.3155
56.5	0.1492
57.5	0.1462
58.5	0.1462
59.5	0.1462
60.5	0.0942
61.5	0.0942
62.5	0.0899
63.5	0.0899
64.5	0.0866
65.5	0.0866
66.5	0.0866
67.5	0.0865
68.5	0.0861
69.5	0.0861
70.5	0.0856
71.5	0.0853
72.5	0.0849
73.5	0.0839
74.5	0.0839
75.5	0.0825
76.5	0.0822
77.5	0.0815
78.5	0.0815

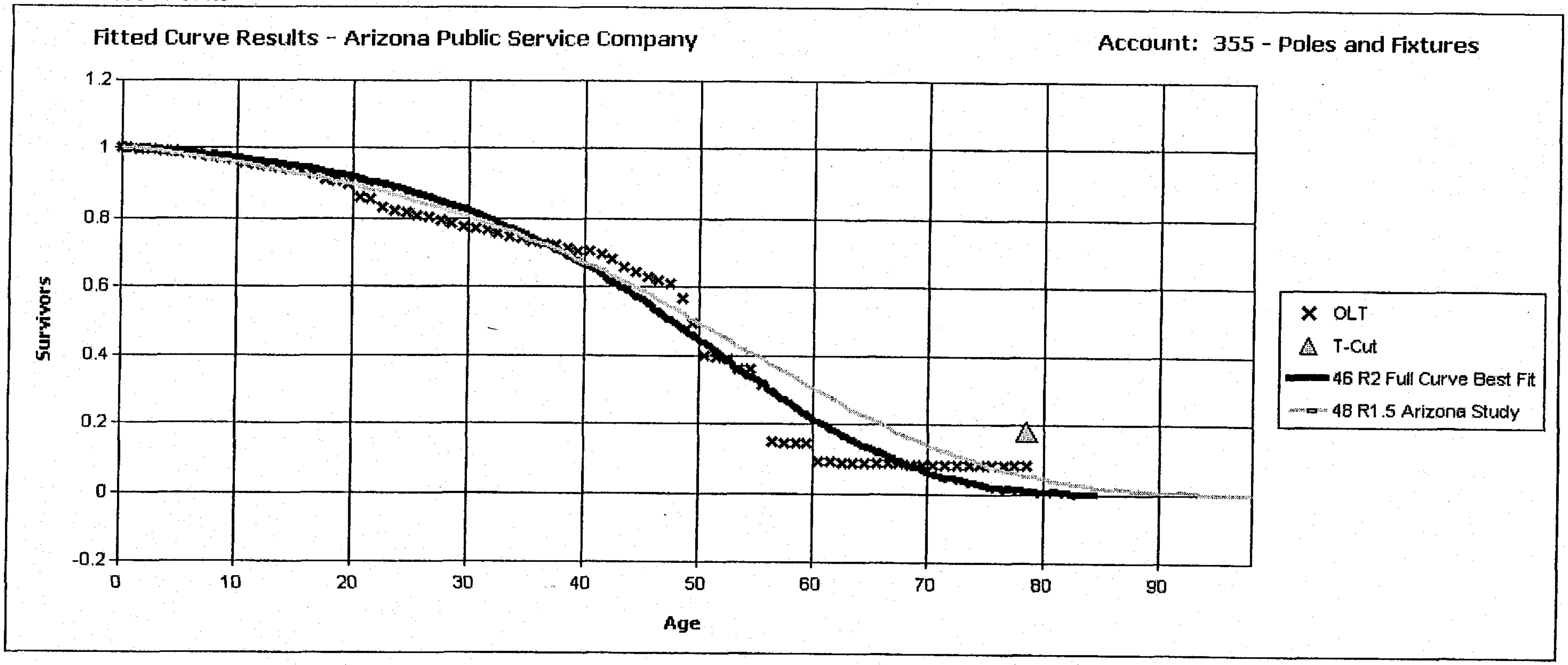
Best Fit Curve Results
Arizona Public Service Company
Account: 355 - Poles and Fixtures

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
R2	46.0	12,097.705
R2.5	47.0	12,181.842
R1.5	46.0	12,622.792
S1.5	47.0	12,988.802
S1	47.0	13,257.341
R3	48.0	13,276.153
S2	48.0	13,383.747
S0.5	46.0	14,043.617
R1	45.0	14,201.306
L3	49.0	14,851.291
L2	49.0	15,106.378
S3	49.0	15,338.537
S0	46.0	15,565.400
L1.5	48.0	15,811.066
R4	49.0	16,543.786
L4	50.0	16,801.095
R0.5	44.0	17,294.515
L1	48.0	17,364.829
S-0.5	45.0	18,181.100
L0.5	48.0	19,304.016
S4	49.0	19,389.723
L5	50.0	21,033.693
O1	44.0	21,895.995
L0	48.0	21,913.997
R5	50.0	22,447.399
O2	49.0	23,530.974
S5	50.0	24,422.205
S6	51.0	30,112.224
O3	63.0	31,939.444
O4	70.0	37,890.088
SQ	51.0	45,418.026

Analytical Parameters

OLT Placement Band:	1908 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	3
Maximum Life Parameter:	70
Life Increment Parameter:	1
Max Age (T-Cut):	78.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1908 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	3
Maximum Life Parameter:	70
Life Increment Parameter:	1
Maximum Age (T-Cut):	78.5

Arizona Public Service Company

Transmission Plant

355.1 - Poles and Fixtures - Steel

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 355.1 - Poles & Fixtures Steel

Depreciable Balance $83,067,888

	APS	Snavely King
Depreciable Reserve	$22,282,935	$22,833,440
Reserve Percent	26.8%	27.5%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)		55.0	55.0
Iowa Curve		R3	R3
Remaining Life (Yrs.)		45.1	45.1
Net Salvage (%)		-15	0
Accrual ($)	2,267,753	1,625,822	1,335,575
Rate (%)	2.73%	1.96%	1.61%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept this judgment based on Mr. Wiedmayer's study and that there is no data to conduct a meaningful statistical analysis.

Arizona Public Service Company

Transmission Plant

355.5 - Poles and Fixtures - SCE 500 KV Line

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 355.5- Poles & Fixtures - SCE 500 KV Line

Depreciable Balance $930,308

	APS	Snavely King
Depreciable Reserve	$341,908	$692,575
Reserve Percent	36.8%	74.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)			
Accrual ($)	30,235	30,235	30,235
Rate (%)	3.25%	3.25%	3.25%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept the proposal to retain the existing depreciation rates.

Arizona Public Service Company

Transmission Plant

356.00 - Overhead Conductors and Devices

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 356 - Overhead Conductors & Devices

Depreciable Balance $205,771,417

	APS	Snavely King
Depreciable Reserve	$70,439,236	$94,269,666
Reserve Percent	34.2%	45.8%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	55.0	55.0	55.0
Iowa Curve	R3	R3	R3
Remaining Life (Yrs.)		38.5	38.5
Net Salvage (%)	-30	-35	0
Accrual ($)	4,444,663	5,391,852	2,896,149
Rate (%)	2.16%	2.62%	1.41%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept the proposal to retain the existing depreciation rates.
See Response to MJM1-4 for information obtained by Company for this account.

Observed Life Table Results
Arizona Public Service Company
Account: 356 - Overhead Conductors and Devices

Age	Cumulative Survivors
0	1.0000
0.5	0.9994
1.5	0.9964
2.5	0.9952
3.5	0.9938
4.5	0.9923
5.5	0.9919
6.5	0.9908
7.5	0.9886
8.5	0.9882
9.5	0.9878
10.5	0.9856
11.5	0.9843
12.5	0.9833
13.5	0.9828
14.5	0.9807
15.5	0.9797
16.5	0.9776
17.5	0.9754
18.5	0.9731
19.5	0.9571
20.5	0.9540
21.5	0.9490
22.5	0.9481
23.5	0.9460
24.5	0.9417
25.5	0.9393
26.5	0.9367
27.5	0.9331
28.5	0.9324
29.5	0.9283
30.5	0.9230
31.5	0.9216
32.5	0.9206
33.5	0.9184
34.5	0.9054
35.5	0.9037
36.5	0.9032
37.5	0.9027
38.5	0.9014
39.5	0.9008
40.5	0.8804
41.5	0.8572
42.5	0.8516
43.5	0.8489
44.5	0.8472

Observed Life Table Results
Arizona Public Service Company
Account: 356 - Overhead Conductors and Devices

Age	Cumulative Survivors
45.5	0.8460
46.5	0.8341
47.5	0.8221
48.5	0.7174
49.5	0.7174
50.5	0.7172
51.5	0.7151
52.5	0.7151
53.5	0.7151
54.5	0.7151
55.5	0.7151
56.5	0.7151
57.5	0.7151
58.5	0.7151
59.5	0.7151
60.5	0.7151
61.5	0.7151
62.5	0.7151
63.5	0.7151
64.5	0.7151
65.5	0.7100
66.5	0.7100
67.5	0.7100
68.5	0.7087
69.5	0.7087
70.5	0.7087
71.5	0.7086
72.5	0.7034
73.5	0.7034
74.5	0.7034
75.5	0.6816
76.5	0.6816
77.5	0.6816
78.5	0.6816

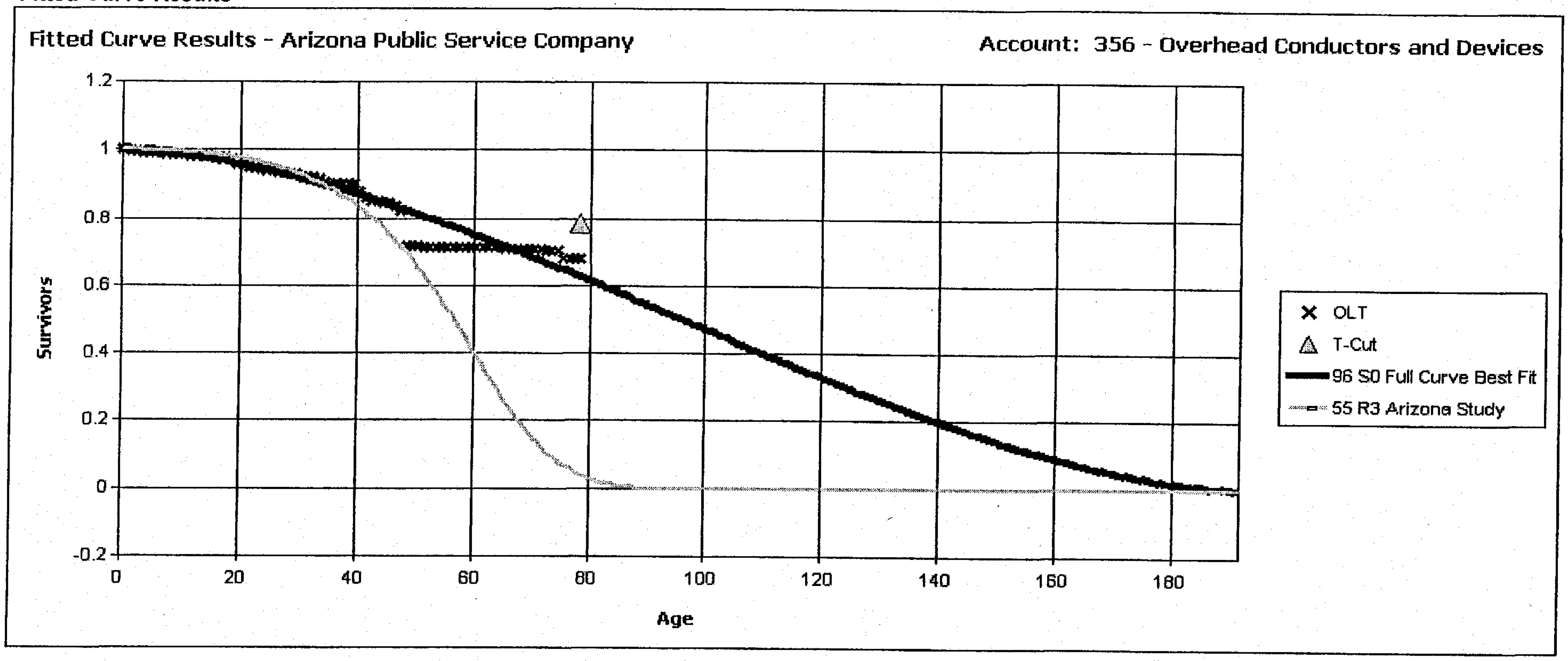
Best Fit Curve Results
Arizona Public Service Company
Account: 356 - Overhead Conductors and Devices

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
S0	96.0	10,857.956
L1	100.0	10,987.756
R1	93.0	11,032.732
S-0.5	100.0	11,120.795
R1.5	86.0	11,141.004
S0.5	90.0	11,154.990
L0.5	100.0	11,275.748
R0.5	100.0	11,292.948
L1.5	94.0	11,590.634
R2	82.0	11,633.591
S1	86.0	11,786.882
R2.5	80.0	12,547.641
S1.5	83.0	12,667.253
L0	100.0	12,710.958
L2	90.0	12,741.725
O1	100.0	12,810.616
S2	81.0	13,962.897
R3	78.0	13,986.645
O2	100.0	15,361.872
L3	83.0	15,787.890
S3	78.0	17,092.122
R4	76.0	17,470.942
L4	79.0	19,355.360
S4	77.0	21,896.643
R5	77.0	23,706.057
L5	78.0	23,916.890
S5	77.0	26,624.589
S6	78.0	30,538.472
O3	100.0	30,983.207
SQ	79.0	38,451.208
O4	100.0	55,774.924

Analytical Parameters

OLT Placement Band:	1908 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	78.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1908 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	78.5

Arizona Public Service Company

Transmission Plant

356.5 - Overhead Conductors & Devices - SCE 500 KV Line

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 356.5 Overhead Conductors & Devices - SCE 500 KV Line

Depreciable Balance $22,653,515

	APS	Snavely King
Depreciable Reserve	$23,670,862	$28,947,611
Reserve Percent	104.5%	127.8%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)			
Iowa Curve			
Remaining Life (Yrs.)			
Net Salvage (%)			
Accrual ($)	736,239	736,239	736,239
Rate (%)	3.25%	3.25%	3.25%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.) We accept the proposal to retain the existing depreciation rates.

Arizona Public Service Company

Transmission Plant

357 - Underground Conduit

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 357 - Underground Conduit

Depreciable Balance $10,444,362

	APS	Snavely King
Depreciable Reserve	$2,989,523	$4,087,064
Reserve Percent	28.6%	39.1%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	50.0	48.0	48.0
Iowa Curve	R3	S1.5	S1.5
Remaining Life (Yrs.)		35.7	35.7
Net Salvage (%)	-5	-10	0
Accrual ($)	229,776	237,777	178,076
Rate (%)	2.20%	2.28%	1.70%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept this judgment based on Mr. Wiedmayer's study and that there is insufficient data to conduct a meaningful statistical analysis.

Observed Life Table Results
Arizona Public Service Company
Account: 357 - Underground Conduit

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	1.0000
5.5	0.9987
6.5	0.9987
7.5	0.9987
8.5	0.9987
9.5	0.9987
10.5	0.9987
11.5	0.9987
12.5	0.9987
13.5	0.9827
14.5	0.9827
15.5	0.9827
16.5	0.9827
17.5	0.9827
18.5	0.9827
19.5	0.9608
20.5	0.9511
21.5	0.9511
22.5	0.9511
23.5	0.8860
24.5	0.8209
25.5	0.8209
26.5	0.8209
27.5	0.8209
28.5	0.8209
29.5	0.8209
30.5	0.8209
31.5	0.8209
32.5	0.8209
33.5	0.8209
34.5	0.8209
35.5	0.8209
36.5	0.8209
37.5	0.8209

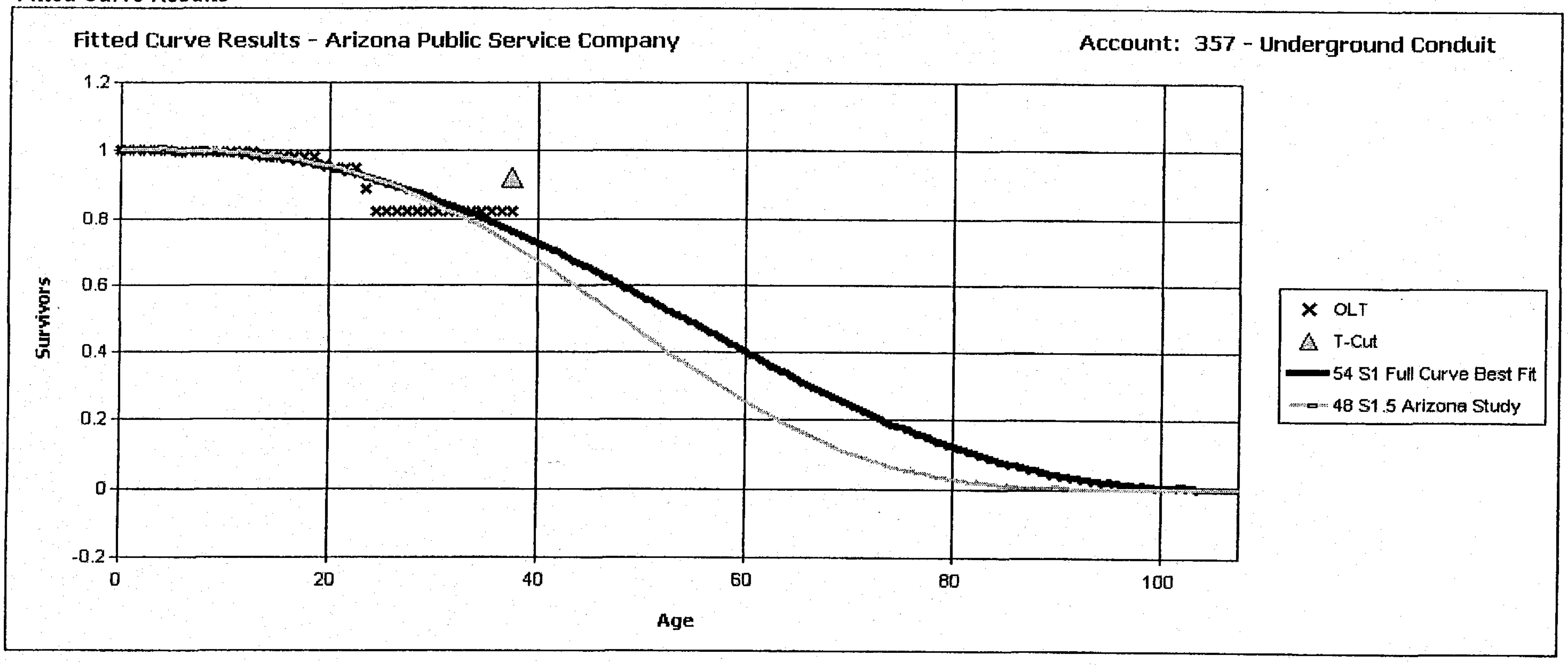
Best Fit Curve Results
Arizona Public Service Company
Account: 357 - Underground Conduit

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
S1	54.0	10,347.325
L1	67.0	10,350.190
S0.5	60.0	10,353.842
L1.5	60.0	10,365.575
S0	67.0	10,392.221
R2.5	48.0	10,415.091
S1.5	50.0	10,415.345
R2	52.0	10,417.168
L0.5	78.0	10,429.032
L2	54.0	10,463.682
R3	45.0	10,503.483
R1.5	60.0	10,509.765
S2	47.0	10,565.270
S-0.5	80.0	10,587.742
R1	71.0	10,597.672
L0	80.0	10,712.446
R0.5	80.0	10,741.057
L3	47.0	10,822.560
R4	41.0	10,931.014
S3	44.0	11,028.570
L4	43.0	11,247.607
O1	80.0	11,285.270
S4	41.0	11,836.354
O2	80.0	11,893.873
R5	40.0	12,008.092
L5	41.0	12,069.536
S5	40.0	12,649.615
S6	39.0	13,287.605
SQ	38.0	14,405.141
O3	80.0	16,199.746
O4	80.0	24,365.412

Analytical Parameters

OLT Placement Band:	1964 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	6
Maximum Life Parameter:	80
Life Increment Parameter:	1
Max Age (T-Cut):	37.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1964 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	6
Maximum Life Parameter:	80
Life Increment Parameter:	1
Maximum Age (T-Cut):	37.5

Arizona Public Service Company

Transmission Plant

358 - Underground Conductors & Devices

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Transmission Plant

Account 358 - Underground Conductors & Devices

Depreciable Balance $18,551,254

	APS	Snavely King
Depreciable Reserve	$6,336,374	$9,702,854
Reserve Percent	34.2%	52.3%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	50.0	40.0	40.0
Iowa Curve	R3	R3	R3
Remaining Life (Yrs.)		26.3	26.3
Net Salvage (%)	-5	-10	0
Accrual ($)	343,198	534,608	336,441
Rate (%)	1.85%	2.88%	1.81%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.) We accept this judgment based on Mr. Wiedmayer's study and that there is insufficient data to conduct a meaningful statistical analysis.

Observed Life Table Results
Arizona Public Service Company
Account: 358 - Underground Conductors

Age	Cumulative Survivors
0	1.0000
0.5	0.9998
1.5	0.9998
2.5	0.9998
3.5	0.9998
4.5	0.9998
5.5	0.9977
6.5	0.9977
7.5	0.9898
8.5	0.9898
9.5	0.9895
10.5	0.9895
11.5	0.9877
12.5	0.9798
13.5	0.9759
14.5	0.9759
15.5	0.9759
16.5	0.9759
17.5	0.9759
18.5	0.9759
19.5	0.9664
20.5	0.9278
21.5	0.9278
22.5	0.9278
23.5	0.8963
24.5	0.8648
25.5	0.8395
26.5	0.8395
27.5	0.8395
28.5	0.8395
29.5	0.8395
30.5	0.8395
31.5	0.8395
32.5	0.8395
33.5	0.8395
34.5	0.8395
35.5	0.8395
36.5	0.8395
37.5	0.8395

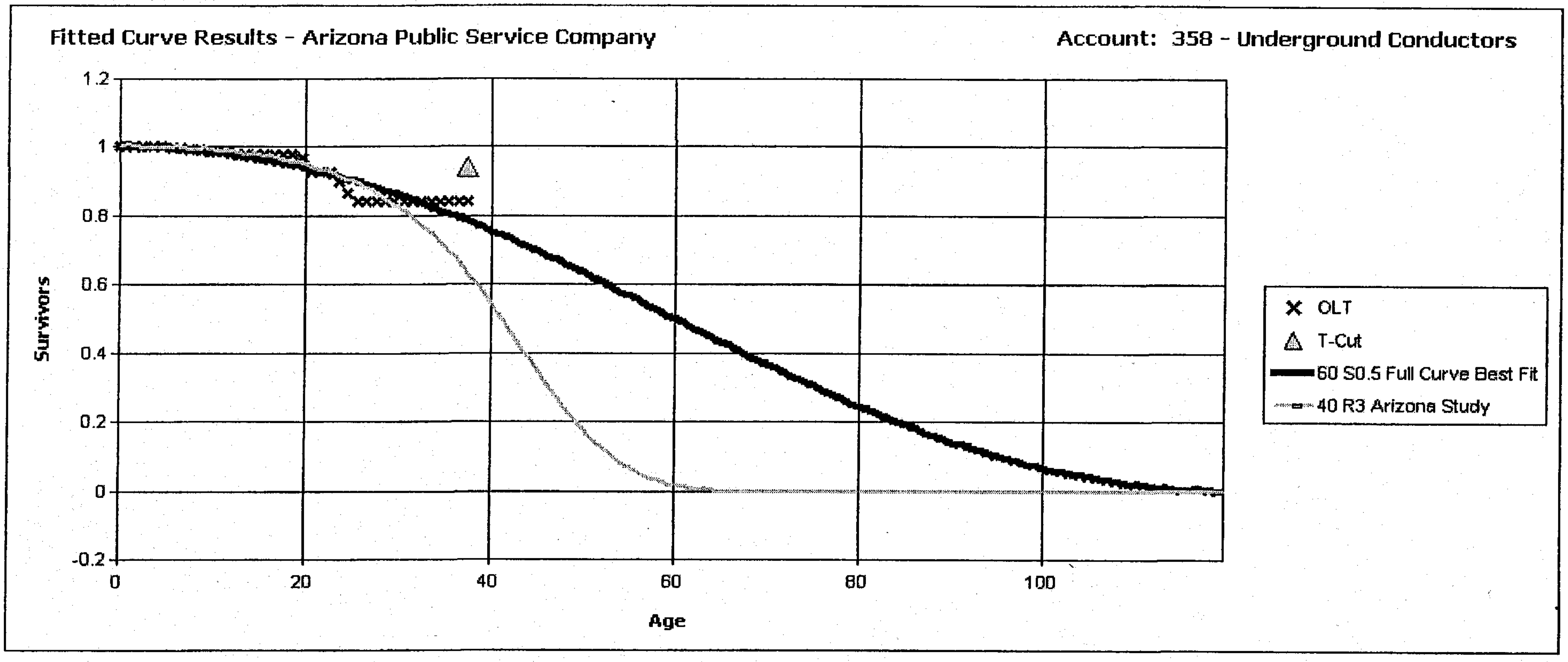
Best Fit Curve Results
Arizona Public Service Company
Account: 358 - Underground Conductors

Curve	Life	Sum of Squared Differences
BAND	**1973 - 2001**	
S0.5	60.0	10,205.399
R2	55.0	10,223.501
S1	56.0	10,224.474
L1.5	60.0	10,247.866
R2.5	50.0	10,248.564
R1.5	60.0	10,288.943
S1.5	52.0	10,304.153
L2	56.0	10,348.504
R3	46.0	10,357.529
S2	49.0	10,470.623
S0	60.0	10,516.640
L1	60.0	10,632.711
L3	49.0	10,684.304
R1	60.0	10,705.936
R4	42.0	10,773.159
S3	45.0	10,888.298
L4	44.0	11,051.833
L0.5	60.0	11,566.868
S4	42.0	11,567.568
S-0.5	60.0	11,631.558
R5	40.0	11,693.356
L5	41.0	11,738.366
R0.5	60.0	11,803.470
S5	40.0	12,231.906
S6	39.0	12,751.390
L0	60.0	13,093.804
O1	60.0	13,540.804
SQ	38.0	13,594.068
O2	60.0	15,306.616
O3	60.0	24,331.113
O4	60.0	37,808.448

Analytical Parameters

OLT Placement Band:	1964 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	37.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1964 - 2001
OLT Experience Band:	1973 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	60
Life Increment Parameter:	1
Maximum Age (T-Cut):	37.5

Arizona Public Service Company

Section D

Distribution Plant

Arizona Public Service Company

Distribution Plant

361.00 - Structures and Improvements

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 361 - Structures & Improvements

Depreciable Balance $25,815,042

	APS	Snavely King
Depreciable Reserve	$7,749,290	$10,429,908
Reserve Percent	30.0%	40.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	40.0	45.0	45.0
Iowa Curve	R2.5	R2.5	R2.5
Remaining Life (Yrs.)		33.1	33.1
Net Salvage (%)	(15.00)	(10.00)	0
Accrual ($)	774,451	623,356	464,808
Rate (%)	3.00%	2.41%	1.80%

****

Comment: Accept Company proposal based on SK analysis

Observed Life Table Results
Arizona Public Service Company
Account: 361 - Structures and Improvements

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	0.9997
2.5	0.9972
3.5	0.9968
4.5	0.9958
5.5	0.9956
6.5	0.9889
7.5	0.9883
8.5	0.9876
9.5	0.9853
10.5	0.9833
11.5	0.9830
12.5	0.9824
13.5	0.9816
14.5	0.9762
15.5	0.9739
16.5	0.9667
17.5	0.9606
18.5	0.9582
19.5	0.9572
20.5	0.9515
21.5	0.9502
22.5	0.9468
23.5	0.9410
24.5	0.9250
25.5	0.9218
26.5	0.9103
27.5	0.8925
28.5	0.8874
29.5	0.7367
30.5	0.7531
31.5	0.7925
32.5	0.6968
33.5	0.6695
34.5	0.6573
35.5	0.6294
36.5	0.6279
37.5	0.6277
38.5	0.6260
39.5	0.6206
40.5	0.6201
41.5	0.6198
42.5	0.6133
43.5	0.5163
44.5	0.5038

Observed Life Table Results
Arizona Public Service Company
Account: 361 - Structures and Improvements

Age	Cumulative Survivors
45.5	0.4931
46.5	0.4728
47.5	1.0000
48.5	0.9807
49.5	0.9157
50.5	0.9212
51.5	0.9212
52.5	0.9969
53.5	0.9969
54.5	0.9969
55.5	0.9969
56.5	0.9969
57.5	0.9969
58.5	0.9969
59.5	1.0000
60.5	1.0000

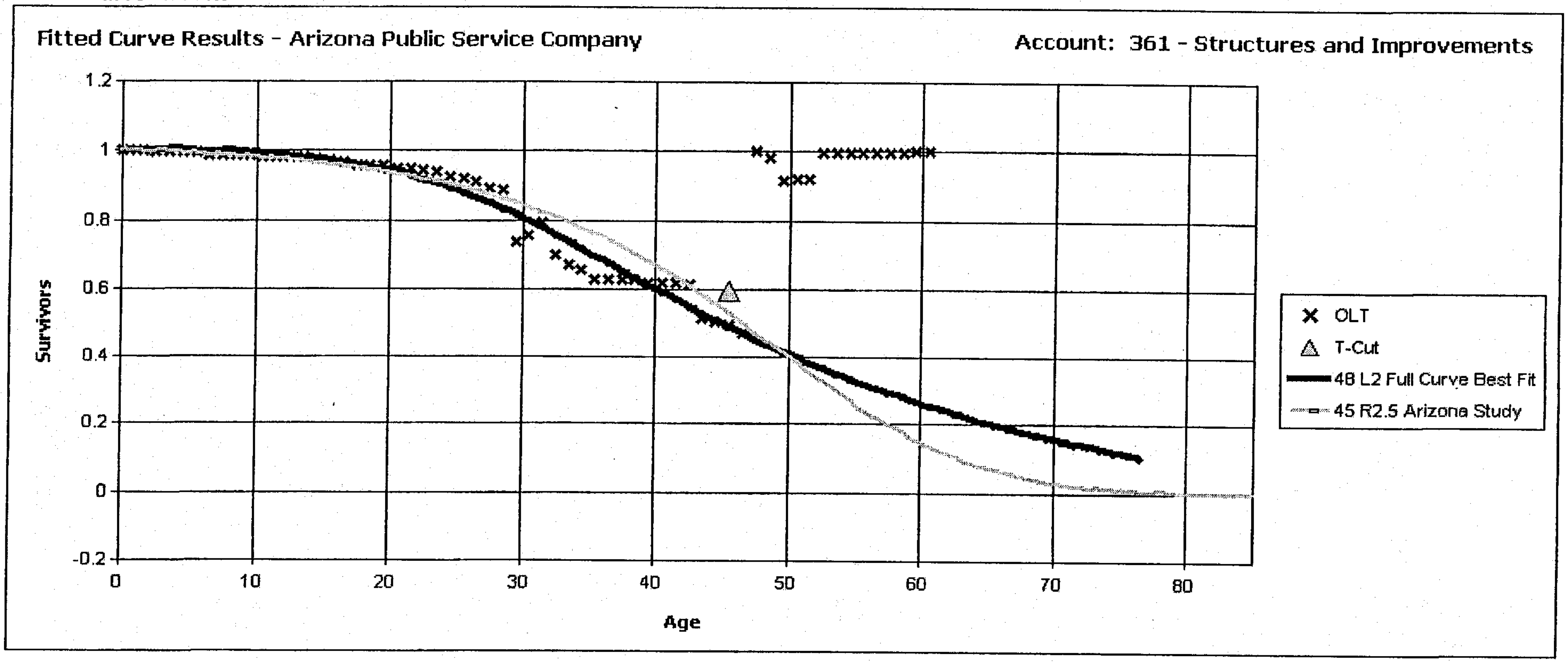
Best Fit Curve Results
Arizona Public Service Company
Account: 361 - Structures and Improvements

Curve	Life	Sum of Squared Differences
BAND	**1940 - 2001**	
L2	48.0	478.546
S1.5	44.0	554.546
S1	46.0	640.663
L1.5	50.0	678.440
S2	43.0	683.841
R2.5	42.0	766.379
R2	43.0	846.511
S0.5	47.0	978.157
R3	42.0	998.407
L1	53.0	1,074.550
L3	45.0	1,111.968
R1.5	45.0	1,321.989
S0	50.0	1,462.908
S3	42.0	1,649.009
L0.5	57.0	1,671.782
R1	48.0	1,999.858
L0	63.0	2,348.553
S-0.5	54.0	2,391.808
R4	42.0	2,450.954
R0.5	53.0	2,813.332
L4	43.0	2,987.995
O2	70.0	3,402.996
O1	62.0	3,405.152
S4	42.0	4,195.060
O3	75.0	5,670.531
L5	42.0	5,948.273
R5	42.0	6,073.464
S5	42.0	7,932.792
S6	43.0	11,957.767
O4	75.0	13,708.121
SQ	45.0	24,166.332

Analytical Parameters

OLT Placement Band:	1940 - 2001
OLT Experience Band:	1940 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	75
Life Increment Parameter:	1
Max Age (T-Cut):	45.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1940 - 2001
OLT Experience Band:	1940 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	75
Life Increment Parameter:	1
Maximum Age (T-Cut):	45.5

Arizona Public Service Company

Distribution Plant

362.00 - Station Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 362 - Station Equipment - Distribution Plant

Depreciable Balance $212,357,577

	APS	Snavely King
Depreciable Reserve	$70,802,963	$52,722,295
Reserve Percent	33.3%	24.8%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	26.0	38.0	44.0
Iowa Curve	R0.5	S0	L0.5
Remaining Life (Yrs.)		31.8	36.9
Net Salvage (%)	0	0	0
Accrual ($)	7,411,279	4,456,837	4,332,029
Rate (%)	3.49%	2.10%	2.04%

****

Comment: Mr. Weidmeyer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) However, Mr. Weidmayer's statistical study was deficient and incomplete because he excluded a substantial portion of the OLT. The complete statistical analysis results is a 44-L0.5 life and curve.

Observed Life Table Results
Arizona Public Service Company
Account: 362 - Station Equipment

Age	Cumulative Survivors
0	1.0000
0.5	0.9991
1.5	0.9983
2.5	0.9953
3.5	0.9872
4.5	0.9786
5.5	0.9716
6.5	0.9624
7.5	0.9533
8.5	0.9474
9.5	0.9403
10.5	0.9338
11.5	0.9292
12.5	0.9187
13.5	0.9055
14.5	0.8945
15.5	0.8724
16.5	0.8625
17.5	0.8335
18.5	0.8245
19.5	0.8059
20.5	0.7865
21.5	0.7702
22.5	0.7541
23.5	0.7411
24.5	0.7295
25.5	0.7185
26.5	0.7064
27.5	0.6952
28.5	0.6844
29.5	0.6695
30.5	0.6489
31.5	0.6283
32.5	0.6054
33.5	0.5881
34.5	0.5710
35.5	0.5414
36.5	0.5188
37.5	0.4906
38.5	0.4800
39.5	0.4754
40.5	0.4709
41.5	0.4677
42.5	0.4580
43.5	0.4451
44.5	0.4206

Observed Life Table Results
Arizona Public Service Company
Account: 362 - Station Equipment

Age	Cumulative Survivors
45.5	0.4058
46.5	0.3954
47.5	0.3706
48.5	0.3550
49.5	0.2987
50.5	0.2982
51.5	0.2963
52.5	0.2963
53.5	0.2963
54.5	0.2963
55.5	0.2963
56.5	0.2909
57.5	0.2909
58.5	0.2900
59.5	0.2337
60.5	0.2337
61.5	0.2337
62.5	0.2337
63.5	0.2337
64.5	0.2337
65.5	0.2337
66.5	0.2337
67.5	0.2337
68.5	0.2337
69.5	0.2337
70.5	0.2337
71.5	0.2337
72.5	0.2337

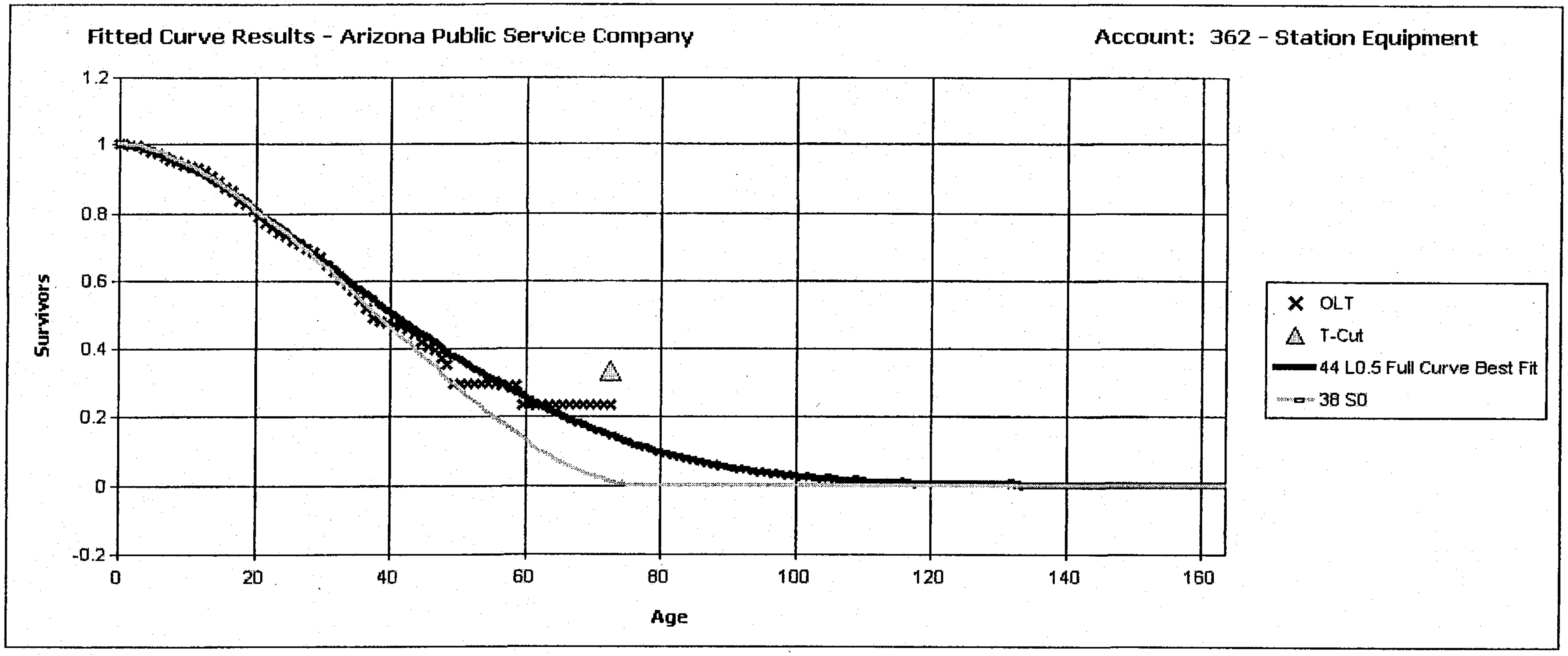
Best Fit Curve Results
Arizona Public Service Company
Account: 362 - Station Equipment

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
L0.5	44.0	10,556.909
L0	45.0	10,778.145
L1	44.0	10,938.226
S-0.5	42.0	11,332.406
O2	46.0	11,475.512
O1	42.0	11,748.923
R0.5	42.0	11,836.442
S0	43.0	12,014.581
L1.5	44.0	12,016.868
R1	43.0	13,405.027
S0.5	43.0	13,406.554
L2	44.0	13,901.031
O3	53.0	13,945.649
R1.5	43.0	15,463.846
S1	43.0	15,579.692
S1.5	43.0	18,217.489
R2	43.0	18,639.714
L3	43.0	20,170.796
S2	43.0	21,570.828
O4	53.0	21,888.844
R2.5	43.0	22,119.845
R3	43.0	26,611.378
S3	43.0	28,665.492
L4	43.0	30,596.605
R4	42.0	34,725.805
S4	42.0	38,007.768
L5	42.0	40,333.960
R5	42.0	44,595.399
S5	41.0	46,930.223
S6	41.0	54,921.108
SQ	38.0	70,449.911

Analytical Parameters

OLT Placement Band:	1929 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	53
Life Increment Parameter:	1
Max Age (T-Cut):	72.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1929 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	53
Life Increment Parameter:	1
Maximum Age (T-Cut):	72.5

Arizona Public Service Company

362 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **44 L0.5**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	19,710,942	44.00	43.54	447,976	19,503,213
2001	1.5	22,738,273	44.00	42.68	516,779	22,056,101
2000	2.5	14,769,021	44.00	41.86	335,660	14,052,309
1999	3.5	19,247,683	44.00	41.08	437,447	17,970,909
1998	4.5	11,457,184	44.00	40.33	260,391	10,500,635
1997	5.5	7,553,299	44.00	39.60	171,666	6,797,392
1996	6.5	7,972,575	44.00	38.89	181,195	7,046,674
1995	7.5	5,307,172	44.00	38.21	120,618	4,608,302
1994	8.5	3,635,828	44.00	37.54	82,632	3,102,390
1993	9.5	5,268,282	44.00	36.90	119,734	4,418,655
1992	10.5	4,505,211	44.00	36.28	102,391	3,715,198
1991	11.5	4,965,704	44.00	35.69	112,857	4,027,366
1990	12.5	4,463,240	44.00	35.11	101,437	3,561,204
1989	13.5	4,563,279	44.00	34.55	103,711	3,583,100
1988	14.5	10,600,431	44.00	34.01	240,919	8,193,562
1987	15.5	5,938,319	44.00	33.49	134,962	4,519,858
1986	16.5	6,657,430	44.00	32.99	151,305	4,991,326
1985	17.5	7,125,197	44.00	32.50	161,936	5,263,644
1984	18.5	4,897,949	44.00	32.04	111,317	3,566,278
1983	19.5	3,627,985	44.00	31.59	82,454	2,604,409
1982	20.5	4,693,455	44.00	31.15	106,669	3,322,720
1981	21.5	2,560,854	44.00	30.73	58,201	1,788,326
1980	22.5	2,239,337	44.00	30.32	50,894	1,542,888
1979	23.5	4,222,966	44.00	29.92	95,977	2,871,206
1978	24.5	2,657,712	44.00	29.53	60,403	1,783,390
1977	25.5	1,779,374	44.00	29.14	40,440	1,178,527
1976	26.5	929,351	44.00	28.77	21,122	607,586
1975	27.5	1,021,052	44.00	28.39	23,206	658,921
1974	28.5	2,211,380	44.00	28.03	50,259	1,408,661
1973	29.5	1,681,722	44.00	27.67	38,221	1,057,433
1972	30.5	2,062,235	44.00	27.31	46,869	1,279,941
1971	31.5	826,357	44.00	26.96	18,781	506,257
1970	32.5	2,170,475	44.00	26.61	49,329	1,312,532
1969	33.5	984,204	44.00	26.26	22,368	587,474
1968	34.5	570,239	44.00	25.92	12,960	335,974

Arizona Public Service Company

362 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **44 L0.5**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1967	35.5	455,823	44.00	25.59	10,360	265,088
1966	36.5	544,078	44.00	25.26	12,365	312,319
1965	37.5	266,554	44.00	24.93	6,058	151,029
1964	38.5	269,185	44.00	24.61	6,118	150,544
1963	39.5	454,572	44.00	24.29	10,331	250,929
1962	40.5	959,099	44.00	23.97	21,798	522,570
1961	41.5	175,577	44.00	23.66	3,990	94,422
1960	42.5	479,854	44.00	23.36	10,906	254,708
1959	43.5	226,691	44.00	23.05	5,152	118,766
1958	44.5	337,056	44.00	22.75	7,660	174,293
1957	45.5	254,786	44.00	22.46	5,791	130,037
1956	46.5	339,426	44.00	22.16	7,714	170,982
1955	47.5	424,231	44.00	21.88	9,642	210,921
1954	48.5	262,735	44.00	21.59	5,971	128,926
1953	49.5	126,409	44.00	21.31	2,873	61,221
1952	50.5	225,561	44.00	21.03	5,126	107,817
1951	51.5	54,517	44.00	20.76	1,239	25,719
1950	52.5	137,358	44.00	20.49	3,122	63,953
1949	53.5	188,317	44.00	20.22	4,280	86,534
1948	54.5	259,920	44.00	19.95	5,907	117,876
1947	55.5	36,496	44.00	19.69	829	16,335
1946	56.5	10,283	44.00	19.44	234	4,542
1945	57.5	80,545	44.00	19.18	1,831	35,111
1944	58.5	-	44.00	18.93	-	-
1943	59.5	3,397	44.00	18.68	77	1,442
1942	60.5	104,403	44.00	18.44	2,373	43,744
1941	61.5	5,369	44.00	18.19	122	2,220
1940	62.5	1,053	44.00	17.96	24	430
1939	63.5	12,143	44.00	17.72	276	4,890
1938	64.5	1,270	44.00	17.49	29	505
1937	65.5	-	44.00	17.26	-	-
1936	66.5	-	44.00	17.03	-	-
1935	67.5	35,712	44.00	16.81	812	13,640
1934	68.5	-	44.00	16.58	-	-
1933	69.5	-	44.00	16.37	-	-
1932	70.5	-	44.00	16.15	-	-

Arizona Public Service Company

362 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **44 L0.5**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1931	71.5	-	44.00	15.94	-	-
1930	72.5	-	44.00	15.73	-	-
1930	73.5	9,640	44.00	15.73	219	3,446
		212,357,777			4,826,313	177,849,321

AVERAGE SERVICE LIFE	44.00
AVERAGE REMAINING LIFE	36.85

Arizona Public Service Company

Distribution Plant

364.00 - Poles and Fixtures - Wood

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 364 - Poles and Fixtures- Wood - Distribution Plant

Depreciable Balance $284,200,711

	APS	Snavely King
Depreciable Reserve	$94,139,326	$81,128,434
Reserve Percent	33.1%	28.5%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	37.0	38.0	38.0
Iowa Curve	R0.5	R0.5	R0.5
Remaining Life (Yrs.)		30.9	30.9
Net Salvage (%)	-10	-10	0
Accrual ($)	7,616,579	7,076,374	6,571,918
Rate (%)	2.68%	2.49%	2.31%

****

Comment: According to Mr. Weidmayer study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgements which considered the nature of the the palnt and equipment,reviews of available historical retirement data and general knowledge of service lives for similar similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept Company proposal based on SK analysis.

Observed Life Table Results
Arizona Public Service Company
Account: 364 - Poles, Towers, and Fixtures

Age	Cumulative Survivors
0	1.0000
0.5	0.9976
1.5	0.9764
2.5	0.9622
3.5	0.9511
4.5	0.9443
5.5	0.9369
6.5	0.9302
7.5	0.9227
8.5	0.9136
9.5	0.9033
10.5	0.8929
11.5	0.8802
12.5	0.8641
13.5	0.8494
14.5	0.8333
15.5	0.8181
16.5	0.8053
17.5	0.7943
18.5	0.7823
19.5	0.7710
20.5	0.7597
21.5	0.7464
22.5	0.7346
23.5	0.7209
24.5	0.7085
25.5	0.6957
26.5	0.6807
27.5	0.6675
28.5	0.6544
29.5	0.6420
30.5	0.6273
31.5	0.6138
32.5	0.6011
33.5	0.5878
34.5	0.5721
35.5	0.5566
36.5	0.5462
37.5	0.5384
38.5	0.5285
39.5	0.5186
40.5	0.5089
41.5	0.4990
42.5	0.4894
43.5	0.4807
44.5	0.4725

Observed Life Table Results
Arizona Public Service Company
Account: 364 - Poles, Towers, and Fixtures

Age	Cumulative Survivors
45.5	0.4555
46.5	0.4305
47.5	0.3901
48.5	0.3402
49.5	0.3167
50.5	0.3012
51.5	0.2850
52.5	0.2698
53.5	0.1801
54.5	0.0580
55.5	0.0079
56.5	0.0038
57.5	0.0010
58.5	0.0004
59.5	0.0002
60.5	0.0001
61.5	0.0001
62.5	0.0000
63.5	0.0000
64.5	0.0000
65.5	0.0000
66.5	0.0000
67.5	0.0000
68.5	0.0000
69.5	0.0000
70.5	0.0000
71.5	0.0000
72.5	0.0000
73.5	0.0000
74.5	0.0000
75.5	0.0000
76.5	0.0000
77.5	0.0000
78.5	0.0000

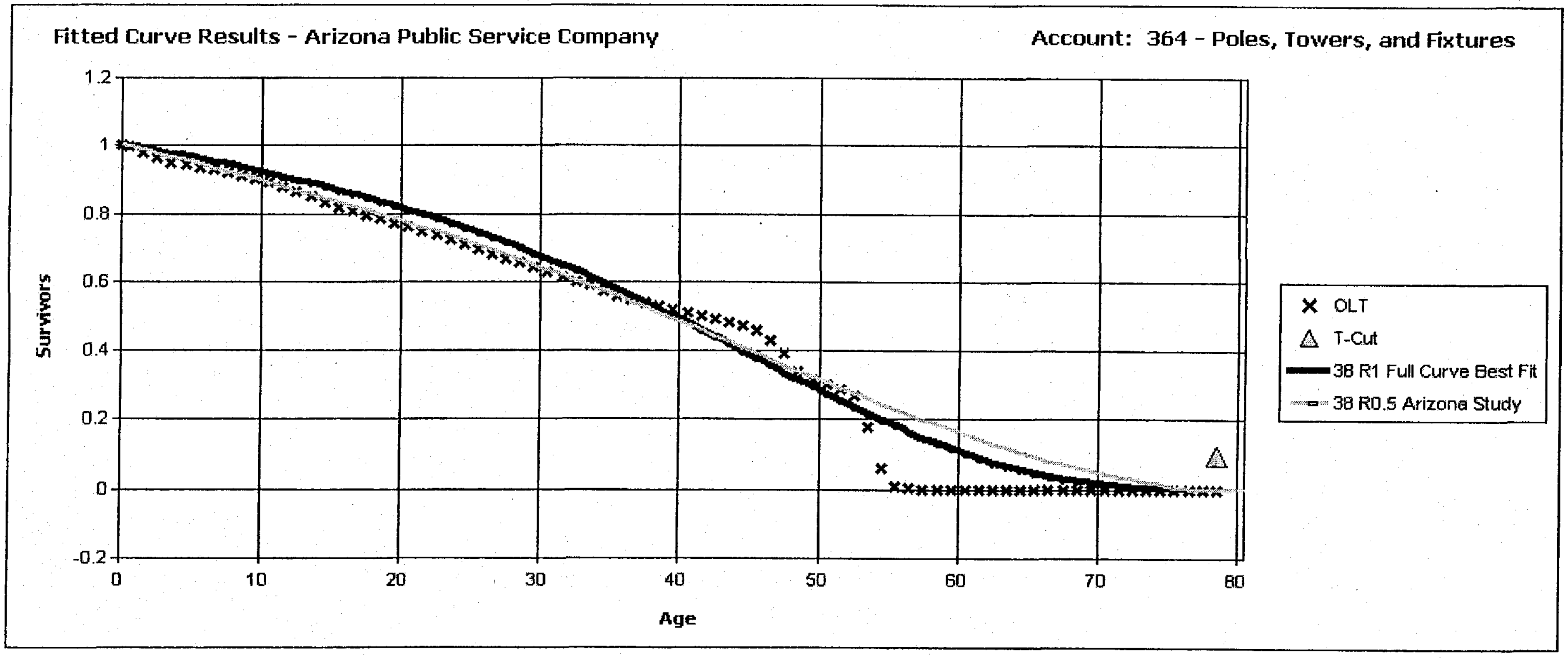
Best Fit Curve Results
Arizona Public Service Company
Account: 364 - Poles, Towers, and Fixtures

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
R1	38.0	12,152.450
R1.5	38.0	12,758.687
R0.5	37.0	12,958.987
S0	37.0	13,005.511
S0.5	38.0	13,253.701
S-0.5	37.0	13,536.020
R2	39.0	14,025.137
S1	39.0	14,053.990
O1	35.0	14,753.878
L1	38.0	15,135.882
L1.5	39.0	15,288.480
S1.5	40.0	15,474.582
L0.5	38.0	15,924.732
L2	39.0	16,141.925
R2.5	40.0	16,222.347
S2	40.0	17,329.400
L0	38.0	17,358.820
O2	39.0	18,763.092
R3	41.0	19,106.424
L3	40.0	19,344.645
S3	41.0	22,162.450
L4	41.0	25,238.492
R4	42.0	25,808.016
O3	45.0	28,246.473
S4	42.0	29,823.155
L5	42.0	32,816.175
O4	55.0	33,681.763
R5	43.0	35,528.846
S5	43.0	38,239.512
S6	43.0	46,373.198
SQ	42.0	63,506.232

Analytical Parameters

OLT Placement Band:	1901 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	3
Maximum Life Parameter:	55
Life Increment Parameter:	1
Max Age (T-Cut):	78.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1915 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	78.5

Arizona Public Service Company

Distribution Plant

364.1 - Poles and Fixtures - Steel

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 364.1 - Poles and Fixtures - Steel - Distribution Plant

Depreciable Balance $53,919,651

	APS	Snavely King
Depreciable Reserve	$5,138,171	$5,601,820
Reserve Percent	9.5%	10.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)		50.0	50.0
Iowa Curve		R3	R3
Remaining Life (Yrs.)		46.6	46.6
Net Salvage (%)		(5)	0
Accrual ($)	1,445,047	1,105,404	1,036,863
Rate (%)	2.68%	2.05%	1.92%

****

Comment: According to Mr. Weidmayer study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgements which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept Company proposal.

Arizona Public Service Company

Distribution Plant

365.00 - Overhead Conductors and Devices

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 365 - Overhead Conductors & Devices - Distribution Plant

Depreciable Balance $218,856,780

	APS	Snavely King
Depreciable Reserve	$58,922,434	$33,437,453
Reserve Percent	26.9%	15.3%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	53.0	53.0	53.0
Iowa Curve	R1	O1	O1
Remaining Life (Yrs.)		47.7	47.7
Net Salvage (%)	(10)	(10)	0
Accrual ($)	3,873,765	3,810,605	3,887,198
Rate (%)	1.77%	1.74%	1.78%

****

Comment: Mr. Weidmeyer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) We accept Company proposal based on a SK analysis.

Observed Life Table Results
Arizona Public Service Company
Account: 365 - Overhead Condcutors and Devices

Age	Cumulative Survivors
0	1.0000
0.5	0.9988
1.5	0.9878
2.5	0.9755
3.5	0.9528
4.5	0.9448
5.5	0.9339
6.5	0.9275
7.5	0.9203
8.5	0.9108
9.5	0.8999
10.5	0.8885
11.5	0.8791
12.5	0.8688
13.5	0.8604
14.5	0.8481
15.5	0.8367
16.5	0.8269
17.5	0.8158
18.5	0.8046
19.5	0.7959
20.5	0.7881
21.5	0.7785
22.5	0.7689
23.5	0.7606
24.5	0.7532
25.5	0.7469
26.5	0.7387
27.5	0.7315
28.5	0.7234
29.5	0.7172
30.5	0.7102
31.5	0.7032
32.5	0.6963
33.5	0.6877
34.5	0.6799
35.5	0.6727
36.5	0.6664
37.5	0.6603
38.5	0.6542
39.5	0.6457
40.5	0.6356
41.5	0.6254
42.5	0.6178
43.5	0.6108
44.5	0.6003

Observed Life Table Results
Arizona Public Service Company
Account: 365 - Overhead Condcutors and Devices

Age	Cumulative Survivors
45.5	0.5922
46.5	0.5821
47.5	0.5725
48.5	0.5559
49.5	0.5484
50.5	0.5442
51.5	0.5425
52.5	0.5370
53.5	0.5021
54.5	0.4487
55.5	0.2511
56.5	0.0000
57.5	0.0000
58.5	0.0000
59.5	0.0000
60.5	0.0000
61.5	0.0000
62.5	0.0000
63.5	0.0000
64.5	0.0000
65.5	0.0000
66.5	0.0000
67.5	0.0000
68.5	0.0000
69.5	0.0000
70.5	0.0000
71.5	0.0000
72.5	0.0000
73.5	0.0000
74.5	0.0000
75.5	0.0000
76.5	0.0000
77.5	0.0000
78.5	0.0000

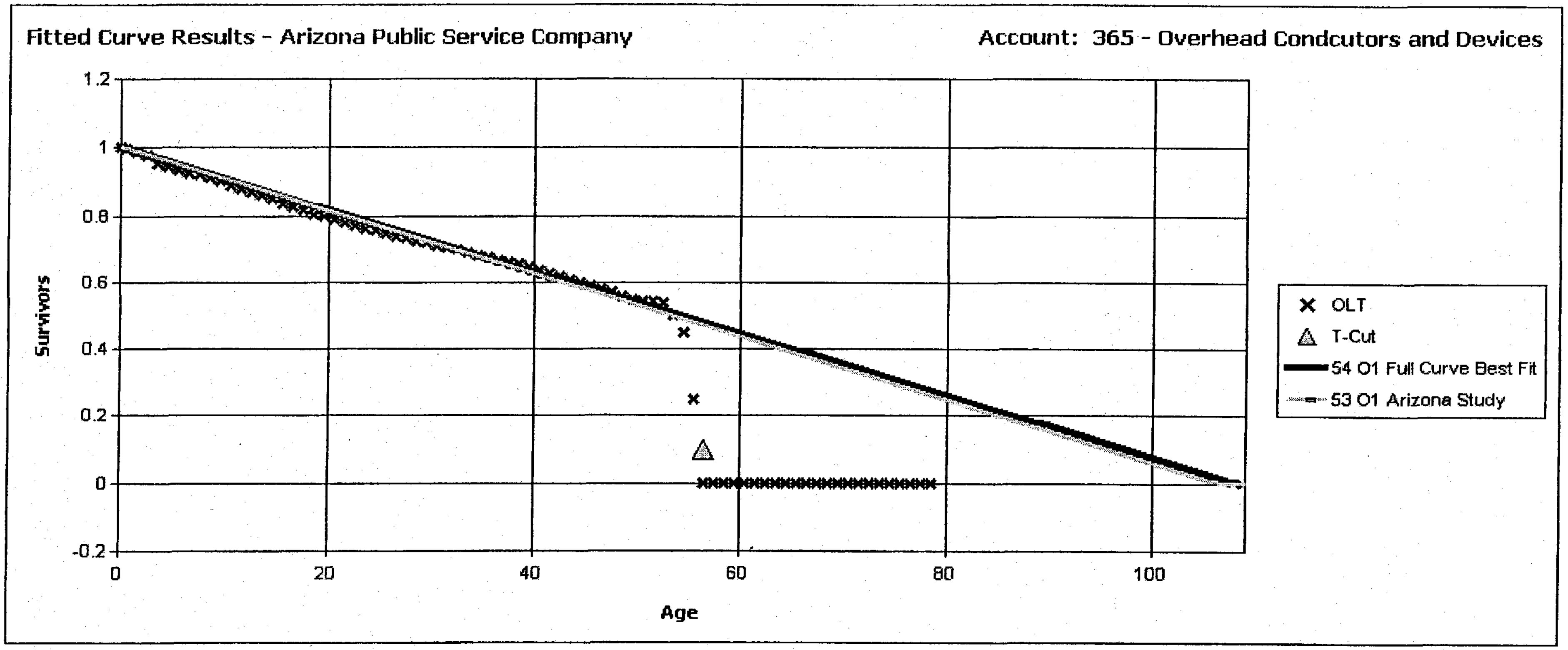
Best Fit Curve Results
Arizona Public Service Company
Account: 365 - Overhead Condcutors and Devices

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
O1	54.0	10,628.111
O2	61.0	10,631.922
R0.5	51.0	10,732.699
O3	83.0	10,746.764
S-0.5	52.0	10,900.979
L0	57.0	10,909.812
O4	100.0	11,282.159
R1	49.0	11,329.647
L0.5	55.0	11,418.404
S0	50.0	11,783.442
L1	53.0	12,319.641
R1.5	48.0	12,402.869
S0.5	49.0	12,837.588
L1.5	52.0	13,644.374
R2	48.0	14,065.163
S1	49.0	14,325.619
L2	51.0	15,598.356
S1.5	49.0	15,970.244
R2.5	48.0	16,104.946
S2	48.0	18,048.829
R3	48.0	18,689.101
L3	50.0	20,007.657
S3	49.0	22,367.475
R4	49.0	24,108.903
L4	50.0	25,347.675
S4	49.0	28,443.633
L5	50.0	31,316.639
R5	50.0	31,866.381
S5	51.0	34,757.474
S6	52.0	40,932.583
SQ	55.0	56,926.182

Analytical Parameters

OLT Placement Band:	1915 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	56.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1915 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	56.5

Arizona Public Service Company

Distribution Plant

366.00 - Underground Conduit

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 366 - Underground Conduit

Depreciable Balance $425,723,116

	APS	Snavely King
Depreciable Reserve	$51,496,065	$26,924,767
Reserve Percent	12.1%	6.3%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	60.0	55.0	86.0
Iowa Curve	R2	R1.5	O1
Remaining Life (Yrs.)		49.4	82.4
Net Salvage (%)	(10)	(5)	0
Accrual ($)	7,535,299	8,009,076	4,837,438
Rate (%)	1.77%	1.88%	1.14%

****

Comment: Mr. Weidmayer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) However, Mr. Wiedmayer's statistical study was deficient and incomplete because he excluded a substantial portion of the OLT. The complete statistical analysis results is a 86-O1 life and curve. Based on SK analysis and MJM 1-4 response, the 86-O1 is a reasonable selection.

Observed Life Table Results
Arizona Public Service Company
Account: 366 - Underground Conduit

Age	Cumulative Survivors
0	1.0000
0.5	0.9989
1.5	0.9956
2.5	0.9927
3.5	0.9879
4.5	0.9863
5.5	0.9843
6.5	0.9821
7.5	0.9797
8.5	0.9761
9.5	0.9716
10.5	0.9658
11.5	0.9597
12.5	0.9492
13.5	0.9329
14.5	0.9122
15.5	0.8908
16.5	0.8836
17.5	0.8769
18.5	0.8706
19.5	0.8634
20.5	0.8551
21.5	0.8443
22.5	0.8377
23.5	0.8302
24.5	0.8236
25.5	0.8151
26.5	0.8088
27.5	0.8041
28.5	0.7997
29.5	0.7970
30.5	0.7942
31.5	0.7910
32.5	0.7889
33.5	0.7858
34.5	0.7836
35.5	0.7791
36.5	0.7774
37.5	0.7750
38.5	0.7736
39.5	0.7686
40.5	0.7678
41.5	0.7672
42.5	0.7672
43.5	0.7654
44.5	0.7642

Observed Life Table Results
Arizona Public Service Company
Account: 366 - Underground Conduit

Age	Cumulative Survivors
45.5	0.7577
46.5	0.7485
47.5	0.7284
48.5	0.7217
49.5	0.7166
50.5	0.7077
51.5	0.7017
52.5	0.6734

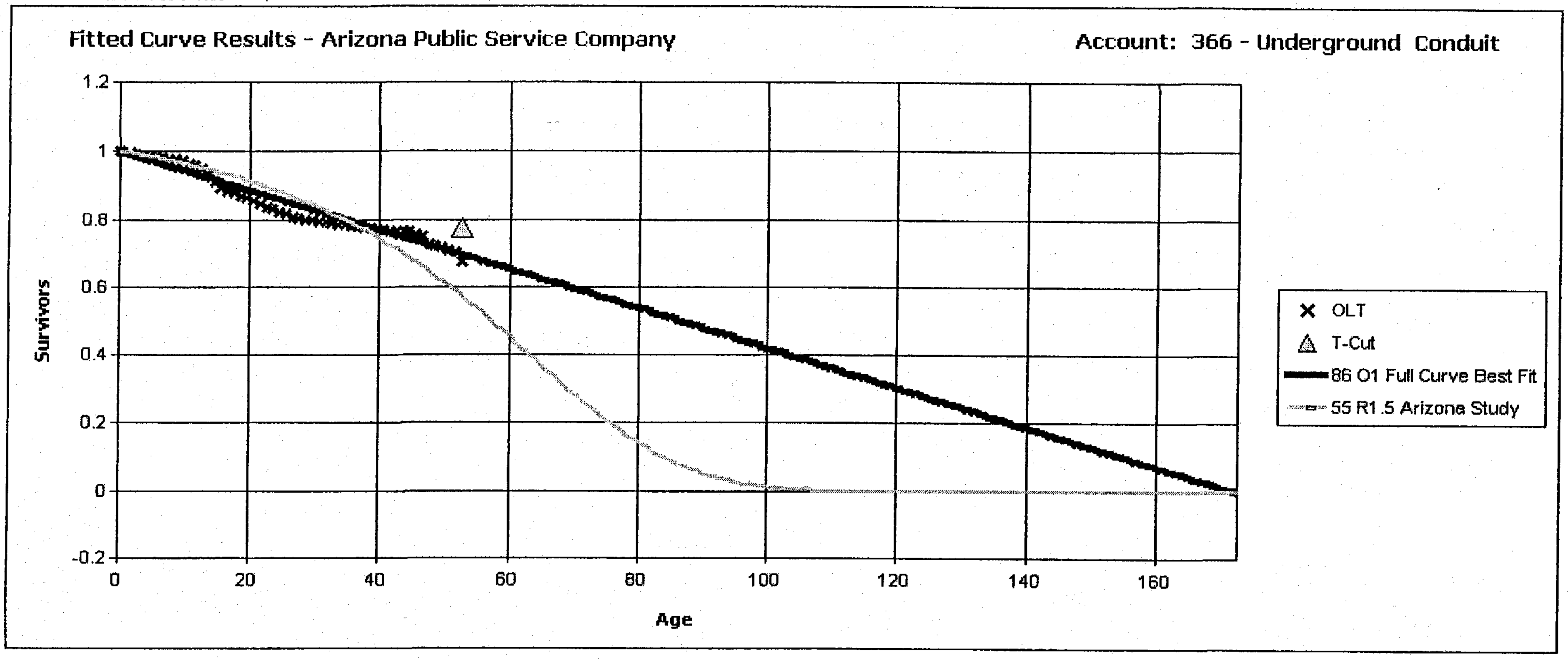
Best Fit Curve Results
Arizona Public Service Company
Account: 366 - Underground Conduit

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
O1	86.0	10,223.238
O2	97.0	10,223.314
R0.5	74.0	10,286.235
S-0.5	74.0	10,388.656
L0	85.0	10,418.043
R1	65.0	10,488.128
L0.5	76.0	10,749.622
S0	67.0	10,865.567
R1.5	61.0	10,874.729
L1	71.0	11,344.874
S0.5	63.0	11,379.584
R2	58.0	11,574.757
L1.5	66.0	11,977.959
S1	60.0	12,177.480
O3	100.0	12,298.004
R2.5	55.0	12,381.223
S1.5	58.0	12,933.548
L2	63.0	13,089.738
R3	54.0	13,538.034
S2	57.0	14,010.828
L3	58.0	15,101.879
R4	53.0	15,831.131
S3	55.0	15,992.994
L4	55.0	17,009.239
S4	53.0	18,476.847
R5	52.0	19,202.566
L5	54.0	19,347.617
O4	100.0	19,799.605
S5	53.0	20,656.035
S6	53.0	22,587.887
SQ	53.0	26,963.096

Analytical Parameters

OLT Placement Band:	0 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	6
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	52.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	0 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	6
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	52.5

Arizona Public Service Company

366 - Underground Conduit

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **86 O1**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2002	0.5	41,614,847	86.00	85.75	483,894	41,495,010
2001	1.5	29,420,538	86.00	85.25	342,099	29,164,772
2000	2.5	32,987,032	86.00	84.75	383,570	32,508,481
1999	3.5	34,476,600	86.00	84.25	400,891	33,776,000
1998	4.5	34,572,458	86.00	83.75	402,005	33,668,913
1997	5.5	32,635,859	86.00	83.25	379,487	31,593,188
1996	6.5	33,588,584	86.00	82.75	390,565	32,320,198
1995	7.5	25,028,025	86.00	82.25	291,024	23,937,399
1994	8.5	31,173,609	86.00	81.75	362,484	29,633,946
1993	9.5	57,372,387	86.00	81.25	667,121	54,205,217
1992	10.5	6,821,566	86.00	80.75	79,321	6,405,331
1991	11.5	12,390,708	86.00	80.25	144,078	11,562,621
1990	12.5	14,180,385	86.00	79.75	164,888	13,150,250
1989	13.5	5,049,619	86.00	79.25	58,717	4,653,432
1988	14.5	8,270,510	86.00	78.75	96,169	7,573,533
1987	15.5	3,502,542	86.00	78.25	40,727	3,187,011
1986	16.5	2,068,865	86.00	77.75	24,057	1,870,461
1985	17.5	807,659	86.00	77.25	9,391	725,509
1984	18.5	2,305,965	86.00	76.75	26,814	2,058,010
1983	19.5	1,938,483	86.00	76.25	22,541	1,718,773
1982	20.5	1,551,508	86.00	75.75	18,041	1,366,638
1981	21.5	1,645,882	86.00	75.25	19,138	1,440,198
1980	22.5	1,387,862	86.00	74.75	16,138	1,206,354
1979	23.5	806,133	86.00	74.25	9,374	696,018
1978	24.5	914,914	86.00	73.75	10,639	784,621
1977	25.5	566,902	86.00	73.25	6,592	482,874
1976	26.5	375,510	86.00	72.75	4,366	317,667
1975	27.5	721,226	86.00	72.25	8,386	605,937
1974	28.5	529,817	86.00	71.75	6,161	442,045
1973	29.5	426,546	86.00	71.25	4,960	353,402
1972	30.5	626,048	86.00	70.75	7,280	515,054
1971	31.5	802,661	86.00	70.25	9,333	655,689
1970	32.5	865,918	86.00	69.75	10,069	702,329
1969	33.5	256,328	86.00	69.25	2,981	206,412
1968	34.5	734,600	86.00	68.75	8,542	587,278

Arizona Public Service Company

366 - Underground Conduit

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **86 O1**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1967	35.5	811,950	86.00	68.25	9,441	644,395
1966	36.5	111,690	86.00	67.75	1,299	87,992
1965	37.5	129,504	86.00	67.25	1,506	101,274
1964	38.5	422,425	86.00	66.75	4,912	327,885
1963	39.5	121,575	86.00	66.25	1,414	93,659
1962	40.5	45,785	86.00	65.75	532	35,006
1961	41.5	943,757	86.00	65.25	10,974	716,082
1960	42.5	16,994	86.00	64.75	198	12,796
1959	43.5	-	86.00	64.25	-	-
1958	44.5	13,047	86.00	63.75	152	9,672
1957	45.5	17,412	86.00	63.25	202	12,807
1956	46.5	670,881	86.00	62.75	7,801	489,534
		425,723,116			4,950,269	408,101,671

AVERAGE SERVICE LIFE	86.00
AVERAGE REMAINING LIFE	82.44

Arizona Public Service Company

Distribution Plant

367.00 - Underground Conductors and Devices

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 367 - Underground Conductors and Devices

Depreciable Balance $805,505,783

	APS	Snavely King
Depreciable Reserve	$227,200,974	$258,865,205
Reserve Percent	28.2%	32.1%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	27.0	29.0	29.0
Iowa Curve	R2	L1	L1
Remaining Life (Yrs.)		22.9	22.9
Net Salvage (%)	(10)	-5.0	0
Accrual ($)	35,603,356	27,036,316	23,870,768
Rate (%)	4.42%	3.36%	2.96%

****

Comment: We accept Company proposal based on SK analysis

Observed Life Table Results
Arizona Public Service Company
Account: 367 - Underground Conductors and Devices

Age	Cumulative Survivors
0	1.0000
0.5	0.9992
1.5	0.9949
2.5	0.9885
3.5	0.9797
4.5	0.9733
5.5	0.9655
6.5	0.9587
7.5	0.9534
8.5	0.9431
9.5	0.9333
10.5	0.9178
11.5	0.8994
12.5	0.8719
13.5	0.8508
14.5	0.8216
15.5	0.7942
16.5	0.7631
17.5	0.7349
18.5	0.6972
19.5	0.6658
20.5	0.6414
21.5	0.6120
22.5	0.5835
23.5	0.5669
24.5	0.5504
25.5	0.5329
26.5	0.5169
27.5	0.4973
28.5	0.4741
29.5	0.4646
30.5	0.4504
31.5	0.4369
32.5	0.4293
33.5	0.4086
34.5	0.3697
35.5	0.3565
36.5	0.3186
37.5	0.2433
38.5	0.2412
39.5	0.2379
40.5	0.2357
41.5	0.1981
42.5	0.1049
43.5	0.1033
44.5	0.1019

Observed Life Table Results
Arizona Public Service Company
Account: 367 - Underground Conductors and Devices

Age	Cumulative Survivors
45.5	0.1001
46.5	0.0872
47.5	0.0840
48.5	0.0063
49.5	0.0055
50.5	0.0007
51.5	0.0000

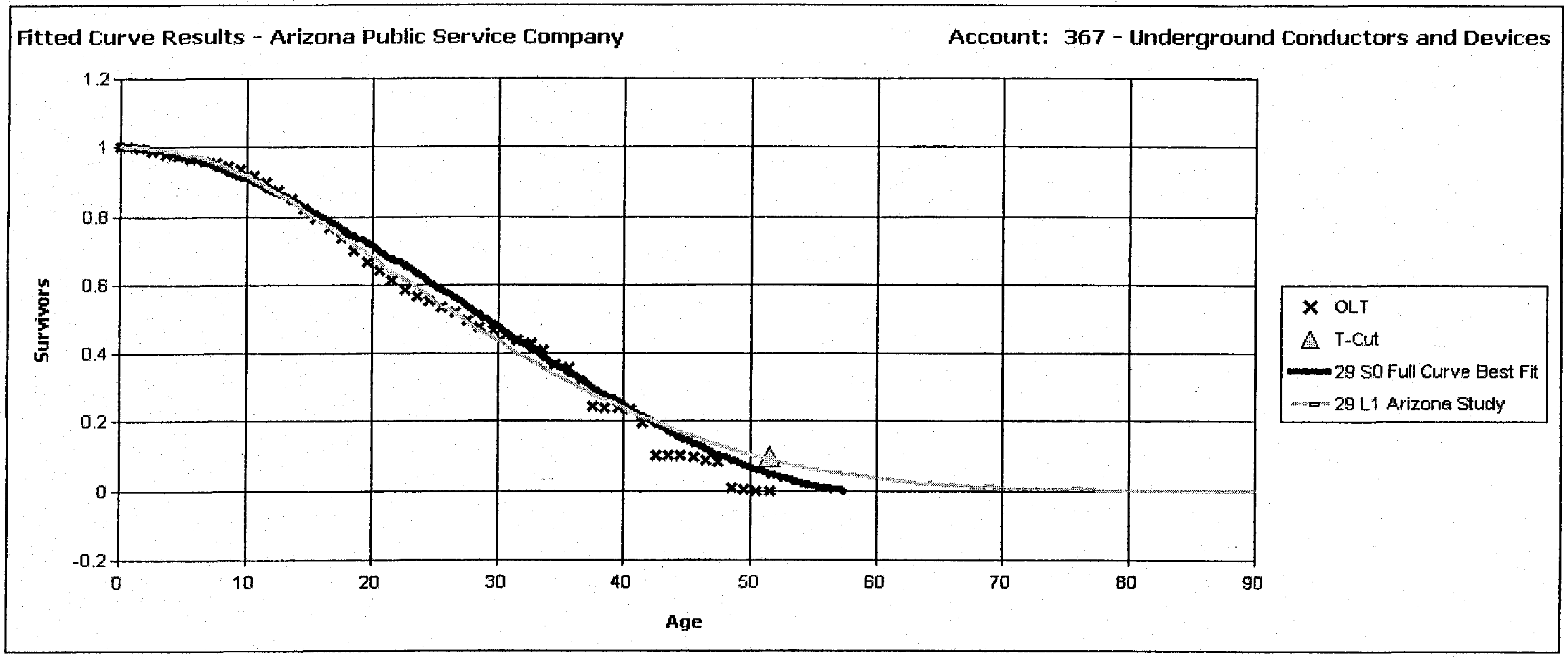
Best Fit Curve Results
Arizona Public Service Company
Account: 367 - Underground Conductors and Devices

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
S0	29.0	18,543.204
S0.5	29.0	18,661.993
R1	29.0	18,720.641
L1	29.0	18,901.455
L1.5	29.0	18,908.846
R0.5	28.0	18,963.542
S-0.5	28.0	19,011.993
R1.5	29.0	19,207.217
S1	29.0	19,327.234
L2	30.0	19,433.151
L0.5	29.0	19,504.182
O1	27.0	20,221.567
R2	29.0	20,464.106
S1.5	30.0	20,515.441
L0	29.0	20,544.278
O2	30.0	21,415.669
S2	30.0	22,113.579
R2.5	30.0	22,295.321
L3	30.0	22,327.633
R3	30.0	24,771.635
O3	37.0	25,709.645
S3	30.0	26,314.953
O4	48.0	27,954.098
L4	30.0	28,152.779
R4	30.0	30,276.022
S4	30.0	32,831.496
L5	30.0	34,752.540
R5	30.0	37,694.340
S5	30.0	39,542.788
S6	30.0	45,560.865
SQ	28.0	57,012.140

Analytical Parameters

OLT Placement Band:	1940 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	65
Life Increment Parameter:	1
Max Age (T-Cut):	51.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1940 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	4
Maximum Life Parameter:	65
Life Increment Parameter:	1
Maximum Age (T-Cut):	51.5

Arizona Public Service Company

Distribution Plant

368.00 - Line Transformers

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 368 - Line Transformers

Depreciable Balance $486,837,053

	APS	Snavely King
Depreciable Reserve	$188,298,226	$235,537,009
Reserve Percent	38.7%	48.4%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)		36.0	36.0
Iowa Curve		R3	R3
Remaining Life (Yrs.)		24.6	24.6
Net Salvage (%)		(5)	0
Accrual ($)	16,503,776	13,147,552	10,215,449
Rate (%)	3.39%	2.70%	2.10%

****

Comment: Mr. Weidmayer relied on statistical analysis for his account. (6F Depreciation Study, p. 11-24.) SK analysis shows the statistics to be marginal for a complete statistical analysis. While the complete results show a 42 R2.5, the information provided in MJM 1-4 provides a reasonable analysis of this account. SK accepts the company proposed assessment. Workpapers from the response to Data Request MJM 1-1 do not agree with Depreciation Study, Attachment LLR-4. This SK analysis uses the Depreciation Study.

Observed Life Table Results
Arizona Public Service Company
Account: 368 - Line Transformers

Age	Cumulative Survivors
0	1.0000
0.5	0.9988
1.5	0.9957
2.5	0.9934
3.5	0.9912
4.5	0.9887
5.5	0.9866
6.5	0.9824
7.5	0.9800
8.5	0.9775
9.5	0.9752
10.5	0.9727
11.5	0.9699
12.5	0.9663
13.5	0.9619
14.5	0.9576
15.5	0.9514
16.5	0.9454
17.5	0.9393
18.5	0.9333
19.5	0.9284
20.5	0.9220
21.5	0.8945
22.5	0.8859
23.5	0.8785
24.5	0.8687
25.5	0.8607
26.5	0.8549
27.5	0.8416
28.5	0.8264
29.5	0.8148

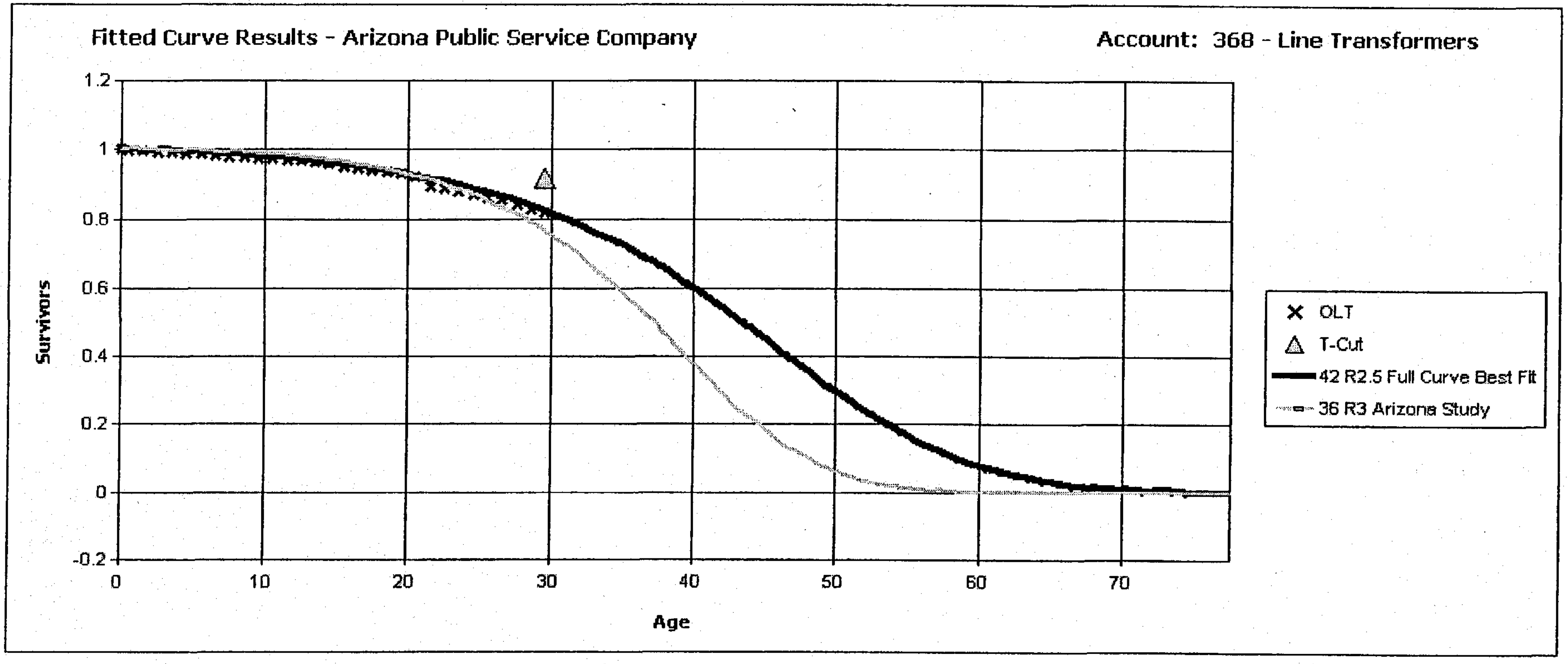
Best Fit Curve Results
Arizona Public Service Company
Account: 368 - Line Transformers

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
R2.5	42.0	10,005.524
L1.5	53.0	10,008.609
S0.5	54.0	10,008.990
R2	47.0	10,016.162
S1	48.0	10,017.249
R3	38.0	10,035.407
S1.5	44.0	10,037.108
L2	47.0	10,042.454
R1.5	54.0	10,066.694
S2	41.0	10,100.532
L3	40.0	10,154.724
L1	54.0	10,160.041
S0	54.0	10,169.935
R4	35.0	10,192.791
S3	37.0	10,254.454
L4	35.0	10,300.567
R1	54.0	10,341.450
S4	34.0	10,527.666
R5	32.0	10,570.522
L5	33.0	10,587.419
L0.5	54.0	10,737.532
S5	32.0	10,830.510
S-0.5	54.0	10,910.143
R0.5	54.0	11,083.689
S6	31.0	11,128.134
L0	54.0	11,773.808
SQ	30.0	11,848.397
O1	54.0	12,269.979
O2	54.0	13,398.521
O3	54.0	19,432.914
O4	54.0	28,891.428

Analytical Parameters

OLT Placement Band:	1972 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	3
Maximum Life Parameter:	54
Life Increment Parameter:	1
Max Age (T-Cut):	29.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1972 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	3
Maximum Life Parameter:	54
Life Increment Parameter:	1
Maximum Age (T-Cut):	29.5

Arizona Public Service Company

Distribution Plant

369.00 - Services

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 369 - Services

Depreciable Balance $242,404,812

	APS	Snavely King
Depreciable Reserve	86,204,425	$91,086,515
Reserve Percent	35.6%	37.6%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	30.0	37.0	37.0
Iowa Curve	R2	S2	S2
Remaining Life (Yrs.)		27.9	27.9
Net Salvage (%)	(3)	(10)	0
Accrual ($)	11,150,621	6,463,178	5,423,595
Rate (%)	4.60%	2.67%	2.24%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We accept this judgment based on SK analysis and the already proposed increase in service life and because there is insufficient data to conduct a meaningful statistical analysis.
Workpapers from the response to Data Request MJM 1-1 do not agree with Depreciation Study, Attachment LLR-4. This SK analysis uses the Depreciation Study.

Arizona Public Service Company

Distribution Plant

370.00 - Meters

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 370 - Meters - Distribution Plant

Depreciable Balance $91,330,710

	APS	Snavely King
Depreciable Reserve	$36,185,262	$34,836,184
Reserve Percent	39.6%	38.1%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	26.0	23.0	29.0
Iowa Curve	R1.5	R1	L0
Remaining Life (Yrs.)		13.5	21.8
Net Salvage (%)	0	0	0
Accrual ($)	4,146,414	4,086,660	2,596,256
Rate (%)	4.54%	4.47%	2.84%

****

Comment: Mr. Weidmayer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) However, Mr. Wiedmayer's statistical study was deficient and incomplete because he excluded a substantial portion of the OLT. The complete statistical analysis results is a 29-L0 life and curve.
Workpapers from the response to Data Request MJM 1-1 do not agree with Depreciation Study, Attachment LLR-4. This SK analysis uses the Depreciation Study.

Observed Life Table Results
Arizona Public Service Company
Account: 370 - Meters

Age	Cumulative Survivors
0	1.0000
0.5	0.9983
1.5	0.9948
2.5	0.9894
3.5	0.9818
4.5	0.9690
5.5	0.9482
6.5	0.9254
7.5	0.8998
8.5	0.8613
9.5	0.8298
10.5	0.7979
11.5	0.7688
12.5	0.7406
13.5	0.7150
14.5	0.6912
15.5	0.6683
16.5	0.6470
17.5	0.6288
18.5	0.6130
19.5	0.5957
20.5	0.5803
21.5	0.5659
22.5	0.5532
23.5	0.5413
24.5	0.5320
25.5	0.5245
26.5	0.5175
27.5	0.5110
28.5	0.5064
29.5	0.5029

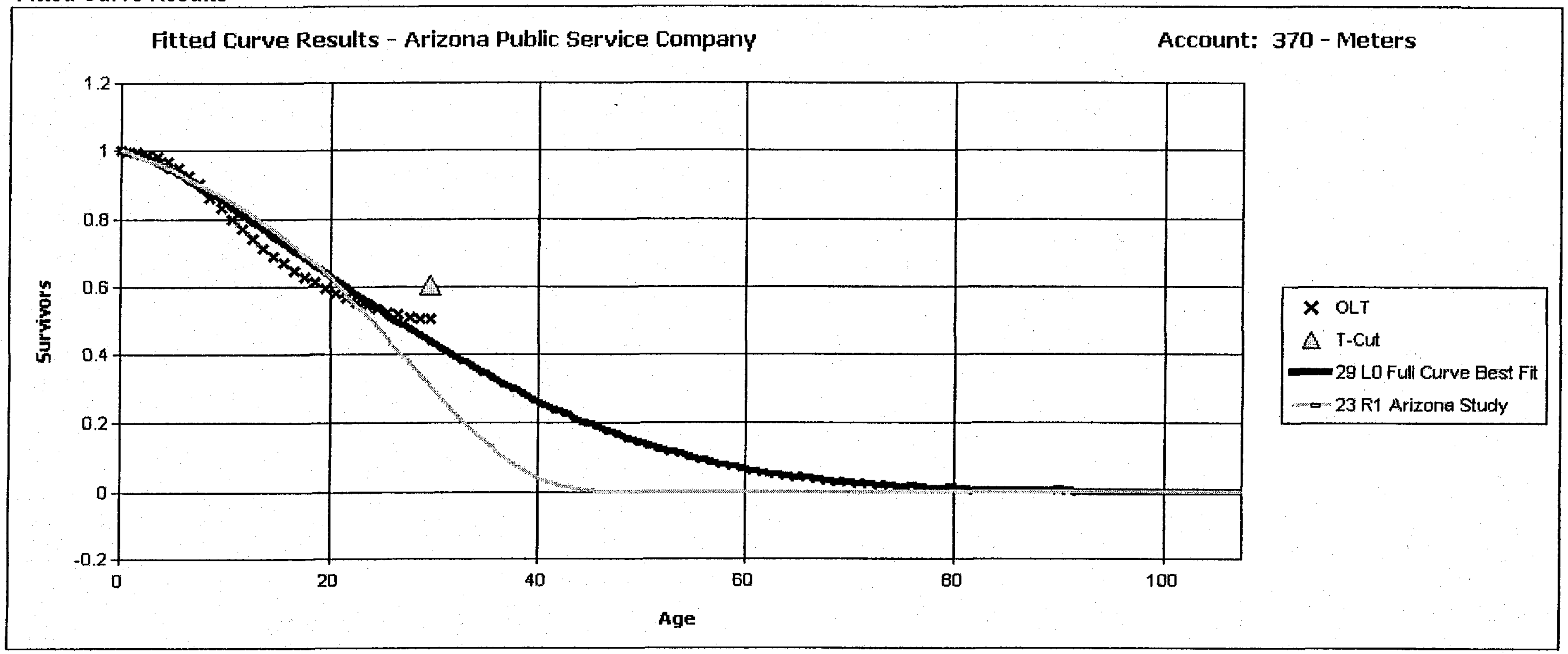
Best Fit Curve Results
Arizona Public Service Company
Account: 370 - Meters

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
L0	29.0	10,263.494
O2	31.0	10,386.567
O1	27.5	10,387.200
S-0.5	26.5	10,401.967
O3	42.0	10,418.689
L0.5	28.0	10,434.023
O4	56.5	10,460.736
R0.5	26.0	10,481.404
S0	25.5	10,731.035
L1	27.0	10,787.123
R1	25.0	10,850.421
S0.5	25.0	11,326.196
R1.5	24.5	11,535.462
L1.5	26.5	11,564.322
S1	25.0	12,144.650
R2	24.5	12,515.099
L2	26.0	12,648.617
S1.5	25.0	13,206.547
R2.5	24.5	13,875.029
S2	25.0	14,501.167
R3	25.0	15,508.951
L3	25.5	15,565.657
S3	25.0	17,448.855
R4	25.5	19,137.240
L4	25.5	19,433.619
S4	25.5	21,708.220
L5	26.0	23,665.703
R5	26.0	24,374.099
S5	26.5	26,140.036
S6	27.0	30,333.731
SQ	29.5	40,270.675

Analytical Parameters

OLT Placement Band:	1972 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	3.5
Maximum Life Parameter:	60
Life Increment Parameter:	0.5
Max Age (T-Cut):	29.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1972 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	3.5
Maximum Life Parameter:	60
Life Increment Parameter:	0.5
Maximum Age (T-Cut):	29.5

Arizona Public Service Company

370 - Meters

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **29 L0**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2002	0.5	-	29.00	28.56	-	-
2001	1.5	-	29.00	27.82	-	-
2000	2.5	-	29.00	27.15	-	-
1999	3.5	-	29.00	26.54	-	-
1998	4.5	-	29.00	25.97	-	-
1997	5.5	-	29.00	25.44	-	-
1996	6.5	-	29.00	24.93	-	-
1995	7.5	6,598,188	29.00	24.44	227,524	5,561,502
1994	8.5	11,709,742	29.00	23.98	403,784	9,682,902
1993	9.5	6,361,178	29.00	23.54	219,351	5,162,520
1992	10.5	14,352,966	29.00	23.11	494,930	11,436,149
1991	11.5	4,278,397	29.00	22.69	147,531	3,347,755
1990	12.5	5,499,803	29.00	22.29	189,648	4,227,129
1989	13.5	7,840,313	29.00	21.90	270,356	5,920,008
1988	14.5	5,562,400	29.00	21.51	191,807	4,126,404
1987	15.5	5,259,712	29.00	21.14	181,369	3,833,510
1986	16.5	1,770,643	29.00	20.77	61,057	1,267,920
1985	17.5	3,410,636	29.00	20.40	117,608	2,399,509
1984	18.5	3,016,539	29.00	20.05	104,019	2,085,077
1983	19.5	1,329,451	29.00	19.69	45,843	902,839
1982	20.5	1,201,945	29.00	19.35	41,446	801,948
1981	21.5	1,730,571	29.00	19.01	59,675	1,134,416
1980	22.5	1,941,619	29.00	18.68	66,952	1,250,444
1979	23.5	1,492,217	29.00	18.35	51,456	944,167
1978	24.5	959,923	29.00	18.03	33,101	596,707
1977	25.5	1,197,492	29.00	17.71	41,293	731,315
1976	26.5	423,807	29.00	17.40	14,614	254,271
1975	27.5	335,523	29.00	17.09	11,570	197,762
1974	28.5	898,193	29.00	16.79	30,972	520,084
1973	29.5	847,786	29.00	16.50	29,234	482,241
1972	30.5	718,911	29.00	16.20	24,790	401,715
1971	31.5	322,391	29.00	15.92	11,117	176,961
1970	32.5	290,108	29.00	15.64	10,004	156,422
1969	33.5	242,895	29.00	15.36	8,376	128,642
1968	34.5	158,278	29.00	15.09	5,458	82,338
1967	35.5	103,616	29.00	14.82	3,573	52,942

Arizona Public Service Company

370 - Meters

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 29 L0

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1966	36.5	135,542	29.00	14.55	4,674	68,019
1965	37.5	84,083	29.00	14.29	2,899	41,440
1964	38.5	156,046	29.00	14.04	5,381	75,526
1963	39.5	133,558	29.00	13.78	4,605	63,479
1962	40.5	144,843	29.00	13.53	4,995	67,600
1961	41.5	134,644	29.00	13.29	4,643	61,703
1960	42.5	113,182	29.00	13.05	3,903	50,925
1959	43.5	100,131	29.00	12.81	3,453	44,233
1958	44.5	70,591	29.00	12.58	2,434	30,612
1957	45.5	57,180	29.00	12.35	1,972	24,341
1956	46.5	40,316	29.00	12.12	1,390	16,845
1955	47.5	43,566	29.00	11.89	1,502	17,866
1954	48.5	40,421	29.00	11.67	1,394	16,268
1953	49.5	33,308	29.00	11.45	1,149	13,154
1952	50.5	25,024	29.00	11.24	863	9,697
1951	51.5	107,821	29.00	11.02	3,718	40,990
1950	52.5	14,865	29.00	10.82	513	5,544
1949	53.5	8,078	29.00	10.61	279	2,955
1948	54.5	2,228	29.00	10.40	77	799
1947	55.5	5,064	29.00	10.20	175	1,782
1946	56.5	5,980	29.00	10.00	206	2,063
1945	57.5	4,531	29.00	9.81	156	1,532
1944	58.5	2,596	29.00	9.61	90	860
1943	59.5	1,982	29.00	9.42	68	644
1942	60.5	1,464	29.00	9.23	50	466
1941	61.5	3,060	29.00	9.04	106	954
1940	62.5	788	29.00	8.86	27	241
1939	63.5	281	29.00	8.67	10	84
1938	64.5	628	29.00	8.49	22	184
1937	65.5	342	29.00	8.31	12	98
1936	66.5		29.00	8.14	-	-
1935	67.5		29.00	7.96	-	-
1934	68.5		29.00	7.79	-	-
1933	69.5	321	29.00	7.61	11	84
1932	70.5		29.00	7.44	-	-
1931	71.5	491	29.00	7.27	17	123

Arizona Public Service Company

370 - Meters

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **29 L0**

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1930	72.5	356	29.00	7.11	12	87
1929	73.5	2,120	29.00	6.94	73	507
1928	74.5	-	29.00	6.77	-	-
1927	75.5	-	29.00	6.61	-	-
1926	76.5	-	29.00	6.44	-	-
1925	77.5	-	29.00	6.28	-	-
1924	78.5	-	29.00	6.12	-	-
1923	79.5	-	29.00	5.96	-	-
1922	80.5	36	29.00	5.80	1	7
		91,330,710			3,149,335	68,527,310

AVERAGE SERVICE LIFE	29.00
AVERAGE REMAINING LIFE	21.76

Arizona Public Service Company

Distribution Plant

371.00 - Electronic Meters

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 370.1 - Electronic Meters

Depreciable Balance $54,691,249

	APS	Snavely King
Depreciable Reserve	$11,298,055	$8,612,961
Reserve Percent	15.7%	20.7%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	26	12	26
Iowa Curve	R1.5	S2	R1.5
Remaining Life (Yrs.)		8.7	23.3
Net Salvage (%)	0	0	0
Accrual ($)	2,482,983	4,987,610	1,975,913
Rate (%)	4.54%	9.12%	3.61%

****

Comment: According to Mr. Wiedmayer's study, p. 11-29, this is one of the accounts where the survivor curve estimates was based on judgments which considered the nature of the plant and equipment, reviews of available historical retirement data and general knowledge of service lives for similar equipment and other electric companies. (6F Depreciation Study, p.11-29.)
We do not accept Company judgment because no data was provided and the life is not supported. SK analysis recommends keeping the existing rates.

Arizona Public Service Company

370.1 - Electronic Meters

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **26 R1.5**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	8,127,704	26.00	25.59	312,604	7,999,016
2001	1.5	7,821,267	26.00	24.77	300,818	7,451,860
2000	2.5	8,309,433	26.00	23.96	319,594	7,658,889
1999	3.5	6,758,092	26.00	23.17	259,927	6,021,425
1998	4.5	16,140,488	26.00	22.38	620,788	13,890,899
1997	5.5	2,336	26.00	21.60	90	1,940
1996	6.5	7,531,929	26.00	20.82	289,690	6,032,539
		54,691,249			2,103,510	49,056,568

AVERAGE SERVICE LIFE	26.00
AVERAGE REMAINING LIFE	23.32

Arizona Public Service Company

Distribution Plant

371 - Installations On Customer Premises

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 371 - Installations On Customer Premises

Depreciable Balance $25,335,831

	APS	Snavely King
Depreciable Reserve	8,708,344	$3,863,126
Reserve Percent	34.4%	15.2%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	30.0	30.0	50.0
Iowa Curve	R0.5	R1	O2
Remaining Life (Yrs.)		22.9	45.0
Net Salvage (%)	(30)	(20)	0.0
Accrual ($)	884,221	945,981	477,065
Rate (%)	3.49%	3.73%	1.88%

****

Comment: Mr. Wiedmayer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) However, Mr. Wiedmayer's statistical study was deficient and incomplete because he excluded a substantial portion of the OLT. The complete statistical analysis results is a 50-O2 life and curve.

Observed Life Table Results
Arizona Public Service Company
Account: 371 - Installations on Customers Premises

Age	Cumulative Survivors
BAND	
0	1.0000
0.5	0.9987
1.5	0.9909
2.5	0.9809
3.5	0.9653
4.5	0.9456
5.5	0.9290
6.5	0.9168
7.5	0.9027
8.5	0.8860
9.5	0.8706
10.5	0.8534
11.5	0.8386
12.5	0.8243
13.5	0.8121
14.5	0.7977
15.5	0.7844
16.5	0.7744
17.5	0.7626
18.5	0.7519
19.5	0.7410
20.5	0.7314
21.5	0.7215
22.5	0.7134
23.5	0.7029
24.5	0.6938
25.5	0.6873
26.5	0.6758
27.5	0.6703
28.5	0.6661
29.5	0.6626
30.5	0.6583
31.5	0.6550
32.5	0.6489
33.5	0.6455
34.5	0.6418
35.5	0.6391
36.5	0.6376
37.5	0.5277
38.5	0.5277

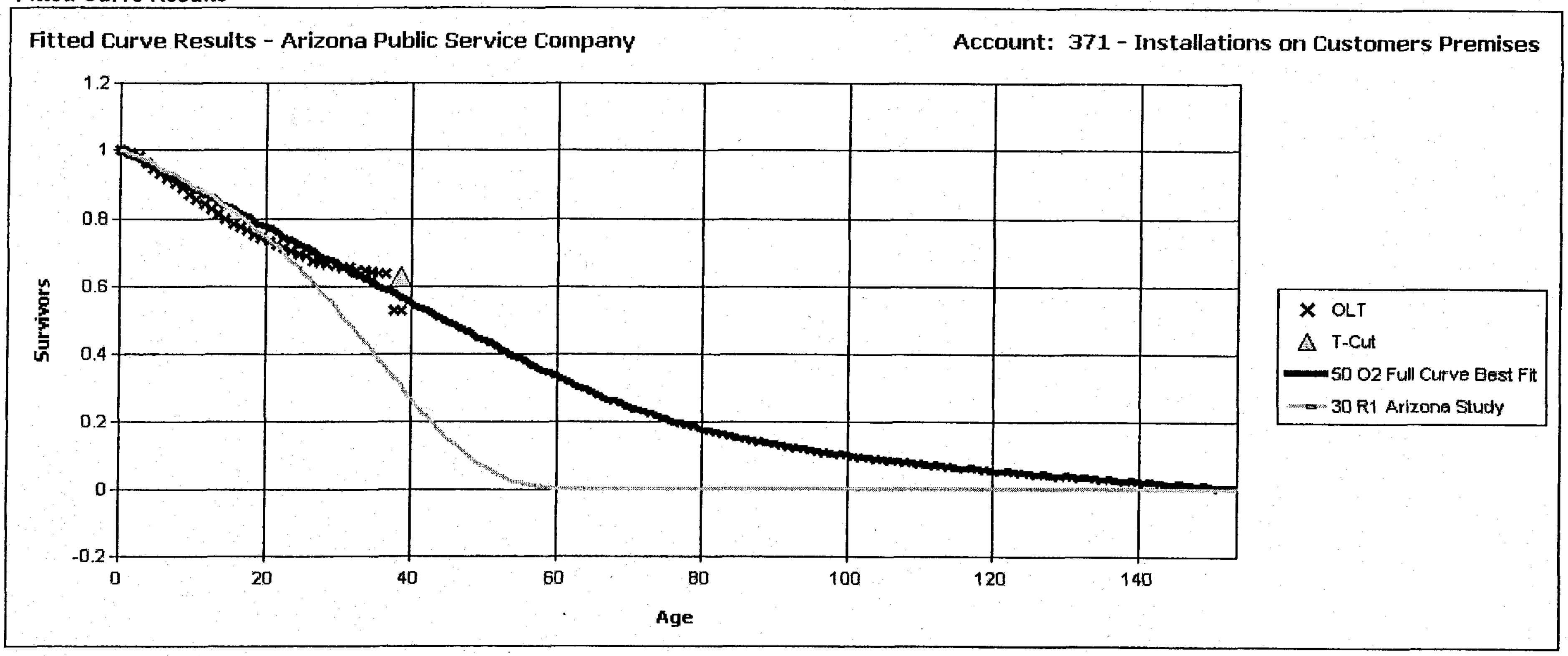
Best Fit Curve Results
Arizona Public Service Company
Account: 371 - Installations on Customers Premises

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
O2	50.0	10,233.310
O1	44.0	10,233.979
R0.5	40.0	10,452.766
L0	46.0	10,544.322
S-0.5	41.0	10,582.651
O3	60.0	10,617.992
R1	38.0	10,942.165
L0.5	43.0	11,018.962
S0	39.0	11,298.869
R1.5	37.0	11,697.328
L1	41.0	11,736.432
S0.5	38.0	12,069.160
L1.5	40.0	12,716.355
R2	36.0	12,789.698
S1	37.0	13,116.758
R2.5	36.0	14,079.064
L2	39.0	14,116.240
S1.5	37.0	14,218.683
O4	60.0	14,872.085
S2	36.0	15,586.724
R3	36.0	15,721.367
L3	38.0	17,036.000
S3	36.0	18,308.156
R4	36.0	18,915.864
L4	37.0	20,117.644
S4	36.0	21,882.338
R5	36.0	23,435.459
L5	37.0	23,446.134
S5	37.0	25,243.123
S6	37.0	28,131.044
SQ	39.0	35,412.735

Analytical Parameters

OLT Placement Band:	1951 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	5
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	38.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1951 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	5
Maximum Life Parameter:	60
Life Increment Parameter:	1
Maximum Age (T-Cut):	38.5

Arizona Public Service Company

371 - Installations on Customers Premises

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **50 O2**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	2,099,294	50.00	49.60	41,986	2,082,665
2001	1.5	1,464,506	50.00	49.16	29,290	1,440,039
2000	2.5	1,953,834	50.00	48.73	39,077	1,904,092
1999	3.5	1,031,626	50.00	48.29	20,633	996,367
1998	4.5	1,367,898	50.00	47.86	27,358	1,309,264
1997	5.5	1,807,630	50.00	47.42	36,153	1,714,507
1996	6.5	1,498,224	50.00	46.99	29,964	1,408,128
1995	7.5	1,312,957	50.00	46.56	26,259	1,222,733
1994	8.5	1,218,109	50.00	46.14	24,362	1,123,991
1993	9.5	1,561,175	50.00	45.71	31,224	1,427,265
1992	10.5	654,712	50.00	45.29	13,094	593,007
1991	11.5	1,053,735	50.00	44.87	21,075	945,539
1990	12.5	556,993	50.00	44.45	11,140	495,128
1989	13.5	834,611	50.00	44.03	16,692	734,943
1988	14.5	685,069	50.00	43.61	13,701	597,570
1987	15.5	330,275	50.00	43.20	6,606	285,364
1986	16.5	115,021	50.00	42.79	2,300	98,436
1985	17.5	581,552	50.00	42.38	11,631	492,953
1984	18.5	216,684	50.00	41.98	4,334	181,916
1983	19.5	193,604	50.00	41.57	3,872	160,980
1982	20.5	110,356	50.00	41.17	2,207	90,878
1981	21.5	532,894	50.00	40.78	10,658	434,606
1980	22.5	185,191	50.00	40.38	3,704	149,576
1979	23.5	91,606	50.00	39.99	1,832	73,273
1978	24.5	207,508	50.00	39.61	4,150	164,374
1977	25.5	77,533	50.00	39.22	1,551	60,822
1976	26.5	166,582	50.00	38.84	3,332	129,412
1975	27.5	297,419	50.00	38.47	5,948	228,820
1974	28.5	170,482	50.00	38.10	3,410	129,893
1973	29.5	211,604	50.00	37.73	4,232	159,670
1972	30.5	305,578	50.00	37.37	6,112	228,361
1971	31.5	278,615	50.00	37.01	5,572	206,216
1970	32.5	82,619	50.00	36.65	1,652	60,567
1969	33.5	341,280	50.00	36.31	6,826	247,812
1968	34.5	190,043	50.00	35.96	3,801	136,693

Arizona Public Service Company

371 - Installations on Customers Premises

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **50 O2**

			BG/VG Average			
Year	**Age**	**Surviving Investment**	**Service Life**	**Remaining Life**	**ASL Weights**	**RL Weights**
1967	35.5	331,929	50.00	35.63	6,639	236,514
1966	36.5	213,427	50.00	35.30	4,269	150,666
1965	37.5	1,003,656	50.00	34.97	20,073	702,012
		25,335,831			506,717	22,805,050

AVERAGE SERVICE LIFE 50.00
AVERAGE REMAINING LIFE 45.01

Arizona Public Service Company

Distribution Plant

373.00 - Street Lightning and Signal Systems

Arizona Public Service Company
Depreciation Study as of December 31, 2002

Distribution Plant

Account 373.00 - Street Lightning and Signal Systems

Depreciable Balance $57,185,737

	APS	Snavely King
Depreciable Reserve	19,618,266	$22,716,125
Reserve Percent	34.3%	39.7%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	32.0	35.0	35.0
Iowa Curve	R1.5	R2	R2
Remaining Life (Yrs.)		25.9	25.9
Net Salvage (%)	(20)	(20)	0
Accrual ($)	2,241,681	1,890,534	1,330,873
Rate (%)	3.92%	3.31%	2.33%

****

Comment: Mr. Wiedmayer relied on statistical analysis for his account. (6F Depreciation Study, p. 11-24.
While SK analytical analysis show a much long life for this account we believe the
results show marginal data for a complete statistical analysis.
We accept the Company results based on the analysis and responses to MJM 1-4.

.)

Observed Life Table Results
Arizona Public Service Company
Account: 373 - Street Lighting and Signal Systems

Age	Cumulative Survivors
0	1.0000
0.5	0.9995
1.5	0.9958
2.5	0.9893
3.5	0.9825
4.5	0.9789
5.5	0.9723
6.5	0.9679
7.5	0.9577
8.5	0.9525
9.5	0.9443
10.5	0.9386
11.5	0.9301
12.5	0.9232
13.5	0.9148
14.5	0.9067
15.5	0.8960
16.5	0.8887
17.5	0.8746
18.5	0.8680
19.5	0.8630
20.5	0.8539
21.5	0.8420
22.5	0.8310
23.5	0.8199
24.5	0.8176
25.5	0.8169
26.5	0.8166
27.5	0.8090
28.5	0.8024
29.5	0.7990

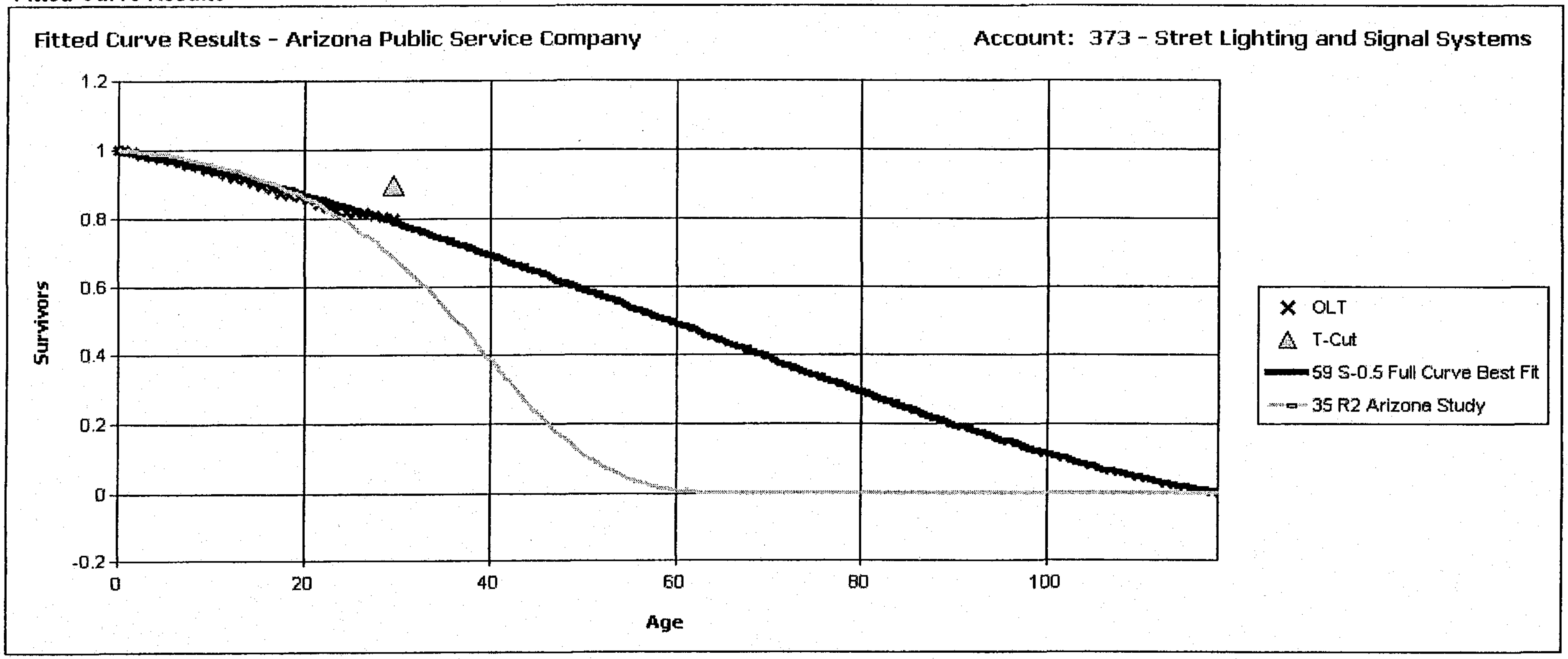
Best Fit Curve Results
Arizona Public Service Company
Account: 373 - Street Lighting and Signal Systems

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
S-0.5	59.0	10,013.713
R1	51.0	10,017.285
R0.5	60.0	10,030.901
R1.5	44.0	10,031.251
L0.5	58.0	10,038.349
S0	50.0	10,052.712
R2	39.0	10,109.533
L0	60.0	10,111.941
S0.5	45.0	10,121.355
L1	51.0	10,131.446
L1.5	46.0	10,226.111
R2.5	37.0	10,232.884
S1	41.0	10,270.081
O1	60.0	10,298.274
S1.5	39.0	10,412.049
L2	42.0	10,452.020
R3	35.0	10,468.633
S2	37.0	10,655.841
O2	60.0	10,711.939
L3	37.0	10,885.066
R4	32.0	11,005.306
S3	34.0	11,124.442
L4	34.0	11,333.419
S4	32.0	11,796.688
R5	31.0	11,931.733
L5	32.0	11,970.842
S5	31.0	12,429.720
S6	31.0	12,959.205
O3	60.0	13,921.292
SQ	30.0	13,987.335
O4	60.0	20,221.502

Analytical Parameters

OLT Placement Band:	1972 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	29.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1951 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	5
Maximum Life Parameter:	60
Life Increment Parameter:	1
Maximum Age (T-Cut):	38.5

Arizona Public Service Company

Section G

General Plant

Arizona Public Service Company

General Plant

390.0 - Structures & Improvements

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 390 - Structures & Improvements

Depreciable Balance $96,667,435

	APS	Snavely King
Depreciable Reserve	$30,654,079	$24,085,116
Reserve Percent	31.7%	24.9%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	30.0	39.0	39.0
Iowa Curve	R1	R1	R1
Remaining Life (Yrs.)		30.7	30.7
Net Salvage (%)	(5)	(15)	0
Accrual ($)	3,383,360	2,624,392	2,364,245
Rate (%)	3.50%	2.71%	2.45%

****

Comment: Mr. Wiedmayer relied on statistical analysis for his account. External information has no impact on statistical results. (6F Depreciation Study, p. 11-24.) However, Mr. Wiedmayer's statistical study excludes portions of the curve and does not show the best fit to the curve. The complete statistical analysis results is a 51-L0 life and curve.

Observed Life Table Results
Arizona Public Service Company
Account: 390 - Structures and Improvements

Age	Cumulative Survivors
0	1.0000
0.5	0.9995
1.5	0.9926
2.5	0.9849
3.5	0.9804
4.5	0.9762
5.5	0.9710
6.5	0.9676
7.5	0.9479
8.5	0.9324
9.5	0.9251
10.5	0.9178
11.5	0.9107
12.5	0.9059
13.5	0.9045
14.5	0.8995
15.5	0.8961
16.5	0.8666
17.5	0.8360
18.5	0.7785
19.5	0.7755
20.5	0.7734
21.5	0.7639
22.5	0.7560
23.5	0.7427
24.5	0.7342
25.5	0.7236
26.5	0.7027
27.5	0.7000
28.5	0.6909
29.5	0.6870
30.5	0.6776
31.5	0.6722
32.5	0.6461
33.5	0.6348
34.5	0.6219
35.5	0.6218
36.5	0.6184
37.5	0.6184
38.5	0.6122

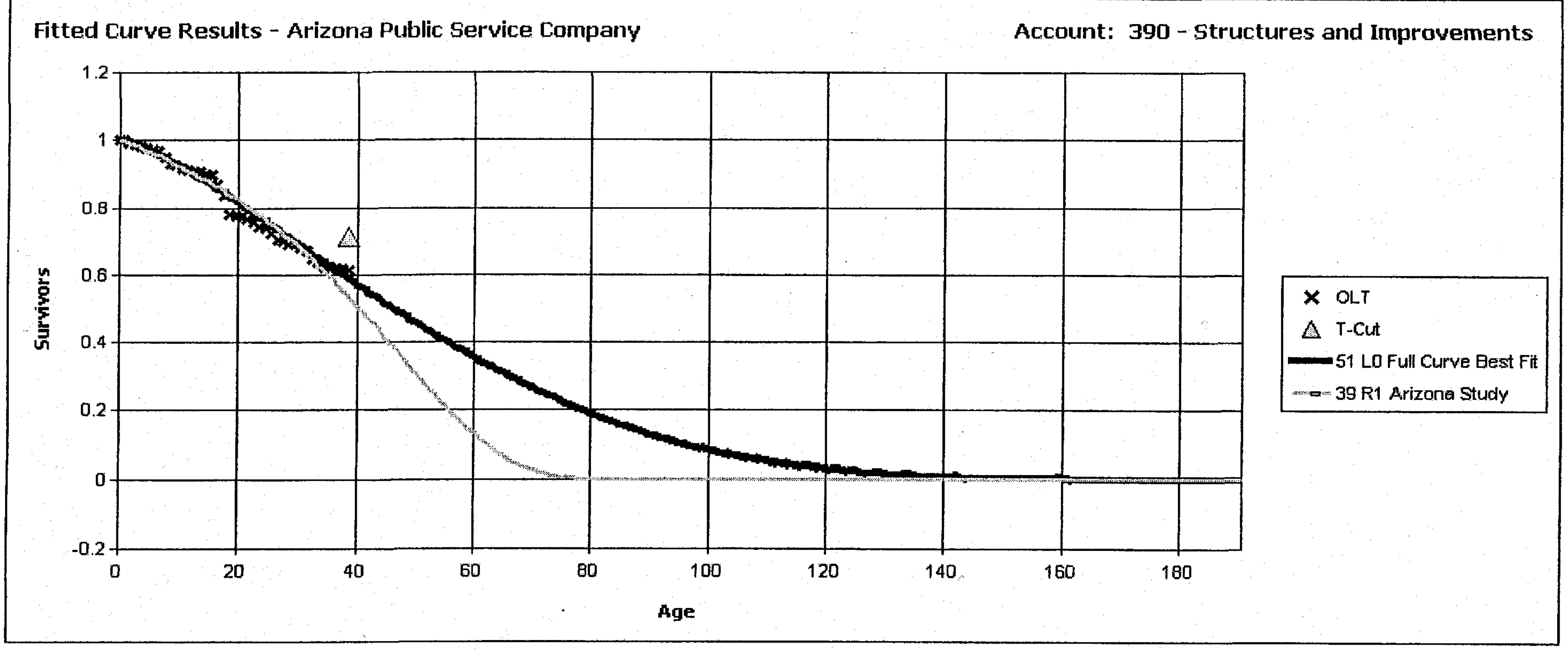
Best Fit Curve Results
Arizona Public Service Company
Account: 390 - Structures and Improvements

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
L0	51.0	10,113.777
S-0.5	45.0	10,147.317
L0.5	47.0	10,178.712
R0.5	44.0	10,204.555
R1	40.5	10,230.322
S0	42.0	10,263.055
O2	56.0	10,281.058
O1	50.0	10,281.531
L1	44.0	10,417.247
R1.5	38.5	10,462.459
S0.5	40.0	10,567.096
L1.5	42.0	10,896.632
R2	37.5	10,972.208
S1	39.0	11,095.418
L2	40.5	11,714.816
R2.5	36.5	11,717.429
S1.5	38.0	11,744.912
O3	60.0	11,959.460
S2	37.5	12,644.747
R3	36.0	12,780.852
L3	38.5	13,726.930
S3	36.5	14,672.610
R4	36.0	15,179.818
L4	37.5	16,156.469
S4	36.5	17,646.648
O4	60.0	18,312.635
R5	36.5	19,044.568
L5	37.0	19,066.660
S5	37.0	20,700.994
S6	37.5	23,587.540
SQ	38.5	30,127.931

Analytical Parameters

OLT Placement Band:	1914 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	1.5
Maximum Life Parameter:	60
Life Increment Parameter:	0.5
Max Age (T-Cut):	38.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1914 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	1.5
Maximum Life Parameter:	60
Life Increment Parameter:	0.5
Maximum Age (T-Cut):	38.5

Arizona Public Service Company

390 - Structures and Improvements

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 51 L0

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2001	0.5	1,654,528	51.00	50.54	32,442	1,639,682
2000	1.5	6,846,351	51.00	49.75	134,242	6,678,379
1999	2.5	2,154,561	51.00	49.02	42,246	2,070,886
1998	3.5	4,350,774	51.00	48.34	85,309	4,123,451
1997	4.5	4,219,011	51.00	47.69	82,726	3,944,948
1996	5.5	3,684,155	51.00	47.07	72,238	3,400,156
1995	6.5	6,585,038	51.00	46.48	129,118	6,000,855
1994	7.5	2,096,429	51.00	45.90	41,106	1,886,992
1993	8.5	1,795,415	51.00	45.35	35,204	1,596,659
1992	9.5	2,070,926	51.00	44.82	40,606	1,820,032
1991	10.5	1,989,393	51.00	44.30	39,008	1,728,220
1990	11.5	2,301,445	51.00	43.80	45,126	1,976,658
1989	12.5	2,472,304	51.00	43.31	48,477	2,099,736
1988	13.5	10,489,412	51.00	42.84	205,675	8,810,850
1987	14.5	4,668,728	51.00	42.37	91,544	3,879,133
1986	15.5	9,609,712	51.00	41.92	188,426	7,899,068
1985	16.5	7,625,834	51.00	41.48	149,526	6,202,060
1984	17.5	1,484,973	51.00	41.04	29,117	1,195,085
1983	18.5	982,963	51.00	40.62	19,274	782,877
1982	19.5	3,501,594	51.00	40.20	68,659	2,760,175
1981	20.5	1,123,834	51.00	39.79	22,036	876,842
1980	21.5	3,417,561	51.00	39.39	67,011	2,639,440
1979	22.5	730,602	51.00	38.99	14,326	558,569
1978	23.5	570,064	51.00	38.60	11,178	431,456
1977	24.5	267,988	51.00	38.21	5,255	200,797
1976	25.5	333,321	51.00	37.83	6,536	247,252
1975	26.5	466,816	51.00	37.45	9,153	342,813
1974	27.5	574,016	51.00	37.08	11,255	417,322
1973	28.5	713,106	51.00	36.71	13,982	513,259
1972	29.5	2,445,237	51.00	36.34	47,946	1,742,364
1971	30.5	156,781	51.00	35.98	3,074	110,598
1970	31.5	335,334	51.00	35.62	6,575	234,189
1969	32.5	191,040	51.00	35.26	3,746	132,083
1968	33.5	142,086	51.00	34.91	2,786	97,255
1967	34.5	87,834	51.00	34.56	1,722	59,519

Arizona Public Service Company

390 - Structures and Improvements

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 51 L0

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1966	35.5	76,565	51.00	34.21	1,501	51,364
1965	36.5	95,233	51.00	33.87	1,867	63,248
1964	37.5	474,062	51.00	33.53	9,295	311,693
1963	38.5	2,545,420	51.00	33.20	49,910	1,656,852
1962	39.5	971,077	51.00	32.86	19,041	625,761
1961	40.5	290,749	51.00	32.54	5,701	185,482
1960	41.5	23,662	51.00	32.21	464	14,944
1959	42.5	-	51.00	31.89	-	-
1958	43.5	7,714	51.00	31.57	151	4,775
1957	44.5	-	51.00	31.25	-	-
1956	45.5	-	51.00	30.94	-	-
1955	46.5	1,345	51.00	30.63	26	808
1954	47.5	41	51.00	30.32	1	24
1953	48.5	-	51.00	30.01	-	-
1952	49.5	313	51.00	29.71	6	182
1951	50.5	-	51.00	29.41	-	-
1950	51.5	24,318	51.00	29.12	477	13,884
1949	52.5	2,057	51.00	28.82	40	1,163
1948	53.5	-	51.00	28.53	-	-
1947	54.5	1,926	51.00	28.25	38	1,067
1946	55.5	-	51.00	27.96	-	-
1945	56.5	-	51.00	27.68	-	-
1944	57.5	-	51.00	27.40	-	-
1943	58.5	-	51.00	27.12	-	-
1942	59.5	-	51.00	26.84	-	-
1941	60.5	-	51.00	26.57	-	-
1940	61.5	-	51.00	26.30	-	-
1939	62.5	-	51.00	26.03	-	-
1938	63.5	-	51.00	25.77	-	-
1937	64.5	-	51.00	25.51	-	-
1936	65.5	-	51.00	25.25	-	-
1935	66.5	-	51.00	24.99	-	-
1934	67.5	-	51.00	24.73	-	-
1933	68.5	-	51.00	24.48	-	-
1932	69.5	-	51.00	24.23	-	-

Arizona Public Service Company

390 - Structures and Improvements

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 51 L0

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
1931	70.5	-	51.00	23.98	-	-
1930	71.5	-	51.00	23.73	-	-
1929	72.5	-	51.00	23.48	-	-
1928	73.5	-	51.00	23.24	-	-
1927	74.5	-	51.00	23.00	-	-
1926	75.5	-	51.00	22.76	-	-
1925	76.5	-	51.00	22.52	-	-
1924	77.5	-	51.00	22.29	-	-
1923	78.5	-	51.00	22.05	-	-
1922	79.5	-	51.00	21.82	-	-
1921	80.5	-	51.00	21.59	-	-
1920	81.5	-	51.00	21.37	-	-
1919	82.5	-	51.00	21.14	-	-
1918	83.5	-	51.00	20.92	-	-
1917	84.5	-	51.00	20.69	-	-
1916	85.5	-	51.00	20.47	-	-
1915	86.5	-	51.00	20.25	-	-
1914	87.5	13,789	51.00	20.04	270	5,418
		96,667,435			1,895,440	82,036,324

AVERAGE SERVICE LIFE	51.00
AVERAGE REMAINING LIFE	43.28

Arizona Public Service Company

General Plant

391.0 - Office Furniture & Equipment - Furniture

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 391 - Office Furniture & Equipment - Furniture

Depreciable Balance $19,919,640

	APS	Snavely King
Depreciable Reserve	$9,897,448	$11,543,613
Reserve Percent	49.7%	58.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	25.0	20.0	20.0
Iowa Curve	O1	SQ	SQ
Remaining Life (Yrs.)		10.1	10.1
Net Salvage (%)	(5)	0	0
Accrual ($)	788,818	994,570	829,310
Rate (%)	3.96%	5.00%	4.16%

****

Comment: SK agrees with Mr. Wiedmayer's analysis for this account.

Observed Life Table Results
Arizona Public Service Company
Account: 391 - Office Furniture and Equipment - Furn

Age	Cumulative Survivors
BAND	
0	1.0000
0.5	1.0000
1.5	0.9986
2.5	0.9970
3.5	0.9959
4.5	0.9483
5.5	0.7661
6.5	0.6675
7.5	0.4828
8.5	0.4134
9.5	0.3509
10.5	0.3300
11.5	0.3169
12.5	0.2707
13.5	0.2308
14.5	0.2232
15.5	0.2053
16.5	0.1908
17.5	0.1804
18.5	0.1759
19.5	0.1493
20.5	0.1201
21.5	0.1139
22.5	0.1125
23.5	0.0988
24.5	0.0871
25.5	0.0768
26.5	0.0541
27.5	0.0430
28.5	0.0417
29.5	0.0030
30.5	0.0028
31.5	0.0028
32.5	0.0027
33.5	0.0027
34.5	0.0027
35.5	0.0027
36.5	0.0024
37.5	0.0023
38.5	0.0023
39.5	0.0023
40.5	0.0023
41.5	0.0023
42.5	0.0023
43.5	0.0023
44.5	0.0023

Observed Life Table Results
Arizona Public Service Company
Account: 391 - Office Furniture and Equipment - Furn

Age	Cumulative Survivors
45.5	0.0023
46.5	0.0023
47.5	0.0023
48.5	0.0023
49.5	0.0023
50.5	0.0023
51.5	0.0023
52.5	0.0023
53.5	0.0023
54.5	0.0023
55.5	0.0023
56.5	0.0023
57.5	0.0023
58.5	0.0023
59.5	0.0023
60.5	0.0023
61.5	0.0023
62.5	0.0023
63.5	0.0023
64.5	0.0023
65.5	0.0023
66.5	0.0023
67.5	0.0023
68.5	0.0023
69.5	0.0023
70.5	0.0023
71.5	0.0023
72.5	0.0023
73.5	0.0023
74.5	0.0023
75.5	0.0023

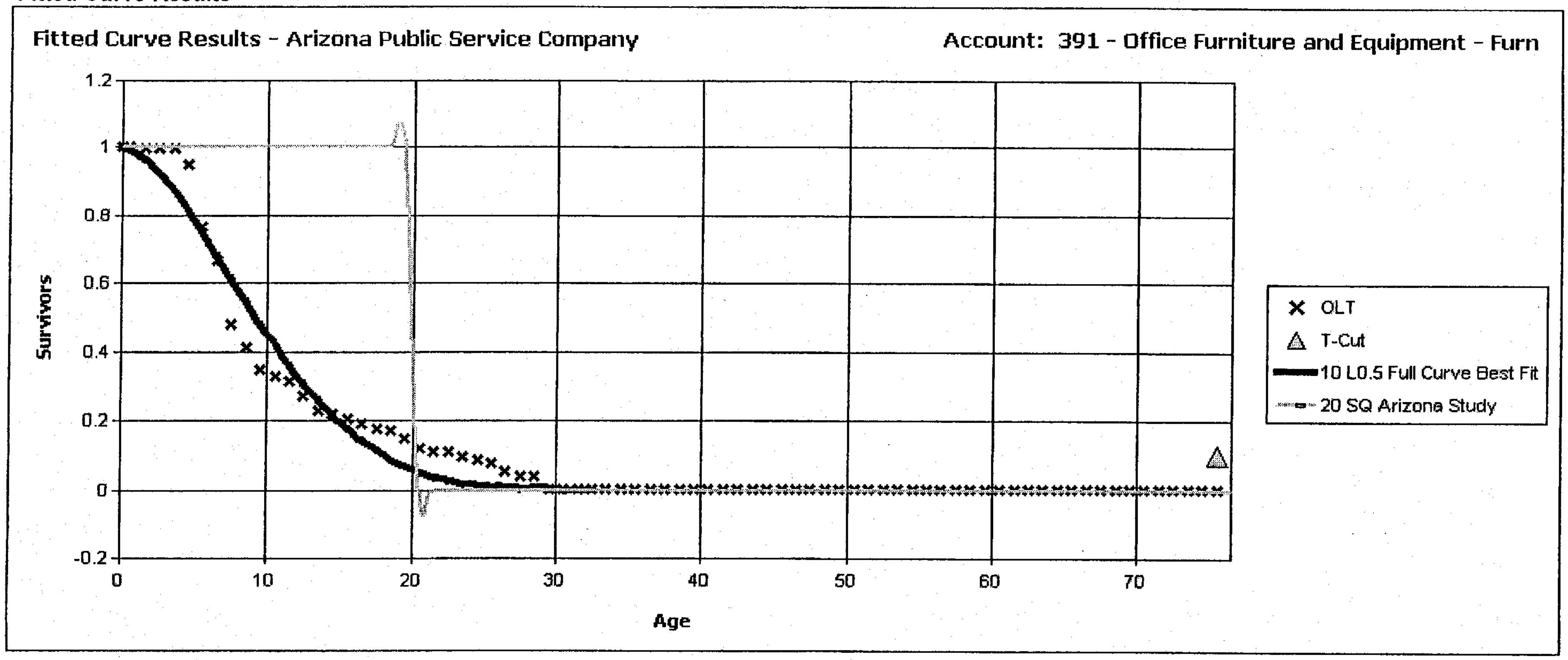
Best Fit Curve Results
Arizona Public Service Company
Account: 391 - Office Furniture and Equipment - Furn

Curve	Life	Sum of Squared Differences
BAND	**1925 - 2001**	
L0.5	10.0	1,655.542
L0	10.0	1,664.314
O2	10.0	1,734.061
L1	10.0	1,830.827
L1.5	9.5	2,012.311
L2	9.5	2,378.492
O3	11.0	2,734.884
S-0.5	9.5	2,836.100
S0	9.5	2,902.650
O1	9.5	3,072.678
R0.5	9.5	3,117.171
S0.5	9.5	3,121.136
S1	9.0	3,473.618
R1	9.0	3,511.723
L3	9.0	3,793.399
R1.5	9.0	3,830.159
S1.5	9.0	3,912.084
R2	9.0	4,388.757
S2	9.0	4,501.716
O4	12.0	4,811.445
R2.5	8.5	4,969.072
R3	8.5	5,692.093
S3	8.5	5,733.650
L4	8.5	5,959.483
R4	8.0	7,076.008
S4	8.0	7,410.038
L5	8.0	7,734.106
R5	8.0	8,615.443
S5	8.0	8,955.143
S6	7.5	10,275.977
SQ	6.5	13,152.333

Analytical Parameters

OLT Placement Band:	1925 - 2001
OLT Experience Band:	1925 - 2001
Minimum Life Parameter:	0.5
Maximum Life Parameter:	50
Life Increment Parameter:	0.5
Max Age (T-Cut):	75.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1925 - 2001
OLT Experience Band:	1925 - 2001
Minimum Life Parameter:	0.5
Maximum Life Parameter:	50
Life Increment Parameter:	0.5
Maximum Age (T-Cut):	75.5

Arizona Public Service Company

General Plant

391.1 - Office Furniture & Equipment - Pc Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 391.1 - Office Furniture & Equipment - Pc Equipment

Depreciable Balance $38,654,946

	APS	Snavely King
Depreciable Reserve	$21,283,348	$15,103,632
Reserve Percent	55.1%	39.1%

	EXISTING *	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	8.0	5.0	8.0
Iowa Curve	R3	SQ	R3
Remaining Life (Yrs.)		2.7	5.3
Net Salvage (%)	0	0	0
Accrual ($)	4,831,868	6,467,368	4,418,633
Rate (%)	12.50%	20.00%	11.43%

****

Comment: SK analysis does not agree with Mr. Wiedmayer's study.
Based on SK analysis and experience, SK recommends the existing curve and life of 8-R3

Observed Life Table Results
Arizona Public Service Company
Account: 391.1 - Office Furniture and Equipment - PC

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	0.9998
2.5	0.9933
3.5	0.9763
4.5	0.9171
5.5	0.8784
6.5	0.7809
7.5	0.7273
8.5	0.6210
9.5	0.4312
10.5	0.2337
11.5	0.2024
12.5	0.0944
13.5	0.0740
14.5	0.0650
15.5	0.0261
16.5	0.0261
17.5	0.0254
18.5	0.0197
19.5	0.0165
20.5	0.0156
21.5	0.0141
22.5	0.0071
23.5	0.0071
24.5	0.0071
25.5	0.0071
26.5	0.0071
27.5	0.0071
28.5	0.0071
29.5	0.0071
30.5	0.0071
31.5	0.0071
32.5	0.0071
33.5	0.0071
34.5	0.0071
35.5	0.0071
36.5	0.0071
37.5	0.0071
38.5	0.0071
39.5	0.0071
40.5	0.0071

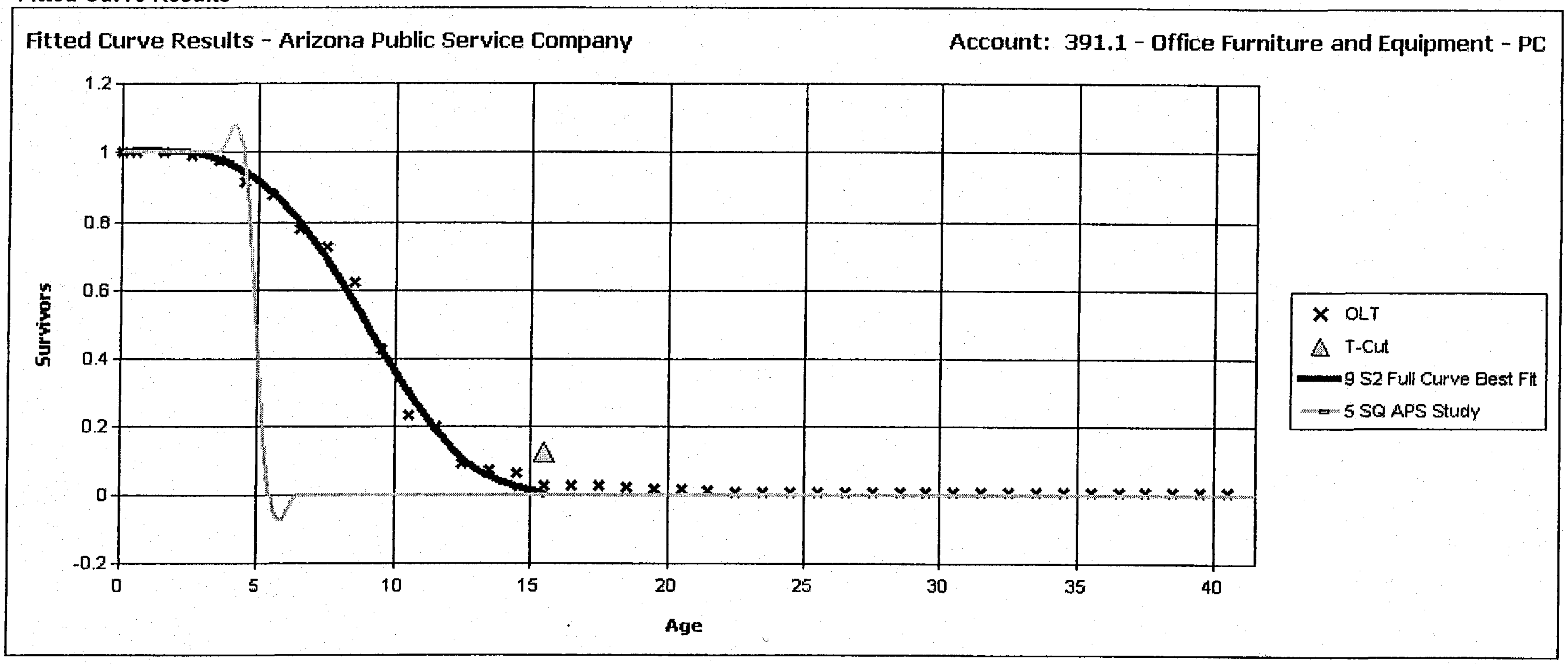
Best Fit Curve Results
Arizona Public Service Company
Account: 391.1 - Office Furniture and Equipment - PC

Curve	Life	Sum of Squared Differences
BAND	**1960 - 2001**	
S2	9.0	143.902
R2.5	9.0	170.822
S1.5	9.0	217.807
R3	9.0	224.908
L3	9.0	264.857
S3	9.0	322.525
R2	9.0	328.495
S1	9.0	442.703
L4	9.0	493.002
R1.5	9.0	657.083
L2	9.0	668.958
R4	9.0	673.496
S0.5	9.0	806.750
S4	9.0	1,013.806
L1.5	9.0	1,049.143
R1	9.0	1,224.553
L5	9.0	1,281.815
S0	9.0	1,339.996
L1	9.0	1,601.007
R5	9.0	1,667.561
R0.5	8.0	1,966.372
S5	9.0	1,990.786
S-0.5	8.0	2,154.662
L0.5	9.0	2,202.152
L0	9.0	2,937.977
O1	8.0	2,976.976
S6	9.0	3,072.354
O2	9.0	3,465.942
O3	12.0	5,634.037
SQ	9.0	5,890.035
O4	15.0	6,611.321

Analytical Parameters

OLT Placement Band:	1960 - 2001
OLT Experience Band:	1960 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	15.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1960 - 2001
OLT Experience Band:	1960 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	15.5

Arizona Public Service Company

391.1 - Office Furniture and Equipment - PC

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 9 S2

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2001	0.5	5,325,396	9.00	8.50	591,711	5,029,329
2000	1.5	4,986,153	9.00	7.50	554,017	4,157,401
1999	2.5	2,514,739	9.00	6.54	279,415	1,826,317
1998	3.5	6,653,336	9.00	5.63	739,260	4,162,761
1997	4.5	537,496	9.00	4.82	59,722	287,601
1996	5.5	7,766,784	9.00	4.10	862,976	3,539,504
1995	6.5	5,780,447	9.00	3.49	642,272	2,238,806
1994	7.5	1,805,477	9.00	2.96	200,609	593,399
1993	8.5	1,853,638	9.00	2.51	205,960	515,942
1992	9.5	-	9.00	2.11	-	-
1991	10.5	239,265	9.00	1.77	26,585	47,160
1990	11.5	252,596	9.00	1.48	28,066	41,410
1989	12.5	613,585	9.00	1.21	68,176	82,625
1988	13.5	142,096	9.00	0.98	15,788	15,461
1987	14.5	88,670	9.00	0.78	9,852	7,645
1986	15.5	89,422	9.00	0.61	9,936	6,039
1985	16.5	5,835	9.00	0.50	648	327
1984	17.5	11	9.00	0.50	1	1
1983	18.5	-	9.00	0.50	-	-
1982	19.5	-	9.00	0.50	-	-
1981	20.5	-	9.00	0.50	-	-
1980	21.5	-	9.00	0.50	-	-
1979	22.5	-	9.00	0.50	-	-
1978	23.5	-	9.00	0.50	-	-
1977	24.5	-	9.00	0.50	-	-
1976	25.5	-	9.00	0.50	-	-
1975	26.5	-	9.00	0.50	-	-
1974	27.5	-	9.00	0.50	-	-
1973	28.5	-	9.00	0.50	-	-
1972	29.5	-	9.00	0.50	-	-
1971	30.5	-	9.00	0.50	-	-
1970	31.5	-	9.00	0.50	-	-
1969	32.5	-	9.00	0.50	-	-
1968	33.5	-	9.00	0.50	-	-
1967	34.5	-	9.00	0.50	-	-

Arizona Public Service Company

391.1 - Office Furniture and Equipment - PC

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 9 S2

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
1966	35.5	-	9.00	0.50	-	-
1965	36.5	-	9.00	0.50	-	-
1964	37.5	-	9.00	0.50	-	-
1963	38.5	-	9.00	0.50	-	-
1962	39.5	-	9.00	0.50	-	-
1961	40.5	-	9.00	0.50	-	-
1960	41.5	-	9.00	0.50	-	-
		38,654,946			4,294,994	22,551,729

AVERAGE SERVICE LIFE	9.00
AVERAGE REMAINING LIFE	5.25

Arizona Public Service Company

General Plant

391.2 - Office Furniture & Equipment - Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 391.2 - Office Furniture & Equipment - Computer Software

Depreciable Balance $7,652,923

	APS	Snavely King
Depreciable Reserve	$4,070,284	$2,932,191
Reserve Percent	53.2%	38.3%

	EXISTING *	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	14.0	10.0	22.0
Iowa Curve	S2	SQ	R4
Remaining Life (Yrs.)		7.8	14.8
Net Salvage (%)	1	0	0
Accrual ($)	541,062	461,909	318,968
Rate (%)	7.07%	10.00%	4.17%

****

Comment: SK analysis does not agree with Mr. Wiedmayer's study.
SK statistical analysis shows a result of a 22-R4 live and curve

Observed Life Table Results
Arizona Public Service Company
Account: 391.2 - Office Furniture and Equipment (Eq.)

Age	Cumulative Survivors
0	1.0000
0.5	1.0000
1.5	0.9999
2.5	0.9980
3.5	0.9963
4.5	0.9867
5.5	0.9370
6.5	0.9352
7.5	0.9253
8.5	0.8894
9.5	0.8678
10.5	0.8641
11.5	0.8632
12.5	0.8564
13.5	0.8515
14.5	0.8398
15.5	0.8302
16.5	0.8286
17.5	0.8265
18.5	0.8174
19.5	0.8135
20.5	0.7428
21.5	0.7371
22.5	0.6615
23.5	0.2405
24.5	0.1801
25.5	0.0794
26.5	0.0735
27.5	0.0417
28.5	0.0099
29.5	0.0099
30.5	0.0099
31.5	0.0099
32.5	0.0099
33.5	0.0099
34.5	0.0099
35.5	0.0099
36.5	0.0099
37.5	0.0099
38.5	0.0099
39.5	0.0099
40.5	0.0099
41.5	0.0099
42.5	0.0099
43.5	0.0099
44.5	0.0099

Observed Life Table Results
Arizona Public Service Company
Account: 391.2 - Office Furniture and Equipment (Eq.)

Age	Cumulative Survivors
45.5	0.0099
46.5	0.0099
47.5	0.0099
48.5	0.0099
49.5	0.0099
50.5	0.0099

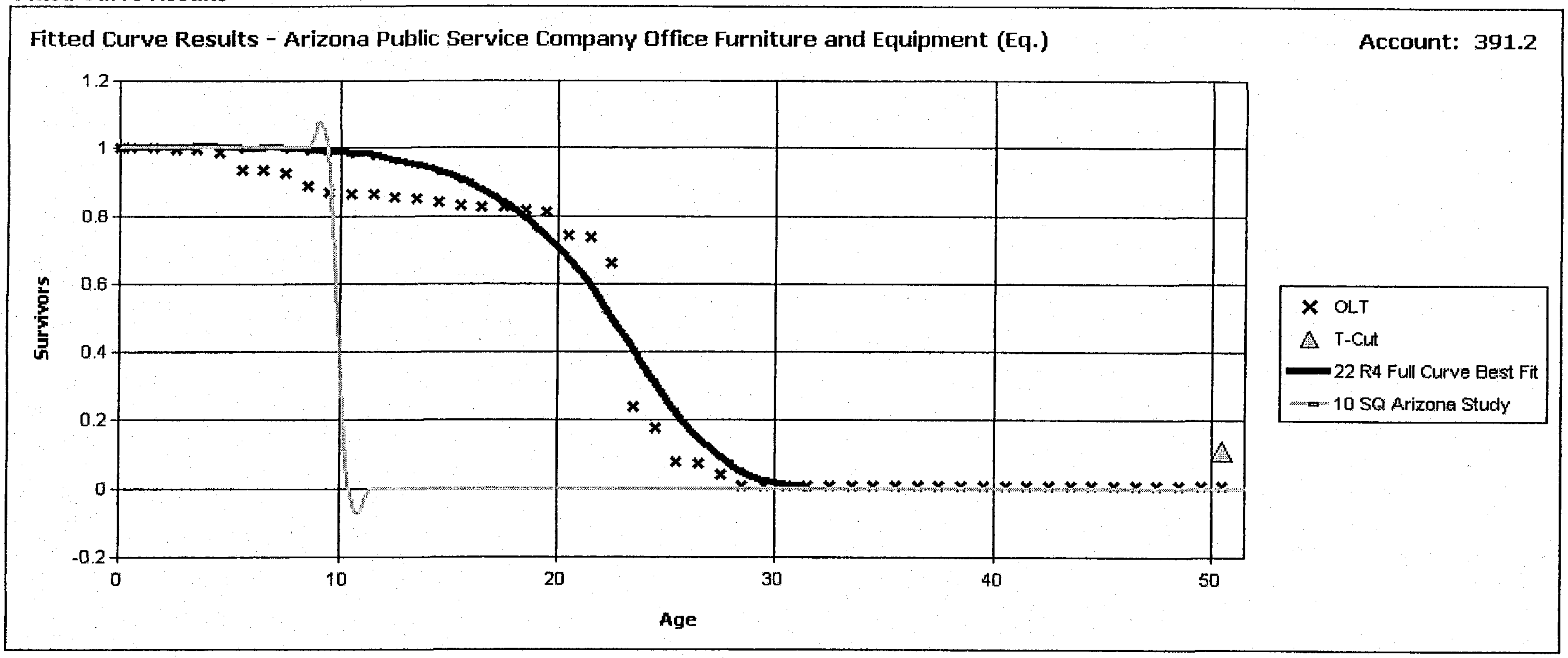
Best Fit Curve Results
Arizona Public Service Company
Account: 391.2 - Office Furniture and Equipment (Eq.)

Curve	Life	Sum of Squared Differences
BAND	**1950 - 2001**	
R4	22.0	2,361.550
R5	22.0	2,601.908
R3	21.0	2,881.789
S4	22.0	2,950.991
L5	22.0	3,121.152
S5	22.0	3,147.762
R2.5	21.0	3,517.936
L4	22.0	3,532.600
S3	22.0	3,576.669
S6	23.0	3,645.460
S2	21.0	4,603.393
R2	21.0	4,648.179
S1.5	21.0	5,296.225
L3	22.0	5,669.048
R1.5	20.0	5,823.030
S1	21.0	6,341.752
SQ	23.0	6,615.327
R1	20.0	7,511.908
S0.5	20.0	7,533.743
L2	22.0	8,170.272
S0	20.0	8,901.878
L1.5	21.0	9,347.696
R0.5	19.0	10,126.205
L1	21.0	10,851.703
S-0.5	19.0	10,987.421
L0.5	21.0	12,534.323
O1	19.0	13,276.477
L0	20.0	14,575.262
O2	21.0	15,988.444
O3	24.0	25,369.044
O4	31.0	30,707.102

Analytical Parameters

OLT Placement Band:	1950 - 2001
OLT Experience Band:	1950 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	50.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1950 - 2001
OLT Experience Band:	1950 - 2001
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Maximum Age (T-Cut):	50.5

Arizona Public Service Company

391.2 - Office Furniture and Equipment (Eq.)

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 22 R4

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	1,333,600	22.00	21.50	60,618	1,303,307
2001	1.5	2,320,311	22.00	20.50	105,469	2,162,289
2000	2.5	33,506	22.00	19.50	1,523	29,705
1999	3.5	98,555	22.00	18.51	4,480	82,915
1998	4.5	47,234	22.00	17.52	2,147	37,606
1997	5.5	389,977	22.00	16.53	17,726	292,962
1996	6.5	2,972	22.00	15.54	135	2,100
1995	7.5	21,691	22.00	14.57	986	14,365
1994	8.5	277,713	22.00	13.61	12,623	171,748
1993	9.5	93,530	22.00	12.66	4,251	53,804
1992	10.5	50,703	22.00	11.72	2,305	27,019
1991	11.5	337,134	22.00	10.81	15,324	165,691
1990	12.5	92,554	22.00	9.93	4,207	41,759
1989	13.5	147,322	22.00	9.07	6,696	60,727
1988	14.5	332,473	22.00	8.24	15,112	124,556
1987	15.5	845,445	22.00	7.45	38,429	286,266
1986	16.5	352,472	22.00	6.69	16,021	107,188
1985	17.5	194,477	22.00	5.97	8,840	52,740
1984	18.5	158,214	22.00	5.27	7,192	37,925
1983	19.5	180,890	22.00	4.62	8,222	37,953
1982	20.5	262,056	22.00	4.01	11,912	47,765
1981	21.5	0	22.00	3.47	-	-
1980	22.5	0	22.00	3.01	-	-
1979	23.5	64,656	22.00	2.62	2,939	7,692
1978	24.5	15,438	22.00	2.28	702	1,597
		7,652,923			347,860	5,149,678

AVERAGE SERVICE LIFE	22.00
AVERAGE REMAINING LIFE	14.80

Arizona Public Service Company

General Plant

393 - Stores Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 393 - Stores Equipment

Depreciable Balance $1,227,371

	APS	Snavely King
Depreciable Reserve	$1,142,564	$1,235,746
Reserve Percent	93.1%	100.7%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	40.0	20.0	20.0
Iowa Curve	R3	SQ	SQ
Remaining Life (Yrs.)		2.8	2.8
Net Salvage (%)	0	0	0
Accrual ($)	30,684	29,921	(2,991)
Rate (%)	2.50%	5.00%	-0.24%

****

Comment: Based on SK analysis and statistical results SK accepts Mr. Wiedmayer's results.

Observed Life Table Results
Arizona Public Service Company
Account: 393 - Stores Equipment

Age	Cumulative Survivors
BAND	1953 - 1995
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	1.0000
5.5	1.0000
6.5	1.0000
7.5	1.0000
8.5	1.0000
9.5	1.0000
10.5	1.0000
11.5	1.0000
12.5	1.0000
13.5	1.0000
14.5	0.9995
15.5	0.9995
16.5	0.9995
17.5	0.9995
18.5	0.9995
19.5	0.9995
20.5	0.9995
21.5	0.8869
22.5	0.8869
23.5	0.8869
24.5	0.8869
25.5	0.8869
26.5	0.8869
27.5	0.8869
28.5	0.8869
29.5	0.8869
30.5	0.8869
31.5	0.8869
32.5	0.8869
33.5	0.8869
34.5	0.8869
35.5	0.8869
36.5	0.8797
37.5	0.8583
38.5	0.8209
39.5	0.8209
40.5	0.8209
41.5	0.8209
42.5	0.8209
43.5	0.8209
44.5	0.8209

Observed Life Table Results
Arizona Public Service Company
Account: 393 - Stores Equipment

Age	Cumulative Survivors
45.5	0.8209
46.5	0.8209
47.5	0.8209

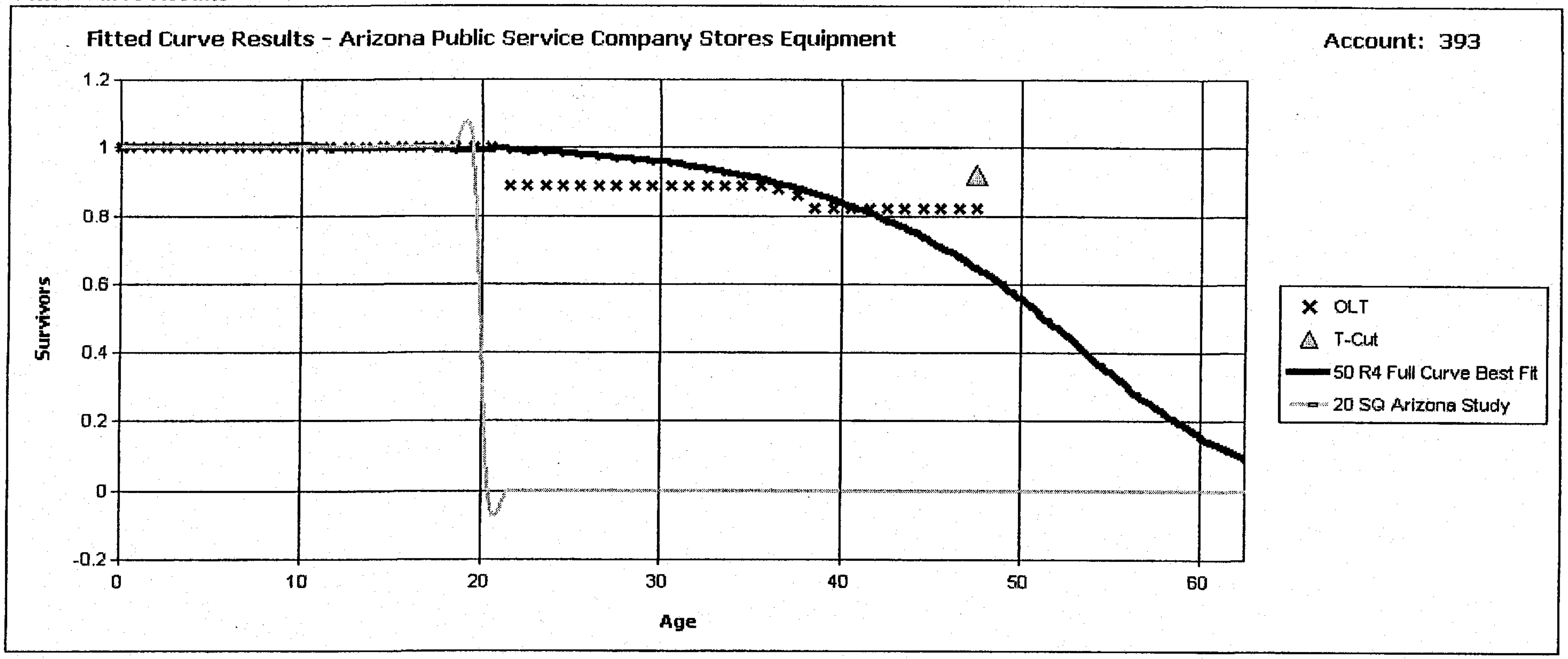
Best Fit Curve Results
Arizona Public Service Company
Account: 393 - Stores Equipment

Curve	Life	Sum of Squared Differences
BAND	**1953 - 2001**	
R4	50.0	1,635.949
R3	50.0	1,808.402
R2.5	50.0	2,388.301
R5	50.0	2,618.958
S4	50.0	2,767.572
S3	50.0	2,778.684
L4	50.0	2,894.301
L5	50.0	2,908.140
S5	50.0	3,316.327
R2	50.0	3,451.239
S2	50.0	3,520.522
S6	49.5	4,067.805
S1.5	50.0	4,244.162
R1.5	50.0	5,072.087
L3	50.0	5,079.531
S1	50.0	5,387.377
SQ	47.5	5,472.553
S0.5	50.0	6,836.959
R1	50.0	7,287.276
L2	50.0	8,036.279
S0	50.0	8,763.042
L1.5	50.0	9,622.615
R0.5	50.0	10,855.853
S-0.5	50.0	11,635.984
L1	50.0	11,872.990
L0.5	50.0	14,624.591
O1	50.0	15,305.507
L0	50.0	17,975.575
O2	50.0	21,660.977
O3	50.0	42,812.855
O4	50.0	66,961.511

Analytical Parameters

OLT Placement Band:	1953 - 1995
OLT Experience Band:	1953 - 2001
Minimum Life Parameter:	4.5
Maximum Life Parameter:	50
Life Increment Parameter:	0.5
Max Age (T-Cut):	47.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1953 - 1995
OLT Experience Band:	1953 - 2001
Minimum Life Parameter:	4.5
Maximum Life Parameter:	50
Life Increment Parameter:	0.5
Maximum Age (T-Cut):	47.5

Arizona Public Service Company

General Plant

394 - Tools, Shops, & Garage Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 394 - Tools, Shop & Garage Equipment

Depreciable Balance $12,673,031

	APS	Snavely King
Depreciable Reserve	$3,989,281	$4,673,542
Reserve Percent	31.5%	36.9%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	25.0	20.0	20.0
Iowa Curve	R3	SQ	SQ
Remaining Life (Yrs.)		13.7	13.7
Net Salvage (%)	0	0	0
Accrual ($)	506,921	633,652	583,904
Rate (%)	4.00%	5.00%	4.61%

****

Comment: Based on SK analysis and statistical results SK accepts Mr. Wiedmayer's results.

Observed Life Table Results
Arizona Public Service Company
Account: 394 - Tools, Shop & Garage Equipment

Age	Cumulative Survivors
BAND	1929 - 2001
0	1.0000
0.5	1.0000
1.5	0.9984
2.5	0.9980
3.5	0.9976
4.5	0.9973
5.5	0.9942
6.5	0.9699
7.5	0.9345
8.5	0.8708
9.5	0.7531
10.5	0.6469
11.5	0.5640
12.5	0.5051
13.5	0.4563
14.5	0.4152
15.5	0.3779
16.5	0.3486
17.5	0.3321
18.5	0.3046
19.5	0.2810
20.5	0.2723
21.5	0.2601
22.5	0.1900
23.5	0.1328
24.5	0.1062
25.5	0.0935
26.5	0.0787
27.5	0.0699
28.5	0.0645
29.5	0.0593
30.5	0.0541
31.5	0.0487
32.5	0.0440
33.5	0.0326
34.5	0.0302
35.5	0.0260
36.5	0.0227
37.5	0.0213
38.5	0.0197
39.5	0.0170
40.5	0.0149
41.5	0.0122
42.5	0.0090
43.5	0.0000
44.5	0.0000

Observed Life Table Results
Arizona Public Service Company
Account: 394 - Tools, Shop & Garage Equipment

Age	Cumulative Survivors
45.5	0.0000
46.5	0.0000
47.5	0.0000
48.5	0.0000
49.5	0.0000
50.5	0.0000
51.5	0.0000
52.5	0.0000
53.5	0.0000
54.5	0.0000
55.5	0.0000
56.5	0.0000
57.5	0.0000
58.5	0.0000
59.5	0.0000
60.5	0.0000
61.5	0.0000
62.5	0.0000
63.5	0.0000
64.5	0.0000
65.5	0.0000
66.5	0.0000
67.5	0.0000
68.5	0.0000
69.5	0.0000
70.5	0.0000
71.5	0.0000

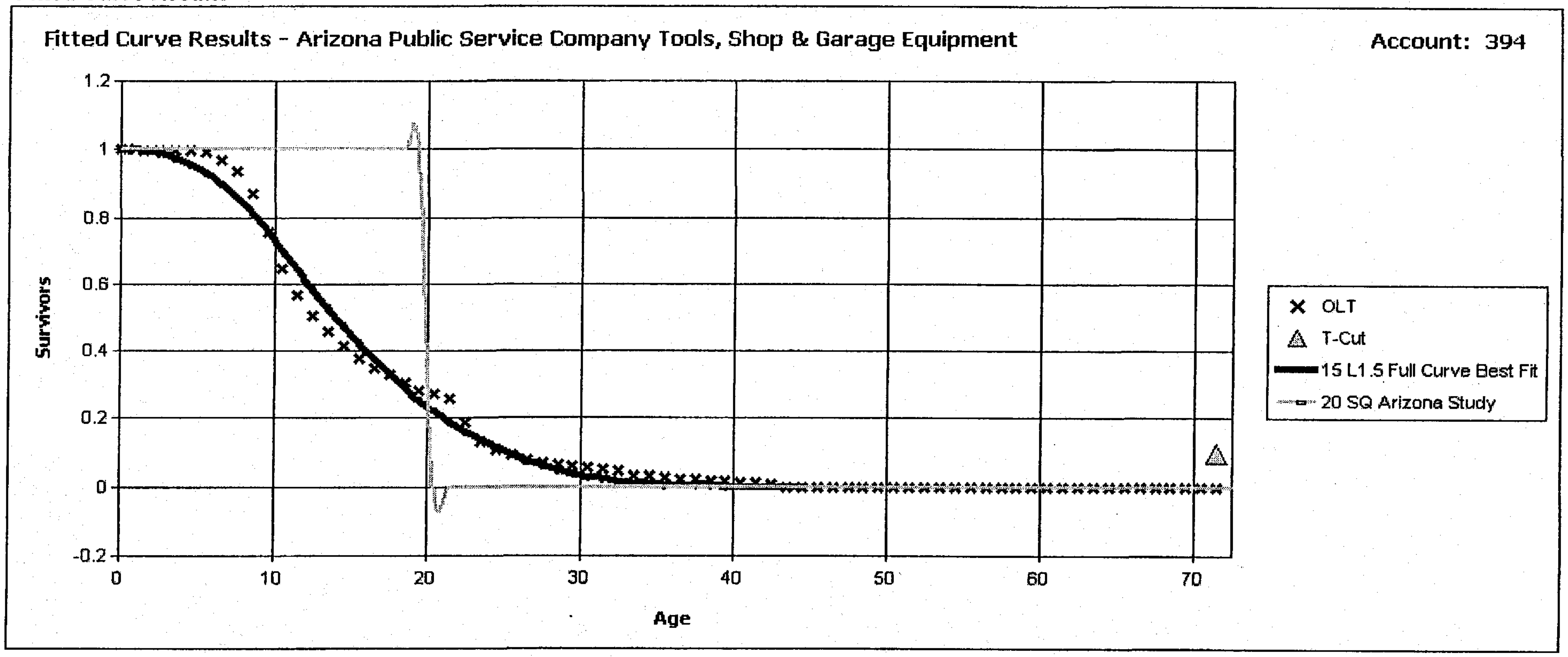
Best Fit Curve Results
Arizona Public Service Company
Account: 394 - Tools, Shop & Garage Equipment

Curve	Life	Sum of Squared Differences
BAND	**1929 - 2001**	
L1.5	15.0	654.102
L2	15.0	784.255
L1	15.0	828.505
L0.5	15.0	1,228.807
S0	14.5	1,366.276
S0.5	14.5	1,386.660
S1	14.5	1,683.498
S-0.5	14.5	1,744.064
L0	15.0	1,905.196
R1	14.5	1,932.407
R0.5	14.5	1,961.292
R1.5	14.5	2,182.932
S1.5	14.5	2,228.717
L3	14.5	2,275.025
O1	14.0	2,564.903
O2	15.0	2,783.334
R2	14.5	2,820.328
S2	14.5	3,017.435
R2.5	14.5	3,675.538
R3	14.5	4,871.886
S3	14.0	5,022.824
L4	14.0	5,494.527
O3	16.0	7,120.020
R4	14.0	7,169.370
S4	13.5	7,889.307
L5	13.5	8,533.159
R5	13.5	10,014.293
S5	13.5	10,678.377
O4	18.0	11,727.808
S6	13.0	13,130.692
SQ	12.5	18,159.694

Analytical Parameters

OLT Placement Band:	1929 - 2001
OLT Experience Band:	1929 - 2001
Minimum Life Parameter:	2.5
Maximum Life Parameter:	50
Life Increment Parameter:	0.5
Max Age (T-Cut):	71.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1929 - 2001
OLT Experience Band:	1929 - 2001
Minimum Life Parameter:	2.5
Maximum Life Parameter:	50
Life Increment Parameter:	0.5
Maximum Age (T-Cut):	71.5

Arizona Public Service Company

General Plant

395 - Laboratory Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 395 - Laboratory Equipment

Depreciable Balance $1,350,583

	APS	Snavely King
Depreciable Reserve	$1,082,162	$531,270
Reserve Percent	80.1%	39.3%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	15.0	15.0	20.0
Iowa Curve	R3	SQ	L1
Remaining Life (Yrs.)		3.6	12.0
Net Salvage (%)	0	0	0
Accrual ($)	90,084	75,200	68,504
Rate (%)	6.67%	6.67%	5.07%

****

Comment: Based on SK analysis the recommended life and curve are 20-L1.

Observed Life Table Results
Arizona Public Service Company
Account: 395 - Laboratory Equipment

Age	Cumulative Survivors
BAND	**1952 - 1999**
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	1.0000
3.5	1.0000
4.5	1.0000
5.5	1.0000
6.5	1.0000
7.5	0.9822
8.5	0.9210
9.5	0.8480
10.5	0.7753
11.5	0.7417
12.5	0.6206
13.5	0.6206
14.5	0.6197
15.5	0.6031
16.5	0.6031
17.5	0.5509
18.5	0.5509
19.5	0.5401
20.5	0.5401
21.5	0.5401
22.5	0.5401
23.5	0.5401
24.5	0.5401
25.5	0.5401
26.5	0.5401
27.5	0.5401
28.5	0.5401
29.5	0.5401
30.5	0.5401
31.5	0.5401
32.5	0.5401
33.5	0.5401
34.5	0.5401
35.5	0.5401
36.5	0.5401
37.5	0.5401
38.5	0.5401
39.5	0.5401
40.5	0.5401
41.5	0.5401
42.5	0.5401
43.5	0.5401
44.5	0.5401

Observed Life Table Results
Arizona Public Service Company
Account: 395 - Laboratory Equipment

Age	Cumulative Survivors
45.5	0.5401
46.5	0.5401

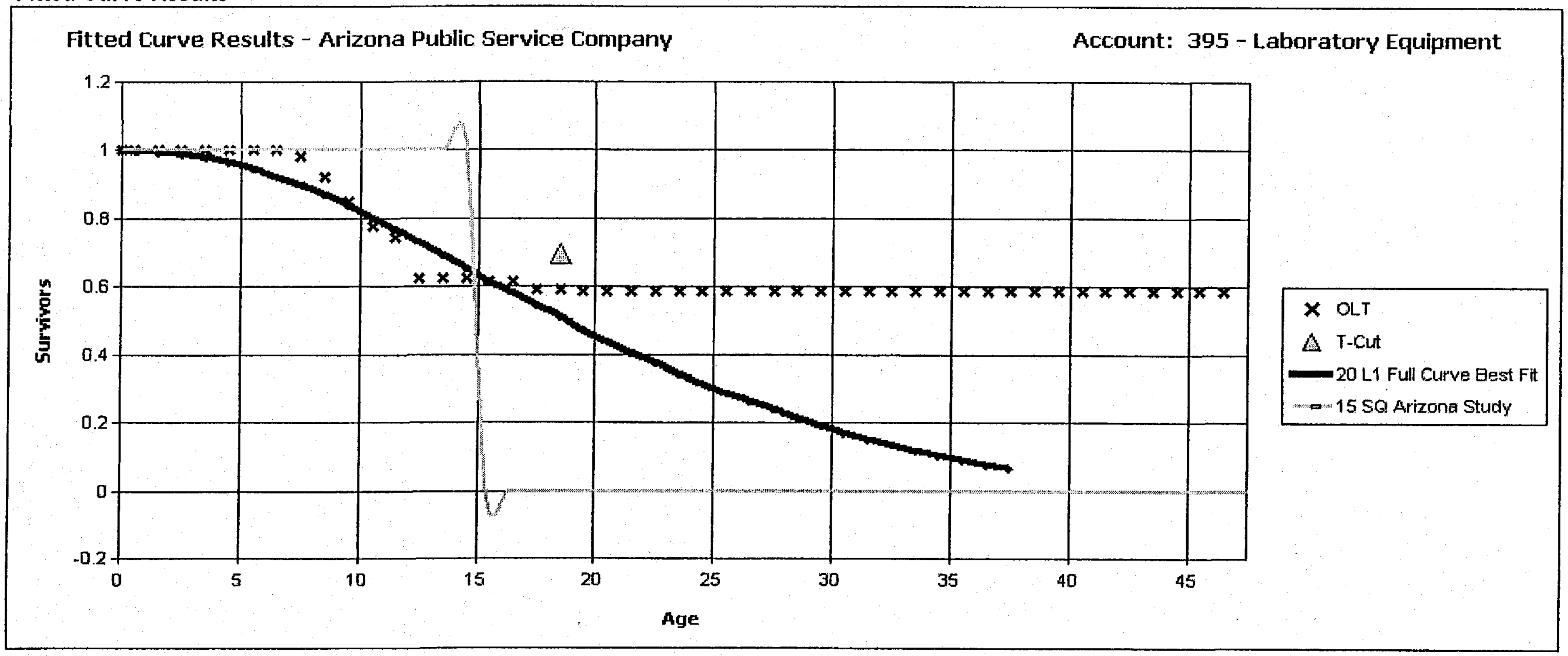
Best Fit Curve Results
Arizona Public Service Company
Account: 395 - Laboratory Equipment

Curve	Life	Sum of Squared Differences
BAND	**1952 - 1999**	
L1	20.0	490.716
L1.5	19.0	588.545
S0	19.0	604.418
S0.5	18.0	609.434
L0.5	22.0	613.876
S1	18.0	665.433
R1.5	18.0	784.750
L0	23.0	787.186
L2	19.0	811.374
R1	19.0	836.697
S-0.5	21.0	839.795
R2	17.0	882.876
S1.5	18.0	944.680
R0.5	20.0	988.144
O1	23.0	1,156.440
O2	26.0	1,156.904
R2.5	17.0	1,178.074
O3	36.0	1,238.302
O4	50.0	1,276.325
S2	17.0	1,302.101
R3	17.0	1,643.764
L3	18.0	1,821.957
S3	17.0	2,383.629
R4	17.0	2,963.393
L4	17.0	3,437.355
S4	17.0	4,311.608
L5	18.0	5,382.596
R5	17.0	5,453.680
S5	18.0	6,491.240
S6	18.0	8,182.887
SQ	19.0	12,095.772

Analytical Parameters

OLT Placement Band:	1952 - 1999
OLT Experience Band:	1952 - 1999
Minimum Life Parameter:	3
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	18.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1952 - 1999
OLT Experience Band:	1952 - 1999
Minimum Life Parameter:	3
Maximum Life Parameter:	60
Life Increment Parameter:	1
Maximum Age (T-Cut):	18.5

Arizona Public Service Company

395 - Laboratory Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA 20 L1

Year (1)	Age (2)	Surviving Investment (3)	BG/VG Average Service Life (4)	BG/VG Average Remaining Life (5)	ASL Weights (6)=(3)/(4)	RL Weights (7)=(6)*(5)
2002	0.5		20.00	19.53	-	-
2001	1.5		20.00	18.62	-	-
2000	2.5		20.00	17.75	-	-
1999	3.5		20.00	16.93	-	-
1998	4.5	38,789	20.00	16.17	1,939	31,357
1997	5.5	0	20.00	15.46	-	-
1996	6.5	4,228	20.00	14.82	211	3,133
1995	7.5	0	20.00	14.23	-	-
1994	8.5	101,225	20.00	13.70	5,061	69,344
1993	9.5	38,992	20.00	13.22	1,950	25,772
1992	10.5	127,003	20.00	12.78	6,350	81,149
1991	11.5	438,006	20.00	12.37	21,900	270,907
1990	12.5	176,146	20.00	11.98	8,807	105,506
1989	13.5	64,472	20.00	11.60	3,224	37,393
1988	14.5	138,581	20.00	11.23	6,929	77,817
1987	15.5	24,730	20.00	10.87	1,237	13,442
1986	16.5	23,132	20.00	10.52	1,157	12,169
1985	17.5	115,702	20.00	10.18	5,785	58,898
1984	18.5	1,938	20.00	9.85	97	954
1983	19.5	4,080	20.00	9.53	204	1,943
1982	20.5	1,224	20.00	9.21	61	564
1981	21.5	0	20.00	8.90	-	-
1980	22.5	630	20.00	8.60	32	271
1979	23.5	0	20.00	8.31	-	-
1978	24.5	315	20.00	8.03	16	126
1977	25.5	0	20.00	7.75	-	-
1976	26.5	1,801	20.00	7.47	90	673
1975	27.5	1,352	20.00	7.21	68	487
1974	28.5	0	20.00	6.95	-	-
1973	29.5	2,392	20.00	6.69	120	800
1972	30.5	43,765	20.00	6.44	2,188	14,096
1971	31.5	0	20.00	6.20	-	-
1970	32.5	2,080	20.00	5.96	104	620

Arizona Public Service Company

395 - Laboratory Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **20 L1**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
		1,350,583			67,529	807,422

AVERAGE SERVICE LIFE	20.00
AVERAGE REMAINING LIFE	11.96

Arizona Public Service Company

General Plant

397 - Communication Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 397 - Communication Equipment

Depreciable Balance $94,309,691

	APS	Snavely King
Depreciable Reserve	$36,587,109	$40,677,647
Reserve Percent	38.8%	43.1%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	21.0	19.0	19.0
Iowa Curve	R3	S1.5	S1.5
Remaining Life (Yrs.)		12.0	12.0
Net Salvage (%)	0	0	0
Accrual ($)	4,489,141	4,811,742	4,469,337
Rate (%)	4.76%	5.10%	4.74%

****

Comment: Based on SK analysis and statistical results SK accepts Mr. Wiedmayer's results.

Observed Life Table Results
Arizona Public Service Company
Account: 397 - Communication Equipment

Age	Cumulative Survivors
BAND	1972 - 2001
0	1.0000
0.5	0.9999
1.5	0.9993
2.5	0.9988
3.5	0.9985
4.5	0.9976
5.5	0.9931
6.5	0.9838
7.5	0.9675
8.5	0.9437
9.5	0.9299
10.5	0.9009
11.5	0.8201
12.5	0.7605
13.5	0.7209
14.5	0.6397
15.5	0.6176
16.5	0.5715
17.5	0.5298
18.5	0.5061
19.5	0.4877
20.5	0.4782
21.5	0.4528
22.5	0.3697
23.5	0.3279
24.5	0.2870
25.5	0.2215
26.5	0.0659
27.5	0.0615
28.5	0.0561
29.5	0.0549
30.5	0.0496
31.5	0.0410
32.5	0.0275
33.5	0.0249
34.5	0.0006
35.5	0.0006
36.5	0.0006
37.5	0.0006
38.5	0.0000

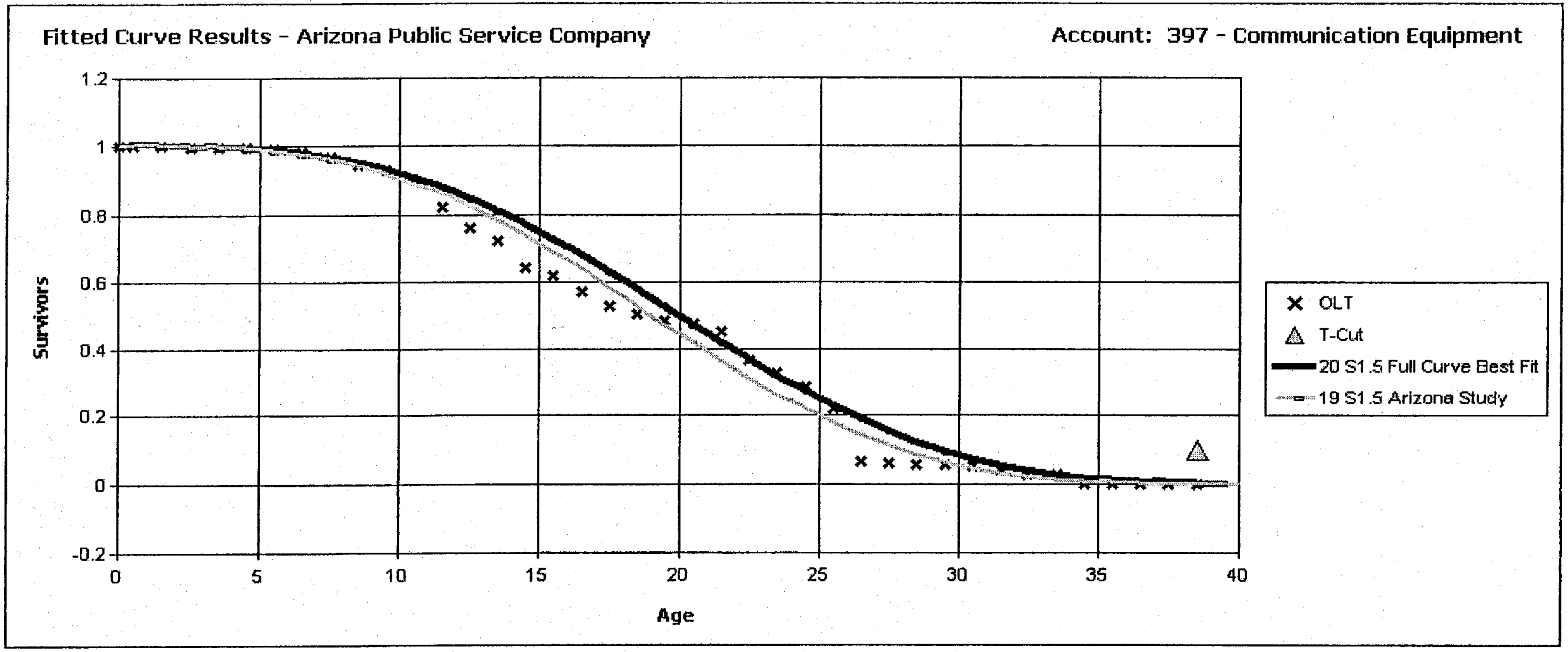
Best Fit Curve Results
Arizona Public Service Company
Account: 397 - Communication Equipment

Curve	Life	Sum of Squared Differences
BAND	**1972 - 2001**	
S1.5	20.0	10,578.984
S1	19.5	10,600.081
R2	19.5	10,727.948
R1.5	19.5	10,881.275
S2	20.0	10,882.345
S0.5	19.5	10,980.826
L2	20.0	11,053.756
R2.5	20.0	11,084.420
L3	20.0	11,274.304
R1	19.0	11,475.587
L1.5	20.0	11,596.836
S0	19.0	11,710.145
R3	20.0	11,877.170
S3	20.5	12,416.319
L1	20.0	12,535.567
R0.5	18.5	12,859.404
S-0.5	19.0	13,077.369
L4	20.5	13,515.910
L0.5	19.5	13,768.036
R4	20.5	14,290.230
O1	18.0	14,869.632
L0	19.5	15,320.578
S4	20.5	15,646.396
O2	20.0	16,608.000
L5	20.5	16,932.608
R5	21.0	18,466.994
S5	20.5	19,657.830
O3	24.5	22,196.621
S6	20.5	23,598.383
O4	32.0	25,049.355
SQ	19.5	31,785.724

Analytical Parameters

OLT Placement Band:	1911 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	0.5
Maximum Life Parameter:	40
Life Increment Parameter:	0.5
Max Age (T-Cut):	38.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1911 - 2001
OLT Experience Band:	1972 - 2001
Minimum Life Parameter:	0.5
Maximum Life Parameter:	40
Life Increment Parameter:	0.5
Maximum Age (T-Cut):	38.5

Arizona Public Service Company

General Plant

398 - Miscellaneous Equipment

Arizona Public Service Company
Depreciation Study as of December 31, 2002

General Plant

Account 398 - Miscellaneous Equipment

Depreciable Balance $1,336,404

	APS	Snavely King
Depreciable Reserve	$584,352	$481,755
Reserve Percent	43.7%	36.0%

	EXISTING	COMPANY PROPOSED	SNAVELY KING RECOMMENDED
Average Service Life (Yrs.)	20.0	20.0	24.0
Iowa Curve	R3	SQ	S1
Remaining Life (Yrs.)		11.5	16.6
Net Salvage (%)	0	0	0
Accrual ($)	66,820	65,276	51,454
Rate (%)	5.00%	5.00%	3.85%

****

Comment: Based on SK analysis the recommended ASL is 24-S1.

Observed Life Table Results
Arizona Public Service Company
Account: 398 - Miscellaneous Equipment

Age	Cumulative Survivors
BAND	1940 - 2001
0	1.0000
0.5	1.0000
1.5	1.0000
2.5	0.9968
3.5	0.9968
4.5	0.9960
5.5	0.9708
6.5	0.9696
7.5	0.9692
8.5	0.9586
9.5	0.9432
10.5	0.8966
11.5	0.8899
12.5	0.8321
13.5	0.8318
14.5	0.8096
15.5	0.7954
16.5	0.7900
17.5	0.7900
18.5	0.7886
19.5	0.7333
20.5	0.7333
21.5	0.5200
22.5	0.4938
23.5	0.4886
24.5	0.4844
25.5	0.4551
26.5	0.4489
27.5	0.4486
28.5	0.4038
29.5	0.2162
30.5	0.2138
31.5	0.2086
32.5	0.2011
33.5	0.1924
34.5	0.1845
35.5	0.1751
36.5	0.1659
37.5	0.1623
38.5	0.1592
39.5	0.0000
40.5	0.0000
41.5	0.0000
42.5	0.0000
43.5	0.0000
44.5	0.0000

Observed Life Table Results
Arizona Public Service Company
Account: 398 - Miscellaneous Equipment

Age	Cumulative Survivors
45.5	0.0000
46.5	0.0000
47.5	0.0000
48.5	0.0000
49.5	0.0000
50.5	0.0000
51.5	0.0000
52.5	0.0000
53.5	0.0000
54.5	0.0000
55.5	0.0000
56.5	0.0000
57.5	0.0000
58.5	0.0000
59.5	0.0000
60.5	0.0000

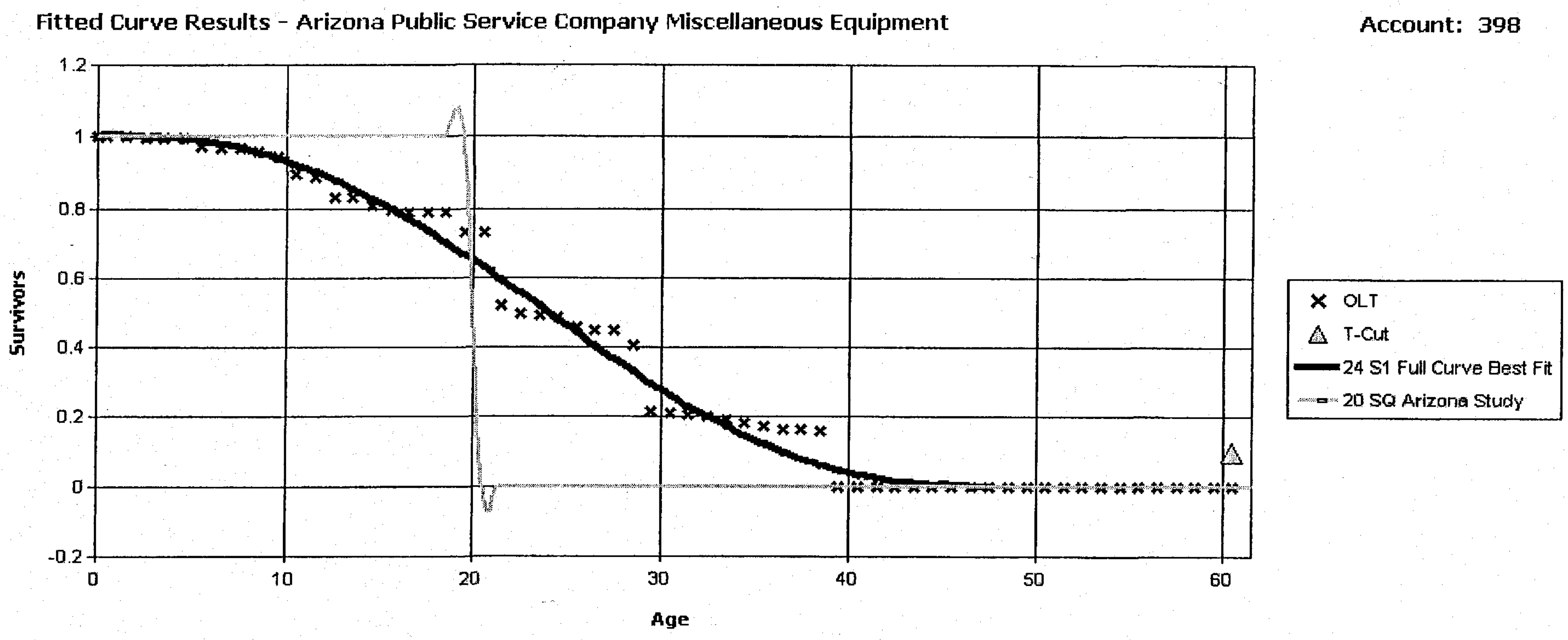
Best Fit Curve Results
Arizona Public Service Company
Account: 398 - Miscellaneous Equipment

Curve	Life	Sum of Squared Differences
BAND	1940 - 2001	
S1	24.0	927.770
R1.5	24.0	1,031.150
S0.5	24.0	1,047.572
S1.5	25.0	1,135.109
R2	24.0	1,221.833
L2	25.0	1,313.368
R1	24.0	1,480.826
S0	24.0	1,624.976
L3	25.0	1,692.365
S2	25.0	1,700.006
L1.5	25.0	1,749.236
R2.5	24.0	1,892.164
L1	24.0	2,593.650
R0.5	23.0	2,641.833
S-0.5	23.0	2,861.849
R3	25.0	3,054.026
S3	25.0	3,630.662
L0.5	24.0	3,837.089
L4	25.0	4,437.326
O1	23.0	4,667.802
L0	24.0	5,519.027
R4	25.0	5,901.496
S4	25.0	7,130.854
O2	24.0	7,344.589
L5	25.0	8,340.774
R5	25.0	10,183.832
S5	25.0	11,319.621
S6	24.0	15,810.157
O3	27.0	16,115.601
O4	34.0	21,809.131
SQ	22.0	25,179.928

Analytical Parameters

OLT Placement Band:	1940 - 2001
OLT Experience Band:	1940 - 2001
Minimum Life Parameter:	2
Maximum Life Parameter:	50
Life Increment Parameter:	1
Max Age (T-Cut):	60.5

Fitted Curve Results



Analytical Parameters

OLT Placement Band:	1940 - 2001
OLT Experience Band:	1940 - 2001
Minimum Life Parameter:	2
Maximum Life Parameter:	50
Life Increment Parameter:	1
Maximum Age (T-Cut):	60.5

Arizona Public Service Company

398 - Miscellaneous Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **24 S1**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	255,380	24.00	23.50	10,641	250,053
2001	1.5	27,403	24.00	22.51	1,142	25,700
2000	2.5	23,461	24.00	21.54	978	21,055
1999	3.5		24.00	20.60	-	-
1998	4.5		24.00	19.68	-	-
1997	5.5		24.00	18.80	-	-
1996	6.5		24.00	17.96	-	-
1995	7.5		24.00	17.15	-	-
1994	8.5	601,135	24.00	16.38	25,047	410,243
1993	9.5	4,383	24.00	15.64	183	2,856
1992	10.5		24.00	14.93	-	-
1991	11.5	2,956	24.00	14.25	123	1,755
1990	12.5	111,815	24.00	13.60	4,659	63,363
1989	13.5	103,445	24.00	12.98	4,310	55,937
1988	14.5	11,188	24.00	12.38	466	5,772
1987	15.5	69,632	24.00	11.81	2,901	34,258
1986	16.5	67,697	24.00	11.26	2,821	31,753
1985	17.5	5,828	24.00	10.73	243	2,605
1984	18.5	11,419	24.00	10.22	476	4,862
1983	19.5	9,787	24.00	9.73	408	3,966
1982	20.5		24.00	9.25	-	-
1981	21.5	25,332	24.00	8.79	1,056	9,282
1980	22.5		24.00	8.35	-	-
1979	23.5		24.00	7.92	-	-
1978	24.5		24.00	7.50	-	-
1977	25.5	469	24.00	7.10	20	139
1976	26.5	5,074	24.00	6.71	211	1,418
		1,336,404			55,684	925,016

Arizona Public Service Company

398 - Miscellaneous Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

SURVIVOR CURVE..IOWA **24 S1**

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)

AVERAGE SERVICE LIFE	24.00
AVERAGE REMAINING LIFE	16.61

Arizona Public Service Company

Section NS

Net Salvage

Arizona Public Service Company
Schedule 1. Summary of Service Life ad Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant in Service at December 31, 2002
Company Parameters With No Net Salvage

Depreciable Group	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/2001	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
PLANT IN SERVICE									
STEAM PRODUCTION PLANT									
311 Structure and Improvements									
Cholla Unit 1	06-2017	75-S1.5	0	2,144,789	1,964,146	180,643	14.0	12,903	0.60%
Cholla Unit 2	06-2033	75-S1.5	0	5,022,179	2,346,306	2,675,873	29.0	92,271	1.84%
Cholla Unit 3	06-2035	75-S1.5	0	9,583,277	6,113,726	3,469,551	29.9	116,038	1.21%
Cholla Common	06-2035	75-S1.5	0	36,234,550	22,949,841	13,284,709	29.9	444,305	1.23%
Four Corners Units 1-3	06-2016	75-S1.5	0	15,972,927	7,395,910	8,577,017	13.3	644,888	4.04%
Four Corners Units 4-5	06-2031	75-S1.5	0	9,195,585	5,253,259	3,942,326	26.8	147,102	1.60%
Four Corners Common	06-2031	75-S1.5	0	3,946,871	2,790,814	1,156,057	26.8	43,136	1.09%
Navajo Units 1-3	06-2026	75-S1.5	0	27,152,517	11,359,467	15,793,050	22.8	692,678	2.55%
Ocotillo Units 1-2	06-2020	75-S1.5	0	3,787,972	1,882,068	1,905,904	17.1	111,456	2.94%
Saguaro Units 1-2	06-2014	75-S1.5	0	2,446,832	2,011,377	435,455	11.3	38,536	1.57%
Yucca Unit 1	06-2016	75-S1.5	0	462,567	471,080	(8,513)	13.1	(650)	-0.14%
Total Account 311				**115,950,066**	**64,537,994**	**51,412,072**		**2,342,664**	**2.02%**
312 Boiler Plant Equipment									
Cholla Unit 1	06-2017	48-L2	0	26,431,681	17,353,280	9,078,401	13.4	677,493	2.56%
Cholla Unit 2	06-2033	48-L2	0	140,612,492	93,979,314	46,633,178	22.0	2,119,690	1.51%
Cholla Unit 3	06-2035	48-L2	0	100,448,965	63,309,215	37,139,750	22.9	1,621,823	1.61%
Cholla Common	06-2035	48-L2	0	22,626,051	11,951,401	10,674,650	24.8	430,429	1.90%
Four Corners Units 1-3	06-2016	48-L2	0	197,139,757	90,637,620	106,502,137	12.7	8,385,995	4.25%
Four Corners Units 4-5	06-2031	48-L2	0	111,591,873	60,671,520	50,920,353	22.1	2,304,088	2.06%
Four Corners Common	06-2031	48-L2	0	3,290,391	2,787,122	503,269	22.8	22,073	0.67%
Navajo Units 1-3	06-2026	48-L2	0	149,350,243	65,220,188	84,130,055	20.6	4,083,983	2.73%
Ocotillo Units 1-2	06-2020	48-L2	0	24,152,351	18,891,592	5,260,759	15.2	346,103	1.43%
Saguaro Units 1-2	06-2014	48-L2	0	24,387,712	17,510,312	6,877,400	11.1	619,586	2.54%
Total Account 312				**800,031,516**	**442,311,564**	**357,719,952**		**20,611,263**	**2.58%**
314 Turbogenerator Units									
Cholla Unit 1	06-2017	65-R2	0	10,417,373	8,187,222	2,230,151	14.0	159,297	1.53%
Cholla Unit 2	06-2033	65-R2	0	28,551,889	18,457,272	10,094,617	27.5	367,077	1.29%
Cholla Unit 3	06-2035	65-R2	0	39,626,197	19,942,381	19,683,816	29.7	662,755	1.67%
Cholla Common	06-2035	65-R2	0	631,278	389,822	241,456	29.0	8,326	1.32%
Four Corners Units 1-3	06-2016	65-R2	0	36,412,926	24,997,649	11,415,277	13.1	871,395	2.39%
Four Corners Units 4-5	06-2031	65-R2	0	14,488,238	8,049,950	6,438,288	26.3	244,802	1.69%
Four Corners Common	06-2031	65-R2	0	1,726,164	1,965,225	(239,061)	23.3	(10,260)	-0.59%
Navajo Units 1-3	06-2026	65-R2	0	24,387,110	15,363,242	9,023,868	22.0	410,176	1.68%
Ocotillo Units 1-2	06-2020	65-R2	0	15,517,601	13,579,702	1,937,899	16.8	115,351	0.74%
Saguaro Units 1-2	06-2014	65-R2	0	16,259,698	12,946,682	3,313,016	11.2	295,805	1.82%
Total Accounts 314				**188,018,474**	**123,879,147**	**64,139,327**		**3,124,723**	**1.66%**

Arizona Public Service Company
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Company Parameters With No Net Salvage

Depreciable Group	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/2001	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
315 Accessory Electric Equipment									
Cholla Unit 1	06-2017	60-R2.5	0	4,756,906	3,537,479	1,219,427	13.9	87,729	1.84%
Cholla Unit 2	06-2033	60-R2.5	0	42,235,618	29,787,215	12,448,403	26.8	464,493	1.10%
Cholla Unit 3	06-2035	60-R2.5	0	29,917,206	18,952,154	10,965,052	28.5	384,739	1.29%
Cholla Common	06-2035	60-R2.5	0	4,476,001	2,804,488	1,671,513	28.7	58,241	1.30%
Four Corners Units 1-3	06-2016	60-R2.5	0	16,353,282	6,735,295	9,617,987	13.2	728,635	4.46%
Four Corners Units 4-5	06-2031	60-R2.5	0	9,183,206	5,249,818	3,933,388	25.9	151,868	1.65%
Four Corners Common	06-2031	60-R2.5	0	2,596,719	3,017,438	(420,719)	21.0	(20,034)	-0.77%
Navajo Units 1-3	06-2026	60-R2.5	0	20,226,194	12,812,227	7,413,967	22.0	336,999	1.67%
Ocotillo Units 1-2	06-2020	60-R2.5	0	2,407,622	2,349,290	58,332	16.3	3,579	0.15%
Saguaro Units 1-2	06-2014	60-R2.5	0	2,654,661	2,598,693	55,968	11.2	4,997	0.19%
Total Account 315				**134,807,415**	**87,844,097**	**46,963,318**		**2,201,244**	**1.63%**
316 Miscellaneous Power Plant Equipment									
Cholla Unit 1	06-2017	40-R2	0	2,315,189	849,777	1,465,412	13.5	108,549	4.69%
Cholla Unit 2	06-2033	40-R2	0	4,846,431	2,942,292	1,904,139	22.1	86,160	1.78%
Cholla Unit 3	06-2035	40-R2	0	4,138,531	2,218,283	1,920,248	23.8	80,683	1.95%
Cholla Common	06-2035	40-R2	0	7,096,069	2,519,563	4,576,506	25.8	177,384	2.50%
Four Corners Units 1-3	06-2016	40-R2	0	4,330,612	557,644	3,772,968	13.1	288,013	6.65%
Four Corners Units 4-5	06-2031	40-R2	0	3,304,340	1,499,998	1,804,342	23.0	78,450	2.37%
Four Corners Common	06-2031	40-R2	0	8,133,224	3,516,915	4,616,309	23.2	198,979	2.45%
Navajo Units 1-3	06-2026	40-R2	0	11,805,250	5,178,470	6,626,780	20.2	328,058	2.78%
Ocotillo Units 1-2	06-2020	40-R2	0	3,711,192	1,047,634	2,663,558	16.2	164,417	4.43%
Saguaro Units 1-2	06-2014	40-R2	0	3,191,024	1,012,665	2,178,359	10.9	199,849	6.26%
Yucca Unit 1	06-2016	40-R2	0	452,868	353,040	99,828	12.2	8,183	1.81%
Total Account 316				**53,324,730**	**21,696,281**	**31,628,449**		**1,718,725**	**3.22%**
TOTAL STEAM PRODUCTION PLANT				**1,292,132,201**	**740,269,083**	**551,863,118**		**29,998,620**	
NUCLEAR PRODUCTION PLANT									
321 Structures and Improvements									
Palo Verde Unit 1	12-2024	65-R2.5	0	161,039,432	68,224,238	92,815,194	21.2	4,384,691	2.72%
Palo Verde Unit 2	12-2025	65-R2.5	0	88,415,270	37,058,726	51,356,544	22.0	2,331,149	2.64%
Palo Verde Unit 3	03-2027	65-R2.5	0	159,591,077	62,020,595	97,570,482	23.3	4,195,723	2.63%
Palo Verde Water Reclamation	03-2027	65-R2.5	0	125,593,913	50,775,392	74,818,521	23.2	3,225,203	2.57%
Palo Verde Common	03-2027	65-R2.5	0	98,127,309	38,045,036	60,082,273	23.2	2,586,955	2.64%
Total Account 321				**632,767,001**	**256,123,987**	**376,643,014**		**16,723,721**	**2.64%**
322 Reactor Plant Equipment									
Palo Verde Unit 1	12-2024	70-R1	0	359,545,213	144,992,453	214,552,760	20.6	10,415,183	2.90%
Palo Verde Unit 2	12-2025	70-R1	0	176,362,235	64,407,419	111,954,816	21.5	5,207,201	2.95%
Palo Verde Unit 3	03-2027	70-R1	0	322,750,700	118,393,045	204,357,655	22.6	9,042,374	2.80%
Palo Verde Water Reclamation	03-2027	70-R1	0	123,313	5,190	118,123	23.0	5,136	4.16%
Palo Verde Common	03-2027	70-R1	0	26,449,873	9,772,755	16,677,118	22.6	737,926	2.79%
Total Account 322				**885,231,334**	**337,570,862**	**547,660,472**		**25,407,819**	**2.87%**

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(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
322.1 Reactor Plant Equipment - Steam Generators									
Palo Verde Unit 1	12-2005	Square	0	30,722,375	31,766,117	(1,043,742)	3.0	(347,914)	-1.13%
Palo Verde Unit 2	12-2003	Square	0	15,870,053	17,917,124	(2,047,071)	1.0	(2,047,071)	-12.90%
Palo Verde Unit 3	12-2007	Square	0	25,413,317	23,597,351	1,815,966	5.0	363,193	1.43%
Total Account 322.1				**72,005,745**	**73,280,592**	**(1,274,847)**		**(2,031,792)**	**-2.82%**
323 Turbogenerator Units									
Palo Verde Unit 1	12-2024	60-S0	0	117,808,078	50,929,473	66,878,605	19.9	3,360,734	2.85%
Palo Verde Unit 2	12-2025	60-S0	0	76,754,224	30,390,765	46,363,459	20.8	2,229,012	2.90%
Palo Verde Unit 3	03-2027	60-S0	0	142,895,088	55,717,208	87,177,880	21.8	3,998,985	2.80%
Palo Verde Water Reclamation	03-2027	60-S0	0	217,707	54,310	163,397	22.0	7,427	3.41%
Palo Verde Common	03-2027	60-S0	0	1,223,879	(131,408)	1,355,287	22.2	61,049	4.99%
Total Account 323				**338,898,976**	**136,960,348**	**201,938,628**		**9,657,208**	**2.85%**
324 Accessory Electric Equipment									
Palo Verde Unit 1	12-2024	45-R3	0	115,495,170	51,830,648	63,664,522	20.0	3,183,226	2.76%
Palo Verde Unit 2	12-2025	45-R3	0	50,119,388	20,346,865	29,772,523	20.9	1,424,523	2.84%
Palo Verde Unit 3	03-2027	45-R3	0	89,143,623	36,276,331	52,867,292	22.1	2,392,185	2.68%
Palo Verde Common	03-2027	45-R3	0	17,918,193	7,373,717	10,544,476	22.0	479,294	2.67%
Total Account 324				**272,676,374**	**115,827,561**	**156,848,813**		**7,479,228**	**2.74%**
325 Miscellaneous Power Plant Equipment									
Palo Verde Unit 1	12-2024	35-R0.5	0	29,671,405	17,609,436	12,061,969	17.7	681,467	2.30%
Palo Verde Unit 2	12-2025	35-R0.5	0	26,389,406	13,408,579	12,980,827	18.7	694,162	2.63%
Palo Verde Unit 3	03-2027	35-R0.5	0	27,284,046	15,083,087	12,200,959	19.2	635,467	2.33%
Palo Verde Water Reclamation	03-2027	35-R0.5	0	88,819	46,552	42,267	19.5	2,168	2.44%
Palo Verde Common	03-2027	35-R0.5	0	48,459,510	21,228,993	27,230,517	19.4	1,403,635	2.90%
Total Account 325				**131,893,186**	**67,376,647**	**64,516,539**		**3,416,898**	**2.59%**
TOTAL NUCLEAR PRODUCTION PLANT				**2,333,472,616**	**987,139,997**	**1,346,332,619**		**60,653,082**	
HYDRO PRODUCTION PLANT									
331 Structures and Improvements	12-2024	Square	0	100,878	100,878	-	0.0	-	0.00%
332 Reservoirs, Dams, and Waterways	12-2004	Square	0	991,936	1,105,086	(113,150)	0.0	-	0.00%
333 Water Wheels, Turbines, and Generators	12-2004	Square	0	157,196	157,196	-	0.0	-	0.00%
334 Accessory Electric Equipment	12-2004	Square	0	627,611	627,611	-	0.0	-	0.00%
335 Miscellaneous Power Plant Equipment	12-2004	Square	0	126,018	126,018	-	0.0	-	0.00%
336 Roads, Railroads, and Bridges	12-2004	Square	0	77,427	77,427	-	0.0	-	0.00%
Hydro Decommissioning Costs					7,864,531	5,335,469 (a)	2.0	2,667,735	
TOTAL HYDRO PRODUCTION PLANT				**2,081,066**	**10,058,747**	**5,222,319**		**2,667,735**	**128.19%**

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Depreciable Group	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/2001	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)
OTHER PRODUCTION PLANT									
341 Structures and Improvements									
Douglas CT	06-2017	80-S1	0	4,562	3,417	1,145	13.9	82	1.81%
Ocotillo CT 1-2	06-2017	80-S1	0	328,749	309,919	18,830	14.5	1,299	0.40%
Saguaro CT	06-2017	80-S1	0	1,288,525	360,293	928,232	14.4	64,461	5.00%
Solar Unit 1		12-SQ	0	375,512	237,890	137,622	3.6	38,056	10.13%
West phoenix CT 1-2	06-2017	80-S1	0	510,951	475,096	35,855	14.2	2,525	0.49%
West Phoenix Combined Cycle 1-3	06-2031	80-S1	0	6,706,722	3,949,614	2,757,108	28.1	98,118	1.46%
Yucca CT 1-4	06-2016	80-S1	0	452,751	155,293	297,458	13.4	22,198	4.90%
Total Account 341				**9,667,772**	**5,491,522**	**4,176,250**		**226,739**	**2.35%**
342 Fuel Holders, Products and Accessories									
Douglas CT	06-2017	70-S1	0	137,759	73,566	64,193	14.0	4,585	3.33%
Ocotillo CT 1-2	06-2017	70-S1	0	719,859	359,329	360,530	14.0	25,752	3.58%
Saguaro CT	06-2017	70-S1	0	1,304,977	804,476	500,501	14.0	35,750	2.74%
West phoenix CT 1-2	06-2017	70-S1	0	1,437,533	840,769	596,764	14.0	42,626	2.97%
West Phoenix Combined Cycle 1-3	06-2031	70-S1	0	19,343,993	2,978,088	16,365,905	27.7	590,827	3.05%
Yucca CT 1-4	06-2016	70-S1	0	3,232,217	2,710,284	521,933	12.9	40,460	1.25%
Total Account 342				**26,176,338**	**7,766,512**	**18,409,826**		**740,000**	**2.83%**
343 Prime Movers									
Douglas CT	06-2017	70-L1.5	0	1,101,449	1,102,406	(957)	0.0	-	0.00%
Ocotillo CT 1-2	06-2017	70-L1.5	0	6,679,324	6,127,017	552,307	14.1	39,158	0.59%
Saguaro CT	06-2017	70-L1.5	0	8,102,651	6,441,288	1,661,363	13.8	120,086	1.48%
West phoenix CT 1-2	06-2017	70-L1.5	0	8,802,636	6,428,854	2,373,782	14.2	167,290	1.90%
Yucca CT 1-4	06-2016	70-L1.5	0	7,920,584	8,796,851	(876,267)	0.0	-	0.00%
Total Account 343				**32,606,644**	**28,896,416**	**3,710,228**		**326,534**	**1.00%**
344 Generators and Devices									
Douglas CT	06-2017	37-R3	0	551,765	546,431	5,334	9.7	549	0.10%
Ocotillo CT 1-2	06-2017	37-R3	0	6,402,044	2,369,080	4,032,964	13.6	296,448	4.63%
Saguaro CT	06-2017	37-R3	0	4,185,247	1,954,137	2,231,110	13.0	171,743	4.10%
Solar Unit 1		12-SQ	0	6,933,081	3,041,951	3,891,130	7.8	498,118	7.18%
West phoenix CT 1-2	06-2017	37-R3	0	4,115,901	2,407,953	1,707,948	12.3	138,912	3.38%
West Phoenix Combined Cycle 1-3	06-2031	37-R3	0	81,920,222	11,064,493	70,855,729	26.2	2,704,417	3.30%
Yucca CT 1-4	06-2016	37-R3	0	5,395,818	3,751,109	1,644,709	11.6	141,655	2.63%
Total Account 344				**109,504,078**	**25,135,154**	**84,368,924**		**3,951,842**	**3.61%**
345 Accessory Electric Equipment									
Douglas CT	06-2017	50-S2	0	353,277	296,417	56,860	13.1	4,339	1.23%
Ocotillo CT 1-2	06-2017	50-S2	0	1,494,636	1,158,282	336,354	13.2	25,401	1.70%
Saguaro CT	06-2017	50-S2	0	1,715,774	1,133,530	582,244	13.4	43,562	2.54%
Solar Unit 1		12-SQ	0	169,527	12,853	156,674	9.9	15,865	9.36%
West phoenix CT 1-2	06-2017	50-S2	0	1,557,744	1,079,614	478,130	13.2	36,163	2.32%
West Phoenix Combined Cycle 1-3	06-2031	50-S2	0	11,925,645	3,758,130	8,167,515	27.8	293,998	2.47%
Yucca CT 1-4	06-2016	50-S2	0	2,166,526	1,818,547	347,979	13.0	26,820	1.24%
Total Account 345				**19,383,129**	**9,257,373**	**10,125,756**		**446,148**	**2.30%**

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	Depreciable Group	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/2001	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	
346	Miscellaneous Power Plant Equipment										
	Douglas CT	06-2017	70-L1	0	40,913	29,882	11,031	13.8	798	1.95%	
	Ocotillo CT 1-2	06-2017	70-L1	0	553,173	460,255	92,918	14.0	6,650	1.20%	
	Saguaro CT	06-2017	70-L1	0	790,906	388,367	402,539	14.1	28,508	3.60%	
	West phoenix CT 1-2	06-2017	70-L1	0	957,431	479,217	478,214	14.1	33,908	3.54%	
	West Phoenix Combined Cycle 1-3	06-2031	70-L1	0	2,608,877	1,714,480	894,397	26.6	33,618	1.29%	
	Yucca CT 1-4	06-2016	70-L1	0	427,175	411,833	15,342	13.2	1,166	0.27%	
	Total Account 346				**5,378,475**	**3,484,034**	**1,894,441**		**104,648**	**1.95%**	
	TOTAL OTHER PRODUCTION PLANT				**202,716,436**	**80,031,011**	**122,685,425**		**5,795,911**		
	TRANSMISSION PLANT										
352	Structures and Improvements		50-R4	0	27,618,299	8,135,201	19,483,098	35.2	553,497	2.00%	
352.5	Structures and Improvements - SCE 500 KV Line				409,725	296,895	235,747		13,316	3.25%	(b)
353	Station Equipment		42-R3	0	428,736,305	173,966,733	254,769,572	31.2	8,167,649	1.91%	
353.5	Station Equipment - SCE 500 KV Line				7,747,282	6,464,972	3,606,497		251,787	3.25%	(b)
354	Towers and Fixtures		60-R3	0	83,464,531	39,991,439	43,473,092	38.3	1,135,068	1.36%	
354.5	Towers and Fixtures - SCE 500 KV Line				13,752,584	13,542,259	4,336,101		446,959	3.25%	(b)
355	Poles and Fixtures - Wood		48-R1.5	0	91,126,939	33,590,493	57,536,446	38.5	1,494,453	1.64%	
355.1	Poles and Fixtures - Steel		55-R3	0	83,067,888	22,282,935	60,784,953	45.1	1,347,782	1.62%	
355.5	Poles and Fixtures - SCE 500 KV Line				930,308	341,908	867,492		30,235	3.25%	(b)
356	Overhead Conductors and Devices		55-R3	0	205,771,417	70,439,236	135,332,181	38.5	3,515,122	1.71%	
356.5	Overhead Conductors and Devices - SCE 500 KV Line				22,653,515	23,670,862	5,778,708		736,239	3.25%	(b)
357	Underground Conduit		48-S1.5	0	10,444,362	2,989,523	7,454,839	35.7	208,819	2.00%	
358	Underground Conductors and Devices		40-R3	0	18,551,254	6,336,374	12,214,880	26.3	464,444	2.50%	
	TOTAL TRANSMISSION PLANT				**994,274,409**	**402,048,830**	**605,873,606**	**289**	**18,365,369**	**1.85%**	
	DISTRIBUTION PLANT										
361	Structures and Improvements		45-R2.5	0	25,815,042	7,749,290	18,065,752	33.1	545,793	2.11%	
362	Station Equipment		38-S0	0	212,357,577	70,802,963	141,554,614	31.8	4,456,837	2.10%	
364	Poles and Fixtures - Wood		38-R0.5	0	284,200,711	94,139,326	190,061,385	30.9	6,150,854	2.16%	
364.1	Poles and Fixtures - Steel		50-R3	0	53,919,651	5,138,171	48,781,480	46.6	1,046,813	1.94%	
365	Overhead Conductors and Devices		53-O1	0	218,856,780	58,922,434	159,934,346	47.7	3,352,921	1.53%	
366	Underground Conduit		55-R1.5	0	425,723,116	51,496,065	374,227,051	49.4	7,575,446	1.78%	
367	Underground Conductors and Devices		29-L1	0	805,505,783	227,200,974	578,304,809	22.9	25,253,485	3.14%	
368	Line Transformers		36-R3	0	486,837,053	188,298,226	298,538,827	24.6	12,135,725	2.49%	
369	Services		37-S2	0	242,404,812	86,204,425	156,200,387	27.9	5,598,580	2.31%	
370	Meters		23-R1	0	91,330,710	36,185,262	55,145,448	13.5	4,086,660	4.47%	
370.1	Electronic Meters		12-S2	0	54,691,249	11,298,055	43,393,194	8.7	4,987,610	9.12%	
371	Installations On Customer Premises		30-R1	0	25,335,831	8,708,344	16,627,487	22.9	726,091	2.87%	
373	Street Lighting and Signal Systems		35-R2	0	57,185,737	19,618,266	37,567,471	25.9	1,450,482	2.54%	
	TOTAL DISTRIBUTION PLANT				**2,984,164,052**	**865,761,801**	**2,118,402,251**		**77,367,297**	**2.59%**	

Arizona Public Service Company
Schedule 1. Summary of Service Life ad Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant in Service at December 31, 2002
Company Parameters With No Net Salvage

Depreciable Group	Probable Retirement Date	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/2001	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life		Calculated Annual Accrual Amount	Rate	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)	(10)=(9)/(5)	
GENERAL PLANT											
390 Structures and Improvements		39-R1	0	96,667,435	30,654,079	66,013,356	30.7		2,150,272	2.22%	(c)
391 Office Furniture and Equipment - Furniture		20-SQ	0	19,919,640	9,897,448	10,022,192	10.1		994,570	5.00%	(c)
Reserve Variance Amortization					-	-	3.0		-		
									994,570		
391.1 Office Furniture and Equipment - Pc Equip		5-SQ	0	38,654,946	21,283,348	17,371,598	2.7		6,467,368	20.00%	(c)
Reserve Variance Amortization					(7,055,994)	7,055,994	3.0	(d)	2,351,998		
									8,819,366		
391.2 Office Furniture and Equipment - Equipment		10-SQ	0	7,652,923	4,070,284	3,582,639	7.8		461,909	10.00%	(c)
Reserve Variance Amortization					-	-	3.0	(d)	-		
									461,909		
393 Stores Equipment		20-SQ	0	1,227,371	1,142,564	84,807	2.8		29,921	5.00%	(c)
Reserve Variance Amortization					(303,976)	303,976	3.0	(d)	101,325		
									131,246		
394 Tools, Shop and Garage Equipment		20-SQ	0	12,673,031	3,989,281	8,683,750	13.7		633,652	5.00%	(c)
Reserve Variance Amortization					(690,684)	690,684	3.0	(d)	230,228		
									863,880		
395 Laboratory Equipment		15-SQ	0	1,350,583	1,082,162	268,421	3.6		75,200	6.67%	(c)
Reserve Variance Amortization					(38,339)	38,339	3.0	(d)	12,780		
									87,980		
397 Communication Equipment		19-S1.5	0	94,309,691	36,587,109	57,722,582	12.0		4,811,742	5.10%	
398 Miscellaneous Equipment		20-SQ	0	1,336,404	584,352	752,052	11.5		65,276	5.00%	(c)
Reserve Variance Amortization					62,877	(62,877)	3.0	(d)	(20,959)		
									44,317		
TOTAL GENERAL PLANT				273,792,024	101,264,511	172,527,513			18,365,282		
TOTAL DEPRECIABLE PLANT STUDIED				8,082,632,804	3,186,573,980	4,922,906,851			213,213,297		
COMPANY PROPOSAL									244,796,360		
DIFFERENCE DUE TO NET SALVAGE									31,583,063		

(a) Future Accruals Related to Hydro Decommissioning are Equal to the Expected Decommissioning Costs of 13.2 Million less the Book Accumulated Depreciation
(b) Assets Related to the 500 KV SCE Transmission Line are Depreciated at a 3.25 Rate
SK Note: For purposes of this analysis, net salvage, if any, is not removed from the 3.25 rate.
(c) Amortization Rate Applicable to those Vintages Within the Amortization Period
(d) Reserve Variances Related to General Plant Amortization Accounts are Amortized Over 3 Years

Arizona Public Service Company
Actual Net Salvage Experience
1998 - 2002

Year	Gross Salvage		Cost of Removal		Net Salvage	
1998	$	6,661,775	$	863,156	$	5,798,619
1999		4,830,835		1,993,667		2,837,168
2000		10,694,073		4,796,643		5,897,430
2001		7,230,051		14,136,598		(6,906,547)
2002		9,119,972		11,046,897		(1,926,925)
Total	$	38,536,706	$	32,836,961	$	5,699,745
Average	$	7,707,341	$	6,567,392	$	1,139,949

Source: FERC Form 1 Reports

Arizona Public Service Company

Section PWEC

Pinnacle West Energy Corporation Calculations

Pinnacle West Energy Corporation

Summary New Gas Plants

	Company Proposed 2002 1/	Snavely King Recommended 2002 2/
Depreciable Base		
Redhawk 1	268,550	268,550
Redhawk 2	268,550	268,550
Redhawk Transmission	49,000	49,000
WP 4	78,133	78,133
WP 5 - Gross Plant @ 6/1/03 for '02	308,644	308,644
Saguaro	36,558	36,558
Total	1,009,435	1,009,435
Depreciation Rate		
Redhawk 1	4.28%	2.86%
Redhawk 2	4.28%	2.86%
Redhawk Transmission	2.34%	1.75%
WP 4	3.61%	2.20%
WP 5 - Gross Plant @ 6/1/03 for '02	4.28%	2.86%
Saguaro	3.76%	2.81%
Total		
Annualized Depreciation Expense		
Redhawk 1	11,494	7,693
Redhawk 2	11,494	7,693
Redhawk Transmission	1,147	857
WP 4	2,821	1,723
WP 5 - Gross Plant @ 6/1/03 for '02	13,210	8,842
Saguaro	1,375	1,028
Total	41,540	27,836

1/ Company Workpaper DGR_WP14, page 18 of 21.
2/ Exhibit___(MJM-3), page PWEC-3 of PWEC-9.
Note: West Phoenix 5 is not included in depreciation study. Used Redhawk rate for this plant to match Company.

PINNACLE WEST ENERGY CORPORATION

Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002
Snavely King Recommendations

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Snavely King Allocated Accumulated Depreciation (6)	Future Accruals (7)=(5)-(6)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)=(7)/(8)	Rate (10)=(9)/(5)
OTHER PRODUCTION									
341 Structures and Improvements									
West Phoenix CC 4	6-2056	80-S1	0	3,768,898	69,749	3,699,149	49.71	74,415	1.97%
342 Fuel Holders, Products and Accessories									
West Phoenix CC 4	6-2056	70-S1	0	4,135,109	62,598	4,072,511	48.32	84,282	2.04%
343 Prime Movers									
West Phoenix CC 4	6-2056	70-L1.5	0	57,116,985	919,686	56,197,299	46.94	1,197,216	2.10%
344 Generators and Devices									
Redhawk CC Units 1 & 2	6-2057	70-O4	0	546,899,426	13,736,086	533,163,340	34.03	15,667,450	2.86%
West Phoenix CC 4	6-2056	37-R3	0	14,296,553	28,896	14,267,657	35.47	402,246	2.81%
Saguaro CT 3	6-2047	37-R3	0	37,659,176	75,121	37,584,055	35.49	1,059,004	2.81%
Total Account 344				598,855,155	13,840,102	585,015,053		17,128,700	2.86%
TOTAL OTHER PRODUCTION PLANT				663,876,147	14,892,135	648,984,012		18,484,613	2.78%
TRANSMISSION									
353 Station Equipment									
Redhawk CC Units 1 & 2		57-R1.5	0	46,000,000	569,193	45,430,807	56.59	802,806	1.75%
West Phoenix CC 4		57-R1.5	0	1,953,105	72,502	1,880,603	55.77	33,721	1.73%
Total Account 353				47,953,105	641,695	47,311,410		836,527	1.74%
355 Poles and Fixtures - Steel									
Redhawk CC Units 1 & 2		55-R3	0	1,500,000	23,458	1,476,542	54.5	27,093	1.81%
356 Overhead Conductors and Devices									
Redhawk CC Units 1 & 2		55-R3	0	1,500,000	23,458	1,476,542	54.5	27,093	1.81%
TOTAL TRANSMISSION PLANT				50,953,105	688,611	50,264,494		890,712	
TOTAL DEPRECIABLE PLANT				714,829,252	15,580,746	699,248,506		19,375,325	
COMPOSITE CALCULATIONS									
Redhawk				546,899,426				15,667,450	2.86%
Redhawk Transmission				49,000,000				856,991	1.75%
West Phoenix 4				81,270,650				1,791,879	2.20%
Saguaro				37,659,176				1,059,004	2.81%
Total				714,829,252				19,375,325	2.71%

PINNACLE WEST ENERGY CORPORATION

Calculation of Theoretical Reserve and Allocation of Book Reserve
Related to Electric Plant at December 31, 2002
Snavely King Recommendations

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Composite Remaining Life (5)	Average Service Life (6)	Original Cost at 12/31/02 (7)	Snavely King Theoretical Reserve (8)	Book Reserve (9)	Snavely King Allocation of Book Reserve (10)
OTHER PRODUCTION									
341 Structures and Improvements									
West Phoenix CC 4	6-2056	80-S1	0	49.71	80	3,768,898	1,426,999		69,749
342 Fuel Holders, Products and Accessories									
West Phoenix CC 4	6-2056	70-S1	0	48.32	70	4,135,109	1,280,702		62,598
343 Prime Movers									
West Phoenix CC 4	6-2056	70-L1.5	0	46.94	70	57,116,985	18,815,967		919,686
344 Generators and Devices									
Redhawk CC Units 1 & 2	6-2057	70-O4	0	34.03	70	546,899,426	281,028,176		13,736,086
West Phoenix CC 4	6-2056	37-R3	0	35.47	37	14,296,553	591,182		28,896
Saguaro CT 3	6-2047	37-R3	0	35.49	37	37,659,176	1,536,902		75,121
Total Account 344						598,855,155	283,156,260		13,840,102
TOTAL OTHER PRODUCTION PLANT						663,876,147	304,679,928	14,892,135	14,892,135
TRANSMISSION									
353 Station Equipment									
Redhawk CC Units 1 & 2		57-R1.5	0	56.59	57	46,000,000	330,877		569,193
West Phoenix CC 4		57-R1.5	0	55.77	57	1,953,105	42,146		72,502
Total Account 353						47,953,105	373,023		641,695
355 Poles and Fixtures - Steel									
Redhawk CC Units 1 & 2		55-R3	0	54.5	55	1,500,000	13,636		23,458
356 Overhead Conductors and Devices									
Redhawk CC Units 1 & 2		55-R3	0	54.5	55	1,500,000	13,636		23,458
TOTAL TRANSMISSION PLANT						50,953,105	400,296	688,611	688,611
TOTAL DEPRECIABLE PLANT						714,829,252	305,080,224	15,580,746	15,580,746

Pinnacle West Energy Corporation

341 - Structures & Improvements

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

WEST PHOENIX CC 4
INTERIM SURVIVOR CURVE..IOWA **80 S1**
PROBABLE RETIREMENT YEAR **6-2056**

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	-	80.00	49.94	-	-
2001	1.5	3,768,898	80.00	49.71	47,111	2,342,130
		3,768,898			47,111	2,342,130

AVERAGE SERVICE LIFE 80.00
AVERAGE REMAINING LIFE 49.71

Pinnacle West Energy Corporation

342 - Fuel Holders, Products and Accessories

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

WEST PHOENIX CC 4
INTERIM SURVIVOR CURVE..IOWA 70 S1
PROBABLE RETIREMENT YEAR 6-2056

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	-	70.00	48.63	-	-
2001	1.5	4,135,109	70.00	48.32	59,073	2,854,656
		4,135,109			59,073	2,854,656

AVERAGE SERVICE LIFE 70.00
AVERAGE REMAINING LIFE 48.32

Pinnacle West Energy Corporation

343 - Prime Movers

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

WEST PHOENIX CC 4
INTERIM SURVIVOR CURVE..IOWA **70 L1.5**
PROBABLE RETIREMENT YEAR **6-2056**

			BG/VG Average			
Year	Age	Surviving Investment	Service Life	Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	-	70.00	47.30	-	-
2001	1.5	57,116,985	70.00	46.94	815,957	38,299,581
		57,116,985			815,957	38,299,581

AVERAGE SERVICE LIFE 70.00
AVERAGE REMAINING LIFE 46.94

Pinnacle West Energy Corporation

344 - Generators and Devices

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

REDHAWK CC 1 & 2
INTERIM SURVIVOR CURVE..IOWA 70 O4
PROBABLE RETIREMENT YEAR 6-2057

			BG/VG Average			
Year	**Age**	**Surviving Investment**	**Service Life**	**Remaining Life**	**ASL Weights**	**RL Weights**
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	546,899,426	70.00	34.03	7,812,849	265,892,430
		546,899,426			7,812,849	265,892,430

WEST PHOENIX CC 4
INTERIM SURVIVOR CURVE..IOWA 37 R3
PROBABLE RETIREMENT YEAR 6-2056

			BG/VG Average			
Year	**Age**	**Surviving Investment**	**Service Life**	**Remaining Life**	**ASL Weights**	**RL Weights**
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	-	37.00	36.44	-	-
2001	1.5	14,296,553	37.00	35.47	386,393	13,704,185
		14,296,553			386,393	13,704,185

SAGUARO CT 3
INTERIM SURVIVOR CURVE..IOWA 37 R3
PROBABLE RETIREMENT YEAR 6-2047

			BG/VG Average			
Year	**Age**	**Surviving Investment**	**Service Life**	**Remaining Life**	**ASL Weights**	**RL Weights**
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
2002	0.5	37,659,176	37.00	35.49	1,017,816	36,124,073
		37,659,176			1,017,816	36,124,073
		598,855,155			9,217,058	315,720,687

COMPOSITE AVERAGE SERVICE LIFE	64.97
COMPOSITE AVERAGE REMAINING LIFE	34.25

Pinnacle West Energy Corporation

353 - Station Equipment

Calculation of Remaining Life
Based Upon Broad Group/Vintage Group Life Group Procedures
Related to Original Cost as of December 31, 2002

Year	Age	Surviving Investment	BG/VG Average Service Life	BG/VG Average Remaining Life	ASL Weights	RL Weights
(1)	(2)	(3)	(4)	(5)	(6)=(3)/(4)	(7)=(6)*(5)
REDHAWK CC 1 & 2						
SURVIVOR CURVE..IOWA			**57**	**R1.5**		
2002	0.5	46,000,000	57.00	56.59	807,018	45,666,377
WEST PHOENIX CC 4						
SURVIVOR CURVE..IOWA			**57.00**	**R1.5**		
2002	0.5	-	57.00	56.59	-	-
2001	1.5	1,953,105	57.00	55.77	34,265	1,910,804
		1,953,105			34,265	1,910,804
		47,953,105			841,283	47,577,181

COMPOSITE AVERAGE SERVICE LIFE	57.00
COMPOSITE AVERAGE REMAINING LIFE	56.55

EXHIBIT
S-11
S-12
Admitted

ALL-STATE LEGAL®

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	DOCKET NO. E-10345A-03-0437

DIRECT TESTIMONY

OF

JAMES R. DITTMER
AND
STEVEN C. CARVER

AND
JOINT ACCOUNTING SCHEDULES

ON BEHALF OF THE
STAFF OF THE ARIZONA CORPORATION COMMISSION

PUBLIC VERSION

("[redacted]" Text Denotes Confidential Material
That Has Been Redacted Within the "Public Version")

FEBRUARY 3, 2004

Staff Exhibit No. __

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	)	DOCKET NO. E-10345A-03-0437

DIRECT TESTIMONY

OF

JAMES R. DITTMER

ON BEHALF OF THE
STAFF OF THE ARIZONA CORPORATION COMMISSION

CONFIDENTIAL VERSION

("[redacted]" Text Denotes Confidential Material
That Has Been Redacted in the "Public Version)

FEBRUARY 3, 2004

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DIRECT TESTIMONY OF
JAMES R. DITTMER

DIRECT TESTIMONY
OF
JAMES R. DITTMER

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-03-0437

Q. Please state your name and address.

A. My name is James R. Dittmer. My business address is 740 Northwest Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. By whom are you employed?

A. I am a Senior Regulatory Consultant with the firm of Utilitech, Inc., a consulting firm engaged primarily in utility rate work. The firm's engagements include review of utility rate applications on behalf of various federal, state and municipal governmental agencies as well as industrial groups. In addition to utility intervention work, the firm has been engaged to perform special studies for use in utility contract negotiations.

Q. On whose behalf are you appearing?

A. Utilitech, Inc. has been retained by the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("ACC" or "Commission") to undertake a review of what would commonly be referred to as the "traditional" rate base and operating income statement components of Arizona Public Service Company's ("APS" or "Company") retail electric cost of service study. Additionally, Utilitech personnel are responsible for assisting in the quantification, and incorporating the recommendations, of other ACC Staff witnesses and co-consultants. Thus, the testimony that I am presenting is offered on behalf of the ACC Staff.

QUALIFICATIONS

Q. Before discussing in greater detail the issues and various recommendations that you will be addressing, please state your educational background.

A. I graduated from the University of Missouri - Columbia, with a Bachelor of Science Degree in Business Administration, with an Accounting Major, in 1975. I hold a Certified Public Accountant Certificate in the State of Missouri. I am a member of the American Institute of Certified Public Accountants, and the Missouri Society of Certified Public Accountants.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Missouri, I accepted a position as auditor for the Missouri Public Service Commission. In 1978, I was promoted to Accounting Manager of the Kansas City Office of the Commission Staff. In that position, I was responsible for all utility audits performed in the western third of the State of Missouri. During my service with the Missouri Public Service Commission, I was involved in the audits of numerous electric, gas, water and sewer utility companies. Additionally, I was involved in numerous fuel adjustment clause audits, and played an active part in the formulation and implementation of accounting staff policies with regard to rate case audits and accounting issue presentations in Missouri. In 1979, I left the Missouri Public Service Commission to start my own consulting business. From 1979 through 1985 I practiced as an independent regulatory utility consultant. In 1985, Dittmer, Brosch and Associates was organized. Dittmer, Brosch and Associates, Inc. changed its name to Utilitech, Inc in 1992.

My professional experience since leaving the Missouri Public Service Commission has consisted primarily with issues associated with utility rate, contract and acquisition matters. For the past twenty-four years, I have appeared on behalf of clients in utility rate proceedings before various federal and state regulatory agencies. In representing those clients, I performed revenue requirement studies for electric, gas, water and sewer utilities and testified as an expert witness on a variety of rate matters. As a consultant, I have filed testimony on behalf of industrial consumers, consumer groups, the Missouri Office of the Public Counsel, the Missouri Public Service Commission Staff, the Indiana Utility Consumer Counselor, the Mississippi Public Service Commission Staff, the Arizona Corporation Commission Staff, the Arizona Residential Utility Consumer Office, the Nevada Office of the Consumer Advocate, the Washington Attorney General's Office, the Hawaii Consumer Advocate's Staff, the Oklahoma Attorney General's Office, the West Virginia Public Service Commission Consumer Advocate's Staff, municipalities and the Federal government before regulatory agencies in the states of Arizona, Alaska, Michigan, Missouri, Oklahoma, Ohio, Florida, Colorado, Hawaii, Kansas, Mississippi, New Mexico, Nevada, New York, West Virginia, Washington and Indiana, as well as the Federal Energy Regulatory Commission.

DEVELOPMENT OF JURISDICTIONAL REVENUE REQUIREMENT ACCOUNTING EXHIBITS

Q. Have you prepared exhibits which quantify, summarize and incorporate the results of the various recommendations being made by ACC Staff witnesses, other co-consultants as well as yourself?

A. Yes. Mr. Steven Carver and I have prepared Staff Exhibit __ which consists of a series of Joint Accounting Schedules. The noted Joint Accounting Schedules reflect the individual and cumulative results of all the various recommendations being made by or on behalf of the Utilities Division Staff.

Q. Please describe how Staff Exhibit __ has been prepared and organized.

A. Staff Exhibit __ largely follows the style and format of the accounting exhibits prepared by the Company as part of the Standard Filing Requirements. Specifically, Schedule A is the Revenue Requirement Summary, which reflects the cumulative impact of the various revenue, operating expense, rate base and cost of capital recommendations being sponsored by witnesses appearing on behalf of the ACC Staff. Also shown on Schedule A are the values of the various components underlying the Company's revenue requirement recommendation. Thus, one can observe on a summary level basis how the various components of Staff's revenue requirement recommendation contrast with the Company's proposal (i.e., rate base, adjusted operating income, overall cost of capital).

Q. Does Schedule A – Revenue Requirement Summary also show a required return on a "fair value" rate base?

A. Yes, however, such number has simply been "backed into" utilizing the return requirement calculated developed with the Staff's proposed original cost rate base. In a manner consistent with the Company's presentation of a "fair value" return requirement, I have calculated a "fair value" rate base which consists of an average of a Reconstruction Cost New – Depreciated ("RCND") and original cost rate base. I have developed a RCND net plant in service value by simply applying ratios derived from APS' original cost and RCND plant in service values. Other RCND rate base components were deemed to be equal to their original cost values. As stated previously, I have developed a "fair value" return and "fair value" rate base in a manner thought to be consistent with that developed by APS.

Q. Please continue your discussion of the development of the Joint Accounting Schedules.

A. Schedule B is the Rate Base Summary. In developing Staff's proposed retail rate base I have started by showing APS' proposed jurisdictional rate base by detailed component (i.e., Column A). In Column B of Schedule B I show the sum of all Staff rate base adjustments, and in Column C one can observe Staff's proposed "as adjusted" retail rate base by detailed category. Immediately following Schedule B – Rate Base Summary are a number of supporting schedules which set forth each individual Staff rate base adjustment. Each individual rate base adjustment has a separate designation such as B-1, B-2, etc. Thus, each rate base adjustment identified and presented with a separate "B-__" designation becomes a reconciling item between APS' and Staff's rate base recommendation.

Schedule C is the Net Operating Income Summary. In a manner similar to the rate base schedules, I begin on Schedule C by showing the Company's "proposed" or "as adjusted" net operating income by major component. The sum of all of Staff's adjustments to net operating income can be found in Column B of Schedule C, with the support for each income statement adjustment developed on separate schedules designated as Schedule C-1, C-2, etc. Thus, like the rate base schedules, each "Schedule C-__" reflects a reconciling component or adjustment between APS' proposed net operating income and Staff's proposed net operating income. Through the remainder of my testimony I will use the terms "Adjustment B-__" and "Schedule B-__" as well as "Adjustment C-__" and "Schedule C-__" interchangeably.

Schedule D reflects the Company's as well as the Staff's proposed capital structure, including the weighted cost of debt, preferred stock and recommended return on equity. Staff's proposed capital structure and component cost recommendations are sponsored by Utilities Division Staff witness Mr. Joel Reiker.

PEAK AND AVERAGE ALLOCATION ADJUSTMENTS

Q. Please describe the first adjustment to APS' proposed retail jurisdictional rate base.

A. Ms. Lee Smith, a consultant with the firm of LaCapra Associates also appearing on behalf of the Utilities Division Staff, is proposing that retail jurisdictional rates be designed by employing a "Peak and Average" methodology for allocating production demand-related costs. I will not describe or reiterate herein the arguments espoused by Ms. Smith in support of the employment of the Peak and Average allocation methodology. Suffice it to say, this methodology has the effect of allocating a somewhat smaller amount of fixed production investment and expense to the ACC retail jurisdiction.

Rate base Adjustment No. B-1 is posted to restate the Company's "as adjusted" or "proforma" retail rate base employing the noted "Peak and Average" allocation methodology. Similarly, income statement Adjustment No. C-1 is posted to restate the Company's proposed "as adjusted" or "proforma" retail operating results. Because we are restating and reflecting the allocation of the Company's "as adjusted" retail cost of service employing the 'Peak and Average" allocation methodology, every subsequent "total company" adjustment which reflects production demand costs which Staff is proposing is therefore allocated utilizing the Peak and Average methodology.

Q. What is the value of allocating rate base and expenses utilizing the Peak and Average allocation methodology versus the Company-proposed 4-CP methodology?

A. The value of the issue will be dependent upon the level of fixed production investment and expense included in the total company cost of service, as well as the authorized rate of return determined to be reasonable. In other words, the value of the jurisdictional allocation issue will rise as more production and investment is included in the total company cost of service and as the overall return found reasonable increases. That stated, the impact of simply revising APS' requested cost of service to reflect the Peak and Average allocation methodology is to reduce APS' requested retail increase by approximately $5.1 million. The Staff is recommending several adjustments to APS' proposed level of production investment and fixed production expenses. Further, Staff is recommending a lower overall cost of capital. Thus, the value of the Peak and Average allocation issue would be smaller if quantified using Staff's proposed production cost levels and cost of capital recommendation.

REMOVAL OF PWEC RATE BASE AND NET OPERATING EXPENSE

Q. Please discuss your next adjustment to APS' proposed retail jurisdictional rate base.

A. The next rate base adjustment found on Schedule B-2 is made to remove the Pinnacle West Energy Corporation ("PWEC") generation assets from APS' proposed retail jurisdictional rate base. A corollary income statement adjustment is found on Schedule C-2. The arguments and support underlying these adjustments are sponsored by Utilities Division Staff consultant Mr. Harvey Salgo of LaCapra Associates. The calculations I undertake and reflect on Schedules B-2 and C-2 are made at Mr. Salgo's direction.

Staff's primary recommendation is to remove all PWEC investment from rate base, as well as eliminate all PWEC operating expenses from cost of service development. Staff does offer an alternative adjustment to reflect the PWEC generating units in rate base, albeit with other accompanying adjustment also sponsored by witnesses from the consulting firm of LaCapra Associates. I shall discuss and describe this "alternative" recommendation in a later section of testimony.

REVERSAL OF WRITE DOWN

Q. Please discuss your next adjustment to APS' proposed jurisdictional rate base.

A. The adjustment shown on Schedule B-3 reverses APS' proposed reinstatement or "add back" of a write-down to plant in service recorded on the Company's books in 1999. There is a corollary income statement adjustment shown on Schedule C-3 wherein APS' proposed amortization of the "add back" to plant is eliminated from revenue requirement consideration. These two adjustments are also sponsored by Ms. Lee Smith..

DEFERRED GAIN ON PACIFICORP SALE

Q. Please describe your next adjustment to APS' proposed jurisdictional rate base.

A. As shown on Schedule B-4, I am proposing that the Deferred Gain on the PacifiCorp Sale be reflected as a reduction to jurisdictional rate base. Such funds represent a cost free source of capital to APS, and accordingly, should be utilized as a reduction to rate base.

Q. What is the source of the cost free funds underlying the items you have referred to as "Gain on PacifiCorp Sale?"

A. In 1991 APS entered into several inter-related agreements that encompassed the sale and exchange of generating assets, as well as the consummation of long term power supply and transmission arrangements. There were several interrelated complex long term agreements that were ultimately approved, with certain conditions, by this Commission.

One element of the noted 1991 power supply agreement provided that APS was to construct for PacifiCorp 150 megawatts of combustion turbines ("CT") that would be interconnected to APS' high voltage transmission system. Such units would be owned by PacifiCorp but operated and maintained by APS. The units were to be constructed and in service by December 31, 1996. APS was to be paid $20 million upon commercial operation of the noted combustion turbines. According to the Company's response to Data Request No. UTI-12-292, PacifiCorp subsequently determined that it would not require the additional CT capacity, but nonetheless agreed to pay APS the $20 million that was to be tendered upon construction of the units. It is the $20 million that APS received from PacifiCorp in January 1997 related to *agreeing* to build CT units which is the source of the cost free funds that exist in the form of, and are recognized on APS' books and records as, the "Deferred Gain on PacifiCorp Sale."

Q. What is the regulatory treatment to be afforded the noted Deferred Gain on PacifiCorp Sale?

A. Pursuant to a settlement entered into between APS and the Utilities Division Staff in 1991 ("1991 Settlement Agreement"), which was ultimately approved by this Commission in Decision No. 57459, the "gain" received from constructing – or eventually merely *agreeing* to construct the combustion turbines for PacifiCorp – is to be amortized for ratepayers' benefit over a ten year period beginning in 2010. The 1991 Settlement Agreement, as well as the ACC decision approving the 1991 Settlement Agreement, does not address the regulatory treatment to be afforded the cost free funds received from PacifiCorp from the time of receipt until they are amortized as a reduction to cost of service beginning in the year 2010.

Q. What is the rationale for deferring the amortization of the gain for constructing the combustion turbines until the year 2010?

A. The deferral of the amortization of the noted gain until the year 2010 was a Staff proposal. Staff's analysis at the time suggested that the entire transaction was only marginally beneficial to ratepayers on a net present value basis over the life of all elements of the complex transaction. Specifically, Staff's analysis indicated that the transaction was, overall, slightly beneficial to ratepayers. However, the way the entire approximate-30-year transaction was structured, ratepayers would receive the majority of economic benefits from the various transactions during the first ten years following the original implementation of the various transactions. The worst of the economic cost or "detriment" of all the various related transactions was forecasted to occur in the last ten years of the 30-year agreement (i.e., year 2010 through year 2019). Accordingly, the Utilities Division Staff proposed, APS agreed to, and this Commission authorized, the amortization of the gain over a ten year period beginning in the year 2010.

Q. Since the Utilities Division Staff once recommended, and still supports, the amortization of the gain for the benefit of ratepayers beginning in the year 2010, why should ratepayers begin to receive the economic benefit of a rate base offset for such funds at this point in time?

A. First, these are truly "cost free" funds to the Company. If such funds are not utilized as a rate base offset, APS will receive an unwarranted and unnecessary return on such funds. In other words, investors will receive a return on an investment that simply does not exist.

Second, the noted 1991 Settlement Agreement, and ACC decision approving the settlement agreement, do not suggest, promise or imply that such cost free funds should not be utilized as a rate base offset from date of receipt until the time they are returned, or begun to be returned, to ratepayers. Admittedly, neither the 1991 Settlement Agreement, or the ACC decision approving the Settlement Agreement, state specifically that the noted "gain" can or should be used as a rate base offset until such time that the funds are amortized for ratepayer benefit. But simple equity would suggest that since such funds are "cost free" to the utility, the Company should not be entitled to earn a return on such "cost free" funds. Accordingly, it is both appropriate and equitable to utilize such funds as a rate base offset at this point in time – even though the amortization benefit to ratepayers will not begin until the year 2010.

Finally, beyond the equity argument for rate base recognition noted above, reflection of such funds as a rate base offset would be in compliance with the intentions of the ACC Staff in 1991 when collectively it was making its recommendations to this Commission regarding the entire complex transaction. When analyzing the complex transaction, and specifically what "costs" and "savings" were expected from the entire transaction, the Utilities Division Staff assumed that 100% of the gains from the construction of PacifiCorp combustion turbines, as well as other sale transactions, would be passed on to ratepayers. In the case of the gain on the construction of the combustion turbines, Staff recommended, and included within its model analyzing the entire transaction, that the benefit of *the amortization* of the gain would occur over a ten year period beginning in the year 2010. Additionally, however, Staff assumed and included within its model analyzing the transaction, that the cost free funds derived from various "gains" occurring from the complex transaction (i.e., gains from CT construction as well as other elements of the transaction) *would be utilized as a rate base offset from date of receipt until returned in their entirety to ratepayers.* In other words, from the Staff's perspective, it was always envisioned and recommended that such gains would be used as a rate base offset.

Q. Are you certain that it was Staff's position that the gains from the construction of PacifiCorp CTs and other transactions were to always be reflected as a rate base offset?

A. Yes. I was one of the Staff's witnesses regarding the PacifiCorp transaction in 1991. More specifically, I prepared the economic model which incorporated the assumptions and recommendations of all Utilities Division Staff witnesses appearing in the 1991 docket. Further, I was the Utilities Division Staff witness who addressed the regulatory treatment being recommended for the "gains" for the construction of the CTs as well as other elements of the transaction. APS was arguing for retaining or sharing the "gains" from various elements of the transaction. Staff's position, as testified to by me, was that 100% of such gains should be passed along to ratepayers. Admittedly, the significant argument addressed in testimony surrounding the regulatory treatment of the "gains" was whether the gains should be "shared." However, it is clear from an exhibit presented in the 1991 docket that Staff always envisioned that any cost free capital arising from "gains" being derived from the various transactions should be immediately reflected as a rate base offset, even if the actual return to ratepayers through amortization as a reduction to the cost of service was not to occur until sometime in the future. Thus, in summary on this point, it was always the Staff's intention that any "gain" from any transaction arising from the PacifiCorp agreement should be assigned in its entirety to ratepayers, and further, that any cost free funds existing in the form of such "gains" should be reflected as a rate base offset until such funds were returned to ratepayers in their entirety.

Q. Do you know why APS did not reflect the gains for constructing the PacifiCorp CTs as a rate base offset?

A. According to the Company's response to Staff Data Request No. UTI-1-66, APS excluded such funds "[i]n accordance with the 1991 Cholla 4 Order (Decision No. 57459)."

Q. Does Decision No. 57459 prescribe or order that the gains for constructing the PacifiCorp CTs be excluded from rate base development?

A. As stated previously, no. In this regard, as a follow up to the response given by APS to Staff Data Request No. UTI-1-66, I asked in Staff Data Request No. UTI-7-224 what "specific language of any ACC order [APS] relied upon to conclude that such gain should be excluded from retail rate base development." The Company's response stated:

> In Decision No. 57459 the ACC explicitly ordered that "the agreement presented to the Commission by Arizona Public Service Company and Staff, and which is attached hereto, is hereby approved as if fully set forth herein." Item No. 3 of the Agreement of Settlement and Stipulation attached to the Decision specified that:
>
> "APS will amortize the Combustion Turbine payment above the line over ten years beginning in 2010. The parties agree that the Commission need not make a determination at this time of the proper allocation between ratepayers and shareholders of any damages won by PacifiCorp, or agreed to by paid [SIC] by APS, for any failure of APS to perform in the construction or operation of Combustion Turbines."
>
> APS has consistently interpreted the above language to mean that the rate base deduction for the unamortized balance of the amount received would also begin in 2010, rather than beginning on the date of receipt.

As evidenced from the language quoted from the 1991 Settlement Agreement above, there is no Commission directive that the payments received for constructing the PacifiCorp CTs be *excluded* from rate base development. Accordingly, I submit that APS has simply been *misinterpreting* the above-quoted language when coming to a conclusion that the unamortized balance of payments received should not be used as a rate base offset.

Thus in summary on this issue, there is no Commission directive to exclude such payments from rate base development until they begin to be amortized in the year 2010. Certainly it was the Utilities Division Staff's intention in 1991 that such funds be used as a rate base offset until returned to ratepayers. Finally, these funds are truly "cost free" to the Company. Accordingly, it is equitable and appropriate to utilize such cost free funds as an offset to rate base in this and future APS rate proceedings.

ELIMINATE DOUBLE COUNT OF VEHICLE LEASE COSTS INCLUDED WITHIN APS' COST OF SERVICE

Q. Please continue by describing your next adjustment to APS' proposed rate base.

A. APS leased a number of vehicles during the historic test year, the cost for which were accounted for as an "operating lease." When leased assets are accounted for as "operating leases," the rental payment is simply charged to operations and maintenance expense. Under Generally Accepted Accounting Principals, some leases meet criteria that cause them to be recorded as an asset on the lessee's books and records. When leased assets are recognized as assets on the lessee's books, they are referred to as "capital leases." Under "capital lease" accounting, the debt financing underlying the leased asset is also shown on the lessee's balance sheet, and further, "depreciation expense" is recorded on the leased assets.

Through discovery and discussions with the Company it was revealed that vehicles which were afforded "operating lease" accounting during the historic test year were, at the end of the test year, also recorded and recognized as a capital lease. While it is appropriate to recognize the cost of these vehicles in the cost of service *once*, it is clearly inappropriate and inequitable to include their costs *twice* (i.e., once as operating lease costs/rental payments and again with rate base/depreciation expense recognition). Accordingly, my next rate base adjustment, as reflected on Schedule B-5, removes certain vehicle costs that are reflected within APS' proposed rate base, but which were also recorded as "operating lease" or rental expense during the test year.

Q. Has the Company acknowledged the need for this adjustment?

A. Yes. I believe the Company agrees that such adjustment needs to be made to APS' case as filed.

Q. Is there a corresponding income statement adjustment?

A. Yes. When calculating its proforma depreciation expense annualization adjustment the Company calculated depreciation expense on the approximate $19 million of rate base (i.e., the capitalized leased vehicles) which I propose to remove on Schedule B-5. Accordingly, in addition to posting the rate base eliminating adjustment found on Exhibit B-5, it is also necessary to remove the annualized depreciation expense on such leased vehicles that is included within the Company's cost of service study. The corresponding adjustment to eliminate related depreciation expense is shown on Exhibit C-5.

Finally on this issue, I note that it is my understanding that the underlying debt financing associated with the leased vehicles was included within APS' proposed capital structure. Mr. Joel Reiker, appearing as Staff's cost of capital witness, has also eliminated such vehicle lease debt from the capital structure that he is sponsoring. In short and in sum, the asset/rate base, depreciation expense and financing cost of the vehicles included within APS' cost of service development as "capital lease" components, but which are also recognized as "operating lease" expense during the historic test year, have been excluded from Staff's cost of service model. Staff has left test year actual vehicle "operating lease" expense unadjusted. In so doing, APS is fully compensated for its leased vehicle costs.

NET LOSS ON REACQUIRED DEBT

Q. Please describe your next adjustment to jurisdictional rate base.

A. APS proposes to include in rate base the balance of deferred losses and deferred gains from reacquiring long-term debt instruments. Specifically, APS proposes to include $7.5 million of its "net" loss on reacquired debt in rate base. On Exhibit B-6 I propose to eliminate the net loss on reacquired debt included in the development of APS' jurisdictional rate base.

Q. Is it your intention, or that of the Staff's, that the Company *not* be allowed to recover costs incurred to refinance a higher cost debt instrument?

A. No. However, the Staff is proposing traditional recovery of such cost vis-à-vis recognition of higher interest costs associated with the debt instruments issued to refinance the debt instruments that were retired. Specifically, Mr. Joel Reiker appearing on behalf of the Utilities Division Staff has reduced the balance of long term debt outstanding by the net loss on reacquired debt which I eliminate from rate base development on Schedule B-6. Furthermore, Mr. Reiker has added the amortization of the net loss on reacquired debt to bond discount and issuance costs. Reducing the debt balance outstanding by the unamortized net loss on reacquired debt, as well as adding the amortization of the net loss on reacquired debt to bond discount and issuance costs, has the impact of raising the calculated *effective* interest rate on the debt instruments issued to refinance the higher cost debt being retired. Recognition of the effective higher interest rate in this manner has the impact of returning to APS the costs incurred to refinance high cost debt *that is supporting utility rate base investment.* The Company-proposed non-traditional method of including the amortization of the net loss on reacquired debt as an above-the-line operating expense, with attendant rate base recognition of the unamortized net loss, results in all the refinancing costs being allocated to regulated utility operations. Accordingly, I believe Staff's proposed traditional recovery of these costs is more equitable to ratepayers in that it ensures that ratepayers will only pay the cost of refinancing related to debt instruments supporting jurisdictional rate base.

TEST PERIOD REVENUE ADJUSTMENTS

Q. Please describe the adjustments proposed by APS to normalize and annualize test year revenues.

A. The Company has proposed several test year revenue adjustments to annualize rate changes, normalize weather conditions and annualize for customer levels at test year-end.

Q. After reviewing the Company's adjustments, does Staff take issue with any of the proposed adjustments?

A. Yes. In its adjustment to annualize customer levels at test year-end, APS has also increased certain Customer Accounts and Customer Service expenses, as if such expenses vary directly with the number of customers served. Mr. Robinson sponsors Attachment DGR-5, Page 4 of 27, which is the summary of his "Pro Forma Adjustment: Annualize Customer Levels to Year-End 2002". At line 14 of this summary, a "Pro Forma Adjustment to Customer Accounts Expense" in the amount of $361 (thousand) is proposed, based upon the presumption that all non-labor expenses incurred in Accounts 901 through 910 vary directly with the number of customers being served. I believe that the direct correlation assumed in the Company's expense adjustment for added customers is unproven, tends to overstate expenses, and thereby understates the profit margins earned by APS when it adds new customers. Accordingly, on Schedule C-4 I reverse that part of APS' proposed customer revenue annualization made to capture certain non-payroll related customer expenses purported to be variable with customers added.

Q. By removing labor costs charged into its Customer Accounts and Customer Services expense accounts, hasn't the Company addressed any concern about whether such costs are fixed, and thus, not variable with new customers added?

A. Certainly the Company's removal of labor costs appears to recognize that APS does not hire new employees each time a new customer is added. In fact, in response to Data Request UTI 3.132, the Company stated, "The exclusion of 'Total O&M Payroll' from expenses charged to those FERC accounts (payroll representing 75% of the FERC accounts' total) removes predominantly fixed expenses from the calculations leading to "Monthly Other O&M per Customer". However, some of the non-labor costs in these accounts are also predominantly fixed and should not be treated as variable with each new customer being added. Specifically, APS' non-labor costs in the Customer Accounts and Customer Services accounts do not vary directly with the number of customers being served, and therefore, should not be recognized as an offset to revenues attributable to new individual customers added and considered within the Company's customer annualization adjustment.

Q. What are the specific types of expenses included in FERC Accounts 901 through 910 that APS has treated as directly variable with the number of customers being served?

A. Summarizing from the FERC Uniform System of Accounts[1], the following activities and costs are contained within the expense amounts in question:

901 Supervision: expenses incurred in the general direction and supervision of customer accounting and collecting activities.

902 Meter Reading: expenses incurred in reading customer meters, and determining consumption when performed by employees engaged in reading meters.

903 Customer Records & Collection: expenses incurred in work on customer applications, contracts, orders, credit investigations, billing and accounting, collections and complaints.

904 Uncollectible Accounts: charged with amounts sufficient to provide for losses from uncollectible utility revenues.

905 Miscellaneous Customer Accounts: costs of labor, materials used and expenses incurred not provided for in other accounts.

907 Supervision: expenses incurred in the general direction and supervision of customer service activities, the object of which is to encourage safe, efficient and economical use of the utility's service.

908 Customer Assistance: expenses incurred in providing instructions or assistance to customers, the object of which is to promote safe, efficient and economical use of the utility's service.

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[1] 18 CFR 1.101, FERC Electric Uniform System of Accounts 901 through 910.

909 Informational Advertising: expenses incurred in activities which primarily convey information as to what the utility urges or suggests customers should do in utilizing electric service to protect health and safety, to encourage environmental protection, to utilize their electric equipment safely and economically, or to conserve electric energy.

910 Miscellaneous Customer Service & Information: expenses incurred in connection with customer service and informational activities which are not includible in other customer information expense accounts.

Once labor costs are removed, the remaining expenses in these accounts include operation and maintenance costs for automated customer billing and service systems, accruals to provide for uncollectible accounts, handling of customer service orders, collections and complaints, remittance processing and costs of communications to customers. Many of these costs do not increase as a direct result of adding new customers.

Q. Did you prepare any quantitative analysis to evaluate the Company's assumed correlation between the number of customers served and the level of non-labor customer accounts and customer service expenses being incurred?

A. Yes. In response to Staff Data Request UTI 2-102, the Company provided a summary of its actual non-payroll charges for each year 1998 through 2002 to each of the FERC Accounts within the Customer Accounts and Customer Service account groupings. This expense information appears in the following table:

Non-Labor Expenses Incurred $000

Account	1998	1999	2000	2001	2002
901	$112	$221	$85	$186	$213
902	788	901	1,163	1,214	1,121
903	7,727	9,060	10,780	15,531	15,787
904	3,743	4,778	5,438	7,609	2,680
905	15,606	1,393	761	2,126	1,463
907	31	38	26	18	24
908	570	198	705	708	314
909	423	470	584	884	489
910	106	157	278	133	816
Total $000	**29,106**	**17,216**	**19,820**	**28,409**	**22,907**
Percentage Change		-40.9%	15.1%	43.3%	-19.4%

From this data, one can observe significant fluctuation in expense values between years as well as no consistent pattern of gradual increases that coincide with annual growth in the number of customers being served. Therefore, the APS presumption that these expenses vary directly with the number of customers served is not supported by actual historical data.

Q. If these expense values are evaluated on a per-customer basis, is there any support for the Company's assumption that these costs increase in direct proportion to the addition of new customers?

A. No. In response to Staff Data Request UTI 2-103, the Company provided data indicating the average numbers of customers served for each of these five years. That information indicates annual growth in APS customer levels from 3 to 4 percent annually. When the information regarding non-labor expenses in the previous table is divided by the number of customers served each year, the lack of any direct correlation between the level of customers and the level of these costs is apparent:

Non-Labor Expense Per Average Customer

	1998	1999	2000	2001	2002
Customers	777,762	810,339	843,480	874,603	902,096
901	$0.14	$0.28	$0.11	$0.24	$0.27
902	$1.01	$1.16	$1.50	$1.56	$1.44
903	$9.93	$11.65	$13.86	$19.97	$20.30
904	$4.81	$6.14	$6.99	$9.78	$3.45
905	$20.07	$1.79	$0.98	$2.73	$1.88
907	$0.04	$0.05	$0.03	$0.02	$0.03
908	$0.73	$0.25	$0.91	$0.91	$0.40
909	$0.54	$0.60	$0.75	$1.14	$0.63
910	$0.14	$0.20	$0.36	$0.17	$1.05
Total	**$37.42**	**$22.14**	**$25.48**	**$36.53**	**$29.45**

Q. What is your recommendation regarding the Company's proposed adjustment for customers added through December 31, 2002?

A. I recommend removal of the "Pro Forma Adjustment to Customer Accounts Expense" in the amount of $361 (thousand), because this element of the Company's adjustment relies upon an unproven assumption that such costs vary directly with the number of customers being served and that assumption is not supported by historical expense trends or the nature of costs in these accounts. ACC Staff Adjustment C-4 has been prepared to include this revision to the Company's proposed adjustment.

PROPERTY TAX ADJUSTMENT

Q. Please continue by describing your next adjustment to test year operating expense.

A. The adjustment shown on Schedule C-6 is made to reduce the Company's proposed level of ongoing property tax expense. While shown as one adjustment on the noted schedule, there are actually two distinct components to this adjustment. Specifically, one element of the adjustment is to remove a "prior period" payment made and recorded as property tax expense in calendar year 2002. The noted "prior period" payment is related to the settlement of a 2001 New Mexico property tax dispute. The other element of this adjustment deals with the level or amount of "ongoing" Arizona property tax expense to be included within the development of proforma operating expense.

Q. Please further elaborate on the first element of the adjustment found on Schedule C-6 – the removal of a prior period expense.

A. According to APS, there was a dispute regarding property taxes to be paid to the Navajo Indian tribe related to production facilities owned by APS, but located in New Mexico. During 2002 the dispute was ultimately settled. The settlement payment in the amount of $7,545,851 made in 2002, and recorded in its entirety as 2002 property tax expense, was tendered to settle 2001 as well as 2002 property tax assessments. Specifically, $3,793,668 and $3,752,182 was paid to settle APS' 2001 and 2002 New Mexico property tax obligations, respectively.

The part of the payment tendered for the 2002 assessment should be considered "ongoing" and included in the development of the test year cost of service (i.e., \$3,752,182). However, the part of the payment related to the 2001 obligation is a "prior period" expense that should be eliminated (i.e., \$3,793,668). Thus, as shown on Schedule C-6, I have removed the New Mexico property taxes paid during the 2002 test year that is related to APS' 2001 property tax obligation.

Q. Please continue by discussing that part of your adjustment that relates to reflecting an "ongoing" level of Arizona property tax expense.

A. First, I would note that it is my proposal to simply reflect as an ongoing level of property tax expense the actual Arizona property taxes assessed and partially paid during 2003. Specifically, in November 2003 APS was officially billed for approximately one-half of the property taxes assessed for calendar year 2003. The remaining half of 2003 property taxes will be paid in May 2004. However, it is the total assessed amount for 2003 that I am proposing to reflect as "ongoing" for cost of service development.

My proposal contrasts with APS' proposal wherein the Company basically applied 2002 tax rates (last known to APS at the time of preparing its filing) to the Company's proposed end-of-test year plant in service values.

Q. Please briefly describe the property tax assessment process in Arizona.

A. Property taxes "assessed" in any given year are derived from the value of property owned at the end of the calendar year two years preceding the "assessment year." For instance, 2003 "assessed" property taxes were ultimately derived by considering the property which APS owned at December 31, 2001. It should also be noted that only half of 2003 "assessed" property taxes are paid in November 2003. The remaining half of 2003 "assessed" property taxes will be paid in May 2004. Even though not all 2003 "assessed" property taxes are paid in 2003, the total amount of 2003 "assessed" property taxes is accrued as an operating expense during calendar year 2003.

While the assessment process begins by considering the "book value" of plant as well as materials and supplies, the "book value" of utility assets are translated, pursuant to statutorily derived formulas, into "full cash values." Further, once the "full cash value" is derived, the "assessed" value is determined, again pursuant to statute, to be 25% of "full cash value." Once the assessed value has been derived and relayed to the various taxing authorities, individual taxing authorities can develop a specific tax "rate" to be applied to all assessed values within their jurisdiction. While the "full cash value" determination for various classes of utility property has changed *occasionally* over the years, the individual tax "rate" applied to assessed values will change *every* year based on the individual taxing authority's fiscal needs for the forthcoming year.

I believe two significant points should be emphasized from the brief explanation of the property tax assessment process in Arizona. First, the derivation of property taxes "assessed" in any given calendar year begins with the consideration of a utility's "book value" of property *two years prior to the assessment year*. Second, while there is an undeniable dependence or linkage to a utility's "book value" in the property tax assessment process, there is not a pure or *direct* correlation between a utility's "book value" and the amount of property tax it is ultimately assessed. For again, each taxing authority will set a different tax "rate" each calendar year based upon the cumulative "assessed" value of property within its jurisdiction as well as the fiscal needs of the governmental entity. Thus, from year to year a taxpayer will not necessarily experience a change in property taxes to be paid that is exactly proportional to the change in its "book value" of property.

Q. Please explain why you believe reflection of 2003 Arizona property tax assessments is reasonable for cost of service development in this case.

A. First, the noted 2003 assessed amounts are "actual" amounts. Second, the amounts assessed by the various taxing authorities were obviously calculated utilizing last known "actual" property tax rates. And third, inclusion of such amounts captures the most recently-available assessments, which in turn, reflect the most-recent cumulative fiscal needs of all the property taxing authorities to which APS is obligated.

Q. What do you find unacceptable in the Company's approach?

A. First, in light of 2003 property tax data now available, it is more precise and equitable to consider this more-current data. Specifically, the composite or "average" property tax rate as a percentage of the assessed value of all Arizona property fell from 9.56% in 2002 (the rate the Company effectively employed in its property tax adjustment) to 9.25% in 2003. I should quickly point out that the 2003 "average" property tax rate was not available to the Company when it was preparing its filing.

Second, for two years running APS' "book value," "full cash value," and "assessed value" have risen. However, while the three noted "values" have all risen, the composite or "average" Arizona property tax rate paid on assessed property values by APS has *declined*. The net result is that, in total, Arizona property taxes have fluctuated. More specifically, there has not been a direct correlation between changes in APS' book value of plant and actual property taxes eventually paid – a correlation implicitly assumed within APS' calculations.

In developing its proforma Arizona property tax level, APS begins with its end-of-test-year plant values. Utilizing historical relationships, APS then derives a "full cash value" and "assessed value" to which it applies the historical 2002 average property tax rate. As previously noted, for two years running, the average property tax rate paid by APS to all Arizona taxing authorities has declined. APS' method basically assumes that property taxes will rise in direct proportion to its investment in utility plant, even though that relationship has not existed – at least for a couple of years.

I do not believe the method that APS employed would be inappropriate or lead to inequitable results in cases where there is a fairly direct relationship between growth or decline in "book values" and increases or decreases in actual property taxes ultimately paid related to those book values. However, in this case, where the correlation is not that good, and where there is better information now available to consider (i.e., 2003 actual assessments), I believe it is much more precise and equitable to simply utilize 2003 actual property tax assessments for cost of service development.

Q. Please describe how your adjustment was calculated.

A. Referring to Schedule C-6, on lines one (1) through five (5) I calculate the increase in 2003 over 2002 Arizona property tax expense. On line eight (8) I show the removal of the 2001 "prior period" New Mexico property tax payment included as 2002 property tax expense. Line eleven (11) shows the sum of the two noted components of my property tax expense adjustment. In other words, line eleven (11) shows the "net" adjustment to *test year actual* property tax expense recorded. However, because we are reflecting adjustments to APS' proposed *proforma* cost of service, it is also necessary to subtract out APS' proposed increase in test year Arizona property tax expense. This calculation is reflected on a "total company electric" basis on lines twelve (12) through seventeen (17). Finally, the jurisdictional impact of the property tax adjustment is reflected on line twenty-two (22).

ELIMINATE NON-RECURRING MAIN FRAME COMPUTER LEASE COSTS

Q. Please describe your next adjustment to test year operation and maintenance expense.

A. The adjustment shown on Exhibit C-7 eliminates the costs incurred during the first half of the historic test year associated with leasing a mainframe computer. In answer to Staff Data Request No. UTI-10-265, the Company acknowledged that the mainframe lease which expired in May 2002 was not renewed. Furthermore, in response to Staff Data Request No. UTI-12-291, APS acknowledged that the mainframe that had been leased during the first four months of the historic test year was purchased in April 2002. Because the cost of the purchased mainframe is included within APS' proposed year-end rate base, and proforma depreciation has been calculated on such year-end plant value, it is equitable to eliminate the operating lease expense recorded during the historic test year related to the mainframe computer. Accordingly, on Exhibit C-7 I have eliminated the "non-recurring" mainframe operating lease expense recorded during the historic test year.

FUEL AND PURCHASED POWER EXPENSE

Q. Is the Staff proposing any adjustments to fuel and purchased power expense?

A. Yes. On Schedule C-8 I have posted an adjustment to APS' proposed level of fuel and purchased power expense *assuming the PWEC assets are not included in the development of jurisdictional rate base.* This adjustment is being sponsored by Mr. Douglas C. Smith of LaCapra Associates.

ECONOMIC DEVELOPMENT EXPENSES

Q. Please describe your next adjustment reflected on Schedule C-9.

A. This adjustment removes the test period expenses incurred by APS for Community Relations and Economic Development activities. Such expenditures are discretionary and not required for the provision of regulated electric utility services. These costs provide no direct, tangible benefit to ratepayers, and therefore should not be included in the Company's jurisdictional revenue requirement.

Q. What activities are undertaken by APS that are the subject of this Staff adjustment?

A. The Company engages in and sponsors business recruitment, business retention and expansion, and community development activities in an effort to enhance the economic vitality and viability of the communities it serves in Arizona. Expenditures include the development and maintenance of information for a www.move2az.com website containing comparative statistics for Arizona communities with out-of-state business locations, sponsoring and publishing studies of the business climate in Arizona, and maintaining information about available business sites. If such activities are successful, there is little doubt that APS demands might grow along with the local economy. However, such expenditures to promote local and state-wide economic development raise a regulatory policy issue regarding whether the Company should be allowed to directly charge such costs to its ratepayers.

Q. If the Commission removes these costs from the APS revenue requirement, won't the Company be discouraged from funding economic development and community relations activities?

A. Not necessarily. Even if these costs are not explicitly included in the determination of revenue requirements, APS can continue to incur economic development costs and will benefit between rate case test years from any incremental electric sales and revenues associated with load growth caused by successful economic development efforts. Regulatory lag allows shareholders to retain the profit margins associated with serving new customers between test periods. Notably, utilities routinely incur costs for charitable contributions, political advocacy and civic event sponsorships even though such costs are not chargeable above-the-line for recovery from utility customers.

Q. Can the Company's Community Relations and Economic Development costs be thought of as discretionary payments to promote the welfare of the local communities being served?

A. Yes. And in this sense such costs are analogous to Donations that are required to be charged to a below-the-line account under the FERC Uniform System of Accounts:

> **426.1 Donations:** This account shall include all payments or donations for charitable, social or community welfare purposes.[2]

As an alternative to making these discretionary expenditures, APS could elect to instead make direct donations to community welfare organizations to assist in funding their economic development programs. If made in this way, such donations would be recorded in below-the-line account 426.1 and not be at issue in this proceeding.

NUCLEAR DECOMMISSIONING EXPENSE

Q. Is the Utilities Division Staff proposing any modification to APS' recommended level of nuclear decommissioning expense?

A. Yes. Mr. Harold Judd of Accion Group is appearing on behalf of the Utilities Division Staff. Mr. Judd has reviewed APS' nuclear decommissioning study. As a result of such review Mr. Judd is proposing some modifications to APS' proposed nuclear decommissioning funding level. The impact of Mr. Judd's proposed changes is reflected within the adjustment shown on Schedule C-10.

DEPRECIATION AND AMORTIZATION EXPENSE

Q. Has the Utilities Division Staff reviewed APS' proposed depreciation rates?

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2 Id. Account 426.1

A. Yes. Mr. Michael Majoros with the firm of Snavely, King, Majoros, O'Connor and Lee was retained by the Staff to review APS' depreciation study. Mr. Majoros is making several recommendations regarding APS' depreciation rates and depreciation accounting. A summary of Mr. Majoros' recommendations is contained within Schedule C-11, which reflects Staff's proposed changes to APS' proforma depreciation expense.

ELIMINATE TEST YEAR DEMAND SIDE MANAGEMENT CHARGES FOR RECOVERY THROUGH A TRACKING MECHANISM

Q. Please discuss your next adjustment to test year operating expense.

A. On Schedule C-16 I eliminate test year charges for Demand Side Management ("DSM") activities. The Utilities Division Staff, through Ms. Barbara Keene, is proposing that DSM costs be "tracked" or recovered through an automatic adjustor mechanism. While DSM expenses incurred during the test year are being eliminated on Schedule C-25, such adjustment should not be considered a "disallowance" inasmuch as the Staff is simply proposing that such costs be recovered vis-à-vis an adjustor mechanism.

ADVERTISING EXPENSE DISALLOWANCE

Q. Please describe your next adjustment to test year advertising expense.

A. Staff Schedule C-17 reflects a detailed calculation of an adjustment to remove the expenses incurred by APS in the test year for discretionary advertising that is not required in the provision of safe and adequate service and is of no direct, tangible benefit to ratepayers. The proposed partial disallowance of APS advertising removes the direct and indirect costs incurred for test year image-building advertising and sports team sponsorships that are designed to promote APS as a highly reliable, affordable, customer-friendly and cost-effective company. Such image-building or positioning advertisements are unnecessary if APS actually provides safe and reliable service in a cost-effective manner in its role as the incumbent retail supplier of electric utility services. Further, as the provider of a regulated service in a certificated service territory, there is no reason to undertake the image building advertising that may otherwise make economic sense for a firm selling non-essential goods or services in a competitive open market.

Q. Please explain the types of messages that are communicated in the advertising that is disallowed in Adjustment No. C-17.

A. Most of the objectionable costs relate to the Company's "Simple Things Campaign" that was emphasized throughout the test period. Television, radio, print and outdoor ads were placed to achieve positive imagery for the Company, with the following types of messages or tag lines:

- At APS, we're doing loads of things to make sure electricity is there when and where you need it. Like securing new sources of electricity to meet Arizona's ever-growing needs.
- Thanks to APS, you'll never have to worry about things that go bump in the night…Like your toes.

- At APS, our Customer Call Center is open day and night. So, you're never left in the dark.
- At APS, we do some pretty cool things. Like power your fan for less than 2 cents an hour.
- APS – The Power to Make It Happen [tag-line]
- You're not thinking about the electricity that powers those video games. That's our job. At APS, we're always thinking about how to keep your electricity affordable and reliable so you can focus on important things like bonding with the people you care most about.

In its response to Staff Data Request UTI-1-18, the Company provided copies of advertisements and cost information and stated:

> Please note that many of the advertisements concern customer service; public notices; customer safety, energy efficiency, information on billing, payment and rate options; and the like. Taken in total, these communications with our customers are directed towards customer service and satisfaction and have led to marked increases in customer satisfaction.

Q. Does the adjustment you sponsor remove **all** advertising costs that were incurred in the test year?

A. No. Staff's adjustment does not remove advertising costs where the message is about customer safety, public notices, energy efficiency, or information on billing, payment and rate options. For example, significant costs were incurred in the test period for the APS "Power Tips" campaign that provided information to consumers about energy conservation on peak demand days, Surepay billing programs, aps.com and online billing, appliance efficiency, the selection of qualified contractors, or electric safety. A review of the first four lines of Schedule C-17 and the related footnotes illustrates how costs for television, print, and radio media placement of APS advertising were distributed between image-building (disallowed) costs and specific (allowed) advertising of tangible benefit to ratepayers because of an information, conservation, efficiency or safety message.

Q. Why are the costs of advertisements for KNXV Weather, Dodge Theater, and various professional sports teams, as set forth at lines 4 through 9 of Schedule C-17 disallowed on a 50 percent basis?

A. APS sponsorship costs represent financial commitments made for charitable as well as public relations purposes. In response to Data Request UTI 1-18, the Company stated:

> To encourage and support downtown Phoenix re-development the Company has sponsored entities such as the Dodge Theater, the Arizona Diamondbacks, and the Phoenix Suns. Such redevelopment allowed APS to garner additional sales revenues and margins from the above entities, plus margins from those support entities that derived their business from downtown redevelopment (e.g. restaurants), using, in part, already existing APS infrastructure. And in conjunction with these same sponsorships, the Company did a Simple Things Campaign directed at customer service and satisfaction.
>
> Also, many if not all, sponsorships/advertising contained multiple elements. These included "pure" advertising, public service announcements, charitable programs, environmental or renewable program participation, employee or customer benefits (e.g., free or reduced admission to events), etc. Some, but not all, of the sponsorships/advertising allocated specific costs to each such element. Others charged a lump sum for the entire package of APS benefits.

Staff's 50 percent disallowance of sports team sponsorship costs is a conservatively generous cost recovery proposal, based upon the mix of "package" benefits received by APS for such expenditures, given the absence of tangible, direct value to ratepayers from Phoenix economic development, charitable programs and free or reduced price admission to events. A review of the Company's stadium/arena advertising and bundled TV and radio messages alone would support disallowance of at least 50 percent of sports sponsorship costs, because an emphasis was placed upon the "Simple Things" campaign messages (i.e., the disallowed image building campaign) in such advertising, as previously discussed.

Q. Is there any linkage between favorable public opinion about APS service quality and value, in relation to incentive compensation amounts earned by Company management?

A. Yes. As explained in Mr. Carver's testimony, one determinant of how much incentive compensation is payable to management is the percentage of customers stating they are "very satisfied" with APS service in responding to customer survey questioning. Image-building advertising can be employed and timed to create goodwill toward the Company and a strengthened perception that informed ratepayers should be "very satisfied" with APS, given the repeated messages about reliability, value and customer responsiveness within the "Simple Things" campaign.

Q. Regarding the Company's suggestion that downtown re-development may promote additional sales revenues and margins, shouldn't such promotional costs, if effective, be included in the revenue requirement?

A. Probably not. Promotional advertising by energy utilities is often disallowed by regulators as a matter of policy because it may be contrary to conservation and integrated resource planning goals. Further, sales gains made by the electric supplier may be achieved in part from sales losses by the competing regulated natural gas distribution utility. Moreover, it is difficult to determine whether economic development financial participation by a utility is cost effective in relation to sales growth that might be achieved even if economic development activities were left entirely to other private and public entities. In addition, it should be noted that, assuming incremental revenues from customers added exceed incremental cost to provide such service, sales gains made by APS between rate case test periods provide benefits solely to shareholders because regulatory lag does not "capture" the impact of increases in sales margins until the "next" rate case occurs.

Q. Would APS have a greater interest in promotional advertising and favorable public impressions about the Company if industry restructuring and competition had been implemented as planned in Arizona?

A. Yes. Achieving favorable service quality and value impressions among the buying public would be highly desirable in a competitive market and may have influenced company judgments regarding the level and types of advertising purchased in the test period. However, such costs should ultimately be borne out of profits earned through the competitive supply of energy and not the regulated delivery service pricing.

Q. Please explain your treatment of "Indirect Payroll, Administration and Ad Agency Fees" at lines 12 and 13 of Schedule C-17.

A. The advertising elements listed on lines 1 through 10 represent the direct costs of advertising placement paid to vendors during the test period. In addition to these direct costs that are totaled on line 10, APS incurs certain indirect costs for Company personnel and advertising agencies for planning, development and administration of the advertising and sponsorship programs. These indirect overhead costs are disallowed in proportion to the treatment of the direct costs, using the percentage value developed on lines 10 and 11.

STATE INCOME TAX CREDITS AND PERMANENT BOOK/TAX DIFFERENCES

Q. Please describe your next adjustment to APS' proforma level of income tax expense.

A. Within its development of proforma income tax expense, APS has failed to capture 1) the test year savings it achieved by way of Arizona state income tax credits and 2) the test year cost penalty it incurred as a result of *not* being able to deduct certain meals and entertainment expense. The adjustment shown on

Schedule C-18 is therefore made to reinstate the *net impact* of the two items noted.

Q. Was the net impact of the two items reflected within test year actual operating results?

A. Yes. However, the Company's total company and ACC jurisdictional *proforma* cost of service study was developed by simply applying the composite federal and state income tax rate (i.e., 39.5%) to total company and ACC jurisdictional *proforma* above-the-line operating results less below-the-line interest expense that was calculated by multiplying APS' proposed rate base times APS' proposed weighted cost of debt. The Company's methodology had the impact of eliminating the savings recognized during the test year stemming from the Arizona state income tax credits and the cost penalty resulting from the inability to deduct certain "meals and entertainment" expense. It is therefore necessary to reflect an adjustment to capture the net impact of the two noted events.

Q. Please briefly describe what events or transactions give rise to receiving an Arizona state income tax credit.

A. During the test year APS received four separate Arizona state tax credits First, it received a credit in the amount of $60,500 related to its hiring of employees within qualified enterprise zones. Second, APS received a credit in the amount of $1,167,690 stemming from its investment in facilities constructed to control or prevent pollution. Third, the Company received a credit in the amount of

$1,167,690 related to the purchase of coal consumed in generating electrical power in Arizona. Fourth, APS received a credit in the amount of $1,108,206 for its investment in an alternative fuel delivery system for the dispensing of renewable fuels. According to the Company's response to Data Request UTI-6-188, the credit for investing in alternative fuel delivery systems was repealed with an effective date of January 1, 2004. While this repeal date is well beyond the end of the test year, I have nonetheless conservatively excluded this credit in developing the adjustment shown on Schedule C-18.

Q. Are the "meals and entertainment" expenses which are *not* deductible for purposes of calculating taxable income included as above-the-line operating expenses?

A. According to Company representatives, theses items do relate to above-the-line test year operating expenses. As previously discussed in testimony, in Adjustment C-17 I have eliminated certain sports and entertainment sponsorship programs undertaken by APS. To the extent that any or all of those expenses eliminated in my Adjustment C-17 are included as test year non-deductible "meals and entertainment" expense, a revision to either Adjustment C-17 or C-18 will be required. As of the time this testimony was to be prepared I had discovery outstanding on this issue. For purposes of developing Adjustment C-17 I have assumed that all of the expense being eliminated within Adjustment C-17 (i.e., the sports/entertainment adjustment) *was* deductible for purposes of developing taxable income.

INTEREST SYNCHRONIZATION

Q. Please discuss your next adjustment to APS' proforma level of income tax expense.

A. The adjustment shown on Schedule C-19 is undertaken to synchronize the interest deduction for consideration in the development of Staff's cost of service income tax expense with the jurisdictional rate base and weighted cost of debt being proposed or recommended by various Staff witnesses. This adjustment, which is routinely calculated and adopted by regulatory commissions in utility rate cases, is derived by multiplying Staff's proposed retail jurisdictional rate base times the weighed cost of debt included within Staff's development of the overall cost of capital. To the extent this Commission may adopt a different rate base or cost of capital than that being proposed by the Utilities Division Staff, it would be appropriate to revise this calculation or adjustment for the return and rate base found reasonable by the ACC in this docket.

TURN AROUND OF EXCESS DEFERRED INCOME TAXES

Q. Are you proposing any other adjustments to APS' proposed level of income tax expense incorporated within the Company's cost of service?.

A. Not at this point in time. I am, however, still investigating the need for an adjustment to reflect the amortization of excess accumulated deferred federal income taxes. I have reserved Schedule C-20 for such an adjustment if forthcoming data indicates that an adjustment is appropriate.

Q. What transactions give rise to "accumulated deferred income taxes?"

A. Utilizing guidelines set forth as Generally Accepted Accounting Principles ("GAAP") which are established by the Financial Accounting Standards Board, companies will record receipts and expenditures of monies as either revenues, income, expense or investment. By following GAAP, the transactions are intended to be recorded in a consistent manner following such guidelines so that the various companies' reported income and investment can be reviewed and compared on a consistent basis.

The recognition of revenues and expense for financial statement reporting purposes does not always coincide exactly with the development of revenues and expense for purposes of developing current taxable income. The difference in the development of revenues, expense and income for financial statement reporting purposes versus the development of current taxable income gives rise to "book and tax" differences. Some of the differences are "permanent" differences – as in the case of the non-deductible meals and entertainment expense. However, the majority of book and tax differences are merely "timing" differences. For instance, one of the largest recurring book/tax timing differences stems from the development of depreciation expense recognized for financial statement reporting purposes versus that recognized for purposes of calculating current federal and state taxable income.

Using a convention commonly referred to as "normalization accounting," APS as well as virtually all other regulated and unregulated companies, derive an amount of income tax expense shown for financial statement reporting purposes by essentially applying the current federal and state income tax rates to "book income." To the extent that "taxable income" varies from reported "book" or "financial statement" income because of book and tax *timing* differences, an "accumulated deferred income tax reserve" is established by applying the current federal/state tax rates to the various timing differences. Later, when a timing difference reverses (i.e., taxable income exceeds book income or vice verse), the related accumulated deferred tax reserve established when the timing difference first arose is, likewise, reversed. Thus, under such "normalization accounting," income tax expense for financial statement reporting purposes *in total* will approximately equal "book income" times the current federal and state tax rates. However, the split or distribution of *total reported income tax expense* between "current" and "deferred" income tax expense can fluctuate significantly from year to year as book/tax timing differences arise and reverse.

Q. What has given rise to *excess* accumulated federal income tax reserves?

A. The amount of taxes deferred or "reserved" in any given taxable year related to book/tax timing differences is based upon the then-current federal and state effective tax rates. While the current corporate federal income tax rate of 35% has remained fairly constant since the mid-1980's, up through the mid-1980's the rate was considerably higher – ranging from 46% to 48%. Specifically, there were depreciation deductions taken for tax purposes for which deferred tax reserves were established assuming that when the timing difference turned around the federal income tax rate would still be 46% or 48%. Since the current federal tax rate is 35%, there exists *excess* accumulated deferred income taxes accrued at 46%/48% that should, nonetheless, be returned to ratepayers vis-à-vis an amortization mechanism.

Q. Does APS recognize the need for this adjustment?

A. From discussions that I have recently held with APS accounting personnel, I am certain that APS conceptually agrees with the need or equity in crediting ratepayers for excess deferred taxes accrued on its books and collected in rates in prior years. However, the Company's position is that there is an exact offset or shortfall to such *excess* accumulated deferred income taxes, and accordingly, no further adjustment to test year cost of service income tax expense is warranted. As stated at the outset of this section of my testimony, I am not posting an adjustment at this point in time as I continue discussions with APS on this complex issue. If at a later point in time I determine that ratepayers have not been, or are not being, credited for *excess* accruals of deferred taxes I will supplement my direct testimony and post an adjustment to test year income tax expense as deemed appropriate.

SCHEDULE 1 TARIFF CHANGES

Q. What is the purpose of the adjustment set forth at Staff Schedule C-21?

A. At Attachment DGR-5, page 5, the Company proposes a ratemaking adjustment for the revenue impact of changing certain miscellaneous service charges under its Schedule 1 tariff. The Specific Company-proposed rate changes are described in APS witness Rumolo's testimony starting at page 3. However, as discussed in the testimony of Staff witness Ms. Barbara Keene, different Schedule 1 charge amounts are being proposed by Staff in this Docket. Therefore, it is necessary to modify the Company's adjustment to reflect the revenue impact of Staff's alternative Schedule 1 rate proposals, as shown in Schedule C-21. Ms. Keene is responsible for the Staff rate proposals on this Schedule.

ACCELERATED AMORTIZATION OF REGULATORY ASSETS

Q. Is APS proposing to amortize certain expenses that have been deferred pursuant to ACC orders?

A. Yes. The Company has eliminated the amortization of deferred costs which, pursuant to a 1996 Settlement Agreement which was subsequently approved by the ACC, will be fully recovered by June 30, 2004. However, APS witness Mr. Donald Robinson notes that other costs have been deferred since the 1996

Settlement Agreement. APS proposes to recover such remaining deferred costs over a five year period.

Q. Are you in agreement with APS' proposed five year amortization of such deferred costs?

A. No. The net deferred costs consist primarily of 1) remaining deferred Palo Verde sale/leaseback payments and 2) Net Unamortized Loss on Reacquired Debt. Referring first to the Net Unamortized Loss on Reacquired Debt, as discussed in a previous section of testimony, Staff is proposing to recover such costs vis-à-vis its development of the effective interest rate on bonds issued to retire higher cost bonds. Accordingly, it is not necessary, and indeed, it would be duplicative, to also reflect such costs as an above-the-line operating expense. Further, there is no apparent reason to accelerate the recovery of such deferred costs as APS has proposed. The benefit of retiring such high cost bonds will be realized over the life of the new lower cost bonds. Accordingly, because the Staff has considered such costs in the development of its effective interest rate on long term debt, it is not necessary to also reflect such costs as an above-the-line operating expense – on an accelerated five-year basis as proposed by APS or over the life of any new bonds issued to retire higher costs bonds.

The other significant deferred costs which APS proposes to amortize over a five year period relates to deferred Palo Verde Sale Leaseback payment. There is approximately twelve years remaining on the Palo Verde Unit 2 lease.

Accordingly, I am proposing that deferred Palo Verde lease expense be amortized, or recovered, over the remaining life of the Palo Verde Unit 2 lease. On Schedule C-22 I propose an adjustment to 1) eliminate APS' proposed above-the-line amortization of net losses on reacquired debt, and 2) lengthen the amortization of deferred Palo Verde Unit 2 lease payments from the APS-proposed five year period to the remaining life of the lease – or in other words – twelve years.

CONTRIBUTIONS TO CIVIC AND CHARITABLE ORGANIZATIONS

Q. Are you proposing an adjustment to eliminate contributions to any civic and charitable organizations?

A. Yes. As shown on Schedule C-23, I am proposing to eliminate contributions charged during the test year to above-the-line operating expense. Such contributions are not necessary to the provision of safe and reliable utility service. Further, contributions can be viewed as serving the same purpose as imagine building advertising which I have previously discussed in testimony.

Q. Are you suggesting that APS should no longer make voluntary contributions to civic and charitable organizations?

A. It is the Company's decision as to whether to continue making such voluntary contributions. However, if made, such contributions should be charged below-the-line and absorbed by shareholders. To include such expenditures above-the-line for cost of service determination places the ratepayers in the position of becoming *involuntary* contributors to such organizations. Accordingly, such expenses should be removed from cost of service development.

AMORTIZATION OF GAINS ON SALES OF PROPERTY

Q. Has this Commission historically required that any gains on sales of utility property be shared between shareholders and ratepayers?

A. Yes. While there are a few examples of exceptions, it is my understanding, and it has been my observation, that the ACC typically requires that gains on sales of property be shared 50/50 between shareholder and ratepayers.

Q. Have there been any gains on sales of property in recent years that have not yet been credited to ratepayers?

A. Yes. In answer to Data Request No. UTI-105 the Company has identified gains on sales of property that have been deferred for crediting to ratepayers. On Schedule C-24 I propose an adjustment to amortize the ratepayers' portion (i.e., 50%) of such gains over a five year period.

ALTERNATIVE REVENUE REQUIREMENT RECOMMENDATION ASSUMING PWEC ASSETS ARE INCLUDED IN THE DEVELOPMENT OF JURISDICTIONAL RATE BASE

Q. Near the outset of your testimony you indicated that, while the Staff's primary recommendation in this case is to remove or eliminate PWEC assets from jurisdictional rate base development, the Staff is also presenting an alternative proposal that reflects inclusion of the PWEC assets in rate base with accompanying adjustments. Please describe the development of Staff's *alternative* rate recommendation that reflects the inclusion of PWEC assets in rate base.

A. Mr. Harvey Salgo discusses and describes Staff's *alternative* revenue requirement recommendation in the event the Commission elects to consider the PWEC assets in the development of jurisdictional rate base. I will not repeat such discussion herein. While I am not the Staff witness responsible for the theory underlying Staff's *alternative* revenue requirement recommendation, I have assisted in the calculation and presentation of Staff's alternative revenue requirement recommendation that incorporates the inclusion of PWEC assets in rate base.

Q. Please describe the development of Staff's alternative revenue requirement recommendation.

A. First, I note that I have prepared an *alternative* Revenue Requirement Summary, *alternative* Rate Base Summary and *alternative* Net Operating Income Summary schedules comparable to Staff's base or primary case that I have designated as Schedule A-Alternative, Schedule B-Alternative and Schedule C-Alternative, respectively. In Staff's *alternative* case, the only difference from – or incremental change to – Staff's primary case is 1) the add back of the PWEC investment to rate base, 2) the add back of expenses related to owning and operating the PWEC assets, and 3) the amortization of lost savings stemming from APS' purchase of Track B power below market prices that ratepayers would otherwise forego absent the noted adjustment if the PWEC assets are included in the development of jurisdictional rate base.

Turning first to Schedule B-Alternative (Rate Base Summary), one can observe where I simply "added back" the jurisdictional investment in the PWEC assets that were removed from Staff's base case within Adjustment/Schedule B-2. The adjusted rate base values shown on Schedule B-Alternative are carried forward to Schedule A-Alternative (Revenue Requirement Summary).

On page 2 of Schedule C-Alternative (Net Operating Income Summary), I show the add back of revenues and expenses related to owning and operating the PWEC units.

Q. In your development of page 2 of Schedule C-Alternative do you merely add back or "reverse" the components that you adjusted in Staff's base case with Adjustment/Schedule C-2?

A. No. There are several differences which I shall briefly explain. Starting first with the "revenue" portion of the adjustment, the Commission needs to understand that APS' PWEC adjustment to the income statement which I essentially reversed on Adjustment/Schedule C-2 consisted of two components. One component consisted of estimated incremental off-system sales margins thought to be achievable and available for crediting to ratepayers if the PWEC units were included in the development of jurisdictional rate base. The other component of what APS designated as a "revenue" adjustment was not really a "revenue" transaction at all. Specifically, as discussed in APS witness Mr. Donald Robinson's direct testimony (page 29), APS' PWEC income statement adjustment also effectively imputed the revenue requirement savings that would be achieved vis-à-vis recognition of a more-highly-debt-leveraged/lower-overall-cost capital structure that reflected some $500 million of additional debt financing that had lower cost, tax deductible interest expense obligations. APS reflected such imputed capital cost savings as additional "revenues" within its PWEC income statement adjustment, even though such savings do not really consist of "revenues."

On page 2 of Schedule C-Alternative I have added back the off-system sales margins estimated to be achievable if the PWEC units are included in rate base. However, I have not added back the imputed capital cost savings that were originally removed in Staff Adjustment/Schedule C-2. It is my understanding that Staff cost of capital witness Mr. Joel Reiker is recommending the same capital structure and cost rates regardless of whether the PWEC units are included or excluded in rate base development. Accordingly, it would be inappropriate to "add back" the imputed capital cost savings that were included within APS' original PWEC income statement adjustment.

Q. Please continue describing the development of other subcomponents of the PWEC income statement adjustment found on page 2 of Schedule C-Alternative.

A. The "Purchased Power & Fuel Costs" adjustment found on line 2 was developed and provided by Mr. Douglas Smith of LaCapra Associates. The amount provided is a somewhat different amount than that posted when "reversing" the Company's PWEC income statement adjustment as reflected on Schedule C-2. This difference has arisen by virtue of the fact that Mr. Smith is taking issue with some of APS' assumptions employed in developing fuel and purchased power expense under the alternative "PWEC in rate base" scenario.

The "Operations and Maintenance" Expense (other than Fuel & Purchased Power) amount merely adds back the expense level that was eliminated or reversed on Schedule C-2.

The Depreciation and Amortization Expense amount derived on page 3 of Schedule C-Alternative and carried forward to page 2 of Schedule C-Alternative has been developed by applying depreciation rates being proposed by Mr. Michael Majoros to the PWEC plant in service values.

The property taxes or "Other Taxes" calculated on page 3 of Schedule C-Alternative and carried forward to page 2 of Schedule C-Alternative were developed by applying the 2003 actual composite or average Arizona property tax rate to the assessed value of the PWEC units as developed by APS.

Finally, Income Tax Expense was developed by applying the composite Federal and State income tax rate to the change in taxable income. Taxable income was developed by considering the various revenue and expense adjustments described above, as well as the additional interest expense deduction that would be available if the PWEC units are included within jurisdictional rate base.

Q. Please describe the development of Schedule A-Alternative.

A. Schedule A-Alternative calculates a revenue requirement by considering the adjustments to rate base and operating income which were calculated on Schedule B-Alternative and Schedule C-Alternative, respectively. As shown on line 10, column (c) of Schedule A-Alternative, the net impact of adding back the PWEC investment to jurisdictional rate base and adding back Staff's proposed level of operating and ownership costs, is to increase our recommended jurisdictional revenue level by approximately $123 million. However, as shown on line 14 of Schedule A-Alternative, Mr. Salgo of LaCapra

Associates is also proposing an incremental adjustment to jurisdictional revenue requirement to reflect savings stemming from APS' Track B purchase of power at below market rates.

NAC INTERNATIONAL – AFFILIATE CONTRACT FOR TRANSPORTABLE DRY SPENT NUCLEAR FUEL STORAGE SYSTEMS

Q. What is NAC International?

A. NAC International ("NAC") is an affiliate of APS that develops, markets and contracts for the manufacture of cask designs for spent nuclear fuel storage and transportation. El Dorado Investment Company is a wholly owned subsidiary of Pinnacle West Capital Corporation. El Dorado Investment Company, in turn, is the majority owner of NAC. Thus, NAC is an affiliate of APS.

Q. Does NAC transact business with APS?

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

[redacted]

Q. Should there be any exceptions to the requirement to competitively bid the second and subsequent batches of dry cask storage systems?

A. I believe that if APS does not elect to undertake a competitive bid process, the burden should be on APS in future rate cases to demonstrate why the competitive bid process was *not* practical, reasonable or likely to produce benefits for ratepayers. Thus, I am not stating unequivocally that the competitive bid process must be undertaken or will always lead to the least cost, most efficient resolution. But to emphasize – the burden for *not* undertaking the competitive bid process would be on APS – with "all ties" regarding facts and assumptions on the evaluation falling to the ratepayers' advantage.

Q. Does that conclude your direct testimony?

A. Yes, it does.

Staff Exhibit No. __

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	)	DOCKET NO. E-10345A-03-0437

DIRECT TESTIMONY

OF

STEVEN C. CARVER

ON BEHALF OF THE
STAFF OF THE ARIZONA CORPORATION COMMISSION

'EBRUARY 3, 2004

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STEVEN C. CARVER

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DIRECT TESTIMONY OF
STEVEN C. CARVER

Q. Please state your name and business address.

A. My name is Steven C. Carver. My business address is 740 NW Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. What is your present occupation?

A. I am a principal in the firm Utilitech, Inc., which specializes in providing consulting services for clients who actively participate in the process surrounding the regulation of public utility companies. Our work includes the review of utility rate applications, as well as the performance of special investigations and analyses related to utility operations and ratemaking issues.

Q. On whose behalf are you appearing in this proceeding?

A. Utilitech was retained by the Staff of the Arizona Corporation Commission ("Staff" and "ACC", respectively) to review and respond to the rate case filing of Arizona Public Service Company ("APS" or "Company") and to file testimony with this Commission regarding the results of our review, primarily regarding APS' test year revenue requirement.

Q. Have you previously testified before this Commission in proceedings that involved APS?

A. No. Although I have not previously filed testimony in a proceeding involving APS, I have filed testimony and participated in a number of other rate proceedings before this Commission dating back to the late 1980's, including: US West Communications (now Quest Communications), Southwest Gas Corporation, and Citizens Utilities Company.

Q. Please summarize the purpose and content of your testimony.

A. Generally, my responsibilities in this docket encompass the review and evaluation of various elements of rate base and operating income included within the overall revenue requirement. As a result, I address one rate base adjustment (Staff Adjustment B-7) and four adjustments to operating income (Staff Adjustments C-12 through C-15). The Staff ratemaking adjustments, which I do not sponsor, are separately addressed in the direct testimony of ACC Staff witness James Dittmer or other identified Staff witnesses. The revenue requirement effect of the various Staff adjustments and recommendations are reflected within Staff's Joint Accounting Schedules, which are discussed in greater detail by Mr. Dittmer.

EDUCATION AND EXPERIENCE

Q. What is your educational background?

A. I graduated from State Fair Community College, where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting.

Q. Please summarize your professional experience in the field of utility regulation.

A. From 1977 to 1987, I was employed by the Missouri Public Service Commission ("MoPSC") in various professional auditing positions associated with the regulation of public utilities. In April 1983, I was promoted by the Missouri Commissioners to the position of Chief Accountant and assumed overall management and policy responsibilities for the Accounting Department. I provided guidance and assistance in the technical development of Staff issues in major rate cases and coordinated the general audit and administrative activities of the Department.

I commenced employment with the firm in June 1987. During my employment with Utilitech, I have been associated with various regulatory projects on behalf of clients in the States of Arizona, California, Florida, Hawaii, Kansas, Illinois, Iowa, Indiana, Mississippi, Missouri, Nevada, New Mexico, New York, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia and Wyoming. I have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water). Since joining the firm, I have also appeared as an expert witness before the MoPSC on behalf of various clients, including the Commission Staff. Additional information regarding my educational background, professional experience and qualifications are summarized in Attachments SCC-1 and SCC-2.

EXECUTIVE SUMMARY

Q. Please describe Staff's approach to quantifying revenue requirement in this proceeding.

A. Staff's Joint Accounting Schedules use APS' "prefiled" jurisdictional amounts (including Company pro forma adjustments) for rate base, revenues and expenses as a starting point. The Company's proposed amounts were then further adjusted to reflect the impact of the various modifications recommended by Mr. Dittmer, other Staff witnesses and myself.

By starting with the Company's adjusted "prefiled" jurisdictional amounts, each ratemaking adjustment recommended by Staff represents a reconciling difference, positive or negative, between the overall revenue requirement recommendations of Staff and APS.

Q. How will you identify and refer to the individual accounting adjustments that you sponsor?

A. Both rate base and operating income adjustments have been numbered sequentially, but separately, beginning with the number "one". In order to distinguish the first rate base adjustment from the first operating income adjustment, the adjustment number is preceded by a reference to the schedule on which the adjustment was posted. For example, the posting schedule for the rate base adjustments is Schedule B. So, the first rate base adjustment would then be referenced as Schedule (or Adjustment) B-1. Similarly, the first operating income adjustment would be identified as Schedule (or Adjustment) C-1, since Schedule C is the posting schedule for the income statement adjustments. For purposes of testimony presentation in this proceeding, Mr. Dittmer and I may use the words "schedule" and "adjustment" interchangeably when referring to the individual ratemaking adjustments proposed by Staff.

Q. Do the Joint Accounting Schedules provide calculation detail supporting each Staff adjustment?

A. Yes. The Joint Accounting Schedules contain individual adjustment "schedules" that show the quantification of each rate base and operating income adjustment, with footnote references to supporting documentation. Since virtually all information relied upon by Staff in developing these adjustments was supplied by APS in response to written discovery, the adjustment schedules refer to the relevant data sources, already in the Company's possession, that represent the primary support for the Staff adjustments affecting overall revenue requirement. Due to the detailed calculations required to support certain Staff adjustments, additional workpapers or spreadsheet files may have been created in support of certain adjustments.

Q. Please describe how the remainder of your testimony is organized.

A. The remainder of my testimony is arranged by topical section, following the Table of Contents presented previously. This Table identifies the specific areas I address in testimony and references the testimony pages as well as any related adjustment support located in the Joint Accounting Schedules.

CASH WORKING CAPITAL

Q. Please describe Staff Adjustment B-7.

A. Staff Adjustment B-7 reduces rate base to reflect the proper recognition of Cash Working Capital ("CWC") as a source of ratepayer supplied "zero" cost capital, using methodologies consistent with prior ACC decisions.

Q. Has APS proposed a rate base allowance for CWC?

A. Yes. As discussed in the direct testimony of Company witness Laura L. Rockenberger,[1] APS has prepared a lead lag study for its Arizona retail operations for purposes of quantifying CWC in the instant proceeding.

1 Direct testimony of Company witness Rockenberger, pages 9-14.

Referring to Ms. Rockenberger's Attachment LLR-2, APS has proposed a CWC allowance of $54.1 million, as summarized in the following table:[2]

Description	Working Capital Requirement (Source)
Cash Required For (Provided By) Operating Expenses	$(20,969,724)
Non Rate-Based Elements of Rate-Based Components	74,809,380
Special Deposits and Working Funds	258,266
Net Cash Working Capital Required For (Provided By) Operations	$54,097,922

Source: Rockenberger Direct, Attachment LLR-2.

Q. Could you explain the reference in this table to "Non Rate-Based Elements of Rate-Based Components"?

A. As indicated in Company's response to Staff Data Request No. UTI-3-142, the CWC item identified as "Non Rate-Based Elements of Rate-Based Components" represents APS' proposal to include "non-cash" items in the rate base allowance for CWC.

Q. In quantifying this $54.1 million CWC allowance, did APS employ a methodology that was consistent with the longstanding approach used by this Commission as applied in the Company's last rate case?

A. No. In describing the $54.1 million rate base allowance, Ms. Rockenberger's direct testimony states:

> "Second, my testimony explains the Cash Working Capital component of APS' Allowance for Working Capital (SFR Schedule B-5, Line 1) which was calculated following the lead/lag study method required by the Commission in Decision No. 55931 (April 1, 1988)."
> [Rockenberger Direct, p. 2-3]

[2] APS' proposed $54.1 million net CWC allowance is before jurisdictional separations.

In describing the context of this Company testimony, APS' response to Staff Data Request No. UTI-3-142(c) states:

> "The intent of the cited portion of the testimony was to state that the that [sic] both the $(20,969,724) and the $74,809,380 amounts were calculated using a lead-lag study methodology, as opposed to the 'formula' method or other 'rule of thumb' approach. Decision No. 55931 (at pages 66-67) cited a prior Commission decision for the proposition that cash working capital could be held at zero in the absence of a lead-lag study. However, because there is no administrative rule on what a lead-lag study must (or must not) contain, APS does not believe that Decision No. 55931, precludes APS from presenting a lead-lag study that accurately presents the economic impact of the lag in cash collection of costs that have current rate base impact."

Contrary to the representation set forth in direct testimony, APS' proposed lead lag study approach goes far beyond the Commission's longstanding lead lag study methodology, as addressed within Decision No. 55931, and materially misstates the rate base allowance for CWC by including non-cash items.

Q. In quantifying Staff Adjustment B-7, was it necessary for Staff to prepare a lead lag study from "scratch" in order to correctly quantify this component of rate base?

A. No. Cash Working Capital ("CWC") is a complex, labor intensive valuation issue that requires detailed specialized analysis within general rate case proceedings. Since a regulated entity does not record CWC in its accounting records, the CWC amounts included in rate base must be quantified through a specialized study. Significant resources are required to properly prepare, maintain and review detailed lead lag studies. In lieu of preparing an independent study, Staff resources were applied in the instant proceeding to analyze, test and correct the lead lag study sponsored by APS.

Q. Could you summarize the specific changes and corrections you have proposed with respect to APS' valuation of the CWC allowance?

A. Yes. I recommend that the following changes and/ or corrections be reflected in the Company's lead lag study to more accurately quantify the cash working capital needs of APS in conformance with the Commission's CWC policies, as expressed in prior rate orders:

- Remove non-cash, accrued expense items (e.g., depreciation and amortization expenses, pension and OPEB accruals, deferred income tax expenses, etc.) so that the study results are based on "cash" expenses;

- Recognize cash interest expense and the extended (i.e., quarterly, semiannually, etc.) interest payment patterns in the lead lag study;

- Reflect pro forma ratemaking interest expense and per book current income tax expense directly related to the 2002 test year in quantifying the CWC allowance; and

- Incorporate the following miscellaneous corrections identified during Staff's analysis of the APS study workpapers and supporting documentation:

- Revenue lag: employ average daily accounts receivable balances, rather than only month-end balances, in quantifying collection lag; and correct exclusion of transmission lag from calculation of the composite revenue lag.

- Coal expense lag: correct Cholla coal receipt dates; eliminate "minus 1" lag day technique for Cholla coal and coal freight; and replace Four Corners lag day input errors.

- Fuel Oil: correct lag day input errors and payment dates.

- Materials & Supplies and Other: correct expense lag calculation for certain corporate credit card transactions included in the lead lag study.

- Pension & OPEB: revise test year expense amount to reflect actual expense level per response to Staff Data Request No. UTI-16-329.

- Sales Taxes: recognize net lag between collection and remittance of Arizona sales taxes.

After removing the non-cash items, recognizing the interest expense lag and posting the other corrections to the APS lead lag study, Staff Adjustment B-7 results in a negative CWC allowance which should be used to reduce rate base.

Q. Could you summarize the primary differences in the CWC between Company and Staff?

A. Yes. While I have not attempted to account for each dollar difference in rate base, the following table provides a general summary of the primary CWC quantification issues:

		Approximate CWC Issue Value[3]
APS Recommendation	(a)	$53.8 million
Remove Non-Cash Items		(74.8) million
Recognize Interest Expense		(14.1) million
Correct Current Income Tax Expense		(11.2) million
Recognize Arizona Sales Taxes	(b)	(7.1) million
Revise Revenue Lag		(4.9) million
Other Unreconciled Items		(.8) million
Staff Proposed CWC Allowance	(c)	$(59.1) million

Note (a): Rockenberger Attachment LLR-2.
Note (b): Estimate based on Rockenberger Attachment LLR-3.
Note (c): Staff Adjustment B-7.

Q. Why is it appropriate for the lead lag study methodology to produce a negative allowance that reduces rate base?

A. A "negative" CWC valuation reducing rate base is appropriate for several reasons. First, a negative amount indicates that, on average, the Company collects electric sales revenues from ratepayers prior to the need to disburse cash to pay expenses. Consequently, the Company has the advance use of ratepayer-provided funds for which ratepayers should be compensated through negative cash working capital.

Second, it has been my experience that a properly prepared lead lag study often results in a "negative" value for CWC. This result should neither be surprising nor problematic in adjusting rate base. Just as the Company collects customer advances, deferred income taxes and

3 Amounts shown are before jurisdictional separations.

accumulated depreciation funds from ratepayers, which are used to reduce rate base (i.e., recognized as zero-cost capital), so too is it relatively common for a utility to collect operational cash flows from ratepayers in advance of the disbursement of those funds to pay expenses. If a lead lag study shows that CWC is a "negative" amount, it is reasonable and appropriate to reduce rate base accordingly.

Third, by definition, a fully developed and properly prepared lead lag study is not limited to producing a "zero" or positive rate base allowance. Consistent with this Commission's longstanding practice and procedure, it is possible and appropriate for CWC to yield a significant reduction to rate base, when circumstances warrant.

<u>Overview of Cash Working Capital</u>

Q. What is cash working capital and why should it be included in rate base?

A. Cash working capital is commonly defined as the amount of cash needed by a utility to pay its day-to-day <u>expenses</u> incurred in providing service in relation to the timing of the collection of revenues for those services. In applying this definition, if the timing of a company's cash expenditures, in the aggregate, precedes the cash recovery of those expenses, investors must provide cash working capital. On the other hand, ratepayers are considered the providers of cash working capital in instances where their remittances, on the average, precede the company's cash disbursements for expenses. Whether "positive" or "negative" in amount, cash working capital is typically included in utility rate base to recognize the timing of cash flows through the utility.

Q. In your opinion, how should cash working capital be quantified for inclusion in rate base?

A. In my opinion, sample-based lead lag studies represent the best available method for quantifying the revenue and expense component lags that are used in determining cash working capital. Although it may not be feasible to completely update such studies when a utility routinely seeks an annual rate increase, due to the complex and detailed nature of such an undertaking, major components of the lead lag study should be updated periodically to ensure that the revenue and expense lag calculations reasonably represent current operational conditions and reflect the effects of recent changes in corporate policies as well as organizational structure.

The lead lag study prepared by APS is based on relatively recent transaction detail from the calendar 2002 test year. However, instead of a sample-based approach, the APS lead lag study has relied on various measurement techniques, including: the evaluation of all accounting transactions in pre-selected months of 2002 (3-months for "materials & supplies," 11-months for "other"); analyses of established payment processes and patterns (revenues, payroll, income taxes, etc.); and comparison of data contained in computer system data base files to calculate expense lag days for individual transactions (e.g., materials & supplies, other, etc.).

Staff's evaluation of the Company's lead lag study results included the careful review of data inputs and computational formulae within multiple lag day spreadsheet study files prepared by Company personnel as well as judgmental sampling techniques to obtain transaction source documentation to verify and/ or identify necessary corrections to APS' lag day calculations.

Q. You have previously referred to use of a "lead lag study" to quantify CWC. Please explain that reference.

A. A number of years ago, it was fairly common for regulators to estimate a "provision" for the amount of CWC includable in rate base using an arbitrary "formula" method. The most common method was referred to as the 45-day, or 1/8th of O&M, formula. Until the mid-1970's, regulators generally used such a formula method, as modified from time to time to include or exclude certain items from the formula calculation. Since the mid-1970's, it has been fairly common for regulators to rely on actual measurements of cash flows using detailed lead lag studies to quantify the rate base allowance for CWC.

A lead lag study represents a systematic measurement of the timing of cash flows through a utility. Specific calculations are made of the number of days between the provision of service to customers and the collection of related cash revenues for those services. The timing of cash outflows for the major cash expense elements comprising cost of service are also measured to determine the average number of days between the Company's receipt of goods or services supplied by vendors/ contractors and the ultimate cash payment for such items.

If more "lag days" on average are involved in the collection of revenues from ratepayers than are available to a utility in the delayed payment of expenses after the related goods and/ or services are received, investors are considered to provide the necessary cash working capital to bridge this gap between payment and collection, and an <u>addition</u> to rate base is appropriate. On the other hand if cash disbursements are sufficiently delayed, or revenue collections are accelerated, so that the average expense lag days exceed the revenue lag days, ratepayers are considered to be the providers of cash working capital, and a <u>reduction</u> from rate base is appropriate.

Q. Earlier, you defined cash working capital. What is the significance of that definition?

A. The definition of cash working capital is significant in the identification of the particular investment amounts that are includable in the determination of rate base. This definition leads to, or implies, the establishment of certain boundaries as to which cash flows are relevant for ratemaking purposes, thereby defining the scope of the lead lag study.

Q. Please identify the major cash flows of a typical public utility, indicating which cash flows are relevant to the measurement of utility cash working capital requirements.

A. The major sources and uses of cash are observable in a utility's statement of cash flows, or its equivalent, as follows:

Sources of cash for a utility ordinarily include:

- Operating revenues.
- Non-operating and non-jurisdictional revenues.
- Proceeds from outside financings or debt/ equity infusions from parent.
- Asset sales.

Uses of utility cash include:

- Payment of utility expenses.
- Utility plant construction expenditures.
- Payment of non-operating or non-jurisdictional expenses.
- Net change in other assets (inventory, cash, prepayments).
- Retirement of debt or equity.

Given the definition of cash working capital discussed previously (i.e., "the amount of cash needed by a utility to pay its day-to-day <u>expenses</u> . . ."), cash flow timing and measurement is focused <u>solely</u> on the first cash "source" and the first cash "use" listed above. All other sources and uses are either separately considered in the ratemaking process or are non-operational, financing or investing functions – not transactions related to the day-to-day payment of operating expenses. It is also important to note that some operating revenues represent a utility's recovery of recorded non-cash expenses, such as depreciation and deferred tax expense. These accrued expenses are properly included in determining overall revenue requirements, but do not require the current expenditure of cash. Consequently, these "non-cash" expenses fall outside the scope of a properly prepared lead/lag study.

<u>Corrections / Modifications to APS Study</u>

Q. Have you reviewed the Company's lead lag study workpapers and identified any specific corrections which should be recognized therein?

A. Yes. I have systematically reviewed the Company's lead lag study workpapers and supporting calculations. This work did not verify the accuracy of the Company's transaction data (i.e., receipt dates, payment dates, payment amounts, etc.) underlying <u>each</u> of the thousands of transactions contained in the multiple worksheets supporting APS' study results. Instead, Staff's review was focused on the analysis, testing and correction of the most important lead lag study elements sponsored by APS, including reliance on judgmental sampling techniques to obtain transaction source documentation. As a result of this effort, specific corrections to the Company's study have been identified. The following table briefly summarizes the corrections, which have been reflected in the CWC calculation set forth in Staff Adjustment B-7:

Item	Correction
Expense Levels:	Include cash pro forma interest expense; remove out-of-period transactions from 2002 current income tax expense; and revise Pension & OPEB expense to actual test year level.
Revenue lag:	*[Staff 40.13 days vs. APS 41.81 days]* • Modify the CIS revenue collection lag (based on turnover ratio) to reflect average daily accounts receivable balances, rather than calendar month-end balances. • Correct APS' unintended assignment of a "zero" revenue lag to transmission revenues.
Coal expense lag:	*[Staff 31.63 days vs. APS 30.86 days]* • Correct Cholla coal delivery dates for twenty-two transactions included in the APS lead lag study to correspond with actual dates contained in Cholla coal freight study, consistent with the response to Staff Data Request No. UTI-11-276. • In quantifying Cholla coal and coal freight transaction payment lags, APS compared payment date with receipt date then deducted "1" (i.e., net lag "minus 1"). APS study formulae were modified to remove the "minus 1" from the expense lag. • Correct Four Corners coal lag to replace input lag days with lag day formula to reflect average receipt date at mid-point of prior month.
Fuel Oil:	*[Staff 28.51 days vs. APS 27.40 days]* • Correct APS-Oil input error: transaction lag input as 130.5 days, but should have been 116.5 days. • Navajo-Oil: APS calculated lag days by inputting time lapse, rather than computing lag days via spreadsheet cell formulae. The input lag days used payment date other than the actual date listed in APS spreadsheet file. Corrected calculation for three transactions to reflect actual payment date.
M&S and Other:	*[Staff 30.29 days vs. APS 29.34 days]* • Correct corporate credit card expense lag to recognize additional 15.21 days attributable to monthly arrearage billing.
Sales Taxes:	Recognize net lag between collection and remittance of Arizona sales taxes.

Q. In quantifying its proposed CWC allowance, did APS include pro forma levels of expense in the lead lag study?

A. No. In quantifying its proposed rate base allowance for CWC, APS included actual, per books unadjusted test year expenses.[4] Generally, the use of unadjusted test year expenses for CWC quantification purposes can be considered reasonable, absent material ratemaking adjustments to the various expense components reflected in the study. However, referring to APS Schedule C-1, the Company has proposed ratemaking adjustments that increase O&M expense by $120.2 million on a total Company basis (or $101.0 million on an ACC jurisdictional basis).

During the test year, APS also recorded negative current income tax expense and has proposed to further decrease test year "total" income tax expense for the impact of its various pro forma adjustments to taxable income – excluding the $66 million pro forma effect of the Company's requested rate increase on current income tax expense.[5] The magnitude of these items suggest potentially large shifts in the "weighting" of lag days that may warrant use of pro forma, rather than unadjusted, test year expense amounts.

[4] Total Company unadjusted, per book expenses per APS Schedule C-1, column (a) ties to Rockenberger Attachment LLR-3, column (1). Also, see APS response to Staff Data Request No. UTI-12-284.

[5] APS Schedule A-1 (ACC Jurisdictional): Increase in Base Revenue Requirements $166,807,000 less Operating Income Deficiency $100,918,000 equals $65,889,000 of additional current Federal and State income tax expense.

Q. Given the reality of quite large ratemaking adjustments to test year actual expenses levels, what amounts should be included in the APS lead lag study?

A. When feasible and significant to the outcome, material ratemaking adjustments to test year expense levels should be recognized in the lead lag study results, in order to ensure that the CWC rate base allowance is not materially misstated due to inconsistencies between actual and pro forma test year expense levels.

Q. Does Staff Adjustment B-7 fully reflect the net effect of the pro forma adjustments proposed by the Company and Staff?

A. No. While the Company has proposed ratemaking adjustments increasing jurisdictional O&M expense by about $101 million, Staff Schedule C (page 1) summarizes the various adjustments proposed by Staff that offset a large portion of the Company's proposed increase by reducing jurisdictional O&M expense in excess of $60 million. Because of the diverse ratemaking recommendations of the parties in this proceeding, I have adopted APS' proposed use of per book expense levels for CWC valuation purposes – except for current income tax expense and interest expense. When readily identifiable and material in amount, Staff recommends that it is appropriate for a lead lag study to recognize pro forma expense levels in quantifying the rate base allowance for CWC.

Q. Are there any lead lag study components where Staff has not used test year per book expense for CWC purposes?

A. Yes. Staff has proposed to revise the expense levels for two lead lag study components where reliance on "per book" expense levels would yield distorted results. During the test year, APS recorded "negative" current income tax expense due, in large part, to a change in accounting method on the 2001 income tax return, but first reflected in the Company's 2002 financial statements. This change in accounting method caused a material shift between current and deferred income tax expense in the 2002 test year, which should not be allowed to materially impact CWC.[6]

In response to Staff Data Request No. UTI-14-315, APS provided additional information allowing Staff to determine the amount of current income tax expense related to 2002 operating results, excluding the impact of the correcting entries recorded in 2002 for the 2001 change in accounting method. Staff recommends rejection of the "negative" current income tax expense recorded in 2002 for lead lag study purposes, instead recognizing the current income taxes actually related to test year operating results.

In addition, Staff has proposed inclusion of interest expense in the lead lag study, contrary to APS' proposed exclusion. For ratemaking purposes,

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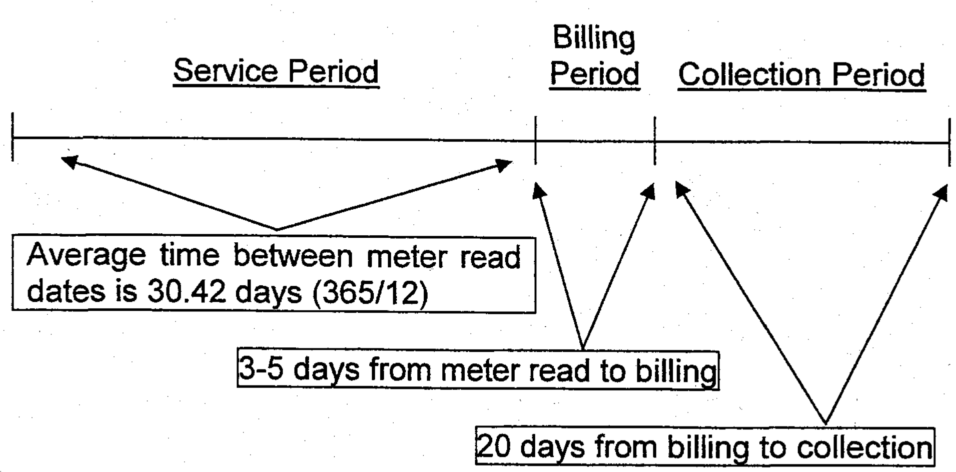
[6] See APS response to Staff Data Request No. UTI-14-314.

Staff's CWC allowance recognizes the amount of pro forma interest expense resulting from Staff's interest synchronization adjustment set forth on Staff Schedule C-19, in lieu of the actual amount of interest expense recorded by APS during the test year.

Q. Please explain how the revenue lag is employed in a lead lag study.

A. As mentioned earlier, a lead lag study is a means of measuring cash flows through the utility. In other words: Does the company, on average, collect revenues from its customers before or after it is required to disburse cash in payment of the goods and services consumed in support of its day to day operations? In answering this question, it is necessary to quantify the revenue lag, which is the average time lapse between the provision of utility service to customers and the collection of the related revenues. The following chart summarizes the components of the revenue lag, using hypothetical billing and collection lags:



Assuming utility service is provided to customers evenly throughout the service period, the follow table illustrates the components comprising the typical revenue lag, using hypothetical values:

Description	Days
Service Lag (1/2 the service period)	15.21
Billing Lag	5.00
Collection Lag	20.00
Revenue Lag	40.21

The revenue lag (i.e., 40.21 days in this example) is then compared to the expense lag quantified for each cash expense component (e.g., coal expense, payroll expense, etc.) of the lead lag study, as appears on Staff Adjustment Schedule B-7.

Q. Please explain how the collection lag element of the revenue lag is estimated in the Company's lead lag study.

A. Rather than conducting a detailed, sample-based analysis of actual customer bill payment patterns, APS employed an accounting technique generally referred to as the accounts receivable turnover ratio to quantify the collection lag. In essence, this turnover ratio estimates how many days-worth of average daily revenues are in the accounts receivable balance, using the following algorithm:

Average Accounts Receivable Balance $ /
(Annual Revenue $ / 365 Days)

APS modified this formula for each test year month, as follows:

Month-End Accounts Receivable Balance $ /
(Monthly Revenue $ / # Days in Month)

Accurate application of the accounts receivable turnover ratio is highly dependent upon the reasonable quantification of average accounts receivable balances throughout each of the 365 days of the year. Thus, an average daily balance is required to calculate reliable results.

Q. How does APS' use of month-end accounts receivable balances, rather than average daily balances, affect the collection lag calculation?

A. Because utilities typically read customer meters on a billing cycle basis (i.e., about 20 billing cycles in a calendar month), it is relatively common for month-end accounts receivable balances to not be representative of the average daily outstanding receivable balances recorded by the utility throughout any given month. In quantifying the revenue collection lag, APS relied only upon month-end accounts receivable balances, which resulted in a collection lag of 22.21 days. In lieu of the month-end balances, Staff recalculated the collection lag based on the average daily accounts receivable balance from information supplied by APS.[7] Staff's calculation is more detailed, incorporating daily balances in place of the twelve month-end data points APS assumed were representative of actual accounts receivables throughout the year.

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7 See APS response to Staff Data Request Nos. UTI-4-155 and UTI-15-323.

Staff's calculation revealed that APS' average daily accounts receivable balances are significantly less than the month-end balances, which results in a lower collection lag of 19.93 days – about 2.3 days shorter than APS' collection lag calculation.

Q. Do you have any comments or observations regarding APS' collection lag?

A. Yes. While a turnover ratio only provides an estimate of the time lapse between rendering customer bills and the utility's collection of related customer payments, it is interesting to observe that the <u>average</u> collection lag estimates of both APS (22.21 days) and Staff (19.93 days) appear to indicate that a significant majority of the Company's customer billings are delinquent on a recurring basis.

According to APS' standard offer tariffs:

> All bills rendered by the Company are due and payable no later than fifteen (15) days from the billing date. Any payment not received within this time frame shall be considered delinquent. ... All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.[8]

The CWC collection lags quantified by both Company and Staff yield <u>average</u> lag day estimates that significantly exceed the 15-day

[8] APS Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Par. 4.2.1.

delinquency provision of APS' existing tariffs. Therefore, one would reasonably expect the Company's late payment charges, assessed at an annual rate of 18%, to generate significant late payment fee revenues due to what would appear to be a prevalence of delinquent customer payments. However, a review of APS' 2002 FERC Form 1 indicates that the Company recorded about $6.1 million of late payment fees during the test year. As indicated by the following calculation, it would appear that this level of actual test year late payment fees were assessed, on average, on only 22% of the Company's 2002 retail revenues. In other words, only 22% of APS' 2002 revenues were considered delinquent and resulted in late payment fee revenues, even though collection lag calculations imply much higher levels of delinquent remittances:

	Amount
2002 Forfeited Discounts (A/C 450)	$6,137,618
Divide: Monthly Late Fee Rate (18% / 12 months)	1.5%
Revenues Subject to Late Fees	$409,174,533
Divide: Sales to Ultimate Customers	1,852,149,140
% Annual Revenues Considered Delinquent	22.09%

Source: APS 2002 FERC Form 1, p.300.

Q. What do you conclude from this information?

A. Based on this data, it would appear that APS has either failed to consistently apply its late payment fee tariff (i.e., in that only 22% of sales to ultimate customers are treated as delinquent) and fully collect all delinquency fees otherwise due from its customers <u>or</u> the turnover ratio methodology tends to materially overstate the revenue collection lag (i.e., ranging from Staff 19.93 days to APS 22.21 days). I assume that APS is fully complying with all terms and conditions of its filed tariffs and Commission rules, such that forfeited discount revenues are <u>not</u> understated during the test year. Instead, it would appear that the collection lag used in the lead lag study, even using Staff's corrected 19.93 day lag, are conservatively overstated (i.e., longer than actually occurs) which translates into a higher rate base allowance for cash working capital than would otherwise be supportable.

Q. Have you inquired about the efforts undertaken by the Company to reduce its revenue collection lag?

A. Yes. Staff Data Request No. UTI-4-154 specifically asked the Company to identify and describe all efforts during the past five years to reduce the revenue collection lag. A portion of this response directly discussed the collection lag and late payment fees, as follows:

> APS' efforts to reduce collection lag are to a large extent constrained by the ACC's rules, which require certain minimum periods from customer billing to payment. In September of 2000, we began, again, assessing a late fee when unpaid charges became delinquent, <u>25 days</u> after billing. The late fee allowed is 18% per annum, or 1.5% monthly on the delinquent charges.
> [Emphasis Added]

In light of the apparent conflict between the 15-day delinquency period included in APS' tariff and the reference to 25-days in the response to Staff Data Request No. UTI-4-154, I reviewed the Arizona Administrative

Code accessible through the internet.[9] According to Title 14, Chapter 2, R14-2-210(C)(1):

> All bills for utility services are due and payable no later than 15 days from the date of the bill. Any payment not received within this time-frame shall be considered delinquent and could incur a late payment charge.

While the above quote from the Arizona Administrative Code is permissive, in the use of the word "could", the APS tariff language cited earlier is clear that delinquent charges "will" be subject to late fees.

Q. In describing the various corrections and modifications Staff has proposed to the Company's lead lag study, you referred to the elimination of "minus 1" from APS' calculation of the coal and coal freight expense lags. Could you describe why that correction was necessary?

A. Yes. APS' lead lag study workpapers contain narrative "documentation" describing the Company's approach to quantifying the revenue or expense lag days for each study component. According to Company workpapers, the "minus 1" quantification technique is designed to exclude the date of payment from the calculation of the expense lag.[10] This quantification technique is flawed, as it fails to capture the entire benefit period from the date of receipt of particular goods or services and the Company's related payment.

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9 http://www.sosaz.com/public_services/Title_14/14-02.pdf

10 APS LLR_WP2 workpaper are composed of 400 printed pages. For example, see LLR_WP2 54/400 for the discussion of Cholla Coal and Freight Procedures, including a reference to the "minus 1" quantification technique.

For example, assume the Company received a coal shipment on the first day of the month (e.g., January 1) and paid for that shipment the next day (e.g., January 2). Under this example, the Company would have the benefit of the coal for one day before remitting payment. However, the Company's "minus 1" technique would assign a zero expense lag[11] to that transaction, thereby understating the expense lag and overstating the amount of CWC includable in rate base. Staff has attempted to eliminate this "minus 1" technique from all components of the Company's lead lag study.

Q. Did APS employ the "minus 1" technique for all coal and coal freight transactions as well as for other fuel and non-fuel lead lag study components?

A. No. A review of the Company's lead lag study workpapers indicates that this technique was only applied in quantifying the Cholla coal and coal freight expense lags. If APS has used the "minus 1" technique in other fuel or non-fuel components of its lead lag study, it is not apprarent from Staff's review of the Company's expense lag calculations.

[11] Step 1: January 2 minus January 1 = 1 day lag. Step 2: 1 day lag "minus 1" = 0 day lag.

Q. Did you inquire about the Company's use of this "minus 1" technique?

A. Yes. In response to an informal Staff inquiry as to why the Company used this quantification technique, APS simply stated: "Somewhat different techniques were used and documented in preparing the lag days for different payment groups." While it is true that different approaches are used to quantify the expense lag for various expense components (e.g., coal, payroll, income taxes, etc.), the Company's informal response does not provide any basis to support a conclusion that the "minus 1" technique is appropriate for the Cholla coal and coal freight components.

Q. You previously referred to certain revisions to APS' coal expense lags, other than the "minus 1" problem. Could you briefly explain the bases for those revisions?

A. Yes. During our review of APS' Cholla coal and coal freight expense lag calculations, the Company provided copies of sample invoice documentation for purposes of testing the delivery dates used in the lead lag study. Upon detailed review of this information, certain discrepancies were observed between the delivery dates used in the Cholla coal calculations and those used for Cholla coal freight. In other words, the coal freight portion of the lead lag study employed delivery dates that were consistently earlier than the delivery dates used for the same coal in computing the coal expense lag. In response to Staff Data Request No. UTI-11-276, APS confirmed that the correct dates were those used in the coal freight study component. Staff modified the Company's Cholla coal lag to recognize the proper delivery dates.

In addition, APS' Four Corners coal lag calculation was based on input lag days, rather than cell formulae that calculated the difference between the coal receipt dates and payment dates set forth in Company workpapers. Staff's proposed coal expense lag also modified these inputs to be consistent with the actual payment dates contained in the APS study.

Q. You also briefly described certain corrections to APS' input of fuel oil expense lags. Is the reason for Staff's corrections in this area similar to the explanation of the Four Corners coal lag?

A. Yes.

Q. Why was it necessary for Staff to correct the corporate credit card expense lag?

A. Staff's review of APS' lead lag study workpapers identified extremely short expense lags (e.g., 9 days) attributed to cash payment transactions involving corporate credit cards. Since credit card accounts are typically billed in arrears and the charges to such accounts were material to the materials and supplies cash expense component of APS' lead lag study, Staff Data Request No. UTI-12-290 was submitted to assess whether and to what extent the Company's relatively short expense lag fully captured the average time lapse between receipt of the underlying goods and/ or services and ultimate payment thereof. The Company's response to this discovery request basically indicated that the credit card expense lags used in the study incorrectly used the invoice date as a proxy for the date the goods and services were received. As a result, the Company concurred that the expense lag for these transactions were understated and should be increased by about 15.21 days – the time between the mid-point of the month and the invoice date.

Q. Please describe Staff's modification to the Company's lead lag study to recognize the net lag associated with the collection and remittance of Arizona sales taxes.

A. In response to Staff Data Request No. UTI-17-331,[12] APS described its accounting for sales taxes collected from ratepayers and remitted to taxing authorities. During 2002, APS paid approximately $128 million in state and local privilege taxes on retail sales to utility customers.

According to this same discovery response, APS becomes responsible for paying the sales taxes upon customer billing and remits any tax due the taxing authorities by the 25th day of the month following customer billing. Recognizing that APS employs a cycle billing process, the sales tax expense lag proposed by Staff represents the sum of one-half the billing

[12] See Attachment SCC-6 appended hereto.

period (i.e., 15.21 days) plus the additional 25 days until remittance is due, for a total expense lag of 40.21 days.

Q. For lead lag study purposes, did Staff apply the full 40.13 day revenue lag in quantifying the sales tax impact on CWC?

A. No. As indicated previously, sales taxes are due on the 25th day of the month following customer "billing". At the time a customer is actually billed, it does not take 40.13 days for the Company to collect the revenues billed, including sales taxes, from its customers. Instead, Staff's proposed collection lag of 19.93 days represents the average time between customer billing and collection. Consequently, the 19.93 day collection lag is the appropriate revenue lag to be used in computing the net lag associated with sales taxes.

Q. Referring to Staff Adjustment B-7, what is the amount of the sales tax expense used in Staff's calculation of CWC?

A. For this element of the lead lag study, Staff used $127,980,680 of sales taxes (before jurisdictional allocation) charged to FERC Account 408.1 during the test year.[13] Staff's proposed treatment of sales taxes for CWC purposes has the effect of reducing rate base by approximately $7 million, as set forth on Staff Adjustment B-7.

[13] See APS 2002 FERC Form 1, pages 262-263.

Q. Are there alternative approaches that could have been used to quantify the rate base offset for sales taxes in lieu Staff's proposed CWC treatment?

A. Yes. Referring to Attachment SCC-6, the response to Staff Data Request No. UTI-17-331 provided the month-end balance in the sales tax liability account from January 2002 through November 2003. During this time period, APS' sales tax liability ranged from $5,496,542 to $13,887,315, with a monthly average in excess of $8 million.

Q. Do you have any further comments regarding APS' lead lag study calculations?

A. Yes. Staff's efforts in quantifying the sales tax lag included a review of the other taxes (i.e., taxes other than income taxes) detail set forth on pages 262-263 of APS' 2002 FERC Form 1. During this review, it was noted that the Company's lead lag study appears to have recognized the net lag associated with the employees' share of payroll tax withholdings, but overlooked the employer's share of such taxes (e.g., FICA and Medicare). Absent information to confirm and finalize a correction to APS' lead lag study, Staff has raised the concern for Company review and discussion in its rebuttal filing.

CWC and Non-Cash Items

Q. Would you briefly explain your proposal to eliminate non-cash items from the lead lag study?

A. The most significant lead lag methodology difference in this proceeding relates to the Staff's removal of non-cash expenses (e.g., depreciation, amortization, deferred taxes, etc.) that APS improperly included in its lead lag study. These items are not reasonably allowed or considered within lead lag studies because they are "non-cash" transactions. These substantive non-cash expenses improperly and significantly overstate the cash working capital required to pay APS' ongoing, day to day expenses. Removal of non-cash expenses is necessary to comply with previous ACC Decisions addressing this issue, as noted herein.

Q. What is the CWC rate base impact of APS' inclusion of non-cash items in its lead lag study?

A. Attachment SCC-3 represents a copy of the APS workpaper (i.e., LLR_2, page 10 of 400) supporting the calculation of the $74.8 million increase to rate base associated with these non-cash items, accrual-basis expense items including: nuclear amortization, pension and OPEB, Palo Verde gain amortization, depreciation and amortization, and deferred income tax expense.

Q. Referring to Attachment SCC-3, the Company has assigned a "zero" expense lag day to each of these items. If the assigned expense lag is "zero", why do you believe that the Company has improperly overstated its cash working capital needs?

A. The use of an assumed "zero" expense lag in and of itself is not a problem. However, the Company has employed a study methodology which applies a revenue lag (i.e., 41.81 days per APS' workpaper)[14] to each of these "non-cash" expense items. Consequently, the Company's method results in the assignment of a positive revenue lag (see Column 2) and a "zero" expense lag (see Column 3) to each non-cash item (i.e., lines 6, 17, 25, 31, 32, 33 and 40), thereby improperly overstating CWC by $74.8 million as a result. By including these non-cash items, the Company's approach implies an expansion in the scope of cash working capital to include cash flows related to the construction and depreciation of plant and the accrual and later payment of deferred income taxes.

Assuming that the purpose of a lead/lag study was expanded to track the timing of <u>all</u> cash flows into and out of the utility, the analysis and measurement would encompass <u>all</u> cash transactions, whether related to current period expenses, dividend payouts or construction activity. However, other rate base elements would also require analysis, as construction costs are not typically paid immediately in "cash" – as implied

[14] See Rockenberger Attachment LLR-3.

by an assumed zero expense payment lag for depreciation. APS' proposed expansion of CWC fails to analyze or account for delayed cash outflows in payment of construction costs or the turn-around and payment of deferred taxes and should be rejected.

Q. Why are deferred income tax expenses considered to be non-cash items?

A. Deferred income tax expenses, as the name implies, represent non-cash, deferred accounting transactions. In other words, the Company does not disburse cash in the current year for deferred income tax expenses. Such income tax expenses arise from normalization accounting of tax/ book timing differences that originate in one year and reverse or "turn-around" in other years. Since deferred income taxes are included in revenue requirement and "collected" from ratepayers, but are not currently paid to the taxing authorities, they become a <u>source</u> of cost free capital separately considered in determining rates (i.e., accumulated deferred income tax reserves are recognized as a rate base offset) and need not be financed or provided by investors. Consequently, deferred income taxes do not require or increase the Company's cash working capital requirements – because there are no current period cash outflows.

Deferred income tax expenses are somewhat similar to depreciation expenses: both represent accrued expenses; both expenses are recovered through utility rates; the cumulative recoveries of both expenses are recognized as zero cost capital and used to reduce rate base; neither of these expenses involve payments to suppliers or vendors; and both expenses provide a source of cash that can be used for investment in plant construction or to support other corporate activity.

Q. Why should non-cash expense items be excluded from a lead lag study?

A. As indicated previously, non-cash expense items represent elements of cost of service that do <u>not</u> require a current period cash payment. Therefore, they do not influence a Company's need for cash working capital, under the commonly used approach to lead lag analysis. Such accrued expense items themselves do not involve issuance of a cash voucher to pay, for example, for depreciation expense.

Thus, non-cash expense items are properly excluded from a lead lag study. Their inclusion would be inconsistent with the widely accepted view of cash working capital as the amount of invested capital required to bridge the gap between the <u>payment</u> of expenses and the <u>collection</u> of related revenues. When there is no expense payment, no cash working capital is required. Depreciation and deferred income tax expenses do not require current period cash payments. Since investors are not required to provide cash advances for these expense items prior to the collection of revenues, it would be improper to include such items in a study of cash working capital requirements.

Q. Why should interest expense be included in Staff's recommended lead/lag study?

A. Interest expenses arise as a direct result of the Company's debt obligations. Each debt issue requires the periodic cash payment of interest expense in known amounts that are due and payable at predetermined points in time (e.g., quarterly or semi-annual interest payments).

In the traditional revenue requirement formula, interest costs are included in the weighted cost of capital that is applied to rate base. Through this ratemaking formula, interest expense becomes as much a part of jurisdictional revenue requirement (i.e., costs borne by ratepayers) as do operating expenses such as fuel and payroll costs. Since the ratemaking process allows recovery of capital costs that include these periodic payments to debt holders and ratepayers pay for utility service on a monthly basis, fairness requires that the lead lag study recognize the Company's use of these interest funds for the extended time period between collection from ratepayers and payout of interest to debt holders.

Q. Should the lead lag study include quarterly common equity dividends, since Staff is proposing to recognize interest expense?

A. No. While I am aware of utility recommendations in other proceedings that have proposed such treatment, common equity cash flows (including common stock dividends) are less certain as to timing and do not represent "cash" expenses. "Net income," from which common dividends are paid, represents the residual equity return remaining for shareholders after all other expenses are deducted from revenues, rendering it comparatively unpredictable in amount. However, CWC recognition of quarterly dividend payments would yield an estimated payment lag in excess of 45 days (i.e., 90 days in calendar quarter divided by two plus additional lag from end of quarter to dividend disbursement date), ignoring the retention of "current" earnings. A presumed "expense" lag over 45 days would exceed the Company's proposed 41.81 day revenue lag, resulting in a negative CWC allowance for common "dividends". As a result, any recognition of common dividends for lead lag study purposes would further decrease Staff's proposed "negative" CWC recommendation.

Consistency with Prior ACC Decisions

Q. You previously indicated that non-cash items, including depreciation and deferred income tax expenses, are not reasonably included within lead lag studies. How has the ACC previously treated these non-cash items?

A. While I have not conducted exhaustive research in this area, I am familiar with the Commission's treatment of these items in a number of rate proceedings dating back to the early 1980's. Attachment SCC-4 contains excerpts from a series of prior ACC decisions concerning lead lag studies and CWC theory. I am not aware of any ACC order adopting the inclusion of non-cash expense as requested by APS in the pending case.

Perhaps of greatest immediate relevance, the Commission specifically excluded non-cash expense items and recognized interest expense in quantifying the CWC allowance adopted in its April 1988 APS rate order (Decision No. 55931):

> The fundamental reason for the difference between APS's calculation and those of the FEA and Staff is the treatment of "non-cash" items, such as deferred taxes and depreciation. Although the argument is somewhat more difficult to follow with respect to deferred taxes (they represent taxes which will be paid in the future), we agree with APS that depreciation accounting represents the return of a cash outlay it made at the time it acquired utility assets. Thus, use of the term "non-cash item" may be a misnomer if read literally. However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. We have repeatedly rejected the inclusion of deferred taxes and depreciation in the calculation of current cash working capital requirements. We have also finally concluded that interest expense should be included in a lead/lag study, and we have expressly approved the concept of negative cash working capital. E.g., Mountain States Tel. & Tel. Co., Decision No. 54843 (January 10, 1986). Therefore, in this case we have used the Staff's negative cash working capital requirement of ($46,757,000) in our rate base determination.

The Commission has issued numerous orders applying and interpreting the lead lag study approach to cash working capital. Although not exhaustive in scope, Attachment SCC-4 contains excerpts from ten (10) different ACC decisions that discuss various CWC topics, including non-cash items, interest expense and use of pro forma (i.e., adjusted) operating expenses.

Q. Please summarize the CWC issues in dispute.

A. While Staff has proposed a series of corrections to APS' lead lag study results, the primary factors driving the significant difference (i.e., over $100 million) in the CWC recommendations of Company and Staff fall into three general areas – each of which are consistent with the Commission's longstanding, lead lag study policies:

- Exclude non-cash items (e.g., depreciation and deferred income tax expense);
- Recognize payment lags related to interest expense; and
- Use of pro forma/ adjusted expenses, particularly interest expense and current income tax expense.

2002 SEVERANCE PROGRAM

Q. What is the purpose of Staff Adjustment C-12?

A. During the 2002 test year, APS offered a voluntary severance package to employees and recorded expense of about $33.1 million (before jurisdictional allocation) associated with the 2002 Severance Program offering. In assembling its revenue requirement recommendation, APS witness Robinson[15] proposed an adjustment to levelize (i.e., amortize) these test year costs over a three-year period.[16] Staff Adjustment C-12 removes the amortization proposed by APS from test year expense.

Q. Could you briefly describe the 2002 Severance Program?

A. In general terms, a voluntary employee retirement program typically offers enhanced benefits to employees nearing or meeting retirement age/ years of service criteria in order to reduce overall staffing levels, by inducing targeted employees to retire earlier than expected. The 2002 Severance Program consisted of two phases: Phase 1 was offered to all employees eligible to retire as of December 31, 2002, while Phase 2 was offered to all employees in positions that would no longer be refilled as a result of that position being vacated.[17] This program was briefly discussed in a press release issued by Pinnacle West on July 23, 2002:[18]

> The Company today also announced cost-containment measures that include a voluntary workforce reduction of 500-600 positions. These reductions will be implemented in the second half of this year and are expected to produce annual operating expense savings of $30-35 million beginning in 2003, and a comparable one-time charge to earnings later in 2002.

According to the Company's response to Staff Data Request No. UTI-8-239, the benefits payable to those eligible employees electing to participate under this plan are different for each phase:

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15 Robinson direct testimony, pages 31-32.
16 See APS Schedule C-2, page 4, Adjustment 11.
17 See Staff Data Request No. UTI-1-17.
18 The press release is publicly available at http://pinnaclewest.com.

- Phase 1 Benefits: $15,000 lump sum transitional retirement payment; continued medical, dental and group life insurance coverage (during severance period); and severance pay (4 weeks of base pay plus 2 additional weeks of base pay for each year of service, with a maximum of 52 weeks).

- Phase 2 Benefits: continued medical, dental and group life insurance coverage (during severance period); and severance pay (4 weeks of base pay plus 2 additional weeks of base pay for each year of service, with a minimum of 8 weeks and a maximum of 52 weeks).

Q. Has APS recognized any cost savings or benefits resulting from the severance program, such as reduced employee levels, in the quantification of overall revenue requirement?

A. Yes. Company witness Robinson briefly discusses this matter in his direct testimony.[19] In annualizing payroll expense for ratemaking purposes, the Company's original filing employed year-end 2002 employee levels and recognized March 2003 wage rates. The Company's payroll annualization adjustment incorporated all reductions in employee levels that were actually achieved by the end of 2002.

Q. If APS has recognized the lower employee levels in its wage annualization, why have you proposed to eliminate the Company's proposed 2002 Severance Program amortization from pro forma operating expense?

A. APS' proposed amortization of the 2002 Severance Program costs does not represent either the net cost incurred by the Company nor ongoing

[19] Robinson direct testimony, pages 30-31.

expense levels. Acceptance of the Company's proposed amortization adjustment will improperly overstate the ongoing cost of providing utility service.

Q. Is it your opinion that the 2002 Severance Program should not have been undertaken?

A. No. Staff Adjustment C-12 should not be interpreted in that context. Regulated entities should undertake reasonable steps to reduce and contain costs, while continuing to provide safe and adequate service. While Staff does not contest the decision, or the incurrence of costs, to implement this severance program, Staff does recommend that APS' proposed program cost amortization be excluded from pro forma operating expense.

Q. If APS incurred $33.1 million to implement the severance program, how can the amortization of that amount (i.e., net of the portion recovered from power plant participant owners) misstate the cost of providing utility service?

A. It is true that APS did incur those costs and that the Company has recognized the impact of the resulting decline in employees in quantifying the pro forma payroll annualization adjustment sponsored by Mr. Robinson. Unfortunately, the Company's pro forma adjustment only provides ratepayers with the benefit of <u>prospective</u> reductions in expense

– a benefit that will not be realized until the rates resulting from the pending rate proceeding are fully effective, which is estimated for July 2004.[20] What APS' ratemaking treatment ignores is the savings realized and retained for shareholders until new utility rates are implemented that reflect the lower staffing levels.

While Mr. Robinson has proposed to amortize the 2002 severance costs over a three-year period, the Company's adjustment ignores the offsetting "savings" realized during and subsequent to the test year, but prior to July 2004. Instead, APS would retain all Severance Program "savings" realized during 2002, 2003 and 2004 for the sole benefit of its shareholders, until new rates are implemented in mid-2004, while still recovering the "cost" of this program in future rates – through its three-year amortization proposal.

Q. Does APS concur that the 2002 Severance Program resulted in cost savings during and subsequent to the test year?

A. Yes. In response to Staff Data Request Nos. UTI-1-17, confidential UTI-8-239 and UTI-15-318, APS provided the estimated savings for 2002 and 2003 expected to result from the 2002 Severance Program. Although this information was not presented on a monthly basis, a reasonable allocation of the expected savings for the first six months of 2004 indicates that the

[20] Per the response to Staff Data Request No. UTI-8-243, APS has requested an effective date as close to July 1, 2004 as possible.

severance program costs (before allocation to APS and removal of joint power plant participant owners' share) should be recovered through retained savings by the time rates from the pending rate proceeding are implemented. The following table summarizes that comparative information:

2002 Severance Program
(000's)

Year	Costs		Savings	
2002	$35,691	(a)	$(9,000)	(b)
2003	0		(19,900)	(c)(d)
2004 (Jan-July)	0		(9,950)	(e)
Total	$35,691		$(38,850)	

Sources:
(a) APS workpaper DGR_WP16, p. 2/4 (before non-APS participant share).
(b) APS response to Staff Data Request No. UTI-2-111, includes APS & PWCC.
(c) APS response to Staff Data Request Nos. UTI-1-17 & UTI-8-239 (amounts reflect PWCC O&M budget reductions for 2003).
(d) Excludes "other" savings of $10.1 million per response to Staff Data Request No. UTI-15-318(a).
(e) 2003 $(19,900) annual savings times 6/12^{ths}.

Since the ratemaking process will not recognize any 2002 Severance Program savings realized by the Company prior to July 2004, it would be totally inappropriate to saddle ratepayers with any portion of APS' cost to implement the program in a way that does not recognize the offsetting savings realized during this same interim period. Otherwise, the amortization mechanism proposed by APS would provide a one-sided opportunity for the Company to retain all savings realized prior to the implementation of new rates (July 2004) and then explicitly recover all costs incurred during the test year at ratepayer expense.

Q. Is it possible to know with absolute certainty that APS realized $38.85 million of severance related savings during 2002, 2003 and January through July 2004?

A. No. Utilities typically do not implement mechanisms to track the actual "savings" realized as a result of implementing a cost savings program, instead relying on estimated savings analyses. Consequently, no one can know with absolute certainty whether the actual savings realized as of July 2004 will be significantly more or less than $38.85 million. However, as stated in response to Staff Data Request Nos. UTI-1-17 and UTI-2-111: "No formal feasibility studies were done for this program."

There is no question that APS expected to commence realizing benefits or cost savings immediately upon implementation of the 2002 Severance Program. As indicated in the earlier quote from the Pinnacle West press release dated July 23, 2002, the voluntary employee "...reductions will be implemented in the second half of this year and are expected to produce annual savings of $30-35 million beginning in 2003, and a comparable one-time charge to earnings later in 2002."

What is known with absolute certainty is that APS is seeking to amortize its share of the costs associated with implementation of the 2002 Severance Program with no offset for, or recognition of, the significant cost savings that it began realizing as a direct result of that very program and will continue to retain for the benefit of shareholders through July 2004.

Q. Does Staff's recommendation have the effect of assigning all costs of implementing the 2002 Severance Program to APS shareholders, while flowing all savings through to ratepayers?

A. No. With regard to the Company's request to explicitly amortize the 2002 severance implementation costs (i.e., gross of related savings), Staff is recommending that APS be allowed to offset all costs incurred during the test year with the actual savings realized by the Company from the date of program implementation through the effective date of the rate change resulting from the pending rate case. The ratemaking process would then only reflect, on a prospective basis, the normal annualized ongoing level of wages and salaries, payroll taxes, benefit costs, and incentive compensation.

Q. Has APS or Pinnacle West offered other similar workforce reduction or efficiency programs?

A. According to the Company response to Staff Data Request No. UTI-15-322, similar workforce reduction programs have not been offered in recent years, at least dating back to 1997. In the fourth quarter of 2003, APS did implement an involuntary reduction to both the Marketing & Trading and Information Services groups, due to the deteriorating western power market and reductions in capital budget expenditures, respectively.

WAGE & PAYROLL TAX ADJUSTMENT

Q. Please describe Staff Adjustment C-13.

A. Staff Adjustment C-13 revises the Company's pro forma payroll annualization adjustment[21] to reflect actual employee levels and wage rates as of October 2003.

Q. Why should these Company adjustments be revised to recognize actual employee levels and wage rates as of October 2003?

A. As discussed in the direct testimony of APS witness Robinson,[22] the payroll annualization contained in the Company's original filing was based on 2002 year-end employee levels and March 2003 wage rates. In response to Staff discovery,[23] APS indicated that its 2002 Severance Program was a voluntary offering that the Company was required to make available to all similarly-situated employees. Because some employees

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[21] See APS Schedule C-2, page 4, Adjustment 10.
[22] See Robinson direct testimony, page 30.
[23] See APS response to Staff Data Request No. UTI-8-241.

were lost that were still needed by APS and would have been retained in the absence of the voluntary nature of that severance program, the Company commenced hiring replacement employees in 2003 to fill those vacancies.

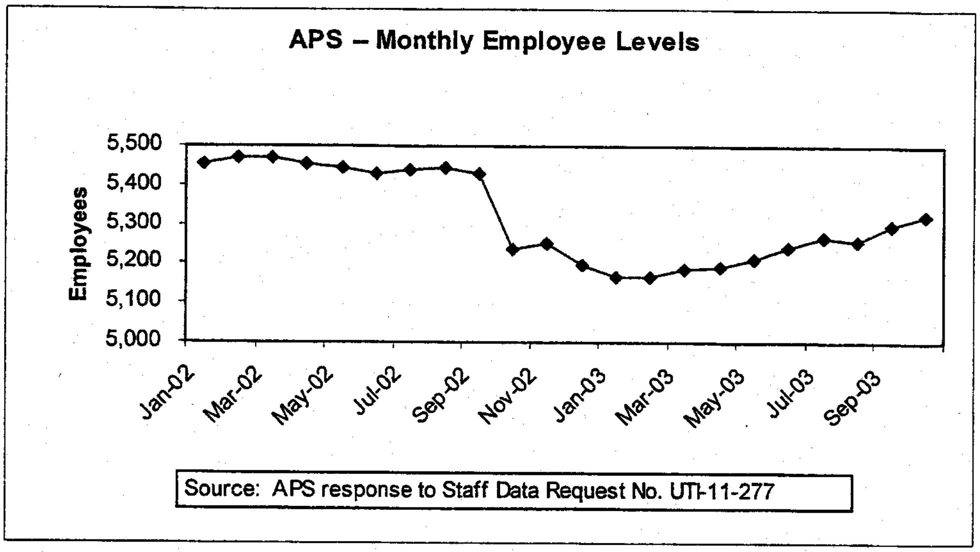
When the 2002 Severance Program was offered, the Company estimated that about 20% of the resulting reduction in workforce would need to be replaced (i.e., hire new employees to fill position vacancies created by certain employees accepting severance). Because an "involuntary" severance program had not been considered, the Company did not perform an evaluation of each employee position to determine the exact number of employees that would have otherwise been retained. However, the month-end employee levels as of October 2003 would reflect APS' success in filling those vacancies.[24] By revising the Company's payroll annualization adjustment to reflect the October 2003 data, pro forma payroll expense will recognize ongoing employee levels at their actual wage rates.

Q. How have employee levels changed during and subsequent to the test year?

A. As part of the Company's original payroll annualization workpapers and through the response to Staff Data Request No. UTI-11-277, APS

[24] See APS response to Staff Data Request No. UTI-15-319.

provided monthly employee counts from January 2002 through October 2003. The following chart graphically illustrates the monthly change in APS (direct) employee levels during this period of time:



Although Staff Adjustment C-13 is based on employee levels at October 2003, the revision to the Company's proposed annualization adjustment still reflects lower headcounts than actually experienced during the test year.

Q. You previously discussed Staff Adjustment C-12, which reversed the Company's proposed amortization of the 2002 Severance Program costs. Is Staff's proposed revision to the APS payroll annualization consistent with the elimination of the severance amortization?

A. Yes. Staff recommends that the Commission deny APS' proposed amortization of the 2002 Severance Program costs, but be allowed to retain all related cost savings realized between program implementation and the effective date of the Commission's order in the pending rate case proceeding. By modifying the APS payroll adjustment to reflect ongoing employee levels (i.e., as of October 2003), Staff has attempted to ensure that utility rates will not allow ratepayers to inadvertently participate in temporary savings attributable to lower than expected employee levels experienced as of December 2002. Accordingly, APS will be allowed to retain all "interim" savings to offset the severance program implementation costs, with ratepayers only benefiting on a prospective basis.

Q. Are you aware of any additional modifications or corrections at this time that should be made with respect to the Company's wage and payroll tax annualization adjustment?

A. No. I am not aware of any additional changes that should be made at this time.

UNION CONTRACT SIGNING BONUS

Q. Please describe Staff Adjustment C-14.

A. During the test year, APS disbursed certain one-time incentive payments to union employees related to the successful completion of union contract negotiations. IBEW Local 387 ratified the labor agreement effective April 1, 2002.[25] Staff Adjustment C-14 amortizes those incentive payments, or

[25] See APS response to Staff Data Request No. UTI-16-325.

signing bonuses, over the three-year term of the union contract for ratemaking purposes.

Q. Did APS charge the full amount of the incentive payments to expense during the test year?

A. Yes. According to the response to Staff Data Request No. UTI-16-325, the labor agreement provided for an incentive payment for each employee represented by IBEW Local 387 in the amount of $1,009.22. APS recorded the cost associated with this incentive payout in May 2002.

Q. Do you know why the Company did not amortize the cost of the signing bonus over the contract term?

A. Yes. The Company considered the incentive payment to be a "current period obligation and therefore should only be realized in the period in which it occurred."[26]

Q. Why should the signing bonus be amortized over the term of the contract?

A. Typically, a signing bonus may be used as an inducement to expedite the successful completion of contract negotiations. Although such bonuses are often paid in a lump sum at or near contract ratification, the benefits resulting from the successful contract negotiations extend over the entire term of the agreement. Consequently, such incentive payments are

[26] See APS response to Staff Data Request No. UTI-16-325(e).

reasonably apportioned over the term of the contract for regulatory and ratemaking purposes.

Q. If the Company actually made the incentive payments to eligible union employees in 2002, why do you believe that 100% of the cost of those payments should not be included in the 2002 test year?

A. Absent explicit provisions to the contrary, APS will <u>not</u> make similar signing bonus payments each and every year that the contract is in effect. Consequently, a reasonable argument can be made that such signing bonuses, when they occur during a rate case test year, represent non-recurring transactions that could be removed from the ratemaking process – in other words, none of the non-recurring incentive payments would be recognized for ratemaking purposes. However, such an approach would discount the role of the incentive payments in mutually resolving the contract negotiations between the Company and the union. For that reason, Staff has proposed to amortize the signing bonus over a three-year period.

Q. If the Commission does not concur with the three-year amortization proposal, do you have an alternative recommendation on this issue?

A. Yes. While I strongly believe that the amortization approach reasonably balances the considerations and interests of the parties, I also strongly believe that including 100% of the signing bonus in test year expense for ratemaking purposes, as proposed by APS, is wholly inappropriate. Should the Commission decline to adopt Staff's amortization proposal, I would urge the Commission to remove 100% of the signing bonus from test year expense, as non-recurring transaction costs, rather than include 100% of such one-time costs in the current proceeding and set utility rates as if these costs were annually recurring.

INCENTIVE COMPENSATION

Q. What is the purpose of Staff Adjustment C-15?

A. Staff Adjustment C-15 represents a partial disallowance of test period incentive compensation expenses. Staff proposes to eliminate the costs associated with APS' stock-based incentive compensation, while allowing ratemaking recovery of test period expense associated with the cash-based incentive compensation plans. After Staff's adjustment, the 2002 test period will still include approximately $10.5 million[27] of "cash" incentive compensation expense (before jurisdictional allocation) – providing APS with a conservatively generous recovery of various non-stock based incentive plan costs that are driven by both financial and operational performance measures.

[27] See APS response to Staff Data Request No. UTI-12-298: Document RC 02412 indicates total recorded expenses of $11.056 million, inclusive of $540 thousand PNW allocated costs, but reduced by $515 thousand of A&G credits from shared plant participants.

Q. Please describe the stock-based incentive program Staff is proposing be disallowed from test period expenses.

A. Several types of incentives are provided to executives and directors under certain Long Term Incentive Plans in the form of Pinnacle West common stock, including: Performance Stock Option Awards, Performance Share Awards, Stock Ownership Awards and Restricted Stock grants.[28] These awards resulted in benefits to APS executives and management team members during the test year, resulting in the incurrence of about $3 million of expenses recommended for disallowance by Staff. Additional awards can also be provided to Directors of Pinnacle West and to employees already holding Pinnacle West stock, so as to encourage employee stock ownership. The granting of stock options, or shares, by the Pinnacle West Board of Director's Human Resources Committee was discussed in a December 7, 2001 Memorandum from Bill Post:[29]

> "As we prepare for next year our prevailing philosophy of rewarding performance and aligning our interest with those of our shareholders remains our major focus. We all need to work together and continue the commitment to increase shareholder value and value to our customers. I know I can count on each of you to do just that."

Notably, because they are stock-based, these incentive compensation programs are driven by the financial performance of Pinnacle West, rather than performance criteria directly linked to customer service, employee safety, cost reductions or utility operational achievements.

[28] See APS responses to Staff Data Request Nos. UTI-1-85 and UTI-12-293.

[29] See APS response to Staff Data Request No. UTI-1-85, attachment RC00581.

Q. Please describe the cash-based incentive compensation programs that resulted in expenses recorded during the test period, but have not been included in Staff's proposed ratemaking adjustment.

A. In 2002, an annual cash bonus Variable Incentive Plan ("VIP") was effective for Pinnacle West and subsidiary company employees and was composed of two primary components: (1) a Company plan and (2) various Business Unit plans. Cash bonuses payable under the VIP were established for different employee groups in a range of specified percentages relative to salary levels or a bonus pool established for particular groups. The following table generally summarizes plan parameters for various employee groups, with more complex plan details for some groups simply noted as "complex" where plan terms were not conducive to this summarization:

	Company Plan Earnings		Business Unit Plan	
	$ Millions	Payout %	Indicators	Payout %
PNW Incentive Plan	$293-337	0% - 3%	various	0% - 3%
PVNGS Plan	$293-337	0% - 3%	various	various
PNW Shared Services	$293-337	0% - 3%	various	0% - 3%
Management Incentive	$293-337	0% - 7.5%	various	0% - 7.5%
Senior Management	$293-337	0% - 15%	various	0% - 15%
Officer Incentives	$293-337	0% - range	various	various
CEO Plan	$293-337	0% - 200%	none	none
Attorney Incentives	$293-337	0% - 7.5%	various	0% - 7.5%
Power Marketing/Trading	$293-337	complex	complex	complex
Nuclear Safety Plan	$293-337	complex	complex	complex
Nuclear Outage Plan	$293-337	complex	complex	complex
Fossil Incentive Plans	$293-337	complex	complex	complex

Note: If $293 million earnings threshold is met and customer satisfaction per survey indicates >43% "very satisfied" an additional 1% can be added to certain Company Plan payout levels.

Source: APS response to Staff Data Request No. UTI-1-77.

According to the terms of this plan, the "Company Plan Earnings" component of the 2002 VIP conditioned funding upon Pinnacle West consolidated earnings reaching the $293 million threshold target level, with amounts payable under this portion of the incentive plan driven by the achievement of earnings above the threshold level.[30] The Business Unit Plan component involved the establishment of Critical Success Indicators tailored to the responsibilities and goals of the individual business units, which are simply noted as "various".[31] Examples of Critical Success Indicators generally include: minimization of recordable injuries, achievement of targeted cost levels, equipment reliability and availability target achievements, outage minimizations, and various other operational and financial metrics. However, even the Business Unit incentives were not to be funded unless Pinnacle West achieved the threshold earnings levels in calendar year 2002. In effect, the Company's entire cash-based incentive program is primarily driven by Pinnacle West's attainment of the minimum earnings level.

Q. What amount of incentive compensation expense, for each of the plans and in total, has APS included in its test period revenue requirement?

A. APS' proposed test year expense includes approximately $3.2[32] million of stock-based incentive compensation and another $10.5[33] million in cash-

[30] See APS response to Staff Data Request No. UTI-1-77, attachment RC00585.
[31] See APS response to Staff Data Request No. UTI-1-77, attachment RC00585.
[32] See APS response to Staff Data Request No. UTI-12-295.
[33] See APS response to Staff Data Request No. UTI-12-298.

based incentive compensation, resulting in total "per books" incentive compensation costs of approximately $13.7 million.[34]

Q. How does the amount of cash-based incentive compensation APS has proposed to recover in this proceeding compare to the amounts incurred during recent years?

A. APS has proposed to include the actual test year level of cash-based incentive compensation in determining overall revenue requirement. The following table compares the Company's proposed level of such cash incentive compensation costs with historical calendar year expense levels provided in response to Staff Data Request No. UTI-8-244:

Period	$ Millions
1999	$ 16.0
2000	$ 15.7
2001	$ 13.2
2002	$ 11.1

[Note: all amounts prior to participant offset credits related to A&G incentives.]

Q. Do these incentive compensation expenses include amounts directly incurred by APS as well as allocations to APS from affiliates?

A. Yes. However, the amounts shown do not reflect reductions for "participant offset credits" of administrative costs allocable to co-owners of joint generating units, that amounted to about $0.5 million in 2002.

[34] Amounts before allocation to regulated retail operations.

Q. Why is the 2002 level of cash-basis incentive compensation cost lower than prior years?

A. In 2002, Pinnacle West failed to achieve consolidated earnings at the threshold level technically required as a precondition to any funding of cash bonuses. However, this precondition was not strictly applied, according to the Company:

> "The Board determined to pay incentives based on 50% of the individual business unit performance achievement, plus the 1% adder for frontline employees based on achieving the 2002 fourth quarter customer satisfaction survey targeted performance level."

The rationale for this action was explained in a January 23, 2003 letter from Bill Post to all employees, provided in response to Staff Data Request No. UTI-12-299 and appended hereto as Attachment SCC-5.

Q. Why has Staff proposed to allow full recovery of the lower 2002 actual cost of the cash-based incentive plans, while excluding the cost associated with the stock-based incentives in the test period?

A. Even though corporate earnings also serve as a threshold or precondition to the payout of cash-based incentive compensation, the reduced test year cash incentives are tied primarily to performance measures that directly benefit APS consumers, particularly since test period payouts did not include the Company Plan earnings percentages that were payable in prior years. In contrast, the stock-based incentives are entirely driven by

Pinnacle West objectives that, only very indirectly, might benefit consumers.

For example, the targets used to award stock-based incentives under the Performance Shares Plan are based upon Pinnacle West Earnings per Share ("EPS") growth from one year to the next in relation to a comparison group of electric utilities. Comparative EPS growth is not a criteria or element directly considered as a cost component in establishing electric utililty rates. In and of itself, efforts to enhance EPS growth may not be consistent with the interests of utility customers or reasonable pricing for the regulated business, where changes in the level of rate base assets and the cost of capital are more directly relevant to earnings achievable by the utility.

In Staff's view, rate recovery of the reduced test year cash-based incentive compensation is conservatively generous to the Company, where no showing has been made by APS of any customer benefit from either of its discretionary incentive compensation programs.

Q. Should the Commission carefully consider incentive compensation programs and cost levels, in order to balance the interests of utility consumers in reasonable rates with rewards granted to employees for achievements that enhance corporate operational and financial objectives?

A. Yes. Incentive compensation is a method of providing monetary awards to the work force through non-guaranteed or "at risk" cash bonus, or other payment programs, in addition to base wages. According to the Company's response to Staff Data Request No. UTI-12-294: "APS has proposed full inclusion of the compensation paid to APS employees (and the APS-related portion of PWCC employees) in cost-of-service because such compensation is both reasonable and a legitimate cost of doing business independent of how the compensation of specific individual [sic] is calculated and irrespective of the form of the compensation."

Obviously, a decision by management to incur incentive compensation costs is an indication that such costs were viewed as reasonable by the Company, but regulators need not allow above-the-line accounting for all discretionary costs incurred by management absent a showing that such costs provide direct, tangible benefits to ratepayers. In the context of stock-based incentives, the same APS response states:

> "The targets are based on Earnings per Share ('EPS') growth from one year to the next relative to our comparison group. EPS growth as a target is considered by management to encompass virtually all performance measures of the Company, most of which are linked to the cost effective provision of reliable regulated services by APS. Additionally, the vast majority of PNW earnings are derived from APS. Therefore, it is an appropriate measure to use for stock based compensation in the revenue requirement calculation."

However, the consolidated earnings of Pinnacle West and the rate of growth in Pinnacle West EPS relative to a peer group is only distantly related to any tangible benefits of direct importance to APS ratepayers. With this in mind, Staff proposes recovery of only the cash-based compensation program costs in the test year, which were largely incurred without regard to financial results, so as to recognize employee rewards for business unit performance.

Q. If the corporation fails to achieve its financial targets, will employees necessarily be required to forego all compensation associated with the incentive plans?

A. No. As indicated by Mr. Post's previously referenced letter,[35] the Company has waived formal plan parameters and judgmentally awarded employee incentive payments, even when financial performance falls below threshold levels.

Q. If employees are unsuccessful in helping APS and PNW achieve the corporate targets or business unit goals, will shareholders be required to forego all benefits associated with the incentive plans?

A. No. Since incentive compensation is "at-risk" to the employee, the amount of such compensation from year to year is not fixed, regular nor even certain to occur. In the event that minimum targets are not met,

35 See Attachment SCC-5.

employees do not receive incentive payments and the amount of incentive compensation included in rates (e.g., $10.5 million recommended for recovery by Staff) would contribute to increasing utility profits. In other words, ratepayers are placed at-risk to fund incentive plan costs regardless of payout, while employees are at-risk because targets might not be achieved for any number of reasons. At the same time, neither the Company nor its shareholders would necessarily be at-risk with respect to the $10.5 million of incentive pay, because the allowed expenses would be recovered through rates, regardless of future payouts.

Q. Has the Company provided any evidence that its overall executive or employee compensation levels would be inadequate to attract and retain human resources in the absence of full recovery of both its cash and stock-based incentive program costs?

A. No. Staff Data Request Nos. UTI-1-77(f) and UTI-12-296 were submitted, in part, to determine whether total salary and bonus compensation levels for Company employees were comparable to market compensation levels. Unfortunately, the response provided by APS contained "percentage" data, without providing or discussing overall compensation comparisons relevant to an analysis of the incentive programs.

Q. Does this conclude your direct testimony?

A. Yes.

STEVEN C. CARVER
SUMMARY OF QUALIFICATIONS

Education and Experience

I graduated from State Fair Community College where I received an Associate of Arts Degree with an emphasis in Accounting. I also graduated from Central Missouri State University with a Bachelor of Science Degree in Business Administration, majoring in Accounting. Subsequent to the completion of formal education, my entire professional career has been dedicated to public utility investigations, regulatory analysis and consulting.

From 1977 to 1987, I was employed by the Missouri Public Service Commission in various professional auditing positions associated with the regulation of public utilities. In that capacity, I participated in and supervised various accounting compliance and rate case audits (including earnings reviews) of electric, gas and telephone utility companies and was responsible for the submission of expert testimony as a Staff witness.

In October 1979, I was promoted to the position of Accounting Manager of the Kansas City Office of the Commission Staff and assumed supervisory responsibilities for a staff of regulatory auditors, directing numerous rate case audits of large electric, gas and telephone utility companies operating in the State of Missouri. In April 1983, I was promoted by the Commission to the position of Chief Accountant and assumed overall management and policy responsibilities for the Accounting Department, providing guidance and assistance in the technical development of Staff issues in major rate cases and coordinating the general audit and administrative activities of the Department.

During 1986-1987, I was actively involved in a docket established by the Missouri Public Service Commission to investigate the revenue requirement impact of the Tax Reform Act of 1986 on Missouri utilities. In 1986, I prepared the comments of the Missouri Public Service Commission respecting the Proposed Amendment to FAS Statement No. 71 (relating to phase-in plans, plant abandonments, plant cost disallowances, etc.) as well as the Proposed Statement of Financial Accounting Standards for Accounting for Income Taxes. I actively participated in the discussions of a subcommittee responsible for drafting the comments of the National Association of Regulatory Utility Commissioners ("NARUC") on the Proposed Amendment to FAS

Statement No. 71 and subsequently appeared before the Financial Accounting Standards Board with a Missouri Commissioner to present the positions of NARUC and the Missouri Commission.

In July of 1983 and in addition to my duties as Chief Accountant, I was appointed Project Manager of the Commission Staff's construction audits of two nuclear power plants owned by electric utilities regulated by the Missouri Public Service Commission. As Project Manager, I was involved in the staffing and coordination of the construction audits and in the development and preparation of the Staff's audit findings for presentation to the Commission. In this capacity, I coordinated and supervised a matrix organization of Staff accountants, engineers, attorneys and consultants.

Since commencing employment with Utilitech in June 1987, I have conducted revenue requirement and special studies involving various regulated industries (i.e., electric, gas, telephone and water) and have been associated with regulatory projects on behalf of clients in twenty State regulatory jurisdictions.

Previous Expert Testimony

I have continued to appear as an expert witness before the Missouri Public Service Commission on behalf of various clients, including the Commission Staff. I have filed testimony before utility regulatory agencies in Arizona, California, Florida, Hawaii, Kansas, Indiana, Nevada, New Mexico, Oklahoma, Pennsylvania, Utah, and Washington. My previous experience involving major electric company proceedings includes: PSI Energy, Union Electric (now Ameren), Kansas City Power & Light, Missouri Public Service/ UtiliCorp United (now Aquila), Public Service Company of Oklahoma, Oklahoma Gas and Electric, Hawaiian Electric, and Sierra Pacific Power/ Nevada Power.

Exhibit SCC-2 summarizes various regulatory proceedings in which I have filed testimony.

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2004 (January)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Kansas City Power & Light	Missouri	PSC	ER-78-252	Staff	1978	Rate Base, Operating Income
Gas Service Company	Missouri	PSC	GR-79-114	Staff	1979	Rate Base, Operating Income
United Telephone of Missouri	Missouri	PSC	TO-79-227	Staff	1979	Rate Base, Operating Income, Affiliated Interest
Kansas City Power & Light	Missouri	PSC	ER-80-48	Staff	1980	Operating Income, Fuel Cost
Gas Service Company	Missouri	PSC	GR-80-173	Staff	1980	Operating Income
Southwestern Bell Telephone	Missouri	PSC	TR-80-256	Staff	1980	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-85	Staff	1981	Operating Income
Missouri Public Service	Missouri	PSC	ER-81-154	Staff	1981	Interim Rates
Gas Service Company	Missouri	PSC	GR-81-155	Staff	1981	Operating Income
Gas Service Company	Missouri	PSC	GR-81-257	Staff	1981	Interim Rates
Union Electric Company	Missouri	PSC	ER-82-52	Staff	1982	Operating Income, Fuel Cost
Southwestern bell Telephone	Missouri	PSC	TR-82-199	Staff	1982	Operating Income
Union Electric Company	Missouri	PSC	ER-83-163	Staff	1983	Rate Base, Plant Cancellation Costs
Gas Service Company	Missouri	PSC	GR-83-207	Staff	1983	Interim Rates
Union Electric Company	Missouri	PSC	ER-84-168/ EO-85-17	Staff	1984 1985	Construction Audit, Operating Income

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2004 (January)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Kansas City Power & Light	Missouri	PSC	ER-85-128/ EO-85-185	Staff	1983 1985	Construction Audit, Rate Base, Operating Income
St. Joseph Light & Power	Missouri	PSC	EC-88-107	Public Counsel	1987	Rate Base, Operating Income
Northern Indiana Public Service	Indiana	IURC	38380	Consumer Counsel	1988	Operating Income
US West Communications	Arizona	ACC	E-1051-88-146	Staff	1989	Rate Base, Operating Income
Dauphin Consol. Water Supply Co.	Pennsylvania	PUC	R-891259	Staff	1989	Rate Base, Operating Income, Rate Design
Southwest Gas Corporation	Arizona	ACC	E-1551-89-102 E-1551-89-103	Staff	1989	Rate Base, Operating Income
Southwestern Bell Telephone	Missouri	PSC	TO-89-56	Public Counsel	1989 1990	Intrastate Cost Accounting Manual
Missouri Public Service	Missouri	PSC	ER-90-101	Public Counsel/ Staff	1990	UtiliCorp United Corporate Structure/ Diversification
City Gas Company	Florida	PSC	891175-GU	Public Counsel	1990	Rate Base, Operating Income, Acquisition Adjustment
Capital City Water Company	Missouri	PSC	WR-90-118	Jefferson City	1991	Rehearing - Water Storage Contract
Southwestern Bell Telephone Company	Oklahoma	OCC	PUD-000662	Attorney General	1991	Rate Base, Operating Income
Public Service of New Mexico	New Mexico	PSC	2437	USEA	1992	Franchise Taxes
Citizens Utilities Company	Arizona	ACC	ER-1032-92-073	Staff	1992 1993	Rate Base, Operating Income
Missouri Public Service Company	Missouri	PSC	ER-93-37	Staff	1993	Accounting Authority Order

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2004 (January)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Public Service Company of Oklahoma	Oklahoma	OCC	PUD-1342	Staff	1993	Rate Base, Operating Income, Acquisition Adjustment
Hawaiian Electric Company	Hawaii	PUC	7700	Consumer Advocate	1993	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-930074, 0307	Public Counsel/ TRACER	1994	Sharing Plan Modifications
US West Communications	Arizona	ACC	E-1051-93-183	Staff	1994	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	39584	Consumer Counselor	1994	Operating Income, Capital Structure
Arkla, a Division of NORAM Energy	Oklahoma	OCC	PUD-940000354	Attorney General	1994	Rate Base, Operating Income
Kauai Electric Division of Citizens Utilities Company	Hawaii	PUC	94-0097	Consumer Advocate	1995	Hurricane Iniki Storm Damage Restoration
Oklahoma Natural Gas Company	Oklahoma	OCC	PUD-940000477	Attorney General	1995	Rate Base, Operating Income
US West Communications	Washington	WUTC	UT-950200	Attorney General/ TRACER	1995	Rate Base, Operating Income
PSI Energy, Inc.	Indiana	IURC	40003	Consumer Counselor	1995	Rate Base, Operating Income
GTE Hawaiian Tel; Kauai Electric - Citizens Utilities Co.; Hawaiian Electric Co.; Hawaii Electric Light Co.; Maui Electric Company	Hawaii	PUC	PUC 95-0051	Consumer Advocate	1996	Self-Insured Property Damage Reserve

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2004 (January)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
GTE Hawaiian Telephone Co., Inc.	Hawaii	PUC	PUC 94-0298	Consumer Advocate	1996	Rate Base, Operating Income
Oklahoma Gas and Electric Company	Oklahoma	OCC	PUD-960000116	Attorney General	1996	Rate Base, Operating Income
Public Service Company	Oklahoma	OCC	PUB-0000214	Attorney General	1997	Rate Base, Operating Income
Arizona Telephone Company (TDS)	Arizona	ACC	U-2063-97-329	Staff	1997	Rate Base, Operating Income, Affiliate Transactions
US West Communications	Utah	UPSC	97-049-08	Committee of Consumer Services	1997	Rate Base, Operating Income
Missouri Gas Energy	Missouri	PSC	GR-98-140	Public Counsel	1998	Revenues, Uncollectibles
Sierra Pacific Power Company	Nevada	PUCN	98-4062 98-4063	Utility Consumers Advocate	1999	Sharing Plan
Hawaii Electric Light Co., Power Purchase Agreement (Encogen)	Hawaii	PUC	PUC 98-0013	Consumer Advocate	1999	Keahole CT-4/CT-5 AFUDC, Avoided Cost
Kansas City Power & Light Company	Missouri	MoPSC	EC-99-553	GST Steel Company	1999	Complaint Investigation
US West Communications	New Mexico	NM PRC	3008	PRC Staff	2000	Rate Base, Operating Income
Hawaii Electric Light Company	Hawaii	PUC	PUC 99-0207	Consumer Advocate	2000	Keahole pre-PSD Common Facilities
US West/ Qwest Communications	Arizona	ACC	T-1051B-99-105	Staff	2000	Rate Base, Operating Income
The Gas Company	Hawaii	PUC	00-0309	Consumer Advocate	2001	Rate Base, Operating Income, Nonreg Svcs.

STEVEN C. CARVER
Summary of Previously Filed Testimony
1978 through 2004 (January)

Utility	Jurisdiction	Agency	Docket/Case Number	Party Represented	Year	Areas Addressed
Craw-Kan Telephone Cooperative, Inc.	Kansas	KCC	01-CRKT-713-AUD	KCC Staff	2001	Rate Base, Operating Income
Home Telephone Company, Inc.	Kansas	KCC	02-HOMT-209-AUD	KCC Staff	2002	Rate Base, Operating Income
Wilson Telephone Company, Inc.	Kansas	KCC	02-WLST-210-AUD	KCC Staff	2002	Rate Base, Operating Income
SBC Pacific Bell	California	PUC	01-09-001 / 01-09-002	Office of Ratepayer Advocate	2002	New Regulatory Framework / Earnings Sharing Investigation
JBN Telephone Company	Kansas	KCC	02-JBNT-846-AUD	KCC Staff	2002	Rate Base, Operating Income
Kerman Telephone Company	California	PUC	02-01-004	Office of Ratepayer Advocate	2002	General Rate Case, Affiliate Lease, Nonregulated Transactions
S&A Telephone Company	Kansas	KCC	03-S&AT-160-AUD	KCC Staff	2003	Rate Base, Operating Income, Nonreg Alloc
PSI Energy, Inc.	Indiana	IURC	42359	Consumer Counselor	2003	Rate Base, Operating Income, Nonreg Alloc
Arizona Public Service Company	Arizona	ACC	E-10345A-03-0437	ACC Staff	2004	Rate Base, Operating Income

ARIZONA PUBLIC SERVICE COMPANY
OTHER REVENUE LAG ITEMS - CASH WORKING CAPITAL REQUIRED FOR OPERATING EXPENSES - LEAD LAG STUDY
TWELVE MONTHS ENDED DECEMBER 31, 2002

LINE	DESCRIPTION	AMOUNT (1)	REVENUE LAG DAYS (2)	EXPENSE LAG DAYS (3)	NET LAG DAYS (4)	CWC FACTOR (5)	WORKING CAPITAL REQUIREMENT (6)
1	FUEL FOR ELECTRIC GENERATION:						
2	COAL	157,018,541	41.81069	30.86168	10.94901	0.03000	
3	NATURAL GAS	75,641,831	41.81069	41.62912	0.18156	0.00050	
4	FUEL OIL	1,220,091	41.81069	27.40279	14.40790	0.03947	
5	NUCLEAR:						
6	AMORTIZATION	31,251,461	41.81069	0.00000	41.81069	0.11455	3,579,855
7	SPENT FUEL	8,296,700	41.81069	76.37500	-34.56431	-0.09470	
8	TOTAL	273,428,624					3,579,855
9							
10	PURCHASED POWER	343,858,302	41.81069	37.83806	3.97263	0.01088	
11	TRANSMISSION BY OTHERS	10,742,660	41.81069	34.02490	7.78579	0.02133	
12	TOTAL	354,600,962					0
13							
14	OTHER OPERATIONS & MAINTENANCE:						
15	PAYROLL	213,167,640	41.81069	18.44744	23.36325	0.06401	
16	SEVERANCE	28,223,377	41.81069	0.00000	41.81069	0.11455	
17	PENSION AND OPEB	19,989,248	41.81069	0.00000	41.81069	0.11455	2,289,768
18	EMPLOYEE BENEFITS	16,752,698	41.81069	17.02000	24.79069	0.06792	
19	PAYROLL TAXES	13,328,087	41.81069	13.98000	27.83069	0.07625	
20	MATERIALS & SUPPLIES	40,910,931	41.81069	29.34000	12.47069	0.03417	
21	FRANCHISE PAYMENTS	28,932,439	41.81069	68.19607	-26.38538	-0.07229	
22	VEHICLE LEASE PAYMENTS	7,228,287	41.81069	38.09947	3.71122	0.01017	
23	RENTS	4,962,688	41.81069	-31.71012	73.52081	0.20143	
24	PALO VERDE LEASE	45,202,210	41.81069	53.29167	-11.48098	-0.03145	
25	PALO VERDE S/L GAIN AMORT	(4,575,722)	41.81069	0.00000	41.81069	0.11455	(524,149)
26	INSURANCE	2,430,999	41.81069	0.00000	41.81069	0.11455	
27	UNCOLLECTIBLE ACCOUNTS	2,680,484	41.81069	0.00000	41.81069	0.11455	
28	OTHER	76,612,102	41.81069	37.55000	4.26069	0.01167	
29	TOTAL	495,845,469					1,765,619
30							
31	DEPRECIATION & AMORTIZATION	284,659,929	41.81069	0.00000	41.81069	0.11455	32,607,795
32	AMORT OF ELECTRIC PLT ACQ ADJ	15,443,124	41.81069	0.00000	41.81069	0.11455	1,769,010
33	AMORT OF PROP LOSSES & REG STUDY COSTS	99,536,541	41.81069	0.00000	41.81069	0.11455	11,401,911
34	TOTAL	399,639,594					45,778,716
35							
36	INCOME TAXES:						
37	CURRENT:						
38	FEDERAL	(61,961,636)	41.81069	60.05000	-18.23931	-0.04997	
39	STATE	(17,998,536)	41.81069	62.34755	-20.53686	-0.05627	
40	DEFERRED	206,767,266	41.81069	0.00000	41.81069	0.11455	23,685,190
41	TOTAL	126,807,094					23,685,190
42							
43	OTHER TAXES:						
44	PROPERTY TAXES	103,969,716	41.81	212.82	-171.01	-0.46851	
45	SALES TAXES	3,955,025	0.00	0.00	0.00	0.00000	0
46	TOTAL	107,924,741					0
47							
48	TOTAL	1,758,246,484					74,809,380

* CWC is rounded to 5 digits.

Mountain States Telephone and Telegraph Company
[Decision 53849; Page 18; Docket No. E-1051-83-035; December 22, 1983]

Needless to say, the primary discrepancy between Staff and Mountain States came in the area of cash working capital. **Both parties utilized a modified "formula" method.** The Commission has on several occasions indicated the numerous problems associated with the "formula" method of determining cash working capital. See Decision Nos. 53174 (August 11, 1982), 53612 (June 15, 1983), and 53665 (July 27, 1983). **Mountain States should consider itself forewarned that no allowance for cash working capital will henceforth be permitted to Mountain States unless supported by a valid "lead-lag" study.**

In the instant matter, the Commission is bound by the record at hand. Staff and Mountain States agreed that the usual "formula" had to be modified by an allowance for the fact that Mountain States receives local service revenues in advance of rendering local service, a situation contrary to that prevailing with other types of public service corporation. Staff further adjusted the "formula" to reflect the greatly deferred payment schedule for various state and federal taxes as well as the **lag in interest payments**. Mountain States opposed both adjustments, contending that Staff was "double-dipping" since an allowance had already been made for prepaid revenue. We disagree. There is no double counting since the pre-payment of revenue and the deferral of expense are two (2) separate items. Simply because both indicate a lower cash working capital requirement does not make out a case for "double-dipping."

In Decision No. 53761, the Commission, after considerable debate by the parties therein, concluded that interest was not a proper deduction in a "lead-lag" calculation of cash working capital. Upon further analysis, we are now convinced that Decision No. 53761 was in error in that determination. To the extent that the interest payment lag contributes to the common equity return, it is subsumed in our market derived cost of common equity. Although interest is a non-operating expense, we find that this is not dispositive. **Accrued but unpaid interest represents a consumer supplied source of cash working capital and should properly be treated as such.** Any remaining difference between the Commission's determination of a reasonable allowance for cash working capital and that of Mountain States is attributable to the different level of operating and interest expense utilized in the "formula" as modified herein.
[Emphasis Added]

Mountain States Telephone and Telegraph Company
[Decision 54843; Page 27; Docket No. E-1051-84-100 et al.; January 10, 1986]

We are in no such quandary when it comes to cash working capital. **The Commission has repeatedly rejected the inclusion of non-cash items such as deferred taxes and depreciation in cash working capital. Moreover, Staff erred in its exclusion of interest expense from the calculation of cash working capital. The Commission has admittedly taken conflicting positions on this issue in previous Decisions. However, in Decision No. 53849, the Commission finally concluded that the classification of interest expense as a non-operating expense did not preclude its inclusion in a cash working capital "lead/lag" study.** Intervenor Phoenix has utilized its calculation of pro forma interest expense (derived through "interest synchronization") to reduce recommended cash working capital to a negative figure. See Phoenix Exhibit No. 2. **The concept of negative cash working capital was expressly approved by the Commission in Decision No. 53761.**
[Emphasis Added]

Arizona Public Service
[Decision 55931; Page 66; Docket Nos. U-1345-86-062, U-1345-85-367; April 1, 1988]
6. Cash Working Capital

As previously mentioned, APS performed a lead/lag study of its cash working capital requirements. Although this study showed a requirement of $34,706,000, APS made no adjustment to include cash working capital in rate base. Thus, its proposed requirement is zero. APS witness Post testified that APS made this proposal to be consistent with Decision No. 55228 which held cash working capital at zero (in the absence of a lead/lag study), to minimize any Palo Verde rate increase, and to reduce the number of issues to be addressed in this case. (Ex. A-27 at 36.) Both FEA witness Miller and Staff witness Brosch recommended a negative cash working capital.

The fundamental reason for the difference between APS's calculation and those of the FEA and Staff is the treatment of "non-cash" items, such as deferred taxes and depreciation. Although the argument is somewhat more difficult to follow with respect to deferred taxes (they represent taxes which will be paid in the future), we agree with APS that depreciation accounting represents the return of a cash outlay it made at the time it acquired utility assets. Thus, use of the term "non-cash item" may be a misnomer if read literally. However, neither depreciation nor deferred taxes require the expenditure of cash at the time the expense is recorded and thereby charged to the customers. They are not "current" cash expenses. **We have repeatedly rejected the inclusion of deferred taxes and depreciation in the calculation of current cash working capital requirements. We have also finally concluded that interest expense should be included in a lead/lag study, and we have expressly approved the concept of negative cash working capital.** E.g., Mountain States Tel. & Tel. Co., Decision No. 54843 (January 10, 1986). Therefore, in this case we have used the Staff's negative cash working capital requirement of ($46,757,000) in our rate base determination.
[Emphasis Added]

Citizens Utilities Company
[Decision 56807; Page 41; Docket No. U-1954-88-102 et al.; February 1990]
8. Cash Working Capital

Citizens did not include any cash working capital allowance in its OCRB and opposed the use of a lead/lag study.

...

With respect to the cost and benefits of a lead/lag study, the annualized intrastate cost of Citizens' study which will be reflected in rates is $5,095. On the other hand, as a result of Citizens' study and the Staff and RUCO adjustments, our cash working capital determination is a negative $593,514, rather than zero (which was used in Citizens' last rate case, in the absence of a lead/lag study). This rate base adjustment represents approximately $97,500 in gross annual revenues. Thus, although for a company of Citizens' size, the benefit of a lead/lag study is not substantial, the benefit does outweigh the cost. Further, Citizens is a rapidly growing company and, with experience, the cost of preparing a lead/lag study should decline, if only because not all of the lead/lag days need to be recomputed for every study.

In Decision No. 55493, we discussed the benefits of a case-by-case approach to lead/lag studies. Citizens has not presented herein any new arguments or information which would warrant abandonment of that approach in favor of the use of a zero cash working capital requirement for Citizens (and presumably all of the larger utilities) pending completion of unnecessary and counter-productive rule making proceedings.

In summary, we agree with Staff and RUCO on the use of a lead/lag study in this proceeding and will not change our previous order requiring Citizens to prepare and include the results of a lead/lag study in its general rate applications. Further, our cash working capital adjustment to Citizens' OCRB reflects Staff's intrastate approach, **adjusted to reflect any differences in revenues and expenses** as determined hereinabove and inclusion of rate case

expense, the RUCO adjustments to the revenue and expense lags and the minimum bank and working funds balances, **and inclusion of interest expense based on our determination of Citizens' OCRB and embedded cost of debt.**
[Emphasis Added]

Southwest Gas Corporation
[Decision 57075; Page 45; Docket No. U-1551-89-102, et al.; August 31, 1990]

B. CASH WORKING CAPITAL

1. Non-Cash Items

Applicant, Staff, and RUCO relied upon lead/lag studies to calculate the cash component of the working capital allowance for the Central and Southern divisions. **The primary difference between the studies involves the treatment accorded non-cash expense items and interest expense. Staff excluded from its calculation those expenses which do not require current period cash payments, i.e., depreciation expense, deferred income tax expense, and return on equity capital, and included interest expense to capture its working capital effect although it is classified as a non-operating expense.** RUCO agrees that the non-cash items should be excluded.

Applicant contests the exclusion, but the opposition need not detain us. The Commission has repeatedly held that the determination of the cash working capital requirement does not properly encompass non-cash items. The Commission has also found that accrued but unpaid interest, as a customer-supplied source of cash working capital, is a proper deduction in the lead/lag calculation. See, e.g., Mountain States Telephone and Telegraph Company, Decision Nos. 53849 (December 22, 1983) and 54843 (January 10, 1986); APS, Decision No. 55931 (April 1, 1988); and TEP, Decision No. 55659 (October 24, 1989). Applicant has presented no arguments which persuade us to depart from this precedent.

2. Other Methodological Issues

Applicant maintains that the lead/lag methodology followed by Staff to determine cash working capital erroneously used adjusted income statement amounts rather than unadjusted test year values. As Staff witness Brosch explained, consistency requires that the income statement amounts used for purposes of the lead/lag study be synchronized with the adjusted amounts used elsewhere in the revenue requirement calculation. RUCO also used adjusted amounts in its lead/lag study.

...

For the reasons articulated by Mr. Brosch, the Commission will adopt the lead/lag methodology Staff followed.

3. Cash Working Capital Summary

For the Central division, the foregoing adjustments adopted by the Commission will reduce Applicant's proposed cash working capital by approximately $9.1 million and result in a negative component of approximately $3.9 million.

For the Southern division, the adjustments reduce Applicant's figure by approximately $3.9 million and produce a negative cash working capital component of approximately $2.2 million.
[Emphasis Added]

Southern Union Gas
[Decision 57396; Page 12; Docket No. U-1240-90-051; May 24, 1991]
A. Cash Working Capital

...

2. RUCO Adjustment

In its post-hearing briefs and in late-filed Ex. RUCO-9, RUCO refers to a $161,262 reduction to cash working capital as being an adjustment remaining in dispute. According to Ex. RUCO-2, pg. 15, this "working cash adjustment reflects [Commission] precedent because it results mainly from including the lag effect of long term-bond interest, as required by the Commission in [Southwest] and previous decisions." However, **Staff's working capital adjustment, as accepted by Southern Union, already recognizes the interest on long-term debt**. RUCO has provided no explanation of whether or how its adjustment differs from that sponsored by Staff. The Commission will, therefore, reject RUCO's adjustment because it lacks foundation.
[Emphasis Added]

Southwest Gas Corporation
[Decision 57745; Page 19; Docket No. U-1551-90-322; February 28, 1992]
I. Cash Working Capital

In its initial filing in this case, the Company asserted a zero working capital request. Both RUCO and Staff responded by filing lead/lag studies. The Commission in Decision No. 57075 had relied upon such studies to calculate the working allowance for the Company's Central and Southern divisions and determined both were in excess of a negative $4 million. In this case, Staff and RUCO calculated the cash working capital to be a negative $3,734,000 and a negative $2,408,652, respectively.

As in the previous case, Applicant was critical of Staff and RUCO's cash working capital because it did not take into consideration certain "non-cash" items such as depreciation. **As we stated in Decision No. 57075 as well as other Decisions cited therein, the calculation is for "cash working capital" and not "cash and non-cash working capital".** Similarly, as we stated in Decision No. 57075, "Applicant has presented no arguments which persuade us to depart from this precedent." Since Staff simply updated the cash working capital amount approach in Decision No. 57075, we will approve Staff's recommended cash working capital. As a result of criticism by the Company regarding Staff's adjustments to prepayments, Staff revised its calculations and reduced its negative cash working capital to $3,680,000.
[Emphasis Added]

Southwest Gas Corporation
[Decision 58377; Page 12; Docket No. U-1551-92-253; August 13, 1993]
Working Capital

Based on its lead/lag study, the Company determined its cash working capital requirement was ($2,513,921). This amount was then offset by $2,339,698 of prepayments and $1,761,907 for materials and supplies to arrive at the Company's proposed working capital of $1,587,684. Staff proposed a reduction to the Company's cash working capital in the amount of $1,521,237 and a reduction to prepayments in the amount of $433,183. RUCO proposed a reduction in cash working capital in the amount of $268,324 and a reduction to prepayments in the amount of $883,412.

Staff was critical of the Company for using unadjusted test year values in the Company's lead/lag study in calculating cash working capital. Accordingly, Staff modified the study to include adjusted TY amounts. Staff was also critical of the Company for assigning zero lag to items amortized into expenses. According to Staff, such treatment is inappropriate because it nets a cash item with a non-cash item. Included in the Company's proposed cash working capital were the average cash balances related to working funds, petty cash, and cash held by depository banks. Both RUCO and Staff eliminated these average cash balances from the cash working capital requirements. Staff indicated that the cash balances are funds provided by ratepayers while RUCO indicated inclusion of cash balances was not consistent with the use of lead/lag study. In response, the Company indicated the cash balances did represent stockholder funds in providing service to ratepayers. In addition, the Company indicated similar balances had been included in the Company's last five Arizona rate cases.

We generally concur with Staff's modification of the Company's lead/lag study. However, we concur with the Company that a reasonable amount of cash-on-hand is appropriate. There has been no evidence presented to demonstrate that the Company's average cash balances are unreasonable. Accordingly, we will reject Staff and RUCO's proposed $227,616 removal of the Company's average cash balances. Based on all the above, we find the Company's proposed cash working capital should be reduced by $1,293,621 with a result of ($3,807,542). ...
[Emphasis Added]

<u>**Tucson Electric Power Company**</u>
[Decision 58497; Page 26; Docket No. U-1933-93-006 et al.; January 13, 1994]
M. <u>Cash Working Capital</u>

TEP proposed a negative cash working capital ("CWC") in the amount of $16,389,000. Staff, RUCO, and JSA all proposed adjustments to the Company's requested CWC.

JSA recommended that if TEP is allowed to retain the net cash proceeds from its settlement agreement with Southern California Edison Company ("SCE") then TEP's CWC should be reduced by a like amount. According to JSA, this treatment should continue until ratepayers receive $27.6 million of refunds.

In response, the Company indicated this is a "non-current" cash transaction and as such should not be included as part of CWC.

We concur with the Company. As will be more fully discussed later, the Company's shareholders bore the risk and cost of pursuing the SCE litigation and should receive 100 percent of the cash benefits.

The MSR Option gain is being amortized as a credit to retail revenues. The unamortized balance of the revenues is not included as a rate base deduction since the gain was increased to allow for an implicit carrying charge to compensate for the time value of money. According to RUCO, the amortization is a non-cash transaction which is excluded from rate base. As a result, RUCO concluded that TEP's attributing $1.9 million of cash working capital to the MSR revenue was wrong and should be adjusted to zero.

In response, **the Company indicated it has excluded all "non-current" cash transactions. As a result, the Company excluded the MSR revenue credit as well as a number of "non-cash" expense debits.** According to the Company, the debits and credits should be treated consistently. We concur with the Company.

...

TEP deposits funds in a special account to match anticipated medical payments on claims in process. Once notified that payment is due on claims, the Company records the medical expense and reduces the balance in the special account. There were, on average, 19.3 days from the time funds are deposited in the special account until the Company is notified that payment is due on claims. The Company included the 19.3 days as part of its payment lag period of 66.62 days.

Staff deducted the 19.3 days from the payment lag period. According to Staff, the expense is incurred at the time medical services are provided and that is the date from which to measure the payment lag.

In response, the Company indicated that Staff was erroneously assuming that the ratepayers were providing cost free funding of medical expenses. TEP asserted it is Company funds that are being used to fund the medical expenses. As a result, TEP requested Staff's adjustment be denied.

We concur with Staff. The proper payment lag time should be measured from the date the expense is incurred.

Staff proposed to measure the expense lag used in the CWC study from the date an expense is incurred by the Company. The Company objected to Staff's approach and argued the expense lag should be based on the date the cost of service is recorded. Although TEP disputed Staff's concept, the Company indicated it could agree as long as Staff utilized the same concept for both revenue recovery and expense payment lags.

In response, Staff indicated that the revenue lag is not necessarily affected by the expense lag. According to Staff, the revenue lag is measured from the date service is provided to the customer. We concur with Staff.
[Emphasis Added]

Citizens Utilities Company
[Decision 60172; Page 19; Docket No. E-1032-95-417 et al.; May 7, 1997]
E. Cash Working Capital

Both Staff and RUCO proposed adjustments to the Company's cash working capital, a number of which were accepted by the Company, including adjustments to expense lead or lag days with salaries and wages, pumping power expense, administrative office expense, insurance, injuries and damages expense, and other taxes. **The Company also accepted inclusion of interest expense in the lead lag study at a 90-day lag** and also removed preliminary survey and investigation ("PS&I) charges from the working capital balance. Staff and RUCO agree that the revenue lag should be reduced by one day to reflect the Company's new lock box program which will allow customers to pay their bills through the bank rather than remitting them directly to the Company. Staff and the Company have agreed to certain increases to expense lags to reflect check clearing lags and have revised the pension lag expense to reflect an actual contribution made by Citizens to the pension trust. We will adopt those adjustments. RUCO recommends that, consistent with past Commission decisions, including Decisions Nos. 58360 and 58664, the Commission should exclude $83,354 in rate case and deferred TARGET: Excellence expenses from the cash working capital component. We agree with RUCO.

Staff and RUCO proposed that cash balances should be removed from the determination of cash working capital. RUCO notes that these two asset items have never been included in the calculation of cash working capital in any prior Commission decision. Staff notes that with the exception of only Sun City Sewer, there is a negative cash working capital requirement and to include a cash balance in the cash working capital requirement for these companies would grant them a return on cash when they have no cash requirement. We agree with Staff and RUCO's adjustment to remove cash balances.

We note that RUCO believes that the Company's sampling method for determining the lag for the O&M, administrative and general expense category analyzed too few invoices and does not capture the various types of expenses contained in the category. While we will not adopt RUCO's adjustment in this proceeding, we expect the Company to address the issues raised by RUCO in its next lead/lag study.
[Emphasis Added]

**UTILITECH'S TWELVTH SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437**

UTI-12-299 (Reference: APS' response to UTI 1-77, part i) It appears that incentive compensation was awarded in 2002 "even though the threshold earnings level was not achieved", at the discretion of the Board of Directors. Please provide the following:

a. Please confirm this understanding.

b. State the specific measure of "threshold earnings" that was required, but not achieved, and the corresponding amount of actual "earnings" that was achieved.

c. Explain how the amount of the "partial payout" was determined and applied to individual employees.

d. What considerations by APS caused it to conclude that such partial payout amounts were reasonable for inclusion in the Company's asserted revenue requirement?

e. What amount of incentive compensation expense would be incurred if zero percentage was allowed in 2002 for the "Company Plan" element of the incentive formula, instead of the deemed amount reflected in the "2002 Pinnacle West Employee Incentive Plan Results" documentation?

RESPONSE:

a. You are correct.

b. Threshold earnings for 2002 were established as $293,000,000. Actual earnings from our 2002 Annual Report were $149,408,000.

c. The Board determined to pay incentive based on 50% of the individual business unit performance achievement, plus the 1% adder for frontline employees based on achieving the 2002 fourth quarter customer satisfaction survey targeted performance level.

d. Please see attached letter from Bill Post RC02413 to all employees dated January 23, 2003, outlining a number of specific considerations supporting the inclusion in the revenue requirements calculation, all of which affect the provision of electric service to APS customers.

e. For 2002, the only portion of the Company plan element of the incentive formula that was paid out was the frontline 1% adder based on the customer satisfaction survey targeted performance level. This specific amount is not available, but an approximate estimate of its impact on 2002 costs would be $1.9 million.

Witness-Donald Robinson

PINNACLE WEST
CAPITAL CORPORATION

January 23, 2003

To all employees:

The Board of Directors has approved incentive awards for 2002. Your check is enclosed. You will note your total incentive is significantly reduced compared to recent years. This is due to a financial performance that was not what we'd hoped.

The year 2002 wasn't an easy one for us – with critical regulatory issues, the consolidation of the company under APS, power plant start-ups, cost containment efforts and voluntary staff reductions. While our financial performance suffered, we did meet operational performance goals.

I realize it is late January and we are already focused on the challenges of 2003, but I would encourage you to take a brief moment to reflect on last year's accomplishments:

- We continued to work safely – reducing the number of preventable recordable accidents for the second consecutive year.
- We improved customer satisfaction numbers, as measured by an independent third party.
- We quickly changed course and turned this company from one preparing for competition to essentially a vertically integrated utility, as mandated by the Arizona Corporation Commission.
- We met the electricity demands of a rapidly growing region.
- We constructed new power plant additions – on time and under budget.
- We achieved record power plant production.
- We negotiated a new and mutually beneficial union contract.
- We earned a number two ranking out of the 28 electric utilities listed in the S&P 500 for our environmental performance, by international investment advisory firm Innovest.

Your hard work has helped position our company for a strong future. More challenges await us. We must remain vigilant and find ways to do more with less, while continuing to operate safely and maintaining a customer focus. I believe the best for our company is yet to come, and I expect to soon return to the kind of financial performance to which we are accustomed.

Thank you again for your hard work in 2002. I look forward to greater things in 2003.

Bill Post

Bill Post

UTILITECH, INC.'S SEVENTEENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437

UTI-17-331 Ref. APS Attachment LLR-3 & Workpaper LLR_WP2 (CWC-Sales Tax). Please provide the following information regarding APS' accounting (i.e., billing customers and remitting payment) for sales taxes:

a) Are APS' retail sales to utility customers subject to sales taxes? If so, please identify, with specificity, those revenue streams that are and are not subject to sales taxes.

b) Please describe APS' accounting for sales taxes, including: billings to customers, collections from customers, payments to taxing authorities, recording liabilities, recording expenses, etc. [Note: The response should identify FERC accounts in which transactions are recorded.]

c) Does APS record a liability for sales taxes? If so, please provide the liability balance by FERC account by month during and subsequent to the test year.

d) When does APS first recognize the liability for sales tax (e.g., midpoint of service period, meter read date, billing date, etc.)? Please explain.

e) Please describe when APS payments are due for sales taxes in relation to the date bills are processed for customer billing.

f) For the 2002 test year, please provide the amount of sales taxes paid by APS on retail sales to utility customers.

RESPONSE:

a) APS is liable for transaction privilege tax on all customer revenue classes except the following:

1. Non-profit health care organizations, so designated by the State of Arizona;
2. Native Americans living on the reservation; and
3. Environmental Technology facilities, so designated by the Arizona Department of Commerce.

b) See entries attached at RC02484.

c) See attached RC02484.

d) APS recognizes and accrues a liability for sales tax upon billing the customer.

**UTILITECH, INC.'S SEVENTEENTH SET OF DATA REQUESTS
TO ARIZONA PUBLIC SERVICE COMPANY
IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPORVAL OF PURCHASED POWER CONTRACT
E-01345A-03-0437**

e) For sales taxes on retail sales to utility customers, APS is on an accrual basis. Therefore, APS accrues the tax upon billing and remits the tax to the taxing authority by the 25th of the month following billing. Receipt of payments from customers is dependent upon actual payment by customer.

f) APS paid a total of $128,602,576 in state and local privilege taxes on retail sales to utility customers in 2002.

Witness: Laura Rockenberger

UTI-17-331 (b)

APS' Accounting for Customer Utility Service Transactions

(Numbers are used for example only)

Ferc Acct	Account Description	DR	CR
1420	Customer Accounts Recvble	108	
4400	Residential sales revenue		100
4081	Sales Tax Expense		8
Customer is billed and receivable is booked			
4081	Sales Tax Expense	8	
2360	Sales Tax Accrual - CIS		8
Sales tax expense is reclassed to accrual by CIS system			
1310	Cash	108	
1420	Customer Accounts Receivable		108
Funds are collected on customer accounts			
2360	Sales Tax Accrual - CIS	8	
1310	Cash - State/County tax		6
1310	Cash - City tax		2
Sales tax payment to taxing authorities			

Customer billings are created on a daily basis by CIS, thereby passing and uploading revenues, expenses, and receivables to the general ledger system.
The sale tax liability is recorded in the month of customer billing.

		Trial Balance
1420	*Customer Accounts Recvble*	*0*
4400	*Residential sales revenue*	*-100*
4081	*Sales Tax Expense*	*0*
2360	*Sales Tax Accrual - CIS*	*0*
1310	*Cash*	*100*

UTI-178-331 (c)
Sales Tax Liability Account
Ferc Acct 2360

		Acct Balance
January	2002	(7,496,183.77)
February	2002	(6,880,247.76)
March	2002	(6,120,859.13)
April	2002	(6,723,861.82)
May	2002	(7,580,007.03)
June	2002	(5,496,542.17)
July	2002	(12,359,525.79)
August	2002	(12,464,655.62)
September	2002	(12,113,284.14)
October	2002	(9,498,317.46)
November	2002	(6,221,031.61)
December	2002	(6,541,187.85)
January	2003	(7,117,243.80)
February	2003	(6,440,409.00)
March	2003	(6,354,599.41)
April	2003	(5,950,921.90)
May	2003	(6,988,572.98)
June	2003	(5,638,823.21)
July	2003	(11,745,233.08)
August	2003	(13,887,314.68)
September	2003	(13,254,634.56)
October	2003	(10,841,695.49)
November	2003	(7,601,852.39)

2/2

Staff Exhibit ___

ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345-A-0437
INDEX TO STAFF'S JOINT ACCOUNTING SCHEDULES

Schedule No.	Description	Witness
A	**Revenue Requirement Summary**	Dittmer
B	**Rate Base Summary**	Dittmer
B-1	Allocations Utilizing Peak & Average Methodology	Dittmer/L.Smith
B-2	Reverse Company's PWEC Adjustment	Dittmer/Salgo
B-3	1999 Settlement Agreement Write-down	Dittmer
B-4	Deferred PacifiCorp Gain	Dittmer
B-5	Eliminate Capitalized Vehicle Lease	Dittmer
B-6	Net Unamortized Loss on Reacquired Debt	Dittmer
B-7	Cash Working Capital	Carver
B-8	Reserved	
C	**Net Operating Income Summary**	Dittmer
C-1	Allocations Utilizing Peak & Average Methodology	Dittmer/L.Smith
C-2	Reverse Company's PWEC Adjustment	Dittmer/Salgo
C-3	1999 Settlement Agreement Write-down	Dittmer
C-4	Eliminate O&M Costs in APS Proposed Customer Annualization	Dittmer
C-5	Remove Depreciation Expense on Leased Vehicles	Dittmer
C-6	Adjust APS' Proposed Property Tax Expense	Dittmer
C-7	Eliminate Non-Recurring Mainframe Computer Lease	Dittmer
C-8	LaCapra's Fuel & Purchased Power Costs -- w/o PWEC Units	Dittmer/D.Smith
C-9	Eliminate Economic Development Costs	Dittmer
C-10	Nuclear Decommissioning	Dittmer/Judd
C-11	Majoros Depreciation Expense Adjustment	Dittmer/Majoros
C-12	Severance Adjustment	Carver
C-13	Wages & Salaries Adjustment	Carver
C-14	Union Contract Signing Bonus	Carver
C-15	Incentive Compensation Adjustment	Carver
C-16	Eliminate Test Year DSM Expenses	Dittmer/Reiker
C-17	Advertising & Marketing Adjustment	Dittmer
C-18	Income Tax AZ State Credit & Non-deductible Meals / Entertainment	Dittmer
C-19	Income Tax Interest Synchronization	Dittmer
C-20	Reserved -- Excess Deferred Income Tax Expense ARAM Protected	Dittmer
C-21	Schedule 1 Tariff Changes	Dittmer
C-22	Reverse APS' Proposed 5 Year Amort. Of Regulatory Assets	
C-23	Eliminate Contributions to Civic and Charitable Organizations	
C-24	Amortize Gains on Sales of Property	
C-25	Reserved	
D	**Cost of Capital Summary**	Reiker
E	**Reconcilation of Postions**	Dittmer

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Revenue Requirement Summary

ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	Retail Electric Original Cost			Retail Electric Fair Value		
		Per APS	Staff Adjustments	As Adjusted By Staff	Per APS	Staff Adjustments	As Adjusted By Staff
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Adjusted Rate Base	$ 4,207,476	$ (1,155,847)	$ 3,051,629	$ 5,467,466	$ (1,410,969)	$ 4,056,497
2	Required Rate of Return	8.67%	-1.41%	7.26%	6.67%	-1.21%	5.46%
3	Required Net Operating Income	$ 364,788		$ 221,468	$ 364,788		$ 221,468
4 5	Net Operating Income at Current Rates	263,870	51,063	314,933	263,870	51,063	314,933
6 7	Net Operating Income Deficiency/(Excess)	$ 100,918		$ (93,465)	$ 100,918		$ (93,465)
8	Gross Revenue Conversion Factor	1.6529		1.6529	1.6529		1.6529
9 10	Recommended Increase/ (Decrease) in Base Revenues	$ 166,808		$ (154,489)	$ 166,808		$ (154,489)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Rate Base Summary

ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

		Original Cost			RCND		
Line No.	Description	As Adjusted By APS	Staff Adjustments	As Adjusted By Staff	As Adjusted By APS	Staff Adjustments	As Adjusted By Staff
	(a)	(b)	(c)	(d)	(b)	(c)	(d)
1	Gross Utility Plant in Service	$ 8,217,200	$ (1,062,107)	$ 7,155,093	$ 12,561,199	$ (1,623,586)	$ 10,937,613
2	Less: Accumulated Depre & Amort.	3,097,951	(87,018)	3,010,933	4,921,971	(138,252)	4,783,719
3	Net Utility Plant in Service	$ 5,119,249	$ (975,089)	$ 4,144,160	$ 7,639,228	$ (1,485,334)	$ 6,153,894
4	Deductions						
5	Accumulated Deferred Income Taxes	$ 1,281,244	$ (142,661)	$ 1,138,583	$ 1,281,244	$ (142,661)	$ 1,138,583
6	Investment Tax Credits	4,033	-	4,033	4,033	-	4,033
7	Customer Advances for Construction	45,513	-	45,513	45,513	-	45,513
8	Customer Deposits	39,865	-	39,865	39,865	-	39,865
9	Pension Liability	48,751	-	48,751	48,751	-	48,751
10	Other Deferred Credits	123,798	(1,003)	122,795	123,798	(1,003)	122,795
11	Unamortized Gains - Sale of Utility Plant	59,381	(20,990)	38,391	59,381	(20,990)	38,391
12	Total Deductions	$ 1,602,585	$ (164,653)	$ 1,437,932	$ 1,602,585	$ (164,653)	$ 1,437,932
13	Additions:						
14	Regulatory Assets/Liabilities Net	$ 299,822	$ (241,106)	$ 58,716	$ 299,822	$ (241,106)	$ 58,716
15	Miscellaneous Deferred Debits	26,959	-	26,959	26,959	-	26,959
16	Depreciation Fund -- Decommissioning	191,608	(131)	191,477	191,608	(131)	191,477
17	Allowance for Working Capital	172,423	(104,175)	68,248	172,423	(104,175)	68,248
18	Total Additions	$ 690,812	$ (345,411)	$ 345,401	$ 690,812	$ (345,411)	$ 345,401
19	Total Rate Base	$ 4,207,476	$ (1,155,847)	$ 3,051,629	$ 6,727,455	$ (1,666,091)	$ 5,061,364

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY
Rate Base Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	B-1	B-2	B-3	B-4	B-5	B-6	B-7	Reserved	Page Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Gross Utility Plant in Service	$ (35,906)	$ (1,008,234)			$ (17,966)				$ (1,062,107)
2	Less: Accumulated Depre & Amort.	(14,491)	(72,526)							(87,018)
3	Net Utility Plant in Service	$ (21,414)	$ (935,708)	$ -	$ -	$ (17,966)	$ -	$ -	$ -	$ (975,089)
4	Deductions									
5	Accumulated Deferred Income Taxes	$ (5,829)	$ (52,734)	$ (92,243)	$ 8,145					$ (142,661)
6	Investment Tax Credits									-
7	Customer Advances for Construction									-
8	Customer Deposits									-
9	PensionLiability									-
10	Other Deferred Credits	(1,003)								(1,003)
11	Unamortized Gains - Sale of Utility Plant	(426)			(20,563)					(20,990)
										-
12	Total Deductions	$ (7,258)	$ (52,734)	$ (92,243)	$ (12,418)	$ -	$ -	$ -	$ -	$ (164,653)
13	Additions:									
14	Regulatory Assets/Liabilities Net	(75)		(234,000)			(7,031)			$ (241,106)
15	Miscellaneous Deferred Debits									-
16	Depreciation Fund -- Decommissioning	(131)								(131)
17	Allowance for Working Capital	(362)						(103,813)		(104,175)
										-
18	Total Additions	$ (568)	$ -	$ (234,000)	$ -	$ -	$ (7,031)	$ (103,813)	$ -	$ (345,411)
19	Total Rate Base	$ (14,725)	$ (882,973)	$ (141,757)	$ 12,418	$ (17,966)	$ (7,031)	$ (103,813)	$ -	$ (1,155,847)
20	**Brief Adjustment Description:**	Allocations Utilizing Peak & Average Methodology	Reverse Company's PWEC Adjustment	1999 Settlement Agreement Write-down	Deferred PacifiCorp Gain	Eliminate Capitalized Vehicle Lease	Net Unamortized Loss on Reacquired Debt	Cash Working Capital	Reserved	

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjust APS' Proposed Retail Jurisdictional Rate Base Utilizing Peak & Average Methodology
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	ACC Jurisdictional at Company's Revenue Requirement Request: Average & Peak (LCA 2.33)	Four CP (APS Sch. B-1)	Adjustment (Col. b - c)
	(a)	(b)	(c)	(d)
1	Electric Plant in Service	$ 7,617,042	7,651,373	$ (34,331)
2	Gen'l & Intan. Plant	564,252	565,828	(1,575)
3	Total Gross Plant	8,181,294	8,217,200	(35,906)
4	Less: Depre Reserve	3,083,459	3,097,951	(14,491)
5	**Net Plant in Service**	$ 5,097,835	$ 5,119,249	$ (21,414)
6	**Deductions**			
7	Accum. Def Inc. Taxes	$ 1,279,448	$ 1,285,277	$ (5,829)
8	Investment Tax Credits			
9	Customer Adv. for Constr	45,513	45,513	-
10	Customer Deposits	39,865	39,865	-
11	Pension Liability			
12	Other Deferred Credits	171,547	172,549	(1,003)
13	Unamort. Gains - Sale of Plt	58,955	59,381	(426)
14	**Total Deductions**	$ 1,595,327	$ 1,602,585	$ (7,258)
15	**Additions**			
16	Reg. Assets/Liabilities Net	299,822	299,822	-
17	Miscellaneous Deferred Debits	26,884	26,959	(75)
18	Depre. Fund -- Decom.	191,608	191,608	-
19	Working Cash	52,849	52,980	(131)
20	M&S, Prepayments	119,081	119,443	(362)
21	Proforma Adjustments			
22	**Total Additions**	690,243	690,812	(568)
23	**Total Rate Base**	$ 4,192,751	$ 4,207,476	$ (14,725)

Witness: J. Dittmer
H. Salgo

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Reverse APS' Proposed Inclusion of PWEC Assets in Retail Rate Base
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	Total Company [APS Spreadsheet "ProFormaModel (2002)RateBase1"]	Jurisdictional Allocation Factors -- Peak & Average	Jurisdictional PWEC Rate Base Adjustment (Col a X b)
	(a)	(b)	(c)	(d)
1	Plant in Service			
2	Production -- Demand	$ 999,036,000	0.99110	$ 990,144,580
3	Transmission -- Demand	22,850,000	0.79167	18,089,606
4	Total Plant in Service	$ 1,021,886,000		$ 1,008,234,186
5	Accumulated Depreciation			
6	Production -- Demand	$ 72,315,000	0.99110	$ 71,671,397
7	Transmission -- Demand	1,080,000	0.79167	855,001
8	Total Accum. Depre.	$ 73,395,000		72,526,398
9	Reduction in Net Plant			
10	in Service	$ 948,491,000		$ 935,707,788
12	Accumulated Deferred Taxes			
13	Production -- Demand	$ 52,517,000	0.99110	$ 52,049,599
14	Transmission -- Demand	865,000	0.79167	684,793
15	Total	$ 53,382,000		$ 52,734,391
16	Total Rate Base			
17	Reduction	$ 895,109,000		$ 882,973,397

Witness: J.Dittmer
H. Salgo

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Reverse APS' Proposed Reinstatement of
A Previous Plant Write Down Made Pursuant to a
1999 Settlement Agreement

Line No.	Description (a)	Reference (b)	Amount All ACC Jurisdictional (c)
1	Reverse Company's Proposed		
2	Reinstatement of the 1999		
3	Settlement Agreement Write Down		
4	Deferred Debit	APS Schedule B-2 Page 2 of 3	$ (234,000,000)
5	Related Accumulated Deferred	APS Schedule B-2	
6	Income Taxes	Page 2 of 3	$ 92,242,800
7	Net Rate Base Adjustment	Line 2 + Line 3	$ (141,757,200)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Reflect Gain from PacifiCorp
Transactions as a Rate Base Offset

Line No.	Description (a)	Reference (b)	Amount (c)
1	Deferred Gain from PacifiCorp	APS W/P	
2	Transaction -- Total Company	cnf__wp3	$ (20,748,000)
3	Production Demand Allocator		
4	Peak and Average Method		99.110%
5	Jurisdictional Deferred Gain from		
6	PacifiCorp Transaction	Line 2 X 4	$ (20,563,343)
7	Total Company Related Accumulated	APS W/P	
8	Deferred Income Taxes	cnf__wp1	$ 8,218,000
9	Production Demand Allocator		
10	Peak and Average Method		99.110%
11	Jurisdictional Related Accumulated		
12	Deferred Income Taxes	Line 8 X 10	$ 8,144,860
13	Net Jurisdictional Rate Base		
14	Adjustment	Line 6 + 12	$ (12,418,483)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Eliminate Vehicle Leases Included Within APS' Proposed
Rate Base That Was Also Included as Operating Lease Expense

Line No.	Description (a)	Reference (b)	Amount All ACC Jurisdictional (c)
1	Capitalized Vehicle Leases Included		
2	Within APS' Total Company		
3	Rate Base	UTI-1-51	$ 19,553,407
4	Composite Wages & Salaries	Functionalization	
5	Allocator	&Allocation.xls	91.884%
6	Eliminate ACC Jurisdictional Leases		
7	Included Within APS' Proposed		
8	Jurisdictional Rate Base	Line 3 X Line 5	$(17,966,478)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Eliminate Net Unamortized Loss on
Reacquired Debt From APS' Proposed Rate Base

Line No.	Description (a)	Reference (b)	Amount All ACC Jurisdictional (c)
1	Unamortized Loss on Reacquired Debt		
2	Included Within APS' Proposed	APS Workpaper	
3	Total Company Rate Base	cnf__wp4	$ 9,127,420
4	Unamortized Loss on Reacquired Gain		
5	Included Within APS' Proposed	APS Workpaper	
6	Total Company Rate Base	cnf__wp4	(1,475,749)
7	Net Unamortized Total Company Loss		
8	on Reacquired Debt Included Within		
9	APS' Proposed Rate Base	Line 3 + Line 6	$ 7,651,671
10	Composite Jurisdictional Wages &		
11	Salaries Allocator		91.884%
12	Jurisdictional Rate Base Adjustment to		
13	Eliminate Net Unamortized Loss on		
14	Reacquired Debt	Line 9 X Line 11	$ (7,030,672)

Witness: S. Carver

ARIZONA PUBLIC SERVICE COMPANY
CASH WORKING CAPITAL

Line No.	Description (A)		Amount (B)	Revenue Lag (c) (C)	Expense Lag (D)	Net Lag (Days) (E)	CWC Factor (F)	CWC Requirement (G)
1	FUEL FOR ELECTRIC GENERATION							
2	COAL	(d)	$ 157,018,541	40.12940	31.62789	8.50151	0.02329	$ 3,656,962
3	NATURAL GAS		75,641,831	40.12940	41.62912	-1.49972	-0.00411	(310,888)
4	FUEL OIL	(e)	1,220,091	40.12940	28.51162	11.61778	0.03183	38,835
5	NUCLEAR:							
6	AMORTIZATION		31,251,461	0.00000	0.00000	0.00000	0.00000	0
7	SPENT FUEL		8,296,700	40.12940	76.37500	-36.24560	-0.09930	(823,862)
8	SUBTOTAL		273,428,624					2,561,047
9	PURCHASED POWER		343,858,302	40.12940	37.83806	2.29134	0.00628	2,159,430
10	TRANSMISSION BY OTHERS		10,742,660	40.12940	34.02490	6.10450	0.01672	179,617
11	SUBTOTAL		354,600,962					2,339,047
12	OTHER OPERATIONS & MAINTENANCE							
13	PAYROLL		213,167,640	40.12940	18.44744	21.68196	0.05940	12,662,158
14	SEVERANCE		28,223,377	0.00000	0.00000	0.00000	0.00000	0
15	PENSION AND OPEB	(f)	21,612,000	0.00000	0.00000	0.00000	0.00000	0
16	EMPLOYEE BENEFITS		16,752,698	40.12940	17.02000	23.10940	0.06331	1,060,613
17	PAYROLL TAXES		13,328,087	40.12940	13.98000	26.14940	0.07164	954,824
18	MATERIALS & SUPPLIE	(g)	40,910,931	40.12940	30.29000	9.83940	0.02696	1,102,959
19	FRANCHISE PAYMENTS		28,932,439	40.12940	68.19607	-28.06667	-0.07689	(2,224,615)
20	VEHICLE LEASE PAYMENTS		7,228,287	40.12940	38.09947	2.02993	0.00556	40,189
21	RENTS		4,962,688	40.12940	-31.71012	71.83952	0.19682	976,756
22	PALO VERDE LEASE		45,202,210	40.12940	53.29167	-13.16227	-0.03606	(1,629,992)
23	PALO VERDE S/L GAIN AMORT		(4,575,722)	0.00000	0.00000	0.00000	0.00000	0
24	INSURANCE		2,430,999	0.00000	0.00000	0.00000	0.00000	0
25	UNCOLLECTIBLE ACCOUNTS		2,680,484	0.00000	0.00000	0.00000	0.00000	0
26	OTHER		74,989,350	40.12940	37.55000	2.57940	0.00707	530,175
27	SUBTOTAL		495,845,469					13,473,067
28	DEPRECIATION & AMORTIZATION		284,659,929	0.00000	0.00000	0.00000	0.00000	0
29	AMORT OF ELECTRIC PLT ACQ ADJ		15,443,124	0.00000	0.00000	0.00000	0.00000	0
30	AMORT OF PROP LOSSES & REG STUDY COSTS		99,536,541	0.00000	0.00000	0.00000	0.00000	0
31	SUBTOTAL		399,639,594					0
32	INCOME TAXES							
33	CURRENT:							
34	FEDERAL	(a)	137,019,585	40.12940	60.05000	-19.92060	-0.05458	(7,478,529)
35	STATE	(a)	(6,581,447)	40.12940	62.34755	-22.21815	-0.06087	400,613
36	DEFERRED	(a)	(3,630,835)	0.00000	0.00000	0.00000	0.00000	0
37	SUBTOTAL		126,807,303					(7,077,916)
38	OTHER TAXES							
39	PROPERTY TAXES		103,969,716	40.12940	212.81731	-172.68791	-0.47312	(49,190,152)
40	SALES TAXES	(h)	127,980,680	19.93000	40.21000	-20.28000	-0.05556	(7,110,607)
41	SUBTOTAL		231,950,396					(56,300,759)
42	INTEREST EXPENSE	(b)	97,327,451	40.12940	93.14633	-53.01693	-0.14525	(14,136,812)
43	TOTALS		$ 1,979,599,799					$ (59,142,326)
44	LESS: APS CWC ALLOWANCE							53,839,656
45	STAFF CWC ADJUSTMENT							(112,981,982)
46	% ARIZONA RETAIL -- JURISDICTIONAL FACTOR		(Source: Staff "Functionalization & Allocation Tables.xls")					0.91884
47	STAFF CWC ADJUSTMENT -- JURISDICTIONAL							$ (103,812,515)

Footnotes :

(a) Source: Staff Data Request UTI-14-315.
(b) Source: Staff Data Request UTI-11-282, Workpaper B-7 & Staff Sch. C-19.
(c) Source: Staff spreadsheet "Revenue_REVISED.xls"
(d) Source: Staff spreadsheet "Coal Summary_REVISED.xls"
(e) Source: Staff spreadsheet "Fuel Oil_REVISED.xls"
(f) Source: Staff Data Request UTI-16-329.
(g) Source: Staff Data Request UTI-12-290.
(h) Source: Staff Data Request UTI-17-331 & APS 2002 FERC Form 1, p. 262-263

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	As Adjusted By APS	Staff Adjustments	As Adjusted By Staff
	(a)	(b)	(c)	(d)
1	Electric Operating Revenues	$ 1,940,146	$ (1,996,255)	$ (56,109)
2	Purchased Power & Fuel Costs	559,879	28,974	588,853
3	Gross Margin -- Revenues less			
4	Fuel & Purchased Power Costs	$ 1,380,267	$ (2,025,229)	$ (644,962)
5	Other Operating Expenses			
6	Operations & Maintenance	590,073	(2,002,171)	(1,412,098)
7	Depreciation & Amortization	329,983	(116,753)	213,230
8	Other Taxes	110,197	(11,636)	98,561
9	Subtotal Other Operating Expenses	1,030,253	(2,130,560)	(1,100,307)
10	Operating Income Before Income Taxes	$ 350,014	$ 105,331	$ 455,345
11	Income Taxes	86,144	54,268	140,412
12	Net Jurisdictional Operating Income	$ 263,870	$ 51,063	$ 314,933

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Net Operating Income Summary

ACC Jurisdictional for Adjusted Test Year Ended December 31, 2003

Line No.	Description	C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	C-10	Page Subtotal
1	Electric Operating Revenues	$ (1,940,146)	$ (56,094)									$ (1,996,240)
2	Purchased Power & Fuel Costs	-	34,970						(6,012)			28,958
3	Gross Margin -- Revenues less											
4	Fuel & Purchased Power Costs	$ (1,940,146)	$ (91,064)	$ -	$ -	$ -	$ -	$ -	$ 6,012	$ -	$ -	$ (2,025,198)
5	Other Operating Expenses											
6	Operations & Maintenance	(1,941,670)	(41,087)		(361)			(580)		(1,856)		(1,985,554)
7	Depreciation & Amortization	(1,264)	(41,171)	(15,600)		(3,046)	(9,184)				(5,690)	(75,954)
8	Other Taxes	(480)	(11,156)									(11,636)
9	Subtotal Other Operating Expenses	(1,943,414)	(93,414)	(15,600)	(361)	(3,046)	(9,184)	(580)	-	(1,856)	(5,690)	(2,073,144)
10	Operating Income Before Income Taxes	$ 3,268	$ 2,350	$ 15,600	$ 361	$ 3,046	$ 9,184	$ 580	$ 6,012	$ 1,856	$ 5,690	$ 47,946
11	Income Taxes	1,473	15,053	6,150	142	1,201	3,620	229	2,370	732	2,243	33,212
12	Net Jurisdictional Operating Income	$ 1,795	$ (12,703)	$ 9,450	$ 219	$ 1,845	$ 5,564	$ 351	$ 3,642	$ 1,124	$ 3,447	$ 14,734
13	**Brief Adjustment Description:**	Allocations Utilizing Peak & Average Methodology	Reverse Company's PWEC Adjustment	1999 Settlement Agreement Write-down	Eliminate O&M Costs in APS Proposed Customer Annualization	Remove Depreciation Expense on Leased Vehicles	Adjust APS' Proposed Property Tax Expense	Eliminate Non-Recurring Mainframe Computer Lease	LaCapra's Fuel & Purchased Power Costs -- w/o PWEC Units	Eliminate Economic Development Costs	Nuclear Decommissioning	

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2003

Line No.	Description	Prior Page Total	C-11	C-12	C-13	C-14	C-15	C-16	C-17	C-18	C-19	Page Subtotal
1	Electric Operating Revenues	$ (1,996,240)										$ (1,996,240)
2	Purchased Power & Fuel Costs	28,958			16							28,974
3	Gross Margin -- Revenues less											
4	Fuel & Purchased Power Costs	$ (2,025,198)	$ -	$ -	$ (16)	$ -	$ -		$ -	$ -	$ -	$ (2,025,214)
5	Other Operating Expenses											
6	Operations & Maintenance	(1,985,554)		(6,181)	1,297	(303)	(2,906)	(1,051)	(4,421)			(1,999,120)
7	Depreciation & Amortization	(75,954)	(40,649)									(116,604)
8	Other Taxes	(11,636)										(11,636)
9	Subtotal Other Operating Expenses	(2,073,144)	(40,649)	(6,181)	1,297	(303)	(2,906)	(1,051)	(4,421)	-	-	(2,127,359)
10	Operating Income Before Income Taxes	$ 47,946	$ 40,649	$ 6,181	$ (1,314)	$ 303	$ 2,906	$ 1,051	$ 4,421	$ -	$ -	$ 102,144
11	Income Taxes	33,212	16,024	2,437	(518)	120	1,146	414	1,743	(925)	(640)	53,012
12	Net Jurisdictional Operating Income	$ 14,734	$ 24,625	$ 3,744	$ (796)	$ 184	$ 1,761	$ 637	$ 2,678	$ 925	$ 640	$ 49,133
13	**Brief Adjustment Description:**		Majoros Depreciation Expense Adjustment	Severance Adjustment	Wages & Salaries Adjustment	Union Contract Signing Bonus	Incentive Compensation Adjustment	Eliminate Test Year DSM Expenses	Advertising & Marketing Adjustment	Income Tax AZ State Credit & Non-deductible Meals / Entertainment	Income Tax Interest Synchronization	

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY
Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2003

Line No.	Description	Prior Page Total	C-20	C-21	C-22	C-23	C-24	C-25	C-26	C-27	C-28	Page Subtotal
1	Electric Operating Revenues	$ (1,996,240)		$ (15)								$ (1,996,255)
2	Purchased Power & Fuel Costs	28,974										28,974
3	Gross Margin -- Revenues less											
4	Fuel & Purchased Power Costs	$ (2,025,214)	$ -	$ (15)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,025,229)
5	Other Operating Expenses											
6	Operations & Maintenance	(1,999,120)			(2,465)	(586)						(2,002,171)
7	Depreciation & Amortization	(116,604)					(150)					(116,753)
8	Other Taxes	(11,636)										(11,636)
9	Subtotal Other Operating Expenses	(2,127,359)	-	-	(2,465)	(586)	(150)	-	-	-	-	(2,130,560)
10	Operating Income Before Income Taxes	$ 102,144	$ -	$ (15)	$ 2,465	$ 586	$ 150	$ -	$ -	$ -	$ -	$ 105,331
11	Income Taxes	53,012	-	(6)	972	231	59	-	-	-	-	54,268
12	Net Jurisdictional Operating Income	$ 49,133	$ -	$ (9)	$ 1,493	$ 355	$ 91	$ -	$ -	$ -	$ -	$ 51,063
13	**Brief Adjustment Description:**		Reserved -- Excess Deferred Income Tax Expense ARAM Protected	Schedule 1 Tariff Changes	Reverse APS' Proposed 5 Year Amort. Of Regulatory Assets	Eliminate Contributions to Civic and Charitable Organizations	Amortize Gains on Sales of Property	Reserved	Reserved	Reserved	Reserved	

Witness: J. Dittmer
L. Smith

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Reallocate APS' Jurisdictional Cost of Service Study
Utilizing the Peak and Average Method for Allocating Fixed Production Cost

Line No.	Description	As Adjusted By APS Utilizing 4 CP Alloc.	As Adjusted By APS Utilizing Peak & Average	Adjustment to Reflect APS' Request Using P&A
	(a)	(b)	(c)	(d)
1	Electric Operating Revenues	$ 1,940,146	-	$ (1,940,146)
2	Purchased Power & Fuel Costs	559,879	559,879	-
3	Gross Margin -- Revenues less			
4	Fuel & Purchased Power Costs	$ 1,380,267	(559,879)	(1,940,146)
5	Other Operating Expenses			
6	Operations & Maintenance	590,073	(1,351,597)	$ (1,941,670)
7	Depreciation & Amortization	329,983	328,719	(1,264)
8	Other Taxes	110,197	109,717	(480)
9	Subtotal Other Operating Expenses	1,030,253	(913,161)	(1,943,414)
10	Operating Income Before Income Taxes	$ 350,014	353,282	$ 3,268
11	Income Taxes	86,144	87,617	1,473
12	Net Jurisdictional Operating Income	$ 263,870	265,665	$ 1,795
13	Reference:	APS SFR	LCA 2-33	Col. (c) Less
14		Sch. C-1, P. 2		Col. (b)

Witness: J. Dittmer
H. Salgo

ARIZONA PUBLIC SERVICE COMPANY

Reverse Company's PWEC Adjustment Utilizing Peak & Average Methodology
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description (a)	Reverse APS' Total Company PWEC Adjustment (b)	Reverse APS' PWEC Adjustment Utilizing Peak & Average (c)
1	Electric Operating Revenues	$ (56,779,000)	(56,094,175)
2	Purchased Power & Fuel Costs	34,970,000	34,970,000
3	Gross Margin -- Revenues less		
4	Fuel & Purchased Power Costs	$ (91,749,000)	$ (91,064,175)
5	Other Operating Expenses		
6	Operations & Maintenance	(41,456,000)	(41,087,042)
7	Depreciation & Amortization	(41,541,000)	(41,171,285)
8	Other Taxes	(11,256,000)	(11,155,822)
9	Subtotal Other Operating Expenses	(94,253,000)	(93,414,148)
10	Operating Income Before Income Taxes	2,504,000	2,349,974
11	Income Taxes	15,279,785	15,053,229
12	Net Operating Income	(12,775,785)	(12,703,256)
13	Reference:	APS Sch. C-2	Excel w/p Spreadsheet:
14		Page 3, Col. Q	"Allocate Expense
15			Adjt Using
			P&A.xls"

Witness: J. Dittmer
H. Salgo

ARIZONA PUBLIC SERVICE COMPANY

Reverse Company's Proposed Adjustment to Amortize a
Previous Plant Write Down Over a Fifteen Year Period

Line No.	Description (a)	Amount (All ACC Jurisdictional) (b)
1	Reverse Company's adjustment which had	
2	been proposed to restore a $234 million	
3	write down to electric plant in service	
4	pursuant to a 1999 settlement agreement.	
5	This income statement adjustment	
6	eliminates the Company's proposal to	
7	amortize the write down reversal over	
8	a 15 year period	$ (15,600,000)
9	Reference: APS Sch. C-2, Page 8, Col. QQ	

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Eliminate Non-Payroll O&M Included Within APS'
Customer Annualization Adjustment

Line No.	Description (a)	Reference (b)	Total Amount (c)
1	APS Pro Forma Adjustment to Customer		
2	Accounts/Services Expense for Customer Level	APS Attach.	
3	Annualization at Year-end 2002	DGR-5, page 4	$ 361,000
4	Jurisdictional Allocation Percentage		100%
5	Jurisdictional Adjustment to Eliminate APS'		
6	Proposed Customer Accounts/Service for		
7	Customer Revenue Annualization to Year-		
8	End 2002	Line 3 X Line 4	$ (361,000)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Eliminate Proforma Depreciation on Leased Vehicles
That Is Also Reflected as Operating Lease Expense Within
APS' Proposed Retail Cost of Service Study

Line No.	Description (a)	Reference (b)	Amount (c)
1	Vehicle Depreciation Expense Included Within		
2	APS' Proforma Depreciation Annualization		
3	Adjustment That Is Also Reflected As Operating		
4	Lease Expense Within Test Year Operations	APS Workpaper	
5	and Maintenance Expense	DRG__WP24, p.3	$ 3,314,600
6	Composite Wages & Salaries Jurisdictional	Functionalization &	
7	Allocation Factor	Allocation Tables.xls	91.884%
8	ACC Jurisdictional Vehicle Depreciation Expense		
9	Adjustment	Line 5 x Line 7	$ (3,045,591)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Property Tax Adjustment
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	Functionalized Plant Categories: Generation	T&D and Other	Total
	(a)	(b)	(c)	(d)
1	2003 Arizona Property Taxes (a)	$ 34,256,023	$ 68,089,578	$ 102,345,601
2	2002 Arizona Property Taxes (b)	36,543,967	60,397,426	96,941,393
3	Required Adjustment to Reflect			
4	2003 Arizona Property Taxes Paid			
5	(Line 1 minus Line 2)	$ (2,287,944)	$ 7,692,152	$ 5,404,208
6	Less: New Mexico Property Taxes			
7	Paid & Expensed in 2002			
8	Related to 2001 (c)	(3,793,668)		(3,793,668)
9	Subtotal: Required Adjustment to			
10	Recorded Test Year Operating			
11	Results (Line 5 + Line 8)	$ (6,081,612)	$ 7,692,152	$ 1,610,540
12	Less: Company Proposed Property			
13	Tax Adjustment to Test Year			
14	Actual Operating Results (d)	8,342,112	1,857,048	10,199,160
15	Total Company Adjustment to APS'			
16	Proposed Level of Property Tax			
17	Expense (Line 11 minus Line 14)	$ (14,423,724)	$ 5,835,104	$ (8,588,620)
18	Total ACC Jurisdictional			
19	Adjustment to APS' Proposed			
20	Level of Property Tax Expense			
21	Utilizing the Peak & Average			
22	Allocation Methodology (e)	$ (13,614,081)	$ 4,430,277	$ (9,183,804)

23 **Footnotes:**

24 (a) Follow up to UTI -6-210
25 (b) Follow up to UTI -6-210
26 (c) Follow up to UTI -6-210
27 (d) APS workpapers DRG__WP29, page 3
28 (e) Supporting calculations found within Excel Spreadsheet "APS Staff Direct Exhibits.xls"

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY
Eliminate Non-Recurring Mainframe Computer Operating Lease

Line No.	Description (a)	Reference (b)	Amount (All ACC Jurisdictional) (c)
1	Mainframe Computer Operating Lease Expense		
2	Included Within Test Year Operations and		
3	Maintenance Expense that Terminated During	UTI-2-217 and	
4	the Historic Test Year and was not Renewed	UTI-10-265	$ 631,261
5	Composite Wages & Salaries Jurisdictional	Functionalization &	
6	Allocation Factor	Allocation Tables.xls	91.884%
7	ACC Jurisdictional Mainframe Computer		
8	Operating Lease Adjustment	Line 5 x Line 7	$ (580,029)

Witness: J. Dittmer
D. Smith

ARIZONA PUBLIC SERVICE COMPANY

Normalized Fuel and Purchased Power Expense
Assuming PWEC Units Not Included in Jurisdictional Rate Base

Line No.	Description	Reference	Total Amount (000's)
	(a)	(b)	(c)
1	Jurisdictional Fuel & Purchased		
2	Power Cost Adjustment to Test		
3	Year Actual Operating Results	LaCapra	
4	Per LaCapra Associates	workpaper	$ 114,572
5	Jurisdictional Fuel & Purchased		
6	Power Cost Adjustment to Test	APS Sch. C-2,	
7	Year Actual Operating Results	page 3,	
8	Per APS	Column N	$ 120,584
9	Staff Adjustment to Jurisdictional		
10	Fuel & Purchased Power Costs	Line 4 - Line 8	$ (6,012)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Eliminate Test Year Expenditure on
Economic Development Programs

Line No.	Description (a)	Reference (b)	Total Amount (c)
1	Test Period APS Expenses for Community		
2	Relations and Economic Development	UTI 11-283	$ 1,856,000
3	Retail Jurisdictional Factor / Amount		100%
4	Staff Adjustment to Reclassify Test Year		
5	Community Relations and Economic		
6	Development Costs Below-the-Line	Line 2 X Line 3	$ (1,856,000)

Witness: J. Dittmer
H. Judd

ARIZONA PUBLIC SERVICE COMPANY

Nuclear Decommissioning Expense Adjustment

Line No.	Description (a)	Reference (b)	Amount (c)
1	Nuclear Decommissioning Expense		
2	Provision as Recommended by the		
3	Utilities Division Staff		
4	(Mr. Harold Judd -- Accion Group)		$ 13,611,000
5		APS/Robinson	
6	Nuclear Decommissioning Provision	DRG__WP28,	
7	As Recommended by APS	p. 2/11	19,211,000
8	Total Company Nuclear		
9	Decommissioning Expense Adjustment	Line 4 - Line 7	$ (5,600,000)
10	Post Shutdown ISFSI Costs as		
11	Recommended by Utilities Division		
12	Staff (Mr. Harold Judd -- Accion Group		$ 618,000
13	Post Shutdown ISFSI Costs Proposed		
14	by APS	DRG-WP26, p. 1	792,000
15	Total Company Adjustment to Post		
16	Shutdown ISFSI Costs	Line 12 - Line 14	$ (174,000)
17	Total Company Reduction to Nuclear		
18	Decommissioning Costs Proposed		
19	by Utilities Division Staff	Line 9 + Line 16	$ (5,774,000)
20	ACC Jurisdictional Energy Allocation		
21	Factor		98.543%
22	Retail Jurisdictional Nuclear		
23	Decommissioning Expense		
24	Adjustment	Line 19 X Line 21	$ (5,689,873)

Witness: M. Majoros
J. Dittmer

Schedule C-11
Page 1 of 1

ARIZONA PUBLIC SERVICE COMPANY

Depreciation Expense Annualization Utilizing Staff's Proposed Depreciation Rates
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description -- Depreciation by Function		Per APS	Per Staff	Difference	Jurisdictional Factor	Jurisdictional Adjustment
	(a)		(b)	(c)	(d)	(e)	(f)
1	Total Production	\1	$131,708	$113,139	$(18,568)	99.110%	$ (18,403)
2	Total Transmission	\2	23,293	16,863	(6,430)	0.000%	-
3	Total Distribution	\3	83,686	67,067	(16,619)	99.952%	(16,611)
4	Intangible Amortization	\4	21,637	21,637	-	98.191%	-
5	General & Intangible Depre & Amort.	\4	27,363	21,625	(5,739)	98.191%	(5,635)
6	5-Year Average Net Salvage Allowance	\5		-	-	97.114%	-
7	Total Depreciation and Amortization --						
8	Including an Allowance for Recovery of						
9	Net Negative Salvage		$287,687	$240,331	$(47,356)		$ (40,649)

10 \1 Production demand allocator utilizing
11 Peak & Average methodology

12 \2 Since transmission costs are considered by
13 reflecting the FERC authorized OATT rate,
14 no transmission depreciation expense is
15 directly considered in the development of
16 the jurisdictional cost of service

17 \3 Composite jurisdictional distribution
18 allocator functionalizing with the PTD less
19 Land spread (Functionalization & Allocation
20 Tables.xls)

21 \4 Composite jurisdictional allocator
22 functionalizing with the Wages & Salaries
23 spread and allocating production function
24 using the Peak & Average Methodology
25 (Functionalization & Allocation Tables.xls)

26 \5 Composite jurisdictional allocator
27 functionalizing with the PTD less Land
28 Spread and allocating production function
29 using the Peak & Average Methodology
30 (Functioinalization & Allocation Tables.xls)

Witness: S. Carver

ARIZONA PUBLIC SERVICE COMPANY
2002 Severance Program

Line No.	Description (a)	Reference (b)	Amount (c)
1	Test Period Employee Severance -- APS Share	(a) & (b)	$ 29,881,644
2	Less: APS Adjustment -- 3-Year Amortization	(a)	(23,154,729)
3	APS Proposed Amortization Expense		6,726,915
4	% Arizona Retail -- Jurisdictional Factor	(c)	91.884%
5	Retail Amount		$ 6,180,968
6	Staff Adjustment to Disallow Test Year Cost of the 2002 Severance Program		$ (6,180,968)

Footnotes:

(a) Source: APS Schedule C-2, page 4, Adjustment 11; Attachment DGR-5, p.11 & Workpaper DGR-WP16.
(b) Test year expense is net of $3.2 million billed to participant owners in 2002 test year. Per the response to Staff Data Request No. UTI-15-321, the $3.2 million was credited to test year expense.
(c) Source: Staff "Functionalization & Allocation Tables.xls".

Witness: S. Carver

ARIZONA PUBLIC SERVICE COMPANY
Wage & Payroll Tax Adjustment

Line No.	Description	Reference	APS Original Pro Forma Adjustment	Update Adjustment	ACC Staff Adjustment
	(a)	(b)	(c)	(d)	(e)
1	Fuel Expenses		$ 7,247	$ 25,000	$ 17,753
2	Other Operating Expense:				
3	Operations (excluding fuel)		850,721	1,839,000	988,279
4	Maintenance		173,181	597,000	423,819
5	Total		$ 1,031,148	$ 2,461,000	$ 1,429,852
			(a)	(b)	
6	% Arizona Retail -- Jurisdictional Factor	(c)			91.884%
7	Staff Adjustment to Recognize Replacement Employees Hired in 2003 and Actual Wage Rates				$ 1,313,807

Footnotes:

(a) Source: APS Schedule C-2, page 4, Adjustment 10; Attachment DGR-5, p.10 & Workpaper DGR-WP15.
(b) Source: APS response to Staff Data Request No. UTI-8-241.
(c) Source: Staff "Functionalization & Allocation Tables.xls".

Witness: S. Carver

ARIZONA PUBLIC SERVICE COMPANY
Union Contract Signing Bonus

Line No.	Description	Reference		Amount
	(a)	(b)		(c)
1	Test Period APS Expense -- Union Contract Signing Bonus	(a)	$	989,907
2	Staff Proposed 3-Year Amortization Period	(b)		3
3	APS Proposed Amortization Expense			329,969
4	% Arizona Retail -- Jurisdictional Factor	(c)		91.884%
5	Retail Amount		$	303,189
6	Staff Adjustment to Amortize Test Year Expense for Union Contract Signing Bonus Over Three-Year Period		$	(303,189)

Footnotes:
(a) Source: APS response to Staff Data Request No. UTI-6-194.
(b) Source: Contract term per APS response to Staff Data Request No. UTI-16-325.
(c) Source: Staff "Functionalization & Allocation Tables.xls".

Witness: S. Carver

ARIZONA PUBLIC SERVICE COMPANY
Incentive Compensation

Line No.	Description (a)	Reference (b)	Amount (c)
1	Test Period APS Expenses for Stock-Based Key Employee and Director Compensation	(a)	$ 3,163,000
2	% Arizona Retail -- Jurisdictional Factor	(b)	91.884%
3	Retail Amount		$ 2,906,295
4	Staff Adjustment to Disallow Test Year Key Employee and Director Stock-Based Compensation Expenses		$ (2,906,295)

Footnotes:
(a) Source: APS response to Staff Data Request No. UTI 12-295.
(b) Source: Staff "Functionalization & Allocation Tables.xls".

Witness: B. Keene
J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Eliminate Test Year DSM Charges Which the Utilities Division
Staff is Proposing to be Recovered Within an Adjustor Mechanism

Line No.	Description (a)	Reference (b)	Amount ($000's) (c)
1	Test Year DSM Charges to:		
2	FERC Account No. 908	Identified by	($109,531)
3	FERC Account No. 912	Barbara Keene	$ (816,188)
4	FERC Account No. 913		($125,662)
5	Total Test Year DSM Charges Proposed	Sum Lines 1 - 4	$ (1,051,381)
6	By Staff to be Recovered Through an		
7	Adjustor Mechanism		
8	Jurisdictional Percentage		100.00%
9	Jurisdictional Adjustment to Eliminate		
10	Test Year DSM Charges	Line 5 X Line 8	$ (1,051,381)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY
Eliminate Image Building Advertising and Sports/Entertainment Sponsorship Programs

Line No.	Description (a)	Reference (b)	Test Year Amount ($000's) (c)	Disallowance Basis (d)	Disallowance Amount (000's) (e)
1	Television Advertising Campaigns	UTI 1-18	$ 1,521	Note (a)	$ (1,512)
2	Print and Out-of-Home Advertising	"	242	Note (b)	(222)
3	Radio Advertising Campaigns	"	197	Note (c)	(197)
4	KNXV Weather Sponsorship	"	479	Note (d)	(240)
5	Dodge Theater Sponsorship	"	106	Note (d)	(53)
6	Arizona Diamonbacks Sponsorship	"	1,640	Note (d)	(820)
7	Phoenix Suns/Mercury/Arena Sponsorship	"	1,199	Note (d)	(600)
8	Phoenix Coyotes Sponsorship	"	608	Note (d)	(304)
9	Arizona Cardinals Sponsorship	"	35	Note (d)	(18)
10	Total Direct Costs		$ 6,027		(3,965)
11	Percentage of Direct Costs Disallowed	Line 10 - Col. e / Col. C)		65.8%	
12	Indirect Payroll, Administration and Ad Agency F	UTI 1-18	$ 694		
13	Disallowance of Indirects Based on Direct %		Line 11	65.8%	(457)
14	Total Company Adjustment to Advertising		Line 30 + 36		(4,421)
15	Jurisdictional Allocation Factor				100%
16 17	Staff Adjustment to Disallow Test Year Image and Promotional Advertising		Line 14 X Line 15		$ (4,421)

Footnotes : (a) APS "Simple Things" campaign costs are disallowed, while costs for Power Tips (safety) and Qualified Contractor (informational) ads are allowed.

(b) APS "Simple Things" campaign costs disallowed, while costs for realtor and customer office posters (informational, safety) are allowed.

(c) APS "Simple Things" campaign costs 100% disallowed.

(d) Partial 50% disallowance based upon mixed messages including "Simple Things" image campaign as well as "Power Tips" and informational content.

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Income Tax Expense to Reflect Arizona State Income Tax
Credits and Non-Deductible Book/Tax Timing Difference

Line No.	Description (a)	Reference (b)	Amount ($000's) (c)
1	State Income Tax Credits Received in		
2	Calendar 2002 -- Excluding Alternative Fuel		
3	Delivery Systems	UTI-6-189	$ (1,540)
4	Increase in 2002 Income Tax Expense Due to		
5	Non-Deductibility of Meals & Entertainment		
6	Expense	UTI-14-309	533
7	Net Reduction to APS Proposed Level of		
8	Current Federal & State Income Tax Expense	Line 3 + Line 6	$ (1,007)
9	Composite Jurisdictional Allocation Factor	Functionalization &	
10	When Spread on Basis of Wages & Salaries	Allocation Tables.xls	91.884%
11	Net Reduction to Jurisdictional Test Year		
12	Income Tax Expense	Line 8 X Line 10	$ (925)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Income Tax Expense to Synchronize the Interest Deduction
For Staff's Proposed Jurisdictional Rate Base and Weighted Cost of Debt

Line No.	Description (a)	Reference (b)		Amount ($000's) (c)
1	Staff Proposed Retail Jurisdictional Rate Base	Exh. B	$	3,051,629
2	Staff Proposed Weighted Cost of Debt	Exh. D		3.19%
3	Staff Proposed Annualized Retail Jurisdictional			
4	Interest Deduction for Cost of Service Income	Line 1 X		
5	Tax Expense Development	Line 2	$	97,327
6	Company Proposed Retail Jurisdictional Rate			
7	Base Developed Utilizing Peak & Average	LCA 2.33	$	4,192,751
8		AP__WP1		
9	Company Proposed Weighted Cost of Debt	Page 89		3.13557%
10	Company Proposed Annualized Retail Jurisdictional			
11	Interest Deduction for Cost of Service Income			
12	Tax Expense Development Utilizing Peak &	Line 7 X		
13	Average Allocation Methodology	Line 9	$	131,467
14	Jurisdictional Interest Deduction Eliminated With			
15	PWEC Reversal Adjustment	Sch. C-2		(35,759)
16	Subtotal: Net Interest Deduction	Line 13 - 15	$	95,707
17	Staff Jurisdictional Interest Deduction in Excess			
18	of Company's Jurisdictional Interest Deduction			
19	Calculated Considering Average & Peak	Line 5 -		
20	Methodology	Line 16	$	1,620
21	Composite Federal & State Income Tax Rate			39.50%
22	Adjustment to Income Tax Expense to			
23	Synchronize Staff's Proposed Jurisdictional	Line 20 X		
24	Rate Base and Weighted Cost of Debt	Line 21	$	(640)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Income Tax Expense to Reflect
Amortization of Deferred Federal Income Taxes

Line No.	Description	Reference	Amount ($000's)
	(a)	(b)	(c)
1	Reserved -- Pending further analysis and		
2	discussions with APS		

Witness: B. Keene
J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Schedule 1 Service Charges

Line No.	Miscellaneous Service Charges	Reference	APS Proposed Charge Rate	Staff Proposed Charge Rate	Difference	2002 Volume	Annualized Revenues
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Trip Charge	DGR_WP10 2/2	$17.50	$16.00	$ (1.50)	1,050	$ (1,575)
2	After-hour service establishment	"	75.00	75.00	-	1,198	-
3	After-hour other services	"	150.00	75.00	(75.00)	65	(4,875)
4	Overhead reconnection	"	100.00	96.50	(3.50)	336	(1,176)
5	Underground reconnection	UTI-2-98	125.00	115.00	(10.00)	44	(440)
6	On-site energy evaluation	"	90.00	75.00	(15.00)	297	(4,455)
7	Joint site meeting - metro	"	70.00	62.00	(8.00)	0	-
8	Joint site meeting - other area	"	70.00	62.00	(8.00)	0	-
9	Joint site meeting - over 30 minutes	"		53.00	53.00	0	-
10	Meter reread	"	20.00	16.50	(3.50)	268	(938)
11	Meter test - field -1 phase - kW	"					
12	Meter test - field - 1 phase - kW & kWh	"	100.00	50.00	(50.00)	28	(1,400)
13	Meter test - shop	"	30.00	30.00	-	81	-
14	Staff Adjustment to Revise APS Proposed						
15	Changes to Schedule 1 Charges (Rounded)						$ (14,859)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to APS' Proposed Five Year Amortization
of Certain Remaining Regulatory Assets

Line No.	Description (a)	Reference (b)	Amount ($000's) (c)
1	Unamortized Loss on Reacquired		
2	Debt at 12/31/02	UTI-7-223	$ 9,129,000
3	Unamortized Gain on Reacquired		
4	Debt at 12/31/02	UTI-7-223	(1,476,000)
5	Net Unamortized Loss on Reacquired		
6	Debt at 12/31/02	Line 2 + 3	$ 7,653,000
7	Staff Proposed Reduction in Total		
8	Company Amortization of Net Loss		
9	on Reacquired Bonds	Line 6 / 5	(1,530,600)
10	Unamortized Deferred Palo Verde		
11	Lease Payments	UTI-7-223	$ 8,200,000
12	Staff Proposed Amortization Period		
13	Based Upon Remaining Life of		
14	Palo Verde Lease		12
15	Staff Proposed Total Company		
16	Amortization of Deferred PV Lease	Line 11 / Line 14	$ 683,333
17	Less: APS Proposed Five Year Amort.	Line 11 / 5	1,640,000
18	Reduction in APS' Proposed		
19	Amortization of Deferred Palo		
20	Verde Lease Payments	Line 16 - 17	$ (956,667)
21	Staff Proposed Reduction in Total		
22	Company Amortization of Regulatory		
23	Assets	Line 9 + Line 20	(2,487,267)
24	Production Demand Allocator		99.110%
25	Jurisdictional Reduction in		
26	Amortization of Regulatory Assets	Line 23 X Line 24	$ (2,465,130)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Eliminate Test Year Contributions to Civic
And Charitable Organizations Included Within APS' Cost of Service

Line No.	Description (a)	Reference (b)	Amount ($000's) (c)
1	Community Service Fund/	UTI-11-271	$ 71,356
2	United Way Campaign 2003		
3	Community Service Fund/	UTI-11-271	45526
4	United Way Campaign 2002		
5	Miscellaneous Contributions	UTI-11-271	$ 520,995
6	Total Above-the-Line Contributions	Sum Lines 1 - 5	$ 637,877
7	Composite Juris. Allocation Factor	Functionalization &	
8	When Functionalized on Basis of W&S	Allocation Tables.xls	91.884%
9	Jurisdictional Adjustment to Eliminate		
10	Civic and Charitable Contributions		
11	Recorded as Above-the-Line Operating		
12	Operating Expense	Line 4 X Line 6	$ (586,108)

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY
Adjustment to Amortize Gains on Sales of Property

Line No.	Description (a)	Reference (b)	Amount ($000's) (c)
1	Deferred Gains Available to Customers		
2	Pursuant to Semi-Annual Report		
3	Filed with the ACC in January 2001	UTI-2-105	$ 86,101
4	Glen Canyon - Utah Transmission Line	UTI-2-105	729,293
5	Total Gains to be Amortized	Sum Lines 1 - 5	$ 815,394
6	Amortization Period		5
7	Total Company Amortization of		
8	Gains on Sales of Utility Property		$ 163,079
9	Composite Juris. Allocation Factor	Functionalization &	
10	When Functionalized on Basis of W&S	Allocation Tables.xls	91.884%
11	Jurisdictional Adjustment to Amortize		
12	Gains on Sales of Property		$ (149,844)

Witness: J. Reiker

Arizona Public Service Company

Cost of Capital Summary

For Adjusted Test Year Ending December 31, 2002

As Proposed by Utilities Division Staff

Line No.	Invested Capital (a)	Percent of Total Capital (b)	Cost Rate (c)	Weighted Cost (d)
1	Long-Term Debt	54.80%	5.82%	3.19%
2	Preferred Stock			0.00%
3	Common Equity	45.20%	9.00%	4.07%
4	Total Capital	100.00%		7.26%

As Proposed by APS

Line No.	Invested Capital	Capital Outstanding	Percent of Total Capital	Cost Rate	Weighted Cost
5	Long-Term Debt	$ 2,139,965	49.77%	5.81%	2.89%
6	Preferred Stock		0.00%		0.00%
7	Common Equity	2,159,312	50.23%	11.50%	5.78%
8	Total Capital	$ 4,299,277	100.00%		8.67%

9	**Utilities Division Staff Reduction to APS Proposed Overall**	
10	**Cost of Capital**	**-1.41%**

ARIZONA PUBLIC SERVICE COMPANY
RECONCILIATION OF POSITIONS
(000'S)

LINE NO.	SCH./ ADJ. NO.	DESCRIPTION	AMOUNT	DIFFERENCE IN PRETAX RETURN	REVENUE REQUIREMENT VALUE
		(A)	(B)	(C)	(D)
1	SCH. A	**APS Revenue *Requirement***			$ 166,808
2	SCH. B	**Return Difference At APS' Rate Base While APS' Sch. D COC Reflects an overall COC of 8.67% Return, its actual return with PWEC in rate base is 8.31% with a more leveraged cap structure**	$ 4,207,476	-1.77%	(74,644)
3		Subtotal Revenue Requirement			$ 92,164
				PRE-TAX RETURN	
4		**STAFF RATE BASE ADJUSTMENTS**			
5	B-1	Allocations Utilizing Peak & Average Methodology	(14,725)	9.91%	($1,460)
6	B-2	Reverse Company's PWEC Adjustment	(882,973)	9.91%	(87,532)
7	B-3	1999 Settlement Agreement Write-down	(141,757)	9.91%	(14,053)
8	B-4	Deferred PacifiCorp Gain	12,418	9.91%	1,231
9	B-5	Eliminate Capitalized Vehicle Lease	(17,966)	9.91%	(1,781)
10	B-6	Net Unamortized Loss on Reacquired Debt	(7,031)	9.91%	(697)
11	B-7	Cash Working Capital	(103,813)	9.91%	(10,291)
12	B-8	Reserved	0	9.91%	0
13		Total Value of OUCC Rate Base Adustments	(1,155,847)		$ (114,583)
14		STAFF Rate Base Recommendation	$ 3,051,629		
				REVENUE CONVERSION MULTIPLIER	
15	SCH. A	**APS Net Operating Income**	$ 263,870		
16		**STAFF NET OPERATING INCOME ADJUSTMENTS**			
17	C-1	Allocations Utilizing Peak & Average Methodology	1,795	1.6529	($2,967)
18	C-2	Reverse Company's PWEC Adjustment	(12,703)	1.6529	20,997
19	C-3	1999 Settlement Agreement Write-down	9,450	1.6529	(15,621)
20	C-4	Eliminate O&M Costs in APS Proposed Customer Annualization	219	1.6529	(361)
21	C-5	Remove Depreciation Expense on Leased Vehicles	1,845	1.6529	(3,050)
22	C-6	Adjust APS' Proposed Property Tax Expense	5,564	1.6529	(9,196)
23	C-7	Eliminate Non-Recurring Mainframe Computer Lease	351	1.6529	(581)
24	C-8	LaCapra's Fuel & Purchased Power Costs -- w/o PWEC Units	3,642	1.6529	(6,020)
25	C-9	Eliminate Economic Development Costs	1,124	1.6529	(1,858)
26	C-10	Nuclear Decommissioning	3,447	1.6529	(5,697)
27	C-11	Majoros Depreciation Expense Adjustment	24,625	1.6529	(40,703)
28	C-12	Severance Adjustment	3,744	1.6529	(6,189)
29	C-13	Wages & Salaries Adjustment	(796)	1.6529	1,316
30	C-14	Union Contract Signing Bonus	184	1.6529	(304)
31	C-15	Incentive Compensation Adjustment	1,761	1.6529	(2,910)
32	C-16	Eliminate Test Year DSM Expenses	637	1.6529	(1,053)
33	C-17	Advertising & Marketing Adjustment	2,678	1.6529	(4,427)
34	C-18	Income Tax AZ State Credit & Non-deductible Meals / Entertainment	925	1.6529	(1,529)
35	C-19	Income Tax Interest Synchronization	640		0
36	C-20	Reserved -- Excess Deferred Income Tax Expense ARAM Protected	0	1.6529	0
37	C-21	Schedule 1 Tariff Changes	(9)	1.6529	15
38	C-22	Reverse APS' Proposed 5 Year Amort. Of Regulatory Assets	1,493	1.6529	(2,468)
39	C-23	Eliminate Contributions to Civic and Charitable Organizations	355	1.6529	(587)
40	C-24	Amortize Gains on Sales of Property	91	1.6529	(150)
41	C-25	Reserved	0	1.6529	0
42		Total Value of STAFF Net Operating Income Adj.	51,063		$ (83,344)
43	SCH. A	STAFF Net Operating Income Recommendation	$ 314,933		
44		**OTHER RECONCILING ITEMS**			
45	SCH. A	Difference in APS' Cost of Capital Request That was Captured as an Income Statement Adj't			$ (48,538)
46		RECONCILED REVENUE REQUIREMENT			$ (321,109)
47		UNRECONCILED DIFFERENCE			187
48	SCH. A	**STAFF REVENUE REQUIREMENT RECOMMENDATION (w/o PWEC)**			$ (154,489)

ARIZONA PUBLIC SERVICE COMPANY
RECONCILIATION OF POSITIONS

LINE NO.	DESCRIPTION		WEIGHTED COST	REVENUE CONVERSION MULTIPLIER (a)	PRETAX RETURN
	(A)		(B)	(C)	(D)
	RETURN PER APS (PWEC In Rate Base):				
1	Long-Term Debt		3.1356%	1.0000	3.136%
2	Preferred Stock		0.00%	1.6529	0.000%
3	Common Equity		5.17385%	1.6529	8.552%
4	Total Capital	(a)	8.31%		11.69%
	RETURN PER STAFF:				
5	Long-Term Debt		3.19%	1.0000	3.189%
6	Preferred Stock		0.00%	1.6529	0.000%
7	Common Equity		4.07%	1.6529	6.724%
8	Total Capital	(b)	7.26%		9.91%
9	DIFFERENCE IN PRE-TAX RETURNS		-1.05%	1.686281643	-1.77%

FOOTNOTE:
(a) Source: APS Workpaper DRG__WP14, page 4
(b) Source: Staff Schedule D

Witness: J. Dittmer
H. Salgo

ARIZONA PUBLIC SERVICE COMPANY

PWEC in Rate Base Scenario -- Revenue Requirement Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

		Retail Electric Original Cost			Retail Electric Fair Value		
Line No.	Description	PWEC Out Staff Base Case	PWEC Inclusion	PWEC In Rate Base	PWEC Out Staff Base Case	Staff Adjustment	PWEC In Rate Base
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Adjusted Rate Base	$ 3,051,629	$ 882,973	$ 3,934,603	$ 4,056,497	$ 1,128,122	$ 5,184,619
2	Required Rate of Return	7.26%	0.00%	7.26%	5.46%	0.05%	5.51%
3	Required Net Operating Income	$ 221,468		$ 285,548	$ 221,468		$ 285,548
4 5	Net Operating Income at Current Rates	314,933	(4,638)	310,295	314,933	(4,638)	310,295
6 7	Net Operating Income Deficiency/(Excess)	$ (93,465)		$ (24,747)	$ (93,465)		$ (24,747)
8	Gross Revenue Conversion Factor	1.6529		1.6529	1.6529		1.6529
9 10	Subtotal Recommended Increase/ (Decrease) in Base Revenues	$ (154,489)		$ (40,904)	$ (154,489)		$ (40,904)
11 12 13 14	Additional Revenue Requirement Adjustment in "PWEC in Rate Base Scenario" Sponsored by LaCapra Witness Mr. Harvey Salgo			(94,000)			(94,000)
15 16 17 18 19	ACC Utilities Division Staff Jurisdictional Rate Recommendation Assuming PWEC Assets Are Included Within Rate Base Development			$ (134,904)			$ (134,904)

Witness: J. Dittmer
H. Salgo

ARIZONA PUBLIC SERVICE COMPANY

PWEC in Rate Base Scenario -- Rate Base Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	Original Cost: PWEC Out Staff Base Case	Original Cost: PWEC Inclusion	Original Cost: PWEC In Rate Base	Fair Value: PWEC Out Staff Base Case	Fair Value: PWEC Inclusion	Fair Value: PWEC In Rate Base
	(a)	(b)	(c)	(d)	(b)	(c)	(d)
1	Gross Utility Plant in Service	$ 7,155,093	$1,008,234	$8,163,328	$ 10,937,613	$1,541,234	$ 12,478,847
2	Less: Accumulated Depre & Amort.	3,010,933	72,526	3,083,460	4,783,719	115,229	4,898,947
3	Net Utility Plant in Service	$ 4,144,160	$ 935,708	$5,079,868	$ 6,153,894	$1,426,006	$ 7,579,900
4	Deductions						
5	Accumulated Deferred Income Taxes	$ 1,138,583	$ 52,734	$1,191,317	$ 1,138,583	$ 52,734	$ 1,191,317
6	Investment Tax Credits	4,033	-	4,033	4,033	-	4,033
7	Customer Advances for Construction	45,513	-	45,513	45,513	-	45,513
8	Customer Deposits	39,865	-	39,865	39,865	-	39,865
9	Pension Liability	48,751	-	48,751	48,751	-	48,751
10	Other Deferred Credits	122,795	-	122,795	122,795	-	122,795
11	Unamortized Gains - Sale of Utility Plant	38,391	-	38,391	38,391	-	38,391
12	Total Deductions	$ 1,437,932	$ 52,734	$1,490,666	$ 1,437,932	$ 52,734	$ 1,490,666
13	Additions:						
14	Regulatory Assets/Liabilities Net	$ 58,716	$ -	$ 58,716	$ 58,716	$ -	$ 58,716
15	Miscellaneous Deferred Debits	26,959	-	26,959	26,959	-	26,959
16	Depreciation Fund -- Decommissioning	191,477	-	191,477	191,477	-	191,477
17	Allowance for Working Capital	68,248	-	68,248	68,248	-	68,248
18	Total Additions	$ 345,401	$ -	$ 345,401	$ 345,401	$ -	$ 345,401
19	Total Rate Base	$ 3,051,629	$ 882,973	$3,934,603	$ 5,061,364	$1,373,271	$ 6,434,635

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

PWEC In Rate Base Scenario -- Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description (a)	PWEC Out Staff Base Case (b)	PWEC Inclusion (c)	PWEC In Rate Base (d)
1	Electric Operating Revenues	$ (56,109)	$ 56,094	$ (15)
2	Purchased Power & Fuel Costs	588,853	(38,966)	549,887
3	Gross Margin -- Revenues less			
4	Fuel & Purchased Power Costs	$ (644,962)	$ 95,060	$ (549,902)
5	Other Operating Expenses			
6	Operations & Maintenance	(1,412,098)	41,087	(1,371,011)
7	Depreciation & Amortization	213,230	27,836	241,066
8	Other Taxes	98,561	9,717	108,278
9	Subtotal Other Operating Expenses	(1,100,307)	78,640	(1,021,667)
10	Operating Income Before Income Taxes	$ 455,345	$ 16,420	$ 471,765
11	Income Taxes	140,412	21,058	161,469
12	Net Jurisdictional Operating Income	$ 314,933	$ (4,638)	$ 310,295

Witness: J. Dittmer
M. Majoros
D. Smith

ARIZONA PUBLIC SERVICE COMPANY

PWEC In Rate Base Scenario -- Net Operating Income Summary
ACC Jurisdictional for Test Year Ended December 31, 2002

Line No.	Description	Reference	Add Back PWEC Adjustment Utilizing Peak & Average
	(a)	(b)	(c)
1	Electric Operating Revenues	Staff C-2	56,094,175
2	Purchased Power & Fuel Costs	LaCapra Assoc.	(38,966,000)
3	Gross Margin -- Revenues less		
4	Fuel & Purchased Power Costs	Line 1 - Line 2	$ 95,060,175
5	Other Operating Expenses		
6	Operations & Maintenance	Staff C-2	41,087,042
7	Depreciation & Amortization	Page 3	27,836,410
8	Other Taxes	Page 3	9,716,819
9	Subtotal Other Operating Expenses	Sum Lines 6 - 8	78,640,271
10	Operating Income Before Income Taxes	Line 4 - Line 9	16,419,904
11	Income Taxes	Footnote (a)	(4,637,812)
12	Increase in Jurisdictional Net		
13	Operating Income	Line 10 - Line 11	21,057,716
14	(a) Income Tax Calculation:		
15	PWEC Jurisdictional Rate Base	Staff B-2	$ 882,973,397
16	Staff Weighted Cost of Debt	Staff Exh. D -- COC	3.19%
17	Additional Tax Deductible Interest		
18	Deduction with PWEC in Rate Base	Line 15 X Line 16	$ 28,161,200
19	Operating Income Before Tax	Line 10	16,419,904
20	Net Reduction in Jurisdictional		
21	Taxable Income	Line 18 - Line 19	$ 11,741,296
22	Composite Federal/State Income		
23	Tax Rate		39.50%
24	Net Reduction in Jurisdictional		
25	Income Tax Expense	Line 21 X Line 23	$ 4,637,812

Witness: J. Dittmer
M. Majoros

ARIZONA PUBLIC SERVICE COMPANY

PWEC In Rate Base Scenario -- Net Operating Income Summary
Development of Annualized Depreciation and Property Tax Expense
ACC Jurisdictional for Test Year Ended December 31, 2002

Line No.	Description (a)	Reference (b)	Amount ($000's (c)
1	PWEC Depreciable Base		
2	Redhawk 1	APS	$ 268,550
3	Redhawk 2	Workpaper	268,550
4	Redhawk Transmission	DGR__WP	49,000
5	West Phoenix 4	14, page 18	78,133
6	West Phoenix 5		308,644
7	Saguaro		36,558
8	Total PWEC Depreciable Base		$ 1,009,435
9	Staff Proposed Depreciation Rate		
10	Redhawk 1	Provided	2.86%
11	Redhawk 2	by Michael	2.86%
12	Redhawk Transmission	Majoros	1.75%
13	West Phoenix 4		2.20%
14	West Phoenix 5		2.86%
15	Saguaro		2.81%
16	Staff Proposed Total Company		
17	Annualized Depreciation Expense		
18	Redhawk 1	Lin 2 X 10	$ 7,693
19	Redhawk 2	Lin 3 X 11	7,693
20	Redhawk Transmission	Lin 4 X 12	857
21	West Phoenix 4	Lin 5 X 13	1,723
22	West Phoenix 5	Lin 6 X 14	8,842
23	Saguaro	Lin 7 X 15	1,028
24	Total PWEC Depreciation	Sum L. 18 - 23	$ 27,836
25	Jurisdictional Production Demand		
26	Allocator -- Peak & Average		99.110%
27	Annualized Jurisdictional PWEC		
28	Depreciation Expense	Line 24 X 26	$ 27,589
29	PWEC Assessed Value for Property	DGR__WP	
30	Tax Purposes	14, page 20	$ 105,990
31	2003 Average Property Tax Rate	UTI-6-210	9.25%
32	Total Estimated PWEC Property Tax	Line 30 X 31	$ 9,804
33	Jurisdictional Production Demand		
34	Allocator -- Peak & Average		99.110%
35	Annualized Jurisdictional PWEC		
36	Property Tax Expense	Line 32 X 34	$ 9,717

Witness: J. Dittmer
H. Salgo

ARIZONA PUBLIC SERVICE COMPANY

PWEC in Rate Base Scenario -- Revenue Requirement Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

		Retail Electric Original Cost			Retail Electric Fair Value		
Line No.	Description	PWEC Out Staff Base Case	PWEC Inclusion	PWEC In Rate Base	PWEC Out Staff Base Case	Staff Adjustment	PWEC In Rate Base
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Adjusted Rate Base	$ 3,051,629	$ 882,973	$ 3,934,603	$ 4,056,497	$ 1,128,122	$ 5,184,619
2	Required Rate of Return	7.26%	0.00%	7.26%	5.46%	0.05%	5.51%
3	Required Net Operating Income	$ 221,468		$ 285,548	$ 221,468		$ 285,548
4 5	Net Operating Income at Current Rates	314,933	(4,638)	310,295	314,933	(4,638)	310,295
6 7	Net Operating Income Deficiency/(Excess)	$ (93,465)		$ (24,747)	$ (93,465)		$ (24,747)
8	Gross Revenue Conversion Factor	1.6529		1.6529	1.6529		1.6529
9 10	Subtotal Recommended Increase/ (Decrease) in Base Revenues	$ (154,489)		$ (40,904)	$ (154,489)		$ (40,904)
11 12 13 14	Additional Revenue Requirement Adjustment in "PWEC in Rate Base Scenario" Sponsored by LaCapra Witness Mr. Harvey Salgo			(99,000)			(99,000)
15 16 17 18 19	ACC Utilities Division Staff Jurisdictional Rate Recommendation Assuming PWEC Assets Are Included Within Rate Base Development			$ (134,904)			$ (134,904)

ALL-STATE LEGAL®
EXHIBIT
S-13
Hamilton

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2002

Line No.	Description	As Adjusted By APS	Staff Adjustments	As Adjusted By Staff
	(a)	(b)	(c)	(d)
1	Electric Operating Revenues	$ 1,940,146	$ (56,132)	$ 1,884,014
2	Purchased Power & Fuel Costs	559,879	28,974	588,853
3	Gross Margin -- Revenues less			
4	Fuel & Purchased Power Costs	$ 1,380,267	$ (85,106)	$ 1,295,161
5	Other Operating Expenses			
6	Operations & Maintenance	590,073	(62,048)	528,025
7	Depreciation & Amortization	329,983	(116,753)	213,230
8	Other Taxes	110,197	(11,636)	98,561
9	Subtotal Other Operating Expenses	1,030,253	(190,437)	839,816
10	Operating Income Before Income Taxes	$ 350,014	$ 105,331	$ 455,345
11	Income Taxes	86,144	54,268	140,412
12	Net Jurisdictional Operating Income	$ 263,870	$ 51,063	$ 314,933

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2003

Line No.	Description	C-1	C-2	C-3	C-4	C-5	C-6	C-7	C-8	C-9	C-10	Page Subtotal
1	Electric Operating Revenues	$ (23)	$ (56,094)									$ (56,117)
2	Purchased Power & Fuel Costs	-	34,970						(6,012)			28,958
3	Gross Margin -- Revenues less											
4	Fuel & Purchased Power Costs	$ (23)	$ (91,064)	$ -	$ -	$ -	$ -	$ -	$ 6,012	$ -	$ -	$ (85,075)
5	Other Operating Expenses											
6	Operations & Maintenance	(1,547)	(41,087)		(361)			(580)		(1,856)		(45,431)
7	Depreciation & Amortization	(1,264)	(41,171)	(15,600)		(3,046)	(9,184)				(5,690)	(75,954)
8	Other Taxes	(480)	(11,156)									(11,636)
9	Subtotal Other Operating Expenses	(3,291)	(93,414)	(15,600)	(361)	(3,046)	(9,184)	(580)	-	(1,856)	(5,690)	(133,021)
10	Operating Income Before Income Taxes	$ 3,268	$ 2,350	$ 15,600	$ 361	$ 3,046	$ 9,184	$ 580	$ 6,012	$ 1,856	$ 5,690	$ 47,946
11	Income Taxes	1,473	15,053	6,150	142	1,201	3,620	229	2,370	732	2,243	33,212
12	Net Jurisdictional Operating Income	$ 1,795	$ (12,703)	$ 9,450	$ 219	$ 1,845	$ 5,564	$ 351	$ 3,642	$ 1,124	$ 3,447	$ 14,734
13	**Brief Adjustment Description:**	Allocations Utilizing Peak & Average Methodology	Reverse Company's PWEC Adjustment	1999 Settlement Agreement Write-down	Eliminate O&M Costs in APS Proposed Customer Annualization	Remove Depreciation Expense on Leased Vehicles	Adjust APS' Proposed Property Tax Expense	Eliminate Non-Recurring Mainframe Computer Lease	LaCapra's Fuel & Purchased Power Costs -- w/o PWEC Units	Eliminate Economic Development Costs	Nuclear Decommissioning	

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY

Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2003

Line No.	Description	Prior Page Total	C-11	C-12	C-13	C-14	C-15	C-16	C-17	C-18	C-19	Page Subtotal
1	Electric Operating Revenues	$ (56,117)										$ (56,117)
2	Purchased Power & Fuel Costs	28,958			16							28,974
3	Gross Margin -- Revenues less											
4	Fuel & Purchased Power Costs	$ (85,075)	$ -	$ -	$ (16)	$ -	$ -		$ -	$ -	$ -	$ (85,091)
5	Other Operating Expenses											
6	Operations & Maintenance	(45,431)		(6,181)	1,297	(303)	(2,906)	(1,051)	(4,421)			(58,997)
7	Depreciation & Amortization	(75,954)	(40,649)									(116,604)
8	Other Taxes	(11,636)										(11,636)
9	Subtotal Other Operating Expenses	(133,021)	(40,649)	(6,181)	1,297	(303)	(2,906)	(1,051)	(4,421)	-	-	(187,236)
10	Operating Income Before Income Taxes	$ 47,946	$ 40,649	$ 6,181	$ (1,314)	$ 303	$ 2,906	$ 1,051	$ 4,421	$ -	$ -	$ 102,144
11	Income Taxes	33,212	16,024	2,437	(518)	120	1,146	414	1,743	(925)	(640)	53,012
12	Net Jurisdictional Operating Income	$ 14,734	$ 24,625	$ 3,744	$ (796)	$ 184	$ 1,761	$ 637	$ 2,678	$ 925	$ 640	$ 49,133
13	**Brief Adjustment Description:**		Majoros Depreciation Expense Adjustment	Severance Adjustment	Wages & Salaries Adjustment	Union Contract Signing Bonus	Incentive Compensation Adjustment	Eliminate Test Year DSM Expenses	Advertising & Marketing Adjustment	Income Tax AZ State Credit & Non-deductible Meals / Entertainment	Income Tax Interest Synchronization	

Witness: J. Dittmer

ARIZONA PUBLIC SERVICE COMPANY
Net Operating Income Summary
ACC Jurisdictional for Adjusted Test Year Ended December 31, 2003

Line No.	Description	Prior Page Total	C-20	C-21	C-22	C-23	C-24	C-25	C-26	C-27	C-28	Page Subtotal
1	Electric Operating Revenues	$ (56,117)		$ (15)								$ (56,132)
2	Purchased Power & Fuel Costs	28,974										28,974
3	Gross Margin -- Revenues less											
4	Fuel & Purchased Power Costs	$ (85,091)	$ -	$ (15)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (85,106)
5	Other Operating Expenses											
6	Operations & Maintenance	(58,997)			(2,465)	(586)						(62,048)
7	Depreciation & Amortization	(116,604)					(150)					(116,753)
8	Other Taxes	(11,636)										(11,636)
9	Subtotal Other Operating Expenses	(187,236)	-	-	(2,465)	(586)	(150)	-	-	-	-	(190,437)
10	Operating Income Before Income Taxes	$ 102,144	$ -	$ (15)	$ 2,465	$ 586	$ 150	$ -	$ -	$ -	$ -	$ 105,331
11	Income Taxes	53,012	-	(6)	972	231	59	-	-	-	-	54,268
12	Net Jurisdictional Operating Income	$ 49,133	$ -	$ (9)	$ 1,493	$ 355	$ 91	$ -	$ -	$ -	$ -	$ 51,063
13	**Brief Adjustment Description:**		Reserved -- Excess Deferred Income Tax Expense ARAM Protected	Schedule 1 Tariff Changes	Reverse APS' Proposed 5 Year Amort. Of Regulatory Assets	Eliminate Contributions to Civic and Charitable Organizations	Amortize Gains on Sales of Property	Reserved	Reserved	Reserved	Reserved	

Witness: J. Dittmer
L. Smith

ARIZONA PUBLIC SERVICE COMPANY

Adjustment to Reallocate APS' Jurisdictional Cost of Service Study
Utilizing the Peak and Average Method for Allocating Fixed Production Cost

Line No.	Description	As Adjusted By APS Utilizing 4 CP Alloc.	As Adjusted By APS Utilizing Peak & Average	Adjustment to Reflect APS' Request Using P&A
	(a)	(b)	(c)	(d)
1	Electric Operating Revenues	$ 1,940,146	1,940,123	$ (23)
2	Purchased Power & Fuel Costs	559,879	559,879	-
3	Gross Margin -- Revenues less			
4	Fuel & Purchased Power Costs	$ 1,380,267	1,380,244	(23)
5	Other Operating Expenses			
6	Operations & Maintenance	590,073	588,526	$ (1,547)
7	Depreciation & Amortization	329,983	328,719	(1,264)
8	Other Taxes	110,197	109,717	(480)
9	Subtotal Other Operating Expenses	1,030,253	1,026,962	(3,291)
10	Operating Income Before Income Taxes	$ 350,014	353,282	$ 3,268
11	Income Taxes	86,144	87,617	1,473
12	Net Jurisdictional Operating Income	$ 263,870	265,665	$ 1,795
13	Reference:	APS SFR	LCA 2-33	Col. (c) Less
14		Sch. C-1, P. 2		Col. (b)

EXHIBIT
S-14
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT

DOCKET NO. E-01345A-03-0437

DIRECT TESTIMONY

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

ERNEST G. JOHNSON

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 27, 2004

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EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-03-0437

Mr. Johnson provides policy level testimony which summarizes the Settlement process, provides reasons which support Staff's conclusions that the Settlement Agreement is in the public interest and addresses several general policy considerations. Mr. Johnson concludes that the Settlement Agreement is fair, balanced and in the public interest. Mr. Johnson asserts the following as support for Staff's conclusion that the Settlement Agreement is in the public interest:

- Staff believes that the agreement is fair to ratepayers because it precludes inappropriate utility profits and results in just and reasonable rates for consumers.

- Staff believes that it is fair to the utility because it provides revenues necessary for the utility to provide reliable electric service along with an opportunity for a reasonable profit.

- Staff believes that this proposal balances many diverse interests including those of low income customers, the renewable energy sector, DSM advocates, merchant generators and retail energy marketers.

- Staff believes that the Agreement is in the public interest because it allows APS to rate base the PWEC Assets, which are the generating plants originally built by APS' affiliate Pinnacle West Energy Corporation, at a value significantly below their book value.

- Although the Agreement calls for rate basing the PWEC Assets, it also addresses potentially anti-competitive effects associated with such rate basing. The Agreement adopts a self-build moratorium, provides for a competitive solicitation in 2005, and requires Staff to conduct workshops to address future resource planning and acquisition issues. In addition, the rate design section encourages general service customers, which are the customers most attractive to new competitors, to shop for competitive services by adopting cost-based unbundling for generation and revenue cycle services. These provisions are intended to promote competition.

- Staff believes that the Settlement eliminates long, complex litigation by resolving issues associated with prior Commission decisions that are currently on appeal (Track A and certain rate case issues). If the Agreement is approved, these appeals will be dropped.

- Staff believes that the Agreement promotes the public interest by facilitating the provision of reliable electric service at the lowest reasonable rates.

- The Agreement provides additional discounts to low-income APS customers, increases funding for advertising these discounts, and increases funding for APS' low-income weatherization program.

- The Agreement sets forth a comprehensive DSM proposal, which is intended to foster the development of new DSM programs. Significantly, the DSM section of the Agreement also includes provisions to ensure that DSM expenditures will be reasonable and that the Commission will be able to maintain appropriate oversight.

Finally, in concluding that the Settlement Agreement is in the public interest, Mr. Johnson notes that the Agreement addresses and resolves all of the main rate case issues, provides sufficient revenues and return for APS to maintain reliable electric service and results in rates and charges which Staff believes are just and reasonable.

INTRODUCTION/SUMMARY

Q. Please state your name and business address.

A. My name is Ernest G. Johnson, 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Arizona Corporation Commission ("ACC" or "Commission") as the Director of the Utilities Division.

Q. Briefly describe your responsibilities as Utilities Director.

A. I am responsible for the day-to-day operations of the Utilities Division, including policy development, case strategy and overall Division management.

Q. Please summarize your educational background and professional experience.

A. In 1979 and 1982, respectively, I earned Bachelor of Science and Juris Doctorate degrees, both from the University of Oklahoma. I have been involved in the regulation of public utilities since 1986. I was employed by the Oklahoma Corporation Commission in 1986 in various legal capacities. In 1993, I was named acting Director and served in that position until mid-1994. I served as permanent Director from mid-1994 until October 2001. In October of 2001, I assumed my current position with the Arizona Corporation Commission. While serving in these capacities, I have participated in numerous regulatory proceedings including providing policy analysis concerning Electric Restructuring before the Oklahoma Corporation Commission, the Oklahoma State Legislature, and the Arizona Commission.

Q. Did you participate in the negotiations that led up to the execution of the Proposed Agreement?

A. Yes, I did.

Q. What is the purpose of your testimony in this case?

A. I will provide testimony which addresses the settlement process, public interest and general policy considerations.

Q. How is your testimony being presented?

A. My testimony is organized into three sections. Section I provides discussion and insight into the Settlement process. Section II identifies and discusses the reasons why the Settlement Agreement ("Agreement") is in the public interest. Section III addresses several general policy considerations.

Q. Who else is providing Staff testimony and what issues will they address?

A. Staff will present the following witnesses:

- Ms. Linda Jaress provides testimony explaining why approval of the Settlement Agreement is in the public interest and why Staff entered the Agreement.

- Mr. Matt Rowell provides testimony in the form of a Staff report concerning the treatment of certain PWEC generation assets and the treatment of competitive issues.

- Ms. Barbara Keene provides testimony in the form of a Staff report covering Demand Side Management, Renewables and Distributed Generation. Ms. Keene also addresses the low-income programs, adjustor mechanisms and service schedules.

- Mr. Bob Gray provides testimony in the form of a Staff report which principally addresses various adjustment Mechanisms.

- Ms. Erinn Andreasen provides testimony in the form of a Staff report concerning Rate Design.

SECTION I - SETTLEMENT PROCESS

Q. Please discuss the Settlement process.

A. In my 18 years of experience in utilities regulation, this process was unprecedented and unparalleled in its breadth and scope. There were more than 30 parties representing every possible viewpoint – advocates for consumers, including low-income customers and seniors; advocates for retail competition, and even other utilities. Working together over the past approximately four months, we have managed to craft a proposed solution that satisfies nearly all of those diverse interests. If we were unable to resolve a specific issue, we set up a process for that issue to be examined and addressed in the future.

Q. How many Settlement meetings were held?

A. During the period of April 19, 2004 through August 11, 2004, approximately twenty (20) meetings were held.

Q. Who participated in those meetings?

A. Generally, most interests were represented; attendees included Arizona Public Service Company ("APS"), Residential Utility Consumer Office ("RUCO"), Staff, and most intervenors.

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. Diverse interests included consumer representatives, merchant plants, large customers of APS, solar interests, environmental interests, and demand side management ("DSM") advocates, just to name a few.

Q. How many of these parties executed the stipulation?

A. The Agreement was executed by twenty-two (22) parties.

Q. How many parties did not sign the Agreement, but nonetheless do not oppose the Agreement?

A. There are five parties who I would describe as not opposed but not signing the Agreement.

Q. How many parties oppose the Agreement?

A. Only one party stated its opposition to the Agreement.

Q. Who is that party?

A. The Arizona Cogeneration Association ("ACA").

Q. Why is Arizona Cogeneration Association opposing the Agreement?

A. It is my understanding that the ACA believes that certain rate structures contained within the Agreement do not encourage distributed generation.

Q. In your opinion, was there an opportunity for all issues to be discussed and considered?

A. Yes. In my opinion, the issues of concern to the ACA were seriously considered, certainly by Staff. Unfortunately, up to this point, we have been unable to resolve them. Nonetheless, the Agreement provides for a process designed to facilitate further discussion and hopefully resolution of these issues.

Q. Mr. Johnson, what process are you referring to?

A. I am referring to Section XVII of the Agreement which provides that the ACC Staff will schedule workshops to consider outstanding issues affecting distributed generation. The Agreement further provides for the initiation of a rule making proceeding as may be necessary.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented the interests of their constituents. As might be expected, at times the discussions became quite contentious and global resolution of the multitude of very complex issues appeared to be no more than wishful thinking. However, I am extremely pleased with the desire and effort put forth by all parties. While acknowledging that not all parties executed the Agreement, I must note that all parties had the opportunity to be heard and to have their issues fairly considered.

Q. Mr. Johnson, would you describe the process as requiring a lot of give and take?

A. Yes, I would. As a result of the many and varied interests represented in the Settlement process, a willingness to compromise was absolutely necessary. As evidenced in the Agreement, the signatories compromised vastly different litigation positions.

Q. In your previous response, you stated that the parties compromised litigation positions. Is that correct?

A. Yes.

Q. In your opinion, was the public interest unduly compromised?

A. No, not in my opinion. As I will discuss later in this testimony, I believe that the compromises made by the various parties will actually further the public interest.

Q. Mr. Johnson, are there any other comments you would like to make in regard to the Settlement process?

A. Yes. I am very pleased with the outcome of the negotiations and I want very much to thank all parties for their diligent participation in the process. It was difficult at times to ensure that all parties had an opportunity to be fully aware of all discussions among and between participants, especially when some were interested in very narrow issues. In fact, at times, it appeared that extreme efforts were being undertaken to provide opportunities for participation.

SECTION II - PUBLIC INTEREST

Q. Turning now to the issue of public interest. Mr. Johnson, in Staff's opinion, is the Proposed Settlement in the public interest?

A. Yes, absolutely. In Staff's opinion, the Proposed Settlement is fair, balanced and in the public interest.

Q. Mr. Johnson, would you briefly summarize the reasons that Staff concludes that the Settlement is fair, balanced and in the public interest.

A. Yes, the following points support Staff's view:

- Staff believes that the agreement is fair to ratepayers because it precludes inappropriate utility profits and results in just and reasonable rates for consumers.

- Staff believes that it is fair to the utility because it provides revenues necessary for the utility to provide reliable electric service along with an opportunity for a reasonable profit.

- Staff believes that this proposal balances many diverse interests including those of low income customers, the renewable energy sector, DSM advocates, merchant generators and retail energy marketers.

- Staff believes that the Agreement is in the public interest because it allows APS to rate base the PWEC Assets, which are the generating plants originally built by APS' affiliate Pinnacle West Energy Corporation, at a value significantly below their book value.

- Although the Agreement calls for rate basing the PWEC Assets, it also addresses potentially anti-competitive effects associated with such rate basing. The Agreement adopts a self-build moratorium, provides for a competitive solicitation in 2005, and requires Staff to conduct workshops to address future resource planning and acquisition issues. In addition, the rate design section encourages general service customers which are the customers most attractive to new competitors, to shop for competitive services by adopting cost-based unbundling for generation and revenue cycle services. These provisions are intended to promote competition.

- Staff believes that the Settlement eliminates long, complex litigation by resolving issues associated with prior Commission decisions that are currently on appeal (Track A and certain rate case issues). If the Agreement is approved, these appeals will be dropped.

- Staff believes that the Agreement promotes the public interest by facilitating the provision of reliable electric service at the lowest reasonable rates.

- The Agreement provides additional discounts to low income APS customers, increases funding for advertising these discounts, and increases funding for APS' low-income weatherization program.

- The Agreement sets forth a comprehensive DSM proposal, which is intended to foster the development of new DSM programs. Significantly, the DSM section of the Agreement also includes provisions to ensure that DSM expenditures will be reasonable and that the Commission will be able to maintain appropriate oversight.

Q. Turning to your first point, you suggest that the Settlement precludes inappropriate utility profits and results in just and reasonable rates for consumers. Please explain.

A. Yes. APS filed its Application seeking to increase base rates by approximately $166.8 million and to recover approximately $8.3 million through a Competition Rules Compliance Charge ("CRCC") surcharge. Under the Settlement, the base rate increase is reduced by approximately $100 million. The proposed Agreement provides for a modest increase in base rates of approximately $67.6 million and a CRCC surcharge of $7.9 million. The proposed revenue requirement contained in the Settlement is approximately 60 percent less than the revenue requirement requested by the Company (4.21 percent increase in lieu of a 9.8 percent increase). This Agreement allows ratepayers to keep very significant amounts of money in their pockets.

Q. Please discuss how the Settlement is fair to the utility.

A. Staff believes that the Agreement is fair to the utility because it provides an opportunity for APS to earn revenues sufficient for the utility to provide reliable electric service and to achieve a reasonable profit. Illustratively, the Settlement would provide APS with revenues which would allow it an opportunity to earn an overall rate of return of approximately 5.97 percent and a 10.25 percent return on equity. In Staff's opinion, these returns would enable APS to provide reliable service at reasonable rates.

Q. Mr. Johnson, you have indicated that the Settlement Proposal incorporates many diverse interests including those of low-income customers, the renewable energy sector, DSM advocates, merchant generators and retail energy marketers. Please elaborate.

A. Within the Agreement, there are specific provisions which address many of the concerns expressed by the above-referenced interests. By way of example, I would submit the following:

<u>**Competitive Procurement of Power**</u>

This issue is more fully addressed in the Staff Report of Mr. Matt Rowell. But as he generally notes, in order to settle matters relating to competition and the procurement of APS' power from the competitive market, the Parties agreed that APS would not build new, large central station generation with an in-service date before 2015. The self build moratorium is subject to a safety mechanism that permits APS to seek an exemption from the Commission if the wholesale market cannot cost effectively meet the needs of APS' customers. These provisions are designed to retain the opportunity for the competitive power marketplace to meet some of APS' generation needs. In my view, over time, and as an outgrowth of this Settlement, we will be able to better assess the ability of the marketplace to provide reliable, reasonably priced generation to APS' rate payers.

Renewable Energy

Under the Agreement, APS has committed to issuing a Request for Proposal in 2005 seeking at least 100 MW and 250,000 MWh per year of electricity generated by solar, biomass/biogas, wind, small hydro, hydrogen or geothermal resources. This provision should provide an opportunity for renewable sources to further demonstrate value as a reliable component of the generation portfolio of APS.

Demand Side Management

Many parties had a particular interest in the issue of DSM. The Agreement calls for a large increase in expenditures for energy efficiency DSM which would include up to $1.0 million which could be used for low-income weatherization projects/programs. Staff places the highest priority on programs to develop energy efficient schools during new construction and by retrofitting. By utilizing energy efficient DSM programs, schools will be able to lower utility bills, thereby freeing up additional dollars for student education and teacher pay. This ultimately could translate into savings for taxpayers.

Q. **How does the Agreement address regulatory issues and unification of assets as it relates to the Pinnacle West Energy Corporation ("PWEC") Assets?**

A. The PWEC assets being transferred consist of the West Phoenix 4 and 5, Saguaro 3, and Redhawk 1 and 2 generating plants. In its application, APS requested approval to acquire the PWEC assets and to receive rate base treatment of the assets at their book value of $883.0 million. The Agreement proposes the transfer of the assets to APS and inclusion in rate base at the reduced amount of $700.00 million. Thus, the Company's concern regarding unification of assets and the regulatory treatment accorded to those assets will be known and certain.

Q. **Mr. Johnson, you suggested that the Agreement is in the public interest because if approved, it would eliminate long, complex litigation. Please explain.**

A. With Commission approval of the Agreement, several legal matters would be settled. The Parties agreed that the Preliminary Inquiry regarding APS compliance with the Electric Competition Rules would be concluded without further action by the Commission. Upon approval of the Agreement, APS and its affiliates will forego any claim that they were harmed by Commission Decision No. 65154 (the Track A Decision). Furthermore, APS would dismiss with prejudice all of its appeals of Decision No. 65154 and all litigation related to Decision Nos. 65154 and 61973. In Staff's view, continued litigation along with the risks attendant thereto, could result in increased costs to rate payers without any recognizable benefits.

Q. **Please discuss your contention that the Agreement promotes the public interest by facilitating reliable electric service at the lowest reasonable rates.**

A. As previously stated, the Settlement would allow APS the opportunity to earn an overall return of 5.79 percent and a 10.25 percent return on equity. In Staff's opinion, APS should have sufficient revenues and reasonable access to capital, which will allow it to properly maintain its system and provide reliable electric service.

Q. **What impact will the Settlement have on low-income customers?**

A. As previously stated, the Agreement calls for a modest base rate increase. It was the parties' intent to insulate eligible low-income customers from a rate increase. As a result, if the Agreement is approved, nearly all low-income customers would receive a net reduction in rates.

Q. Please explain.

A. Basically, the Agreement adopts a higher rate discount for this group. Illustratively, qualifying low-income customers using 401 to 800 kWh currently receive a 20 percent discount. The discount would increase from 20 percent to 26 percent and would completely offset any increase that the eligible low-income customer may have experienced. This increased discount would be in addition to the approximate $1.0 million available through the DSM allowance to be used for low-income weatherization programs and bill assistance.

SECTION III - POLICY CONSIDERATIONS

Q. Mr. Johnson, in its direct testimony, did Staff recommend against including the PWEC generation assets in rate base?

A. Yes.

Q. Is it not true that the Proposed Agreement provides for rate base inclusion of those assets?

A. Yes.

Q. Could you discuss why Staff withdrew its opposition to rate basing the PWEC generation units?

A. Yes. In its initial testimony, Staff challenged APS to properly support its request to include the five new power plants in rate base. In the absence of persuasive testimony to move the plants into rate base in APS' original application, Staff was compelled to recommend against inclusion. To its credit, in its rebuttal case, APS provided additional data and made additional arguments. These submittals, while not being conclusive as to the issue of the appropriate treatment of the PWEC assets, did warrant further analysis and serious consideration by Staff. However, among other things, Staff still questioned the valuation of the generating plants. Staff was able to reconcile its initial opposition when APS agreed to a significantly reduced valuation and when APS agreed to forego claims to $234 million, which APS had alleged it should recover from ratepayers as a result of the Track A order.

Q. Were there additional reasons?

A. Yes. As more fully discussed in the testimony of Mr. Matt Rowell, the Agreement provides for substantial commitments by APS to market-based approaches aimed at meeting future capacity needs. It is anticipated that the self build moratorium and RFP commitments set forth in Section IX of the Agreement will expand the competitive alternatives available to APS. Finally, in reviewing the totality of the Proposed Agreement, Staff was persuaded that on balance inclusion of the PWEC assets as outlined above was not inappropriate.

Q. Mr. Johnson, how does Staff reconcile moving from a rate reduction scenario to a rate increase scenario?

A. The testimony of Ms. Linda Jaress offers a more complete discussion of the basis for the revenue requirement set forth in the Agreement. In this testimony, I address the policy reasons underlying Staff's change in position. As a policy matter, the single most significant revenue requirement issue was determining the appropriate regulatory treatment to be afforded to the PWEC assets. The revenue requirement associated with these generation plants was approximately $100 million annually. As stated previously, Staff's initial testimony challenged APS to properly support its request to include the five power plants in its rate base. In our view, the Company's initial testimony failed to demonstrate that inclusion of those assets was the best option for ratepayers, especially at the valuation proposed by the Company. In the absence of persuasive testimony supporting inclusion (in addition to other accounting adjustments), Staff was compelled to recommend a rate decrease.

Q. Does the Agreement strike an appropriate balance between the diverse needs of the interested parties?

A. Yes. Staff believes that the Agreement as a whole mitigates the impact on ratepayers associated with rate basing the PWEC assets and balances the potentially anti-competitive effects of rate basing with certain pro-competitive provisions. The ratepayer impact is mitigated because the assets are being added to the rate base at a value substantially less than their book value. Also, because the Settlement provides for APS to drop its pending Track A related lawsuits against the Commission, rate payers will not face the risk of having to fund a $234 million (or more) judgment in APS' favor.

Q. As a policy matter, why should the Commission approve the Settlement Agreement?

A. The Settlement Agreement addresses and resolves all of the major rate case issues and results in rates which we believe are just and reasonable. Staff believes that the agreed upon revenue requirement is sufficient for APS to maintain reliable service to its customers and to provide a fair return to its investors while causing only a modest increase in rates.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT
S-15
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	DOCKET NO. E-01345A-03-0437

DIRECT TESIMONY

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

LINDA A. JARESS

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

SEPTEMBER 27, 2004

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ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-03-0437

Ms. Jaress' testimony summarizes sections of the proposed Settlement Agreement, discusses some of the differences among the parties' positions as set forth in their direct testimony and how the differences were resolved within the Settlement Agreement. She sets forth revenue requirement changes reflected in the Settlement Agreement that resulted in Staff's support of a rate increase and explains how those changes were based on the resolution of both revenue impacting and non-revenue impacting issues.

Ms. Jaress' testimony shows how many of the benefits set forth in the Settlement Agreement are long-term and will be experienced by APS customers far beyond the resolution of this rate case. Finally, Ms. Jaress makes clear why it is in the public interest for the Commission to approve the Settlement Agreement.

ACRONYMS

ACAA - Arizona Community Action Association - An organization that finds avenues of economic self-sufficiency for low-income Arizonans.

AECC - Arizonans for Electric Choice and Competition. A coalition of businesses that advocates on behalf of retail electric customers and supports the advancement of retail competition.

AUIA - Arizona Utility Investors Association. Represents the interests of equity owners and bondholders of Arizona Utilities.

CN&SE - Constellation NewEnergy, Inc. and Strategic Energy, LLC.

COSS - Cost of Service Study

FEA - Federal Executive Agencies. Represents all federal facilities served by APS, two of the largest being Luke Air Force Base and the Marine Corps Air Station in Yuma.

OATT - Open Access Transmission Tariff

PSA - Power Supply Adjustor

RUCO - Residential Utility Consumer Office. Represents the interests of Arizona residential utility ratepayers in rate-related proceedings before the Arizona Corporation Commission.

SWEEP - The Southwest Energy Efficiency Project – A public interest organization dedicated to advancing energy efficiency in southwestern states.

TCA - Transmission Cost Adjustor

WRA – Western Resource Advocates. An environmental law and policy organization dedicated to restoring and protecting the natural environment of the Interior American West.

INTRODUCTION

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

A. My name is Linda A. Jaress. I am an Executive Consultant III in the Utilities Division of the Arizona Corporation Commission ("ACC" or "Commission"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Did you provide direct testimony in this docket?

A. Yes. My direct testimony was filed on February 9, 2004. I also provided an Addendum to my direct testimony on February 23, 2004.

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to explain why approval of the Settlement Agreement is in the public interest and why Staff entered the Agreement.

THE SETTLEMENT AGREEMENT

Q. Why is the Settlement Agreement in this case in the public interest?

A. The parties to the case represent a true cross-section of the public. Residential, low income, commercial and industrial customers, military bases, utility investors, environmentalists, merchant plants, and supporters of distributed generation and solar generation all were zealously represented during the negotiation process. The Agreement that resulted from the negotiations of these parties represents their best efforts to resolve differences which are unlikely to be resolved to their satisfaction in a litigated rate case proceeding.

The Settlement Agreement is in the public interest not only because it represents a consensus of the vast majority of the parties, but also because it provides long-term benefits to the customers of APS and the citizens of Arizona. For example, the reduction in the value of the Pinnacle West Energy Corporation assets, explained below, is recommended not just for adoption in this case but as a permanent reduction. This would benefit customers for many years, until the assets are fully depreciated. The proposed increase in Demand Side Management spending would have long-term effects on the reduction in APS' need for new generation. The provision requiring APS to issue a special RFP for renewables in 2005 is a positive step toward providing long-term improvements to the natural environment in Arizona

Staff, then, believes that adoption of the Settlement Agreement in its entirety by the Commission would provide long-term benefits to every party to the Agreement and to the people of Arizona. We further believe that the resulting revenue requirement is fair and that it is in the public interest for the Commission to approve the Settlement Agreement in its entirety.

REVENUE REQUIREMENT

Q. Please summarize APS' original request for a rate increase and the parties' testimony in response.

A. On June 27, 2003, APS filed an application to increase revenues from its customers by $175.1 million including a proposed additional surcharge of $8.3 million, which represents the Competition Rules Compliance Charge ("CRCC"). Staff's direct testimony, filed in February, 2004, recommended a net reduction of $142.7 million which included a $7.4 million CRCC surcharge. The direct testimony of the Residential Utility Consumer Office ("RUCO") supported a decrease of $53.61 million. Arizonans for Choice and Competition ("AECC"), representing businesses who support the advancement of retail competition, recommended adjustments to APS' request that resulted in a revenue requirement increase of approximately $25.0 million. Ultimately, the parties agreed to a base rate increase of $67.6 million with an additional CRCC surcharge of $7.9 million, for a total increase of $75.5 million.

Q. Please explain how the ultimate revenue requirement of $75.5 million was determined.

A. As mentioned in the testimony of Mr. Ernest Johnson, the settlement process was a give and take process. The resolution of issues was rarely conducted on a "this for that" basis but usually centered around groups of issues or discrete issues, always with attention paid to the Agreement as a whole. Although some issues (such as the treatment of the PWEC assets) had direct effects on revenue requirement, others (such as rate design) did not have a direct effect but may have had an impact on the overall revenue requirement negotiations. In summary, it is difficult to discuss and explain individual issues in isolation. The Agreement is best understood as a comprehensive resolution to interrelated issues.

Q. What are the most significant differences between the Settlement Agreement and Staff's direct testimony?

A. Certainly the issue that had the greatest impact on the movement from Staff's revenue requirement recommendation in its direct case to the revenue requirement in the Settlement Agreement was the transfer and inclusion of certain Pinnacle West Energy Corporation ("PWEC") generation assets in APS' rate base, at the reduced value that will be discussed below. The revenue requirement impact from this change was approximately $76 million.

The adoption by the Settlement Agreement of more current fuel, purchased power expenses and off-system sales margins, as presented in APS' rebuttal testimony, increased the revenue requirement by approximately $34 million. The negotiated capital structure and cost of debt and equity levels also had a significant effect, increasing the revenue requirement from Staff's original proposal by approximately $35 million. Similarly, the resolution of depreciation issues and nuclear decommissioning expense issues resulted in an increase to Staff's revenue requirement position of approximately $33 million.

Q. Do the adjustments related to these five issues total the entire change from Staff's direct testimony?

A. No. Although these issues cause discrete, dollar impacts on the revenue requirement, they do not total the entire difference between Staff's testimony and the proposed revenue requirement. The revenue requirement reflected in the Agreement is derived as a result of consideration of specific revenue impacting adjustments <u>and</u> non-revenue impacting adjustments. The revenue requirement does not represent Staff's or any party's assent or dissent to any particular level of cost or expense not specifically set forth in the Agreement, but instead, represents part of the compromise that occurred over the course of these negotiations.

Q. Does Staff's concurrence with the Settlement Agreement revenue requirement mean that Staff concluded that it could not support its direct case?

A. No, it does not. Staff's concurrence means that, taken as a whole, Staff believes that the settlement agreement will provide sufficient other benefits to ratepayers and the general public to counterbalance the increased level of the revenue requirement.

PWEC ASSETS AND ELECTRIC COMPETITION

Q. The most controversial issue with the largest impact on revenue requirement and on the future of electric competition in Arizona is the transfer and rate base treatment of the generating plants owned by APS' affiliate, Pinnacle West Energy Corporation ("PWEC"). What were the parties' original positions?

A. In its direct case, APS requested the transfer and ratebasing of the PWEC assets at book value, which was then nearly $900 million. Staff's testimony suggested that APS had not justified inclusion of the plants in its rate base and did not recommend either the transfer or ratebasing of those assets. RUCO's testimony asserted that APS had not performed the appropriate studies to determine if the acquisition of the PWEC assets was the "least cost" option for acquiring plant and recommended that the Commission deny APS' request to transfer the PWEC assets or include them in APS' rate base until that was determined. RUCO also recommended that the case be bifurcated and extended for a separate proceeding to further evaluate the PWEC assets. AECC, the Arizona Competitive Power Alliance ("the Alliance"), Constellation NewEnergy, Inc., and Strategic Energy, L.L.C. ("CN&SE") all strongly recommended denial of the transfer and ratebasing of the PWEC assets.

There was also substantial testimony regarding the status of electric restructuring in Arizona filed by several parties. Among the positions put forth, RUCO urged the Commission to scrap electric restructuring completely. The Arizona Community Action Association ("ACAA"), which represents low-income customers, urged the Commission to protect low-income customers from bearing the cost of rectifying the electric restructuring that they had opposed. Other parties filed testimony on the damage that transferring the PWEC assets to APS would cause the electricity market in Arizona.

Q. How will those various parties and the public benefit from the PWEC asset treatment proposed by the Settlement Agreement?

A. The benefits that would be realized by those who were originally opposed to the transfer and ratebasing of the PWEC assets include the retention of the Track B benefits, the removal of uncertainty regarding APS' role in electric competition in Arizona, and the creation of opportunities to sell power to APS.

Q. At what value did the parties agree to include the PWEC assets in rate base and why?

A. APS originally requested recovery of $889.2 in rate base for the PWEC assets as of the end of the 2002 test year. However, as time passed and the plant depreciated, the book value was expected to fall to $848.0 million at December 31, 2004. The parties agreed that the plants would be ratebased at $700.0 million.

Q. What does the difference between $848.0 million and $700.0 million represent?

A. APS is currently under contract with PWEC to purchase electricity from all but one of PWEC's generating units ("the Track B contract"). Staff and other parties believe that the terms of that contract are beneficial to APS customers and that those benefits should be retained as long as possible. Thus, a reduction in the value of the PWEC assets that fairly represents the benefits from the Track B contract was negotiated. This is a permanent reduction to the rate base that will benefit customers long after the Track B contract would have expired.

Q. What impact will the transfer of the PWEC assets have on electric competition in Arizona?

A. Although the Agreement proposes to transfer and rate base the PWEC assets, which APS requested, it also proposes actions to counteract any perceived detriment to electric competition in Arizona that the transfer could cause. For example, APS has agreed not to self-build generation for ten years (unless certain, specific circumstances occur), allowing the merchant electric industry opportunities to supply some of APS' generation needs. Also, APS agreed to issue an RFP during 2005 seeking long-term resources of 1000 MW or more for 2007 and beyond. This solicitation will further support the development of a competitive electricity market in Arizona.

The road that electric competition has traveled in Arizona has been rocky. However, Staff believes that adoption of the Settlement Agreement will enable smoother traveling. The combination of the transfer of the PWEC assets (at a reduced value) to APS, along with the ten-year prohibition against self-building and the issuance by APS of an RFP for a significant amount of power will enhance the potential development of electric competition in Arizona. Finally, adoption of these segments of the Agreement by the Commission will likely eliminate potential appeals, contribute to the protection of the financial health of one of Arizona's largest corporations and employers, and promote the development of the market for merchant electricity.

POWER SUPPLY ADJUSTOR

Q. Although the Power Supply Adjustor ("PSA") does not contribute to the level of the negotiated increase, it is an important issue. Provide some background on this issue.

A. In a previous docket culminating in Decision No. 66567, dated November 18, 2003, Staff did not oppose approval of a PSA for APS that included recovery of both fuel and purchased power expenses. In that Decision, the Commission rejected the concept of including fuel in the adjustor and did not approve Staff's request for an earnings test to ensure that APS does not over-collect. The Decision was clear in its intent to approve the "concept" of a Purchased Power Adjustor yet deferred final "affirmative approval" to this APS rate case.

Q. What were the parties' positions on a PSA in their direct testimony in this case?

A. APS continued to request a PSA. In contrast, RUCO recommended that a purchased power and fuel adjustor be denied. Staff recommended denial of a PSA based on its concern that ratepayers would not experience the reductions in APS' non-fuel cost of service (those costs not included in the adjustment mechanism), but would at the same time bear increasing variable power costs through the adjustor. However, Staff maintained its previous contention that, if the Commission were to approve an adjustor, APS should recover fuel costs along with purchased power expenses.

Q. How does the Settlement Agreement address the adjustor issue?

A. The Settlement Agreement proposes an adjustor similar to that favored by Staff in the Adjustor case with some differences. The adjustor included in the Agreement proposes at least a five-year life instead of the three-year life proposed by Staff in the Adjustor case. It does not include the earnings test that Staff had previously recommended and the Commission denied. However, the proposed PSA contains reporting requirements that are significant. Detailed monthly reports, some publicly available and some not, will provide Staff and RUCO with comprehensive information regarding the operation of each generation plant and each fuel and power purchase in order to enhance Staff's ability to track and determine the appropriateness of APS' fuel and power purchases.

Q. In the Adjustor case decision, the Commission asked "the parties in APS' pending rate case to work on developing a symmetrical incentive or performance based rate ("PBR") mechanism." Did the parties accomplish this request?

A. Yes, they did. On page 4 of the proposed Agreement, the parties agreed that within the PSA, "[t]here shall be an incentive mechanism where APS and its customers shall share in the costs or savings. The percentage of sharing shall be ninety (90) percent for the customers and ten (10) percent for APS with no maximum sharing amount." This, in effect, creates a deadband whereby ten percent of the fuel and purchased power costs that exceed base power costs will be absorbed by the Company; similarly, ten percent of any fuel and purchased power savings will be absorbed by the Company.

Q. What are the benefits of this mechanism?

A. APS will benefit by diminished risk related to volatile purchased power and fuel costs. Customers will benefit because the recommended incentive mechanism should motivate APS to reduce fuel and purchased power costs below their current level.

Q. Did this adjustor affect revenue requirements?

A. Although the PSA does not directly affect revenue requirement, the parties agreed to set the base cost of fuel and purchased power on APS' recent costs, which were higher than those in the test year. This was done partially to recognize recent cost levels and partially to reduce the risk that the adjustor will need to be raised significantly at the end of its first year of existence.

DEPRECIATION

Q. Twenty-one pages of the Appendices to the proposed Agreement list depreciation rates, service lives and net salvage values. Why is it necessary for depreciation issues to be settled and for the Commission to expressly approve depreciation rates, service lives and net salvage values?

A. If new depreciation rates, service lives and net salvage values are not expressly approved by the Commission, then whatever rates, lives and values were last approved would remain in place.

Q. Which parties supplied depreciation testimony in the direct case?

A. Only APS and Staff supplied such testimony.

Q. When were APS' current depreciation rates adopted?

A. APS' current depreciation rates were approved on February 14, 1995. That change in depreciation rates represented an update of a 1992 depreciation study approved by the Commission in June, 1994.

Q. What adjustments to test year depreciation did the parties make in the direct case?

A. APS requested approval of a $3.0 million increase in depreciation expense, Staff requested a $44.3 million decrease, and RUCO made no adjustment to depreciation expense related to depreciation rates, asset lives and salvage values.

Q. What is SFAS No. 143, and what is its relevance to this rate case?

A. As discussed in direct and rebuttal testimony, the Financial Accounting Standards Board ("FASB") issued a statement (SFAS No. 143), which was implemented on January 1, 2003, one day after the end of the test year in this case. SFAS No. 143 requires companies to limit the asset retirement obligations recorded in depreciation expense to those asset retirement obligations that are required by law. For example, there are legal requirements that, at retirement, APS must dismantle certain plants and properly dispose of them. Thus, when APS calculates annual depreciation for these plants, it includes an amount in depreciation expense attributable to the cost of removal.

In the absence of a legal requirement to remove an asset, SFAS No. 143 prohibits companies from including the estimated future cost of removal in the annual depreciation expense for that asset. For example, expected costs to dispose of old computers or service trucks are not included in depreciation rates for those items. However, in the past, APS has included the estimated cost of removal of such assets in its depreciation rates. Thus, Staff recommended an unbundled, identifiable net salvage allowance that could be included as a component of depreciation expense and recorded in accumulated depreciation.

APS argued that SFAS 143 applies to financial accounting and not regulatory accounting. APS also argued that the Commission has long been aware that APS includes in depreciation expense the estimated future cost of removal of assets for which there is no legal retirement obligation and that such recovery has been included in APS' approved depreciation rates for many years. APS has not separately accounted for the cost of removal of such assets, so any current or future adjustment to depreciation expense based upon SFAS 143 would be the result of gross estimates.

Q. What other issue did Staff raise in its direct testimony regarding depreciation?

A. Staff also disagreed with the projected service lives adopted by APS for its current assets and for the assets proposed to be acquired from PWEC. Staff believed that APS chose to use service lives that were too short, resulting in higher depreciation rates, and, therefore, higher depreciation expense.

Q. How does the Settlement Agreement address the SFAS No. 143 issue and the service lives issue?

A. APS agreed to adopt Staff's recommended depreciation lives and to separately record and account for projected costs of removal and salvage within depreciation expense so that they can be identified in future rate cases. The Agreement provides that APS may continue to record all asset retirement obligations in depreciation expense in the manner reflected in their filing until further order of the Commission.

Q. What is the benefit of settling these issues?

A. The determination of the proper depreciation expense requires highly technical studies tempered with a great deal of judgment. Witnesses for commission staffs, consumer advocates and utilities can be equally compelling in their arguments for their respective positions. Yet, depreciation expense has a significant impact on revenue requirement. By coming to a reasonable compromise on depreciation issues, the resources of all the parties and the Commission may be devoted to other issues.

COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What were the parties' original positions on the appropriate capital structure, cost of long-term debt and cost of equity capital?

A. The individual parties' recommended capital structures and costs of debt were very similar. There were great differences among the cost of equity recommendations. Staff recommended a capital structure of 54.8 percent long-term debt at a cost of 5.82 percent and 45.2 percent common equity at a cost of 9.0 percent. Staff's estimates of the cost of common equity range from 7.0 percent to 10.6 percent.

RUCO recommended a capital structure of 53.83 percent at a cost of 5.77 percent, 1.03 percent short-term debt at a cost of 3.0 percent, and common equity of 45.24 percent at a cost of 9.5 percent.

With the inclusion of the PWEC assets in rate base, APS requested a capital structure comprised of 54.95 percent of long-term debt at a cost of 5.76 percent and common equity of 45.05 percent at a cost of 11.5 percent.

Q. What does the Settlement Agreement propose for the capital structure and costs of debt and equity?

A. The Agreement adopted a capital structure of 55.0 percent long-term debt and 45 percent common equity and a cost of debt of 5.8 percent. The Agreement also proposes that the cost of common equity be set at 10.25 percent, which falls at the midpoint between Staff's and the Company's recommendations. It is also within the range of equity costs that Staff's testimony set forth as reasonable. Thus, Staff believes that 10.25 percent is a reasonable compromise.

DEMAND SIDE MANAGEMENT

Q. What were the various positions on Demand Side Management ("DSM")?

A. During the test year, APS incurred approximately $1.1 million in DSM costs. Staff's testimony recommended a $4.0 million per year cap on the level of APS' DSM expenditures. RUCO's testimony recommended increasing annual DSM expenditures by APS to $35.0 million. The Southwest Energy Efficiency Project ("SWEEP") also recommended large increases in funding in each year, beginning at $13.0 million in 2004, increasing to $41 million in 2006 and $50 million in 2014.

In its surrebuttal testimony, APS agreed that an expanded DSM program funded at an initial $3.0 million per year and capped at $10.0 million per year would be reasonable. For expenditures under that $10.0 million ceiling, APS would be permitted to collect net lost revenues, incremental staffing costs, and future funding requirements resulting from DSM workshops or subsequent proceedings.

Q. How did the Settlement Agreement resolve these huge differences?

A. Included in the base rate increase proposed by the Settlement Agreement is $10.0 million for expenditures on approved, eligible methods of DSM. An adjustor is also proposed that would recover a required, additional $6.0 million per year on DSM. This would result in $48.0 million of funding over the three years 2005 through 2007.

Q. Why is this a good compromise?

A. There was no disagreement among the parties that appropriate methods of DSM will ultimately benefit APS ratepayers by postponing or reducing the size of future generation and transmission. The Commission, itself, has expressed interest in implementing additional DSM programs. Thus, the main points of contention were the level of funding and the method of recovery. Although the funding level proposed in the agreement is much higher than current levels, the agreement also places restrictions on these expenditures to ensure that the funds will be devoted to the best economic use. For example, one of the conditions requires APS to submit all of its DSM programs to the Commission for pre-approval. In the past, APS' DSM programs were required to receive only Staff's approval. Also, to induce APS to expend money and effort to reduce demand for electricity, the Agreement includes a performance incentive equal to 10 percent of the total amount of DSM spending.

Thus, the proposed increase in the level of funding, along with other provisions designed to ensure that all DSM expenditures will be reasonable, met the satisfaction of all the parties.

ENVIRONMENTAL PORTFOLIO STANDARD AND OTHER RENEWABLES

Q. In their direct testimony, both Staff and other parties expressed the opinion that APS was not fulfilling the Commission's expectations regarding the use of renewable resources and compliance with the Environmental Portfolio Standard ("EPS"). What were some of the other positions the parties took in their direct testimony?

A. Western Resource Advocates, an organization described as working to protect and restore the natural environment of the interior American West, requested that the Commission remove the caps set in place by A.A.C. R14-2-1618. They also recommended that APS acquire at least 2 percent of its sales of electricity from renewable resources.

RUCO recommended that $6.0 million of the proposed EPS funding be "reassigned" to DSM, thereby placing lesser emphasis on renewables.

Q. How does the Settlement Agreement resolve these concerns?

A. Although the Settlement Agreement does not increase the existing level of expenditures for renewables ($6.0 million generated by base rates and $6.5 million generated through a surcharge in the Test Year) at least until the Commission completes the next EPS rulemaking, the Agreement calls for APS to issue an RFP in 2005 seeking at least 100 MW and 250,000 MWh per year of renewable energy resources. Through this RFP or other procurement, APS would seek to acquire at least 10 percent of its annual incremental peak capacity from renewables. If APS does not achieve this goal by the end of 2006, the Agreement requires APS to report the shortfall to the Commission and all parties to this docket.

Currently, the monthly cap on the EPS surcharge that APS could collect from residential customers is $0.35 and $13.00 from non-residential customers under 3 MW. For non-residential customers 3 MW and over, $39 per month could be collected. As will be discussed below, organizations representing large non-residential customers claim that their rates are subsidizing residential customers. The Settlement Agreement addresses this perceived imbalance; if the Commission increases the total amount of EPS funding before the next APS rate case, the proportion absorbed by non-residential customers will be identical to the proportion of total funding currently provided by non-residential customers.

Q. Why is this a good compromise?

A. The Agreement balances the desires of the parties in this case, for now, while leaving the ultimate level of EPS funding open to discussion and determination by the Commission in future proceedings, which are already underway.

TRANSMISSION COST ADJUSTOR

Q. What is the purpose of a Transmission Cost Adjustor?

A. A Transmission Cost Adjustor ("TCA") is designed to ensure that any potential direct access customers will pay the same for transmission as standard offer customers. If transmission costs change and APS receives approval by Federal Energy Regulatory Commission ("FERC") to change its Open Access Transmission Tariff ("OATT"), APS would be unable, until its next rate case, to pass the increase or decrease to its standard offer customers in the absence of a TCA.

Q. What were the positions of the parties in the direct case?

A. Staff supported the implementation of the TCA in its direct testimony because without a TCA, customers' choice between direct access service and standard offer service could be distorted. RUCO's testimony recommended that the TCA be denied and that the Commission retain "local control" over the transmission aspect of APS' operations.

Q. How does the proposed Settlement Agreement address the TCA issue?

A. The Agreement adopts a TCA but limits it to the recovery or refund of costs associated only with changes in APS' OATT. The Agreement also limits APS from filing for a change in the TCA until transmission costs increase more than 5 percent over test year levels.

Q. How is this an equitable solution?

A. The TCA would ensure that APS' current customers will not be impeded from becoming Direct Access customers or become motivated to become Direct Access customers due to differences in transmission rates.

BARK BEETLE REMEDIATION

Q. What is a bark beetle and why is it addressed in the Settlement Agreement?

A. Bark beetles are small brown beetles about the size of a match head that bore into pinion and ponderosa pine that have been weakened by disease or drought. According to the USDA Forest Service, the current bark beetle infestation has killed tens of millions of pine trees in Arizona. In its rebuttal testimony, APS has requested approximately $8.0 million per year, for five years, for use in clearing dead and dying trees around transmission and distribution lines.

The Settlement Agreement proposes to allow APS to defer, for possible future recovery, the reasonable and prudent direct costs of bark beetle remediation that exceed test year levels of tree and brush control. The deferral account shall not accrue interest and will be subject to Commission review in APS' next rate case. The parties believe this is a preferred and more precise method of recovery than asking the Commission to pre-approve an estimated level of costs.

NUCLEAR DECOMMISSIONING FUND

Q. What were the parties' positions on nuclear decommissioning?

A. Staff was the only party to examine and provide testimony regarding APS' nuclear decommissioning study and requested level of funding. Staff's direct testimony determined that APS' most recent nuclear decommissioning study (completed in 2001) for the most part used reasonable assumptions and conformed to the methodology employed in the industry. However, Staff proposed that APS' Palo Verde Unit 2 decommissioning funding schedule be adjusted to match the licensed life of the unit. Staff also testified that APS had not taken into account possible uses of the decommissioned Palo Verde site and the value of such use.

APS argued that there is no reason to change the funding levels which are under the oversight of the NRC and GAO and have been determined in the past to be adequately funded. APS also argued that the current funding levels have been approved by all of the other Palo Verde participants and that changing them would be difficult procedurally.

The Settlement Agreement proposes to adopt APS' recommended level of decommissioning costs. Staff accepted APS' arguments to a degree, but primarily agreed to the current level of funding based upon the possible negative consequences of underfunding.

COST OF SERVICE AND RATE DESIGN

Q. Which parties were interested in APS' cost of service study ("COSS") and rate design proposals and what were some of their positions?

A. The positions of the parties on these issues are especially disparate. Except for the method of allocation of generation capacity set forth by APS, Staff supported APS' choice of allocators. Staff also provided testimony that, although cost is an important factor in spreading revenue requirement among customer classes and rates, it is not the only factor that should be considered.

RUCO's testimony indicated that APS' cost of service study overstates the cost of serving residential customers and that APS' revenue spread does not conform to good ratemaking principles.

Kroger Company presented issues related to APS' proposed voltage levels in the design of E-32 rates but did not oppose the methodology APS used in its COSS.

The Federal Executive Agencies ("FEA") recommended approval of APS' COSS methodology, but rejected APS revenue spread. FEA asked the Commission to move rates closer to cost, to reduce APS' proposed transmission voltage discount and to increase the primary voltage discount.

Q. How were these issues resolved?

A. The Settlement Agreement does not adopt a particular cost of service study methodology. The rate design section of the Settlement Agreement is comprehensive. In brief, the rates agreed upon are the result of a movement toward cost. The residential rate class, as a whole, would experience a 3.94 percent increase. Within the residential class, E-12, ET-1 and ECT-1R rates (time-of-use rates) will increase by 3.8 percent. Frozen residential rate schedules EC-1 and E-10 would receive a 4.82 percent base rate increase. Most General Service rates and contracts contained in the General Service section of the H schedules will each experience an increase of 3.5 percent.

APS would also establish a Primary Service Discount exclusively for military base customers who are served directly from APS substations. This action reflects the importance to the Arizona economy in general, and specifically to APS' system, of retaining the federal agencies locations in Arizona.

Q. What other rate design related benefits are reflected in the Settlement Agreement?

A. Among several benefits, APS has agreed to submit a study that examines ways in which APS can implement more flexibility in changing its off and on-peak periods to better reflect its peak. The results of such a study can be very important to time of use customers and could ultimately result in lowering peak demand.

Certain rate schedules were streamlined and others clarified, making them more easily understood by the customers and better enabling customers to choose the best rate for their usage patterns. Finally, the rate schedules contained in the Settlement Agreement enhance the opportunity for retail access through the unbundling of standard offer rates and the pricing of certain competitive service rate elements to reflect cost. This provides customers with the price signals they need to make informed decisions about shopping for competitive services.

Q. Are the rates that resulted from the negotiations fair?

A. Staff believes that the rates resulting from the Settlement Agreement will generate the agreed-upon revenue requirement in a fair and reasonable manner and fairly reflect the interests of the parties.

LITIGATION AND OTHER ISSUES

Q. Please describe the litigation-related issues that would be resolved by the Settlement Agreement and explain why their resolution is in the public interest?

A. APS appealed the Track A order in both Superior Court and the Court of Appeals. Affiliates of APS also initiated another lawsuit, which includes breach of contract claims allegedly related to the Track A order, in Superior Court. APS contends in these various appeals that it should be compensated for monetary damages allegedly caused by the Commission. All of these actions are inactive at the present time, and the parties await the outcome of this proceeding.

Any lawsuit creates risk, and Staff recognizes that if APS were to succeed in these claims, ratepayers and/or taxpayers may have to bear significant costs. The Settlement Agreement proposes to resolve these matters. Specifically, APS has agreed to drop its appeals of the Track A order and Decision No. 61973 and to forever forego any claim that APS, PWEC, Pinnacle West Capital Corporation or any of its affiliates were harmed by these decisions. APS has also agreed not to seek recovery of the $234 million write-off recorded at the time of the 1999 settlement agreement in any future proceeding. Thus the determination of alleged harm related to these decisions and related monetary impacts will not be raised by APS in future cases.

The withdrawal of these court cases would relieve the ratepayers of any risk related to a possible negative outcome. The issue of $234 million (and possibly more) that APS believes the ratepayers owe them would disappear with the dismissal of these cases. The resolution of these cases, along with resolution of the Preliminary Inquiry ordered in Commission Decision No. 65796, would essentially "clear the decks" of risky, protracted, complicated proceedings that if not resolved would likely continue generating high costs for all affected parties in terms of time, effort and personnel.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT
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Admitted

M E M O R A N D U M

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: September 27, 2004

RE: STAFF REPORT ON THE TREATMENT OF COMPETITIVE ISSUES AND CERTAIN PINNACLE WEST ENERGY CORPORATION'S ASSETS CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR RATE ADJUSTMENT (DOCKET NO. E-01345A-03-0437)

Attached is the Staff Report on the Treatment of Competitive Issues and Certain Pinnacle West Energy Corporation's ("PWEC") Assets Contained in the Proposed Settlement Agreement of Arizona Public Service Company's Request for Rate Adjustment. Staff recommends approval of the settlement agreement.

EGJ:MJR:rdp

Originator: Matthew Rowell

Attachment: Original and thirteen copies

Service List for: Arizona Public Service Company
Docket No. E-01345A-03-0437)

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STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

TREATMENT OF COMPETITIVE ISSUES AND CERTAIN PWEC ASSETS CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

SEPTEMBER 27, 2004

STAFF ACKNOWLEDGMENT

The Staff Report on the Treatment of Competitive Issues and Certain PWEC Assets Contained in the Proposed Settlement Agreement of Arizona Public Service Company's Request for Rate Adjustment, Docket No. E-01345A-03-0437, was the responsibility of the Staff members listed below.

Matthew Rowell
Chief Economist

MEMORANDUM

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: September 27, 2004

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STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

TREATMENT OF COMPETITIVE ISSUES AND CERTAIN PWEC ASSETS CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

SEPTEMBER 27, 2004

STAFF ACKNOWLEDGMENT

The Staff Report on the Treatment of Competitive Issues and Certain PWEC Assets Contained in the Proposed Settlement Agreement of Arizona Public Service Company's Request for Rate Adjustment, Docket No. E-01345A-03-0437, was the responsibility of the Staff members listed below.

Matthew Rowell
Chief Economist

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Introduction

On August 18, 2004, a proposed Settlement Agreement of Arizona Public Service Company's ("APS") pending rate case was docketed. That agreement contained proposed resolutions of issues regarding the treatment of Pinnacle West Energy Corporation's ("PWEC") Arizona generation assets. The agreement also contains several provisions that are pertinent to competition in the wholesale and retail electric markets in Arizona. The purpose of this Staff Report is to explain the provisions of the Settlement Agreement that deal with the PWEC assets and competitive issues.

PWEC Asset Treatment

Section II of the Settlement Agreement deals with the treatment of certain PWEC assets. The parties to the Settlement Agreement agreed that APS should be allowed to acquire and rate base the following PWEC generating units: West Phoenix CC-4, West Phoenix CC-5, Saguaro CT-3, Redhawk CC-1, and Redhawk CC-2 (collectively, the "PWEC Assets"). The capacity of each of these generating units is displayed in the following table:

Unit	Capacity in MW
West Phoenix CC-4	120
West Phoenix CC-5	500
Saguaro CT-3	100
Redhawk CC-1	530
Redhawk CC-2	530

The Track B competitive solicitation resulted in a contract between APS and PWEC for the purchase of a significant portion of this capacity during the summer months of 2003 through 2006. The rate basing of the above generating units will make this contract unnecessary. In order to recognize the ratepayer benefits associated with that contract, a portion of the value of the PWEC assets will be disallowed. Specifically, \$148 million of the PWEC Assets' value will be disallowed, which results in an original cost rate base value of \$700 million as of December 31, 2004.

APS has agreed that it will never seek recovery of "stranded costs" associated with any of the PWEC Assets.

FERC approval is necessary to transfer the PWEC Assets to APS. APS shall file a request for FERC approval within thirty days of the Commission approving the Settlement Agreement. Upon Commission approval of the Settlement Agreement, APS' rates will reflect the rate basing of the PWEC Assets. However, APS cannot actually acquire the PWEC Assets until FERC approval of the transfer is obtained. To bridge the time between the effective date of the rate increase and the actual date of the asset transfer, APS and PWEC will execute a cost-based purchased power agreement ("Bridge

PPA"). The Bridge PPA will be designed to represent the (non-fuel) costs of the PWEC Assets recovered in base rates per the Settlement Agreement. During the term of the Bridge PPA, APS will flow fuel costs (and off-system sales revenue) related to the PWEC Assets through the power supply adjustor ("PSA"). Any demand and non-fuel energy charges incurred under this Bridge PPA will be excluded from recovery under the PSA because they are already included in APS' base rates. The Bridge PPA shall remain in effect until FERC issues a final order approving the transfer of the PWEC assets to APS and the transfer is completed.

The parties believed it was appropriate to include provisions in the Agreement that deal with the possibility of FERC issuing an order that is in some way inconsistent with the Settlement Agreement. If FERC issues an order denying APS' request to transfer the PWEC Assets, the Agreement provides for the Bridge PPA to become a thirty-year PPA. Prices in this thirty-year PPA will reflect cost-of-service as if APS had acquired and rate-based the PWEC Assets at the value established in the Settlement Agreement. If FERC issues an order approving APS' request to acquire the PWEC Assets but at a value materially less than $700 million, or if FERC issues an order approving the transfer of fewer than all of the PWEC Assets, or if FERC issues an order that is materially inconsistent with the Settlement Agreement, APS shall promptly file an appropriate application with the Commission so that rates may be adjusted. In these circumstances, the Bridge PPA shall continue at least until the conclusion of this subsequent proceeding to consider any appropriate adjustment to APS' rates.

The Commission Decision in APS' last financing case (Decision No. 65796) established a basis point credit that is to be paid by PWEC to APS. That basis point credit established in Decision No. 65796 will continue as long as the associated debt between APS and PWEC is outstanding. Credit for amounts deferred after December 31, 2004 shall be reflected in APS' next general rate proceeding.

The Parties agreed that West Phoenix CC-4 and West Phoenix CC-5 are "local generation" as that term is defined in the AISA protocol or any successor FERC-approved protocol. During must-run conditions, generation from the West Phoenix facility will be available at FERC-approved cost-of-service prices to electric service providers serving direct access load in the Phoenix load pocket.

$234 Million Write-Off

Per Section VI of the Settlement Agreement, APS has agreed that it will not recover (now or in any subsequent proceeding) the $234 million write-off attributable to Decision No. 61973, the Commission order that approved the 1999 APS Settlement Agreement.

Competitive Procurement of Power

Section IX of the Settlement Agreement includes provisions intended to enhance the prospects of the wholesale market in Arizona while still protecting retail customers. APS agrees that it will not pursue any self-build option having an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. This provision does not prevent APS from purchasing a generation plant from a merchant or a utility. It also does not prevent APS from acquiring temporary generation needed for system reliability, distributed generation of less than fifty MW per location, and renewable resources. The up rating of APS generation is also allowed under this provision (not including the installation of new units.)

The Settlement Agreement does not relieve APS of its existing obligation to prudently acquire generating resources. If APS determines it is unable to fulfill that obligation without pursuing a self build option, APS will file an application with the Commission seeking authorization to self-build a generating resource(s).

Any application by APS for Commission authorization to self-build generation prior to 2015 will at a minimum address:

a. APS' specific unmet needs for additional long-term resources.
b. APS' efforts to secure adequate and reasonably priced long-term resources from the competitive wholesale market.
c. The reasons why APS believes those efforts have been unsuccessful, either in whole or in part.
d. The extent to which the self-build application is consistent with APS' resource plans and competitive resource acquisition rules or orders that may result from the Commission's resource planning workshops.
e. Life cycle costs of the self-build option compared to that of available options available from the wholesale market.

The Settlement Agreement does not preclude APS from negotiating bilateral agreements with nonaffiliated parties.

APS will issue an RFP or other competitive solicitation(s) no later than the end of 2005 seeking long-term future resources of not less than 1000 MW for 2007 and beyond.

a. "Long-term" resources means any acquisition of a generating facility or an interest in a generating facility, or any PPA having a term, including any extensions exercisable by APS on a unilateral basis, of five years or longer.
b. Neither PWEC nor any other APS affiliate will participate in the 2005 solicitation.
c. Regarding RFPs and solicitations after 2005, neither PWEC nor any other APS affiliate will participate without the appointment by the Commission or its Staff of an independent monitor.
d. APS will not be obliged to accept any specific bid or combination of bids.
e. All renewable resources, distributed generation, and DSM will be invited to

compete in the 2005 RFP or other competitive solicitation and will be evaluated in a consistent manner with all other bids, including their life-cycle costs compared to alternatives of comparable duration and quality.

The Commission Staff has agreed to schedule workshops on resource planning issues that focus on developing needed infrastructure and developing a flexible, timely, and fair competitive procurement process. These workshops will also consider whether and to what extent the competitive procurement should include an appropriate consideration of a diverse portfolio of short, medium, and long-term purchased power, utility-owned generation, renewables, DSM, and distributed generation. The workshops will be open to all stakeholders and to the public. If necessary, the workshops may be followed with a rulemaking proceeding.

The Settlement Agreement allows APS to continue to use its Secondary Procurement Protocol except as modified by the express terms of this Agreement or unless the Commission authorizes otherwise.

Regulatory Issues

Section X of the Settlement Agreement contains provisions regarding certain regulatory issues. The Parties agreed that APS has the obligation to plan for and serve all customers in its certificated service area, irrespective of size. However, APS is to recognize, in its planning, the existence of any Commission direct access program and the potential for future direct access customers. These provisions do not prevent any Party from seeking to amend APS' obligation to serve at some time in the future.

The parties agreed that any changes in retail access will be addressed through the Electric Competition Advisory Group ("ECAG") or other similar process. One particular issue that will be addressed by the ECAG (or similar proceeding) is the resale by Affected Utilities of Revenue Cycle Services ("RCSs") to Electric Service Providers ("ESPs").

The Parties agreed that APS currently has the ability to self-build or buy new generation assets for native load, subject to the conditions in Section IX and X of the Settlement Agreement.

The Parties agreed that APS should be able to join a FERC-approved Regional Transmission Organization ("RTO") or an organization(s) performing the functions of an RTO. If the Settlement Agreement is approved, APS may participate in such organizations without further order or authorization from the Commission. The Agreement does not establish the ratemaking treatment for costs related to participation in an RTO.

The Settlement Agreement does not create or confirm an exclusive right for APS to provide electric service within its certificated area, diminish any of APS' rights to serve customers within its certificated area, or prevent the Commission or any other governmental entity from amending the laws and regulations relative to public service corporations.

Staff's Position

While Staff was unpersuaded by the company's original argument for inclusion of the PWEC assets in rate base, Staff believes that the Settlement Agreement as a whole provides for a reasonable treatment of those assets. The Settlement Agreement as a whole mitigates the impact on rate payers associated with rate basing the PWEC assets and balances the potentially anti-competitive effects of rate basing with the pro-competitive provisions discussed above. The rate payer impact is mitigated because the assets are being added to the rate base at a value substantially less than their book value. Also, because the settlement provides for APS to drop its pending Track A related lawsuits against the Commission, rate payers will not face the risk of having to fund a $234 million (or more) judgment in APS' favor. The Settlement Agreement provides for substantial commitments by APS to market based approaches to filling future capacity needs. The self build moratorium and RFP commitments outlined in Section IX of the Agreement will bolster the competitive alternatives available to APS. Taken as a whole Staff believes the Settlement Agreement strikes an appropriate balance between market and non-market approaches.

M E M O R A N D U M

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: September 27, 2004

RE: STAFF REPORT ON DEMAND-SIDE MANAGEMENT, RENEWABLES, AND DISTRIBUTED GENERATION ISSUES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR RATE ADJUSTMENT (DOCKET NO. E-01345A-03-0437)

Attached is the Staff Report on Demand-side Management, Renewables, and Distributed Generation Issues contained in the proposed settlement agreement of Arizona Public Service Company's request for rate adjustment. Staff recommends approval of the settlement agreement.

EGJ:BEK:rdp

Originator: Barbara Keene

Attachment: Original and thirteen copies

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Docket No. E-01345A-03-0437)

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ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

DEMAND-SIDE MANAGEMENT, RENEWABLES, AND DISTRIBUTED GENERATION ISSUES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

SEPTEMBER 2004

STAFF ACKNOWLEDGMENT

The Staff Report on Demand-side Management, Renewables, and Distributed Generation Issues Contained in the Proposed Settlement Agreement of Arizona Public Service Company's Request for Rate Adjustment, Docket No. E-01345A-03-0437, was the responsibility of the Staff member listed below.

Barbara Keene

Barbara Keene
Public Utilities Analyst

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Introduction

The proposed settlement agreement in the Arizona Public Service ("APS") rate proceeding (Docket No. E-01345A-03-0437) contains provisions regarding demand-side management ("DSM"), renewables, and distributed generation. These provisions are the result of settlement negotiations on a wide variety of issues in this case. As part of the overall settlement agreement, these provisions are in the public interest.

The settlement agreement is in the public interest because of the following:

- The agreement provides for APS to implement considerably more DSM than is being done today, resulting in customer savings, utility cost reductions, and reduced impact on the environment.

- The agreement provides safeguards to ensure that the level of DSM expenditures will be reasonable, including Commission approval of programs, unspent amounts in base rates being returned to customers, and APS filing semi-annual reports on its DSM programs.

- The agreement provides for expenditures for low income weatherization and bill assistance to more than double over test-year expenditures.

- The agreement places a high priority on energy-efficiency programs for schools, ultimately leading to savings for taxpayers.

- The agreement provides for the establishment of a collaborative DSM working group to provide APS with input on program development, implementation, and performance.

- The agreement changes the Environmental Portfolio Standard ("EPS") surcharge into an adjustment mechanism to allow for flexibility in funding the EPS if the Commission were to approve a funding change.

- The agreement provides for APS to issue a Request for Proposal in 2005 seeking renewable resources that should help provide further diversity to APS' generation portfolio.

Demand-side Management

Cost-effective DSM can meet the demand for electric energy services at a lower cost than purchasing or generating power. Reduced peak demand can delay the need for construction of new generation and transmission facilities. Reduced energy production may also lead to reduced air emissions from power plants and reduced consumption of water by generating unit cooling towers.

The settlement agreement provides for APS to spend $10 million each year through base rates for DSM, plus another $6 million per year through an adjustment mechanism. Although DSM spending could be phased in, APS would be obligated to spend at least $48 million on DSM during calendar years 2005 - 2007. Of that amount, at least $13 million would be spent during 2005, pending approval of the Final Plan discussed below. If APS does not spend the total $30 million in base rate allowance during 2005 - 2007, the unspent amount would be credited to the account balance for the DSM adjustor (described below) in 2008. Eligible DSM expenditures would be energy-efficiency programs, a performance incentive for APS, and low income bill assistance. DSM spending over $16 million per year could include demand response and additional energy efficiency programs.

Attached to the settlement agreement is a Preliminary Plan for eligible DSM-related items for calendar year 2005. The Preliminary Plan includes a listing and brief description of programs, program concepts, and program strategies and tactics. Within 120 days of Commission approval of the settlement agreement, APS would file a Final Plan for Commission approval. The Final Plan would include, at a minimum, program budgets and estimates of energy savings and load reductions.

The Preliminary Plan includes DSM programs for both residential and non-residential customers. At the top of the list is energy-efficient schools, under both new construction and retrofit of existing facilities.

APS would be allowed to recover a performance incentive based on a share of the net economic benefits resulting from energy-efficiency programs. The incentive would be capped at 10 percent of total DSM spending. The specific performance incentive would be included in the Final Plan.

Included in the $10 million annual base rate allowance would be at least $1 million for low income weatherization. Up to $250,000 of the $1 million could be used for bill assistance. The low income weatherization program helps low-income customers to have more energy-efficient homes by installing weather stripping and insulation; repairing ductwork; repairing roofs, windows, doors, ceilings, and floors; and adjusting, repairing, or replacing HVAC (heating, ventilation, and air conditioning) systems, evaporative coolers, and electric water heaters. The bill assistance portion of the program helps customers pay their electric bills. APS would file for Commission approval of the low income weatherization program within 60 days of the Commission's approval of the settlement agreement.

A DSM adjustment mechanism would be established for DSM expenditures above the $10 million in base rates. The adjustor rate, initially set at zero, would be reset each March 1, beginning with March 1, 2006. A per-kWh charge for the year would be calculated by dividing the account balance by the number of kWh used by customers in the previous calendar year. General Service customers that are demand billed would pay a per kW charge instead of a per kWh charge. The DSM adjustor would be applied to both standard offer and direct access customers. APS would combine the DSM adjustor and the EPS adjustor (to be discussed later in this report) as an "Environmental Benefits Surcharge" when billing residential customers. APS could combine the two adjustors when billing other customers.

Large customers whose single site usage is at least 20 MW and can demonstrate that their own DSM program is effective could file for Commission approval of an exemption from the DSM adjustor.

APS would file a plan of administration that describes how the DSM adjustor would operate.

Except for DSM programs that have already been approved, all DSM programs would be pre-approved by the Commission before APS could include their costs in any determination of total DSM costs incurred.

APS would file mid-year and end-year reports on its DSM programs.

APS would establish and maintain a collaborative DSM working group to provide APS with input on program development, implementation, and performance. At a minimum, Staff, the Residential Utility Consumer Office, Arizonans for Electric Choice and Competition, the Arizona State Energy Office, Western Resource Advocates, and Southwest Energy Efficiency Project would be invited to participate in the collaborate DSM working group.

APS would conduct a study to evaluate the merits of allowing large customers to self-direct DSM investments. The study would be filed within one year of Commission approval of the settlement agreement.

APS would conduct a study analyzing rate design modifications that could include, among others, mandatory time-of-use rates and expanded use of inclining block rates. A plan for the study would be presented to the collaborative DSM working group within 90 days of Commission approval of the settlement agreement. APS would submit the final results of the study to the Commission as part of its next general rate case application or within 15 months of Commission approval of the settlement agreement, whichever occurs first. APS would develop and propose to the Commission any appropriate rate design modifications that the study indicates would be reasonable, cost-effective, and practical.

Renewables

Increasing renewable energy could help to reduce reliance on conventional fuel sources such as natural gas. The settlement agreement addresses renewables issues in two ways: by addressing funding of the EPS and by establishing a special RFP.

Environmental Portfolio Standard

In regard to the EPS, APS would continue to recover $6 million annually in base rates. The existing EPS surcharge, which provided $6.5 million during the test year, would be converted into an adjustment mechanism to allow for Commission-approved changes to APS' EPS funding. Changes in funding could occur as a result of amendments to Rule 1618, or APS could apply to the Commission to increase EPS funding beyond that provided in base rates and the EPS surcharge. APS could not file such an application until one year after the termination of the EPS rulemaking docket. Staff would initiate a rulemaking proceeding to modify Rule 1618 within 120 days of Commission approval of the settlement agreement.

The initial charge of the EPS adjustor would be the same as contained in the current EPS surcharge tariff, including caps. Any change in EPS funding requirements would be collected from APS customers in a manner that maintains the proportions between customer categories in the current EPS surcharge. The EPS adjustor would apply to both standard offer and direct access customers. The revenue collected from direct access customers would be made available to electric service providers. For billing purposes, the EPS adjustor could be combined with the DSM adjustor as discussed in the DSM section of this report.

Renewables programs directly involving APS' retail customers would be submitted to the Commission for approval. These programs would include those in which a rebate is given to retail customers.

Special RFP

APS would issue a special RFP in 2005 for at least 100 MW and 250,000 MWh per year of renewable energy resources for delivery beginning in 2006. Either in this solicitation or in subsequent procurements, APS would seek to acquire at least 10 percent of its annual incremental peak capacity needs from renewable resources.

Eligible resources would be solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas), and geothermal. These resources may be, but do not have to be, EPS-eligible. Resources need not provide firm capacity but must be deliverable to the APS system. The resources must be capable of providing at least 20,000 MWh of renewable energy annually, with a minimum of five years. Prices must be fixed or relatively stable and do not vary with either the price of natural gas or of electricity. Renewable resources must be no more costly than 125 percent of the market price of conventional resource alternatives. If APS does not receive sufficient in-state qualified bids, APS could acquire out-of-state resources to meet its 100 MW or 10 percent goals.

APS would circulate a draft of the RFP to potentially interested parties at least 30 days before issuing the RFP and conduct a meeting with potential bidders and interested parties at least 10 days before issuing the RFP.

If APS fails to acquire at least 100 MW of renewable resources pursuant to the RFP by December 31, 2006, APS would file a notice with the Commission by January 31, 2007, that describes the shortfall, explains the circumstances, and recommends actions.

Distributed Generation

In general terms, distributed generation (DG) is small-scale power generation units strategically located near consumers and load centers. DG has the potential to provide benefits to customers and support the economic operation of the power distribution grid.

In 1999, Staff formed a working group to investigate issues related to DG. The final report recommended that further workshops be held to acquire additional information for several issues. The settlement agreement provides for Staff to schedule workshops to consider outstanding issues concerning DG. The workshops may be followed by rulemaking.

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MEMORANDUM

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AZ CORP COMMISSION
DOCUMENT CONTROL

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: October 25, 2004

RE: RESPONSIVE STAFF REPORT ON DISTRIBUTED GENERATION ISSUES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR RATE ADJUSTMENT (DOCKET NO. E-01345A-03-0437)

Attached is the Responsive Staff Report on Distributed Generation Issues contained in the proposed settlement agreement of Arizona Public Service Company's request for rate adjustment.

EGJ:BEK:rdp

Originator: Barbara Keene

Attachment: Original and thirteen copies

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UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

RESPONSIVE STAFF REPORT ON DISTRIBUTED GENERATION ISSUES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

OCTOBER 2004

STAFF ACKNOWLEDGMENT

The Responsive Staff Report on Distributed Generation Issues Contained in the Proposed Settlement Agreement of Arizona Public Service Company's Request for Rate Adjustment, Docket No. E-01345A-03-0437, was the responsibility of the Staff member listed below.

Barbara Keene

Barbara Keene
Public Utilities Analyst

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Introduction

The proposed settlement agreement in the Arizona Public Service ("APS") rate proceeding (Docket No. E-01345A-03-0437) contains provisions regarding distributed generation. On September 27, 2004, Staff filed a Staff Report on Demand-side Management, Renewables, and Distributed Generation Issues. On September 27, 2004, the Arizona Cogeneration Association filed direct testimony from three witnesses: Robert T. Baltes, William J. Murphy, and Peter F. Chamberlain. This Staff Report is a response to their testimony regarding distributed generation.

Response to the Arizona Cogeneration Association

In general terms, distributed generation ("DG") is small-scale power generation units strategically located near consumers and load centers. DG has the potential to provide benefits to customers and support the economic operation of the power distribution grid.

In 1999, Staff formed a working group to investigate issues related to DG. The final report recommended that further workshops be held to acquire additional information for several issues. The proposed settlement agreement provides for Staff to schedule workshops to consider outstanding issues concerning DG. The workshops may be followed by rulemaking.

The Arizona Cogeneration Association ("AzCA"), in its testimony, advocates for a standardized process for DG to interconnect with utility systems. Staff proposes to investigate this issue in the workshops to be held on DG that are mentioned in the proposed settlement agreement. Because developing interconnection standards would involve all electric utilities, this issue would best be addressed in a generic proceeding including all interested parties instead of a rate case proceeding for one utility.

The AzCA also wants pricing signals that encourage DG. Staff proposes to explore the issue of pricing for DG in the upcoming workshops. The Commission could adopt a policy or rules to encourage or require utilities to have specific types of tariffs that would encourage DG. This issue is best addressed in a generic proceeding.

EXHIBIT
ALL-STATE LEGAL®
S-19
Admitted

M E M O R A N D U M

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: September 27, 2004

RE: STAFF REPORT ON RATE DESIGN, LOW INCOME PROGRAMS, AND SERVICE SCHEDULES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR RATE ADJUSTMENT (DOCKET NO. E-01345A-03-0437)

Attached is the Staff Report on Rate Design, Low Income Programs, and Service Schedules contained in the proposed settlement agreement of Arizona Public Service Company's request for rate adjustment. Staff recommends approval of the settlement agreement.

EGJ:EAA:BEK:rdp

Originator: Erinn Andreasen and Barbara Keene

Attachment: Original and thirteen copies

Service List for: Arizona Public Service Company
Docket No. E-01345A-03-0437)

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STAFF REPORT
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ARIZONA CORPORATION COMMISSION

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

RATE DESIGN, LOW INCOME PROGRAMS AND, SERVICE SCHEDULES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

SEPTEMBER 27, 2004

STAFF ACKNOWLEDGMENT

The Staff Report on Rate Design, Low Income Programs, and Service Schedules Contained in the Proposed Settlement Agreement of Arizona Public Service Company's Request for Rate Adjustment, Docket No. E-01345A-03-0437, was the responsibility of the Staff members listed below.

Erinn Andreasen
Public Utilities Analyst
Rate Design

Barbara Keene
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Low Income Programs and Service Schedules

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Introduction

On August 18, 2004, a proposed settlement agreement of Arizona Public Service Company's ("APS") pending rate case was docketed. The proposed agreement addresses certain rate design, service schedule, and low income provisions. These provisions are the result of settlement negotiations on a wide variety of issues in this case. As part of the overall settlement agreement, these provisions are in the public interest.

Overall Increase

The proposed settlement agreement would allow APS to recover an additional $67.5 million in base revenues. The base revenue increase reflects a system average increase of 3.77 percent.

Principles that Influenced Rate Design

One of the principles considered in the settlement process is to adopt rates that reflect cost or movement toward cost. Moving toward cost promotes efficient cost recovery and customer equity by reducing subsidizations among customer classes. With that goal in mind, the rates and provisions adopted by the settlement generally reflect certain cost of service considerations.

While cost of service was an important factor in setting rates, other factors were also considered in the process. These factors include; rate continuity for the customer, adopting rate structures that promote conservation, designing rates that are transparent in nature to promote customer understandability, and the reduction of duplicative and underperforming rate structures.

Rate Unbundling

Under the provisions adopted in the settlement agreement, unbundled rates would be adopted for most rate schedules and cost-based unbundling would be permitted. Unbundling standard offer rates and pricing certain competitive service rate elements to reflect cost enhance the opportunity for retail access in APS' service territory by providing ratepayers with the price signals they need to make informed decisions about shopping for competitive services.

The residential rate design reflects cost-based unbundling of distribution and revenue cycle services. The general service rate design reflects cost-based unbundling of generation and revenue cycle services. With regard to E-32, E-34, and E-35, the revenue requirement was allocated to establish first the unbundled component of generation at cost and then the unbundled component of revenue cycle services.

Residential Rates

Under the proposed settlement agreement, the residential rate class would generate an additional 3.94 percent in revenues from base rates. The residential class as a whole would receive an increase that is only slightly more than the system average increase. The following table summarizes the residential revenue increases by rate schedule as proposed by the settlement agreement.

Residential Rate Schedules		
Rate Designation	Description	Proposed Revenue Increase
E-10	Classic Rate	4.82%
E-12	Standard Rate	3.80%
ET-1	Time-of-Use	3.80%
EC-1	Service with Demand Charge	4.82%
ECT-1R	Time-of-Use with Demand Charge	3.80%

In order to avoid the potential for disproportionate rate impacts to customers, the current residential rate structures, such as the number and size of rate blocks and the time-of-use periods, would be retained.

In order to mitigate the rate impacts of eliminating schedules at the time of the next rate case, rates E-10 and EC-1 would receive a slightly higher increase than the other residential rate schedules. To provide a period for phase out, Schedule E-10 and EC-1 would remain frozen and not be eliminated in this proceeding. However, these rate schedules would be eliminated in APS' next rate proceeding. In order to provide customers with notice of intent to cancel these rate schedules, APS would provide a Staff-approved notice to customers on E-10 and EC-1 at the conclusion of this proceeding and at the time APS files its next rate case.

Residential Time-of-Use

APS would maintain its current on-and-off peak rates for the winter billing period. In response to the concern for flexibility in implementing changes to certain time-of-use provisions, within 180 days of a decision in this matter, APS would submit a study to Staff that would examine the ways in which APS can implement flexibility in changing on- and off-peak time periods and other time-of-use characteristics. APS would also consult with Staff prior to designing its study to ensure that the study addresses all relevant issues. Time-of-use issues would specifically be addressed in APS' next rate case.

In order to enhance time-of-use options for residential customers, experimental time-of-use periods for ET-1 and ECT-1R would be adopted. The experimental periods would provide a limited number of customers with the option of selecting alternative on-peak time periods of 7:00 a.m. to 7:00 p.m. or 8:00 a.m. to 8:00 p.m. The experimental program would be limited to a maximum of 10,000 customers due to the costs associated with the implementation of the program. APS would be required to submit annual reports to Staff evaluating the outcomes of the program and making a recommendation regarding the continuation of the program.

General Service and Classified Rates

Under the proposed settlement agreement, revenues from E-32, E-32R, E-34, E-35, E-53, E-54, and general service contracts would generate an additional 3.5 percent in revenues from base rates. The following table summarizes the revenue increase to general service and classified rate schedules proposed by the settlement agreement.

General Service Rate Schedules		
Rate Designation	**Description**	**Proposed Revenue Increase**
E-21	Frozen Time-of-Use, Small less than 100 kW	5%
E-22, E-23, E-24	Time-of-Use, Small, Medium, and Large	5%
E-30	Extra Small Unmetered	5%
E-32, E-32R	General Service and Partial Requirements Rider	3.5%
E-34, E-35	Extra Large and Extra Large Time-of-Use	3.5%
E-53	Athletic Stadiums and Sports Fields	3.5%
E-54	Seasonal Service	3.5%
	Special Contracts	3.5%

Classified Rate Schedules		
Rate Designation	**Description**	**Proposed Revenue Increase**
E-20	Time-of-Use Religious Houses of Worship	5%
E-38, E-38T	Frozen Agricultural Irrigation Service and Time-of-Use option	5%
E-40	Agricultural Wind Machine Service	5%
E-47	Dusk to Dawn Lighting Service	5%
E-51	Frozen Cogeneration and Small Power Production Under 100 kW	5%
E-58	Street Lighting Service	5%
E-59	Government Owned Street Lighting Systems	5%
E-67	Municipal Lighting Service, City of Phoenix	5%
E-221, E-221-8T	Water Pumping Service and Time-of-Use Option	5%

The majority of APS' general service customers are served on rate schedule E-32, and customers on this rate have diverse usage characteristics. Due to the complexity of the current rate, schedule E-32 would be modified in an effort to simplify its design and improve customer understandability. When designing the rate, consideration was given to smoothing out the rate impacts across customers of varying sizes. Changes include the addition of an energy block for customers with loads under 20 kW and the addition of a demand billing block for customers with loads greater than 100 kW.

To provide a period for phase out, frozen rates E-38 and E-38T would not be eliminated in this proceeding. However, these rate schedules would be eliminated in APS' next rate proceeding. In order to provide customers with notice of intent to cancel these rate schedules, APS would provide a Staff-approved notice to customers on these schedules at the conclusion of this proceeding and at the time APS files its next rate case.

Under the proposed settlement agreement, the changes to the rate structure for lighting tariffs E-47 and E-58 proposed in APS' application would be adopted. These changes allow for a greater menu of options available to lighting customers.

General Service Time-of-Use

The existing 11:00 a.m. to 9:00 p.m. on-peak time periods would remain in effect for general service time-of-use customers, and the summer rate period would begin in May and conclude in October.

APS' current time-of-use rate schedule, E-20, would be frozen. To provide a period for phase out, experimental time-of-use schedules E-22, E-23, and E-24, which are all limited by caps on customer participation, would be frozen. Experimental time-of-use schedule E-21, which had previously been frozen, and E-22, E-23, and E-24 would be eliminated in APS' next rate proceeding. In order to provide customers with notice of intent to cancel E-21, E-22, E-23, and E-24, APS would provide a Staff-approved notice to customers on these schedules at the conclusion of this proceeding and at the time APS files its next rate case.

Under the proposed settlement agreement, a new rate schedule, E-32 TOU, would be adopted to provide general service customers with an additional time-of-use rate.

Voltage Discounts

The settlement adopts transmission and primary voltage discounts for certain general service rates. Customers that take service at transmission and primary voltage levels require less utility funded facilities and equipment. Under the proposed settlement, military base customers that are served directly from APS substations would receive an additional primary service discount of $2.74 per kW due to certain cost of service considerations.

Compliance

As part of APS' compliance filing in this matter, APS would be required to meet and confer with Commission Staff to review APS' rate schedules for consistency with the provisions adopted by the proposed settlement agreement.

Low Income Programs

The settlement agreement provides for expansion of the low income weatherization program, including bill assistance, as discussed in the Staff Report on Demand-side Management, Renewables, and Distributed Generation issues.

It was the intention of the parties to this case that low income customers be insulated from the rate increase proposed in the settlement agreement. Therefore, the discount levels were increased for both the E-3 and E-4 tariffs. In addition, APS would increase its annual funding for marketing its E-3 and E-4 tariffs to $150,000.

Service Schedules

Attached to the settlement agreement are revised versions of Schedules 1, 3, 4, 7, 10, and 15. The proposed changes to each schedule are described below.

Schedule 1 - Terms and Conditions for Standard Offer and Direct Access Services

Schedule 1, contains charges for various services. The settlement agreement proposes to change these charges to be primarily cost-based. The revised charges are summarized in the following table:

Description (Schedule 1 Section)	Current Charge	Proposed Charge
trip charge (2.2.1)	none	$16.00
after-hour service establishment (2.2.2)	$50	$75.00
after-hour other services (2.2.3)	none	$75.00
overhead reconnection (4.5.1)	$87.50	$96.50
underground reconnection (4.5.1)	$125.00	$115.00
on-site energy evaluation (4.6)	$50.00	$82.00
joint site meeting (6.2.3)	$30.00 metro area $75.00 outside metro $30/hr after 30 minutes	$62.00 all areas $53/hr after 30 minutes
reread charge (6.4.4 and 6.4.5)	$10.00	$16.50
meter test (6.5)	$25.00	$30.00 meter shop $50.00 field

Other changes to Schedule 1 include adding a provision for electronic bills, adding provisions regarding enforcement of meter access requirements, clarifying language regarding power factor requirements, and making editorial changes.

Schedule 3 - Conditions Governing Extensions of Electric Distribution Lines and Services

The settlement agreement proposes modifications to Schedule 3 that include the following:

1. For extensions with construction costs not exceeding $25,000, the extension is provided for free if "two times the customer's expected annual revenue" is more than the cost of the extension. To make no distinction between Standard Offer and Direct Access customers, the calculation would be changed to use "six times the customer's expected annual distribution revenue."

2. The economic feasibility analysis for extensions with construction costs exceeding $25,000 examines the return on investment for a particular extension. The extension is free if the extension is determined to be economically feasible. The calculation would be changed to use only distribution revenue.

3. In calculating the economic feasibility of real estate developments, the methodology would be changed to use only distribution revenue and to estimate sales volume by not assuming that all residential customers in a development are all-electric.

4. Currently, irrigation pumping customers advance the total construction cost of extensions. This provision would be changed so that non-agricultural irrigation pumping extensions would be handled in the same manner as other non-residential customers.

5. Language specific to customers served on network distribution systems would be deleted.

6. Language would be added to provide for a customer contribution when the customer requests an additional primary feeder.

7. Language would be added to allow customers to design and construct facilities.

Schedule 4 - Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service

The settlement agreement proposes to change Schedule 4 to make totalizing of meter readings available to residential customers and single-phase commercial customers, to allow customers to request that meters no longer be totalized, and to make editorial changes.

Schedule 7 - Electric Meter Testing and Maintenance Plan

The settlement agreement proposes to change Schedule 7 by adding language for performance monitoring of solid-state meters and by making editorial changes.

Schedule 10 - Terms and Conditions for Direct Access

The settlement agreement proposes to make editorial changes to Schedule 10.

Schedule 15 - Conditions Governing the Provision of Specialized Metering

The settlement agreement proposes to change Schedule 15 by modifying the schedule title to be applicable to additional technology, by better defining cost responsibility, by addressing technical aspects of meter installations, and by making editorial changes.

Public Interest

Staff believes that the provisions regarding rate design and service charges are in the public interest for the following reasons.

- The provisions in the settlement adopt rates and charges that generally move toward cost while minimizing the potential for adverse rate impacts. Moving toward cost for promotes efficient cost recovery and customer equity by reducing subsidizations among customer classes.

- Under the settlement, the opportunity for retail access in APS' service territory is enhanced through the unbundling of standard offer rates and the pricing of certain competitive service rate elements to reflect cost. Such cost based competitive service rate elements will provide ratepayers with the price signals they need to make informed decisions about shopping for competitive services.

- In order to mitigate the potential for disproportionate impacts to customer bills, the current residential rate structures including rate blocks and time-of-use provisions are maintained.

- The settlement promotes efficiency through the phasing out of duplicative and underperforming rate structures.

- In order to address concerns regarding APS' ability to change its on- and off-peak time periods to be more reflective of times of actual system peak, APS would conduct a study to evaluate ways in which it can implement more flexibility. In order for a thorough examination, time-of-use issues would be reexamined in APS' next rate case.

- The settlement enhances time-of-use options through the adoption of experimental on-peak periods for residential time-of-use customers and the adoption of a new general service time-of-use rate, E-32 TOU.

- General service rate schedule E-32 has been redesigned in an effort to simplify the current rate and improve customer understandability. In designing the rate, consideration was given not only to cost, but also to smoothing out the rate impact to customers of varying sizes.

- Qualifying low income customers will benefit from an increase in the available low-income discount.

ALL-STATE LEGAL® EXHIBIT S-20 Admitted

M E M O R A N D U M

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: September 27, 2004

RE: STAFF REPORT ON ADJUSTMENT MECHANISMS CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT OF ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR RATE ADJUSTMENT (DOCKET NO. E-01345A-03-0437)

Attached is the Staff Report on Adjustment Mechanisms contained in the proposed settlement agreement of Arizona Public Service Company's request for rate adjustment. Staff recommends approval of the settlement agreement.

EGJ:RGG/BEK:rdp

Originator: Robert Gray and Barbara Keene

Attachment: Original and thirteen copies

Service List for: Arizona Public Service Company
Docket No. E-01345A-03-0437)

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STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

ADJUSTMENT MECHANISMS
CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

SEPTEMBER 2004

STAFF ACKNOWLEDGMENT

The Staff Report on Adjustment Mechanisms Contained in the Proposed Settlement Agreement of Arizona Public Service Company's Request for Rate Adjustment, Docket No. E-01345A-03-0437, was the responsibility of the Staff members listed below.

Robert Gray
Robert Gray
Public Utilities Analyst

Barbara Keene
Barbara Keene
Public Utilities Analyst

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Introduction

The proposed settlement agreement in the Arizona Public Service ("APS") rate proceeding (Docket No. E-01345A-03-0437) contains provisions for implementing various adjustment mechanisms. These include the Power Supply Adjustor ("PSA"), the Demand Side Management ("DSM") Adjustor, the Environmental Portfolio Standard ("EPS") Adjustor, the Competitive Rules Compliance Charge ("CRCC"), the Returning Customer Direct Access Charge ("RCDAC"), and the Transmission Cost Adjustor ("TCA"). The DSM Adjustor and EPS Adjustor are discussed in the Staff Report on Demand-side Management, Renewables, and Distributed Generation.

The structure and features of the adjustors discussed in this report are the result of settlement negotiations on a wide variety of issues in this case. Staff believes that the PSA, through a variety of provisions, reasonably balances the interests of ratepayers and APS while providing a measure of both certainty and flexibility in the future treatment of the PSA. As part of the overall settlement agreement, the adjustor mechanisms are in the public interest.

Power Supply Adjustor

APS does not currently have a PSA, so there is no provision for variation in fuel and purchased power costs between rate cases. The proposed PSA provides for the tracking of changes in purchased power and fuel costs. Initially, the adjustor rate would be set at zero. The adjustor rate would be reset annually beginning with the first April billing cycle each year, starting in 2006. Each year, APS would file a publicly available report by March 1st, documenting how the new adjustor rate was calculated. The Commission and other interested parties would have the opportunity to review the calculation of the new adjustor rate before it is applied to customer bills. The base cost of fuel and purchased power would be set at $0.020743 per kWh, to be included in APS' base rates.

The entirety of each year's over or under collection would be subject to a sharing mechanism where APS receives a 10 percent share and ratepayers receive a 90 percent share, the net effect of which is that APS would be at risk for 10 percent of each year's under recovery and would receive the benefit of 10 percent of each year's over recovery. This sharing mechanism provides APS with an incentive to reduce the cost of its purchased power and fuel at all times and allows ratepayers to share in those savings.

A bandwidth of $0.004 per kWh would limit the amount the adjustor rate could change from one year to the next. This bandwidth would limit the amount of annual rate change APS customers would see from fuel and purchased power costs, absent specific Commission action. Any remaining over or under collection would be carried over in a balancing account, the contents of which would not be subject to the 90/10 sharing provision in future years. The balancing account would accrue interest based on the one-year nominal Treasury constant maturities rate. Accrual of interest could benefit APS or APS ratepayers, depending on whether the balancing account is over or under-collected.

When the balancing account reaches either a positive or negative $50 million level, APS would have 45 days to file for Commission approval of a surcharge/credit to address the under/over recovery. If APS does not wish to address this balance, it must file a report explaining why action is not necessary. Commission action would be required to establish or change a surcharge created pursuant to this provision. The Commission and its Staff may review the prudence of fuel and purchased power costs and the adjustor calculations at any time. Any costs flowed through the adjustor are subject to refund if they are later found by the Commission to be imprudent.

The life of the PSA would be at least five years from the date the rates resulting from this proceeding go into effect. Within four years of the date the PSA is implemented, APS would file a report, with supporting testimony, regarding its experience with the PSA and recommending whether the PSA should remain in effect. The Commission would consider continuation of the PSA after APS has filed this report, or during its next rate case, whichever comes first. Whether in a future APS rate case or in a review of APS' PSA report, any action to abolish the PSA would not take effect until the five-year period had expired. If the Commission decides to retain the PSA such that it extends beyond the initial five-year period, the Commission may later abolish the PSA at any time, including outside a rate proceeding, subject to the applicable procedural requirements. If the Commission abolishes the PSA, the Commission would address any existing under/over recovery existing at the time of termination. The Commission may also adjust APS' base rates to reflect the costs of fuel and purchased power. These provisions provide the Commission with flexibility in considering whether the PSA should be continued in the future and, if so, in what form.

The settlement agreement requires APS to file on-going monthly reports of PSA-related activity. One report, publicly available, would be provided to Staff and the Residential Utility Consumer Office and would include bank balance calculations, power and fuel costs, customer sales, customer numbers, items excluded from the PSA calculations, adjustments to the PSA calculations, off-system sales margins, system losses, monthly maximum retail demand, and a contact person. A second, confidential, report would be provided to Staff, with detailed information on generating units, power purchases, and fuel purchases. Both reports would be due on the first day of the third month after the end of the month which the report covers. An APS officer would certify under oath that the information contained in the public and confidential reports is true and accurate to the best of her or his information and belief. Additionally, APS would provide the information to be contained in these reports for the base cost of fuel and purchased power costs during the test year, as included in the settlement. These reporting requirements will provide the Commission with a variety of on-going information for use in monitoring APS' purchased power and fuel procurement activities and other matters.

Other provisions of the PSA include ratepayers retaining the benefits of all APS off-system sales, subject to the 90/10 sharing provision and the $0.004 bandwidth provision. Such off-system sales benefits will reduce the overall cost of fuel and purchased power for ratepayers. The PSA would also allow for recovery of the prudent direct costs of hedging contracts for fuel and purchased power, providing APS with flexibility in hedging its fuel and purchased power costs. The PSA would not apply to direct access customers or customers served under Rates E-36, SP-1, Solar-1, and Solar-2. As part of APS' tariff compliance filing, the Company would file a plan of administration, detailing how the PSA would operate.

Competitive Rules Compliance Charge

The CRCC is a charge which would enable APS to recover costs related to the transition to retail competition. The settlement agreement includes approximately $8 million in the test year for this charge, and APS may recover a maximum of $47.7 million plus interest through a charge of $0.000338 per kWh over a five-year collection period. The CRCC would terminate immediately once this amount is recovered. If a balance remains at the end of the five-year period, APS would file an application with the Commission to adjust the CRCC to recover the remaining balance.

The CRCC would be a separate surcharge, i.e., it would not be included in base rates. All customers would pay the CRCC, except for those served on rate schedules Solar-1 or Solar-2. As part of APS' tariff compliance filing, the Company would file a plan of administration, detailing how the CRCC would operate.

Returning Customer Direct Access Charge

The RCDAC would apply to customers who return to standard offer service from direct access service and would be calculated separately for each customer. The RCDAC would address the additional one-time and recurring costs incurred by APS to provide standard offer service to returning customers, which otherwise would be imposed on other standard offer customers. The RCDAC would apply only to customers or aggregated groups with a load of 3 MW or greater and only if the customer or group does not provide APS with a one-year notice of intent to take standard offer service. The RCDAC rate schedule would identify and define the components of the charge as well as a general framework of how the charge would be calculated. The RCDAC would not last longer than 12 months for any individual customer. As part of APS' tariff compliance filing, the Company would file a plan of administration, detailing how the RCDAC would operate.

Transmission Cost Adjustor

The TCA is an adjustor which would be established to ensure that standard offer customers and direct access customers pay the same transmission costs. The TCA would apply only to costs related to changes in APS' open access transmission tariff ("OATT") or the tariff of a regional transmission organization ("RTO") or similar organization. The TCA would not go into effect until APS' transmission component of retail rates exceeds the test year base of $0.000476 per kWh by five percent. APS may then file with the Commission for approval of a TCA rate. When APS files with FERC to change its transmission rates, it would file a notice of such application with the Commission and provide a copy of the application to the Director of the Utilities Division. As part of APS' tariff compliance filing, the Company would file a plan of administration, detailing how the TCA would operate.

Staff Position

The implementation of an adjustor mechanism such as the PSA entails a wide range of considerations which must be weighed carefully to ensure that such a mechanism is in the public interest. Adjustor mechanisms by their nature attempt to balance a variety of possible goals, such as certainty, flexibility, price stability, sending a price signal as prices change, and providing a reasonable opportunity to recover prudently incurred costs. The PSA contained in the proposed settlement agreement contains a variety of provisions which addresses both the interests of ratepayers and APS in a reasonable fashion. While no adjustor mechanism can fully protect ratepayers from the underlying volatility of energy markets, the proposed PSA helps shield ratepayers from price volatility through the provision of regular adjustments of the adjustor rate, the inclusion of a bandwidth limiting the amount of automatic adjustment in the adjustor rate, and the provision of the opportunity for cost recovery of the costs of hedging fuel and purchased power costs. Further, APS is motivated to minimize the cost of fuel and purchased power through the 90/10 sharing mechanism.

The five year life of the PSA and related provisions protect the public interest by providing the opportunity to review the PSA mechanism in the future for possible modification or termination while also providing APS with a level of certainty regarding the method of cost recovery for its substantial fuel and purchased power costs. Such flexibility is important given the new nature of the proposed PSA and the uncertainty regarding what future conditions will be in the electricity industry.

The settlement contains strong safeguards which enable the Commission to review costs which APS would be passing through to its customers via the PSA. The settlement provides a commitment by APS to provide a wide variety of information related to the operation of the PSA on a monthly basis, which will assist the Commission and other interested parties in monitoring and assessing the operation of the PSA. Additionally, the settlement agreement specifically recognizes that the Commission can review the prudence of fuel and purchased power costs at any time. In summary, Staff believes the adjustor provisions contained in the proposed settlement agreement are in the public interest, as they reasonably balance the interests of ratepayers and APS and provide a variety of incentives to the Company to manage the PSA in a manner which is beneficial to its ratepayers while also providing the opportunity to address any problems which may arise in the future operations of the PSA.

EXHIBIT S-21 Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN TEHREON, TO APROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

Docket No. E-01345A-03-0437

NOTICE OF FILING STAFF RESPONSE TO REQUEST FOR ANALYSIS OF HOW THE VARIOUS PROPOSALS FOR APS RATES WILL IMPACT AN AVERAGE CUSTOMER BILL

Commission Staff hereby gives Notice of Filing Staff Response to Request for Analysis of How the Various Proposals for APS Rates Will Impact an Average Customer Bill.

RESPECTFULLY SUBMITTED this 26th day of November, 2004.

Christopher C. Kempley

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Staff Response to Request for Analysis of How the Various Proposals for APS Rates Will Impact an Average Customer Bill

Docket No. E-01345A-03-0437
November 26, 2004

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Summary

As requested by Commissioner Mayes, Staff has projected an average and median customer bill for an APS residential customer served on Schedule E-12, based on actual usage levels for June 2004. Staff also created variations and considered factors as requested by Commissioners Mundell and Gleason. In response to Commissioner Mayes request, Staff varied the volume and price of natural gas consumed by APS to investigate the impact of natural gas prices on APS' proposed Power Supply Adjustor (PSA) and customer bills. Application of the $8.22 per MMBtu NYMEX February 2005 price to the APS Base Case natural gas volumes would result in a PSA rate of $0.00381 per kWh, and a PSA rate impact of $2.81 to an E-12 bill using 738 kWh. In this case the PSA rate approaches, but does not reach the $0.004 per kWh band proposed for the PSA, so therefore, no PSA bank balance would accumulate. Application of the $8.22 per MMBtu price to the 3 percent load growth scenario, with all growth being met through additional natural gas generation, results in the $0.004 per kWh band being reached, so the PSA rate impact is $2.95 on the customer bill, and a PSA bank balance of approximately $67 million would be accumulated. For a number of reasons, including APS' substantial hedging of its 2005 natural gas supplies, **Staff believes that a more likely price scenario is the $5.78 per MMBtu APS Base Case cost of natural gas. At this price and using the APS Base Case volumes, the resulting PSA rate would be $0.00006 per kWh, resulting in a rate impact or $0.04 on an E-12 residential customer using 738 kWh.** When the 3 percent load growth scenario volume is applied to the $5.78 per MMBtu price, it results in a PSA Rate of $0.00182 per kWh and a rate impact of $1.34 on an average E-12 residential customer bill. Scenarios using the $4.00 per MMBtu gas price show sizable E-12 customer bill decreases under both the APS Base Case volume and the 3 percent load growth volume, a decrease of $1.97 and $1.20 respectively. In summary, natural gas prices and volumes are an important factor in the PSA rate as contemplated in the proposed PSA as well as in the resulting customer bills, but a number of factors considerably reduce the impact of changes in natural gas prices and volumes on the proposed PSA and resulting customer bills.

Description of Staff Approach

The basis for this analysis is the request from Commissioner Mayes for estimates of customer bills in April 2006, as contained in the "homework assignment" and follow up clarification sheet. Additionally, during the initial days of the hearing, Commissioner Mundell requested that actual 2003 and 2004 cost information be considered and Commissioner Gleason expressed an interest in looking at bands, where costs are increased or decreased by 10 or 20 percent. Both of these requests are addressed within the overall context of responding to the "homework assignment".

Staff received basic consumption and fuel and purchased power information from APS for the year 2003. This information provided the basis for analyzing the possible impacts of various factors on an average APS Schedule E-12 residential customer's bill. The first time the Power Supply Adjustor (PSA) rate will have its annual update will be in 2006, with the new PSA rate being applicable to customer bills in April 2006. Many things that impact the PSA rate can and likely will change between the 2003 historical data and the actual 2005 data which would be used to calculate the new PSA rate for April 2006. Staff has made a variety of assumptions in creating its projections of consumption, fuel and purchased power costs, and other inputs for the PSA. Appendix A discusses these assumptions in more detail. To summarize briefly, Staff ran a set of 15 scenarios for both the average (738 kwh) and median (460 kwh) June 2004 residential consumption, varying the cost of natural gas and the volume of natural gas burned by APS to test the sensitivity of changes in APS' natural gas supply in relation to what a residential customer would see in their bill. Gas costs were varied to include the APS base case cost of $5.78 per MMBtu, the $8.22 NYMEX scenario, the $8.22 NYMEX scenario adjusted for basin differentials, a $4.00 per MMBtu scenario, and a $10.00 per MMBtu scenario. Gas volumes were varied by using the gas volume contained in the APS base case, a doubling of gas volumes from the APS base case, and a case where load growth is assumed to be 3 percent annually and all the load growth is met by natural gas fired generation. The variations of these five gas cost possibilities and these three gas volume possibilities provide the fifteen scenarios. Admittedly, some of these cost and volume scenarios may not be likely to occur, but inclusion of them is helpful in reviewing the potential impact of natural gas generation in a wide spectrum of cases.

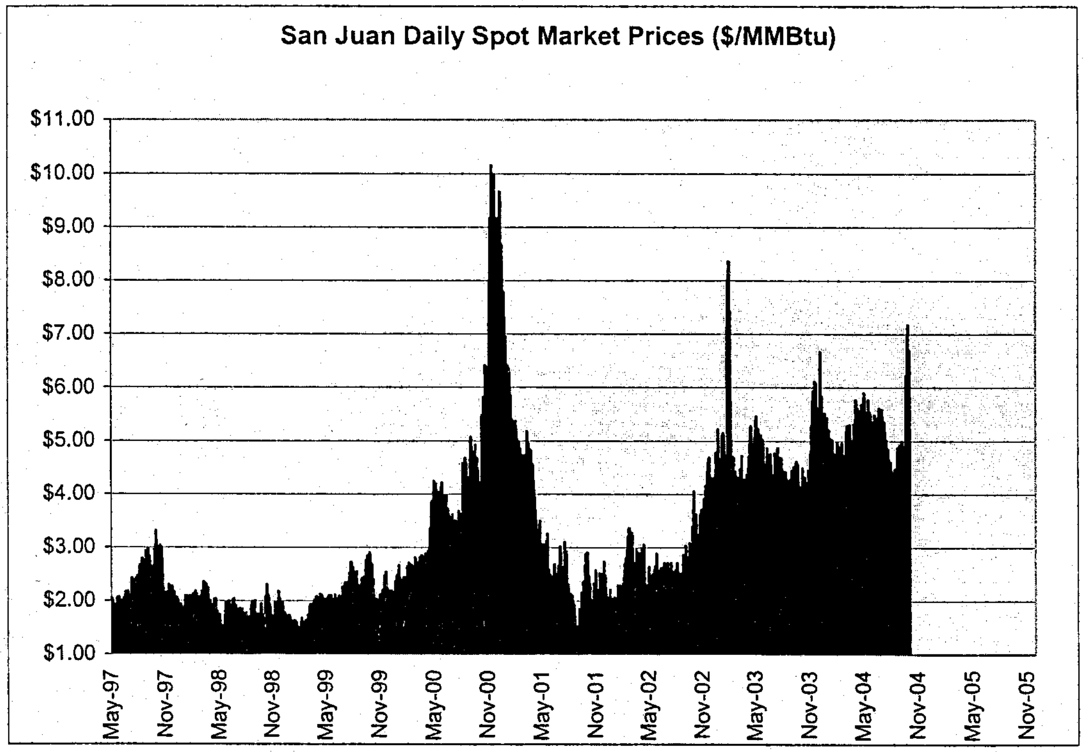
These scenarios were run for all of the seven rate proposals listed in the request for this analysis: Today, APS Original Without Adjustors, APS Original With Adjustors, RUCO Original, Staff Original, Settlement Without Adjustors, and Settlement With Adjustors.

Staff also made estimates of what the various adjustor mechanisms would be and included these estimates in calculating the potential customer bills under the various scenarios. In addition to the PSA calculations, Staff made estimates of the CRCC, TCA, EPS, and DSM adjustor amounts. The RCDAC was not considered because it does not apply to residential customers (except possibly in the case of a very large aggregation of residential customers). Staff also made an adjustment to the customer bill calculations to reflect the changing way in which franchise fees would be assessed. Appendix B discusses in greater detail how the various adjustor rates were estimated and how the franchise fee issue was addressed.

The Staff Findings section below will show the results of the various scenarios, with Appendix C containing the details of the PSA bank balance calculations for each scenario.

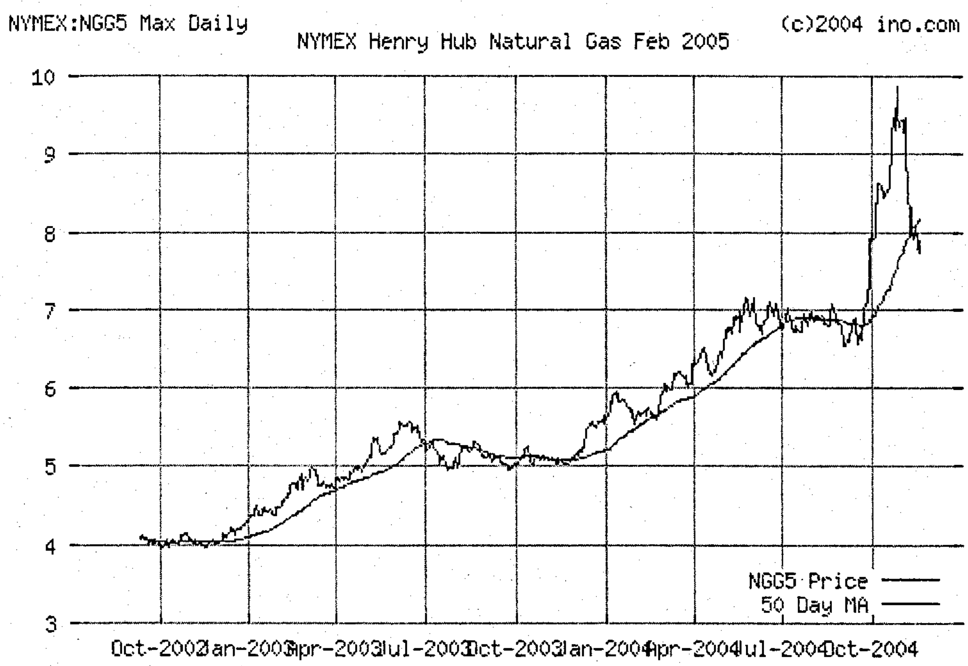
It is worthwhile to briefly discuss APS' gas procurement activities as they relate to this bill estimation exercise. Generally speaking APS buys natural gas in a similar fashion to other Arizona gas buyers, subject to APS' specific needs and circumstances. Virtually all of APS' gas is sourced from the San Juan supply basin in northwest New Mexico and the Permian supply basin in west Texas. San Juan gas is generally preferred, as it typically comes at a lower price than Permian gas. APS' natural gas supplies are delivered via the El Paso Natural Gas Company (El Paso) interstate pipeline system under a variety of pipeline capacity contract rights which are the result of pipeline capacity allocation proceedings at the Federal Energy Regulatory Commission (FERC) in recent years. Within these contract rights, along with any other pipeline services (such as interruptible service or release capacity) which APS may acquire, APS' natural gas supplies are delivered to its electric generation units. The cost and mix of APS' pipeline capacity portfolio will likely change over time due to changing needs; FERC actions; changing market conditions; possible new access to pipelines, supply sources, and storage facilities; and other factors. For example, if the Kinder Morgan Silver Canyon pipeline project is actually constructed, APS' capacity rights on that pipeline, pre-approved by the Commission in Decision Number 67239 (September 15, 2004), would change the nature of APS' supply portfolio and resulting costs.

Shown below is a chart of daily spot market prices in the San Juan basin in recent years.



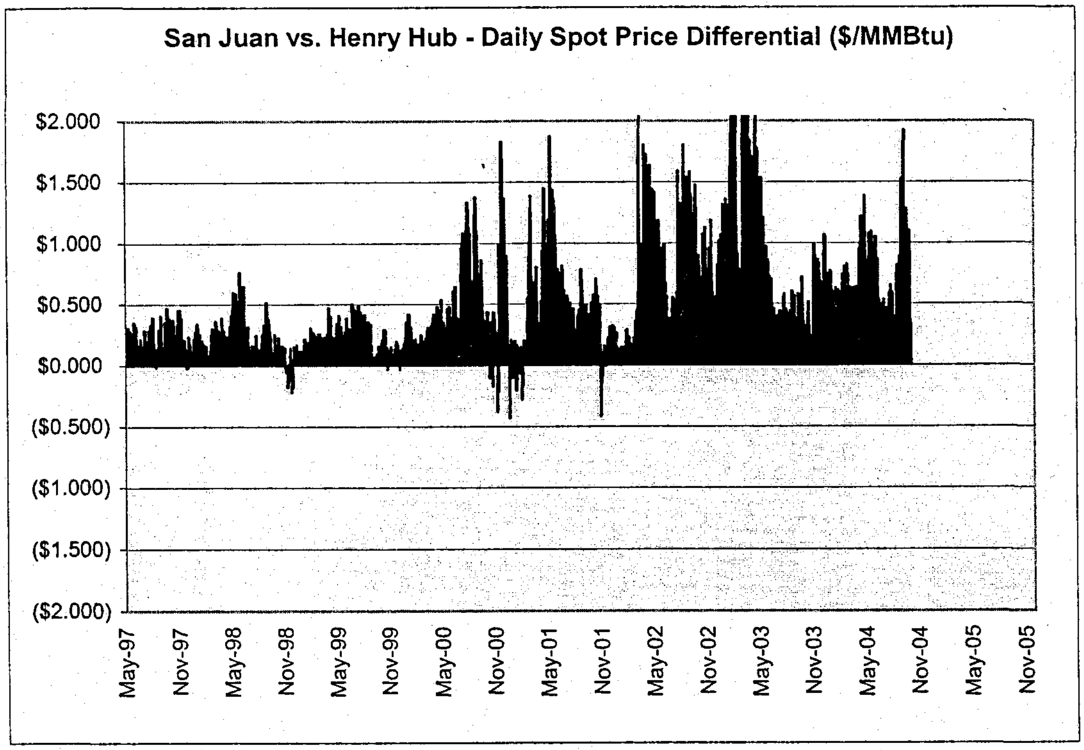
Source: Gas Daily

NYMEX futures prices, such as the $8.22 per MMBtu price being used as the basis for some of the scenarios contained in this study, are useful to consider, as they are a source of information regarding market expectations in the future. However, the price of a given month's futures prices can and does vary significantly over time as market conditions and expectations change. Shown below is a chart of the February 2005 NYMEX natural gas future price over time as well as the 50 day moving average.



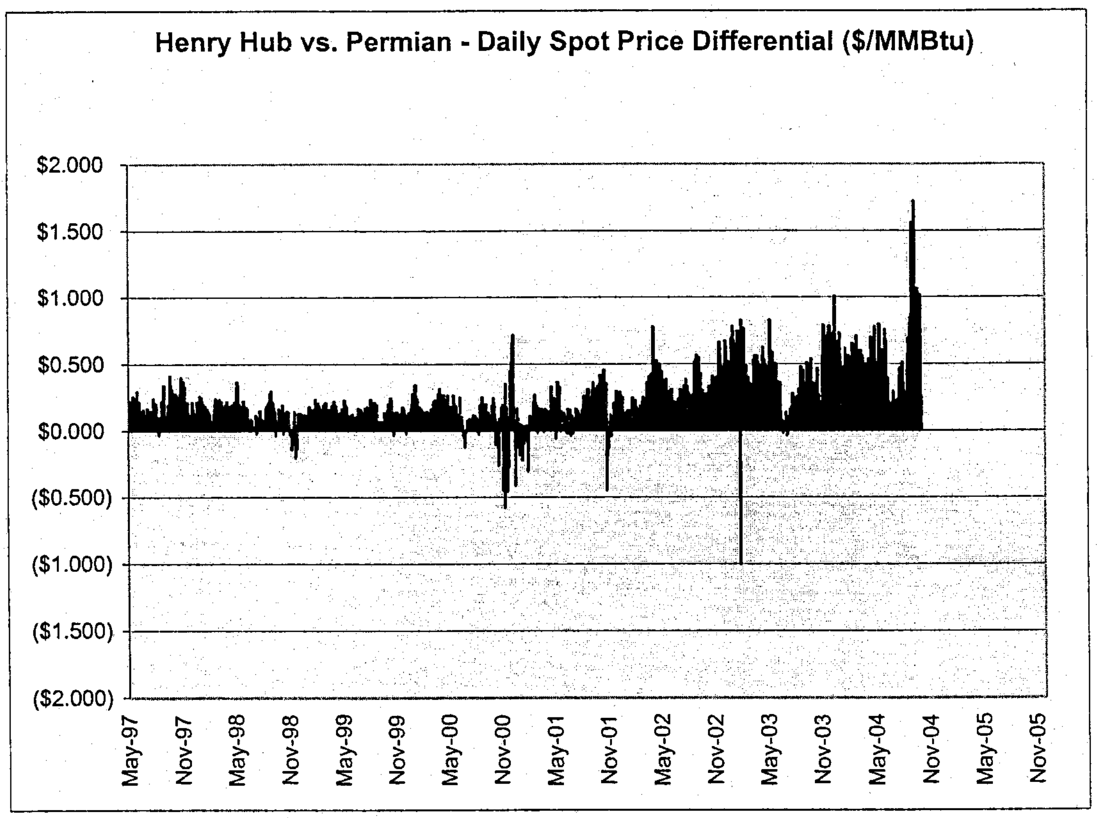
NYMEX futures are based upon physical deliveries at the Henry Hub, a location in Louisiana where five major pipelines come together. Given the location of the Henry Hub and the nature of the national pipeline network, it is highly unlikely that Henry Hub gas would actually be physically delivered to Arizona. Henry Hub prices are heavily influenced by eastern and midwestern market conditions and are typically higher than prices in both the San Juan and Permian basins where APS buys its natural gas. Further, Henry Hub prices tend to be more volatile than the natural gas supplies acquired by APS, particularly San Juan supplies.

The chart below compares Henry Hub and San Juan spot market prices. A positive number indicates that Henry Hub prices are higher than San Juan prices.



Source: Gas Daily

The chart below shows Permian basin spot market prices in comparison to Henry Hub spot market prices, with a positive number indicating that Henry Hub prices are higher than Permian prices.



Source: Gas Daily

The prices paid in the San Juan and Permian basins are significantly different than Henry Hub prices, though the differential varies over time. While NYMEX futures prices are a useful reference point, their use must be tempered by a recognition of the differences between pricing at the Henry Hub and pricing in the locations which APS sources its natural gas from. Appendix A contains an explanation of the adjustment Staff made to the $8.22 per MMBtu NYMEX price, reducing it to $7.60 per MMBtu, to be more reflective of Arizona gas supply prices.

Staff Findings

While a wide variety of assumptions had to be made to create these estimates of April 2006 residential customer bills for customers on Schedule E-12, this exercise nevertheless provides some insight into the impact of natural gas prices and other factors on the change in customer bills. This discussion will primarily focus on the scenarios showing today's rates and rates under the settlement with adjustors, since a comparison of these two scenarios is the most apt to reflect what a current customer might see in changes from current to future APS rates as proposed in the Settlement.

Regarding the five gas price projections used in calculating these scenarios, it should be noted that some price projections are much more likely to be reflective of actual circumstances in the near future than others. With the caveat that natural gas prices are notoriously unpredictable, Staff believes that the most likely of the five price scenarios is the \$5.78 per MMBtu scenario, with the \$7.60 scenario next most likely. The \$4.00 per MMBtu scenario illustrates what could happen with a warm winter dampening natural gas demand at a time when storage facilities are at record high inventories. Natural gas prices have been both high and volatile now for most of the last 4-5 years and industry projections show continued high prices and significant volatility in the near future. However, there is some amount of self-correction in the market, as high prices and volatility tend to result in demand destruction, particularly in the industrial sector. Despite high natural gas prices in recent years, the market has yet to experience annual average prices in the \$7.00 or \$8.00 per MMBtu range. Additionally, APS has already hedged a significant percentage of its natural gas supplies for 2005, approximately 60 percent. Such hedging substantially reduces the likelihood that APS' overall natural gas supply cost would approach the prices reflected in the \$10.00, \$8.22, and even \$7.60 price scenarios. For example, if APS has hedged 60 percent of its 2005 natural gas prices at \$5.00 per MMBtu, it would take an average price of \$11.50 per MMBtu for the other 40 percent of APS' natural gas supplies to reach an average annual price of \$7.60 per MMBtu in 2005. A market price averaging \$11.50 per MMBtu in 2005 would far exceed what the United States natural gas markets have seen during any recent time period, let alone over a twelve month period. Any additional hedging APS does for 2005 natural gas supplies would have a further dampening effect on the likely average natural gas price for APS in 2005.

The three variations on natural gas volumes used by APS are to use the base case APS consumption, which is the 2003 number provided in APS' base case, a doubling of natural gas use by APS, and a three percent annual load growth for APS with all such growth being met by additional natural gas-fired generation. The doubled gas usage in 2005 is a highly unlikely gas usage scenario, but is included to demonstrate the impact which very large increases in natural gas consumption could have on the PSA. This scenario could be more reflective of what the PSA might look like further out in the future if natural gas continues to be the fuel which is relied upon for most or all future incremental electric generation additions. Staff believes that the 2003 base case is probably on the low end of what likely gas usage would be in 2005, with the three percent growth case probably representing somewhere on the high end of likely gas usage in 2005. Somewhere within the range of the base and three percent cases is a likely area of APS gas usage in the near future, based upon the current reliance on natural gas for new electric generation needs. It is worth noting that under the three percent load growth scenario with all growth being met with natural gas-fired generation, this would result in an approximately one third increase in natural gas consumption by APS in the two year period from 2003 to 2005.

Regarding the $0.004 per kWh band on how much the PSA rate can change, it is worth noting that at the base case sales level, approximately $100,000,000 will be recovered by the PSA rate being reset and as sales increase over time, that amount which would be recovered within the $0.004 per kWh band will increase. At current levels the $100,000,000 amount would equal almost 20 percent of APS' net fuel and purchased power costs. For the 738 kWh average usage customer, their monthly bill would reflect a PSA impact of $2.95 if the $0.004 per kWh band is reached in resetting the PSA rate. No additional impact is possible from the PSA on an annual basis, outside a temporary PSA surcharge which the Commission would have to approve.

Given these discussions of what Staff believes are the more likely gas volume and gas price scenarios when the PSA rate is reset for the first time in April 2006, it appears very possible that there will be some level of undercollection in the PSA bank balance when the PSA rate is reset in April 2006, subject to a wide variety of uncertain variables that could move the balance either direction. However the balance level is likely to be relatively small and to have a relatively small impact on customer bills, especially in light of APS' significant level of gas price hedging already in place. In some examples, the effects of both the base rate increase and the other adjustors are noticeably larger than the effect of the PSA. For example, looking at the average usage scenarios, Scenario One, with the APS Base Case gas price and volumes shows a PSA impact on the customer bill of $0.04. Scenario 11, with the APS Base Case price and 3 percent load growth, shows a PSA impact on the customer bill of $1.34, which is slightly larger than the impact of the other adjustors, but still smaller than the impact of the base rate increase.

The impact of the 90/10 split is of note in these scenarios. For example, in the previously referenced Scenario 11, application of the 90/10 split saves ratepayers approximately $5.4 million which absent the 90/10 sharing would have been recovered through a higher PSA rate.

For the rate proposals below, only two, APS Original With Adjustors and Settlement with Adjustors vary between scenarios, as these are the only two which use the PSA rate, which varies depending upon natural gas cost and volumes. The other five rate proposals reflect the same base rate total and final bill through all 15 scenarios in each part. The 15 scenarios using June average usage are shown in Part A, and then the 15 scenarios using June median usage are shown in Part B.

Response to Request by Commissioner Mundell

Commissioner Mundell requested the parties, as part of the homework exercise, to look at the actual 2003 and 2004 fuel costs in assessing possible impacts on customers bills of the PSA. Staff contacted APS regarding this information and APS indicated that its average cost for the most recent 12 months available, October 2003 through September 2004, was $0.021224 per kwh. A comparison of this number with the proposed base cost of fuel and purchased power of $0.020743 per kwh shows that this recent cost information represents a 2.32 percent increase over the average cost reflected in the proposed base cost of fuel and purchased power. If this 2.32 percent increase were applied to the $524.6 million net fuel and purchased power cost total for 2003 used in calculating the base cost of fuel and purchased power, this would result in an increase of approximately $12 million in annual fuel costs, to approximately $536.8 million. Given the large amount of money APS spends annually on fuel and purchased power and the potential significant variation in these costs from year to year due to a variety of factors, the 2.32 percent difference between the costs used in calculating the proposed base cost of fuel and purchased power and the latest 12 months of available fuel costs is relatively minor.

Response to Request by Commissioner Gleason

Commissioner Gleason expressed an interest in looking at the impact of a 10 or 20 percent increase or decrease in the cost of natural gas for APS. Working off the $5.78 per MMBtu cost of gas contained in APS' base case, a 10 percent increase would result in a price of $6.36 per MMBtu and a 20 percent increase would result in a price of $6.94 per MMBtu. A decrease of 10 percent would result in a price of $5.20 per MMBtu and a decrease of 20 percent would result in a price of $4.62 per MMBtu. In comparing these price changes with the five price scenarios considered in the homework assignment, all of these prices fall well within the price scenarios which use $4.00 per MMBtu and $7.60 per MMBtu, so those scenarios can be looked at as further percentage price change scenarios. By comparison, the $4.00 per MMBtu price scenario reflects a 30.8 percent decrease in the natural gas price, while the $7.60 per MMBtu price scenario represents a 31.5 percent increase in the natural gas price. Therefore, as a general rule of thumb, the 10 percent and 20 percent increases would result in approximately one-third and two-thirds of the increase shown in the $7.60 price scenario and the 10 percent and 20 percent decreases would show approximately one-third and two-thirds of the decreases shown in the $4.00 per MMBtu scenario. Using the APS Base Case gas volume, the table below shows the impact which a 10 or 20 percent change in price would have on the annual total fuel and purchased power cost for APS.

Gas Price Variation	Price per MMBtu	Total Annual Gas Cost	Total Annual Fuel and Purchased Power Cost	Percent Change in Total Fuel Cost from APS Base Case
APS Base Case	$5.78	$248,400,000	$524,600,000	-
10% increase	$6.36	$273,200,000	$549,400,000	+4.7%
20% increase	$6.94	$298,100,000	$574,300,000	+9.5%
10% decrease	$5.20	$223,600,000	$499,800,000	-4.7%
20% decrease	$4.62	$198,700,000	$474,900,000	-9.5%

Part A: April 2006 Customers Bills – June Average Usage Scenarios

This set of scenarios is based upon average June 2004 consumption by residential customers served on Schedule E-12.

Average Usage Scenario One

Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $248,400,000
Annual Net Fuel and Purchased Power Costs: $524,600,000, PSA Rate: $0.00006 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$0.04	$0.00	$0.00	$0.00	$0.04
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$77.17	$69.33	$68.67	$73.65	$74.56
Franchise Fee	$1.02	$1.40	$1.41	$1.27	$1.26	$1.35	$1.36
Final Bill	$72.10	$77.66	$78.58	$70.59	$69.93	$75.00	$75.92
% Change in Final Bill From Today		7.7%	9.0%	-2.1%	-3.0%	4.0%	5.3%

Average Usage Scenario Two

Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $353,300,000
Annual Net Fuel and Purchased Power Costs: $$629,500,000, PSA Rate: $0.00381 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.81	$0.00	$0.00	$0.00	$2.81
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$79.93	$69.33	$68.67	$73.65	$77.32
Franchise Fee	$1.02	$1.40	$1.46	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.40	$70.59	$69.93	$75.00	$78.74
% Change in Final Bill From Today		7.7%	12.9%	-2.1%	-3.0%	4.0%	9.2%

Average Usage Scenario Three

Gas Price: $8.22 per MMBtu Adjusted to AZ prices (to $7.60) Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $326,700,000
Annual Net Fuel and Purchased Power Costs: $602,900,000, PSA Rate: $0.00286 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.11	$0.00	$0.00	$0.00	$2.11
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$79.23	$69.33	$68.67	$73.65	$76.62
Franchise Fee	$1.02	$1.40	$1.45	$1.27	$1.26	$1.35	$1.40
Final Bill	$72.10	$77.66	$80.68	$70.59	$69.93	$75.00	$78.03
% Change in Final Bill From Today		7.7%	11.9%	-2.1%	-3.0%	4.0%	8.2%

Average Usage Scenario Four							
Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case							
Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $171,900,000 Annual Net Fuel and Purchased Power Costs: $448,100,000, PSA Rate: -$0.00267 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	-$1.97	$0.00	$0.00	$0.00	-$1.97
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$75.15	$69.33	$68.67	$73.65	$72.54
Franchise Fee	$1.01	$1.40	$1.38	$1.27	$1.26	$1.35	$1.33
Final Bill	$71.59	$77.66	$76.53	$70.59	$69.93	$75.00	$73.87
% Change in Final Bill From Today		7.7%	6.1%	-2.1%	-3.0%	4.0%	2.4%

Average Usage Scenario Five							
Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case							
Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $429,900,000 Annual Net Fuel and Purchased Power Costs: $706,100,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $64,050,904							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Six							
Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $496,800,000 Annual Net Fuel and Purchased Power Costs: $773,100,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $21,486,850							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Seven							
Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $706,700,000 Annual Net Fuel and Purchased Power Costs: $982,900,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $210,306,850							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Eight							
Gas Price: $8.22 per MMBtu Adjusted to AZ Prices ($7.60) Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $$653,400,000 Annual Net Fuel and Purchased Power Costs: $929,600,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $162,336,850							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Nine							
Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $343,800,000 Annual Net Fuel and Purchased Power Costs: $620,100,000, PSA Rate: $0.00009 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$0.07	$0.00	$0.00	$0.00	$0.07
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$77.19	$69.33	$68.67	$73.65	$74.58
Franchise Fee	$1.01	$1.40	$1.41	$1.27	$1.26	$1.35	$1.36
Final Bill	$71.59	$77.66	$78.60	$70.59	$69.93	$75.00	$75.94
% Change in Final Bill From Today		7.7%	9.0%	-2.1%	-3.0%	4.0%	5.3%

Average Usage Scenario Ten							
Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $859,700,000 Annual Net Fuel and Purchased Power Costs: $1,135,900,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $348,006,850							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Eleven							
Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume: 57,527,000 MMBtu, Annual Gas Cost: $332,500,000 Annual Net Fuel and Purchased Power Costs: $608,700,000, PSA Rate: $0.00182 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$1.34	$0.00	$0.00	$0.00	$1.34
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$78.47	$69.33	$68.67	$73.65	$75.86
Franchise Fee	$1.01	$1.40	$1.44	$1.27	$1.26	$1.35	$1.39
Final Bill	$71.59	$77.66	$79.90	$70.59	$69.93	$75.00	$77.24
% Change in Final Bill From Today		7.7%	10.8%	-2.1%	-3.0%	4.0%	7.1%

Average Usage Scenario Twelve							
Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume: 57,527,000 MMBtu, Annual Gas Cost: $472,900,000 Annual Net Fuel and Purchased Power Costs: $749,100,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $67,960,956							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Thirteen

Gas Price: $8.22 per MMBtu Adjusted to AZ prices (to $7.60) Gas Volume: APS Base Case + 3 Percent Annual Load Growth

Annual Gas Volume: 57.527,000 MMBtu, Annual Gas Cost: $437,200,000
Annual Net Fuel and Purchased Power Costs: $713,400,000, PSA Rate: $0.00400 per kWh
Balancing Account after Application of $0.004 per kWh band: $35,830,956

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Fourteen

Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case + 3 Percent Annual Load Growth

Annual Gas Volume 57,527,000 MMBtu, Annual Gas Cost: $230,100,000
Annual Net Fuel and Purchased Power Costs: $506,300,000, PSA Rate: -$0.00163 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	-$1.20	$0.00	$0.00	$0.00	-1.20
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$75.92	$69.33	$68.67	$73.65	$73.31
Franchise Fee	$1.01	$1.40	$1.39	$1.27	$1.26	$1.35	$1.34
Final Bill	$71.59	$77.66	$777.31	$70.59	$69.93	$75.00	$74.65
% Change in Final Bill From Today		7.7%	7.2%	-2.1%	-3.0%	4.0%	3.5%

Average Usage Scenario Fifteen

Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case + 3 Percent Annual Load Growth

Annual Gas Volume 57,527,000 MMBtu, Annual Gas Cost: $575,300,000
Annual Net Fuel and Purchased Power Costs: $851,500,000, PSA Rate: $0.00400 per kWh
Balancing Account after Application of $0.004 per kWh band: $160,120,956

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$70.58	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.01	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$71.59	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Part B: April 2006 Customers Bills – June Median Usage Scenarios

The median June 2004 E-12 residential customer usage is 460 kwh. Median usage is not a usage measure that is typically considered in the review of energy company charges. The same set of 15 scenarios has been run for this usage level. The median usage scenarios show the same general pattern in relation to natural gas price and volume impacts. The main difference is that rate base total and final bill differences from Today's rates are more heavily influenced by differences in the customer charge and the per kwh charge in the first 400 kwh block, as would be expected when looking at customers with a lower usage level.

Median Usage Scenario Sixteen

Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $248,400,000
Annual Net Fuel and Purchased Power Costs: $524,600,000, PSA Rate: $0.00006 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$0.03	$0.00	$0.00	$0.00	$0.03
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$52.94	$41.86	$41.47	$44.31	$45.00
Franchise Fee	$0.61	$0.96	$0.97	$0.77	$0.76	$0.81	$0.82
Final Bill	$43.52	$53.20	$53.91	$42.62	$42.23	$45.12	$45.82
% Change in Final Bill From Today		22.2%	23.9%	-2.1%	-3.0%	3.7%	5.3%

Median Usage Scenario Seventeen

Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $353,300,000
Annual Net Fuel and Purchased Power Costs: $$629,500,000, PSA Rate: $0.00381 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.75	$0.00	$0.00	$0.00	$1.75
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.66	$41.86	$41.47	$44.31	$46.73
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.67	$42.62	$42.23	$45.12	$47.58
% Change in Final Bill From Today		22.2%	27.9%	-2.1%	-3.0%	3.7%	9.3%

Median Usage Scenario Eighteen

Gas Price: $8.22 per MMBtu Adjusted to AZ prices (to $7.60) Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $326,700,000
Annual Net Fuel and Purchased Power Costs: $602,900,000, PSA Rate: $0.00286 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.32	$0.00	$0.00	$0.00	$1.32
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.23	$41.86	$41.47	$44.31	$46.29
Franchise Fee	$0.61	$0.96	$0.99	$0.77	$0.76	$0.81	$0.85
Final Bill	$43.52	$53.20	$55.22	$42.62	$42.23	$45.12	$47.14
% Change in Final Bill From Today		22.2%	26.9%	-2.1%	-3.0%	3.7%	8.3%

Median Usage Scenario Nineteen

Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $171,900,000
Annual Net Fuel and Purchased Power Costs: $448,100,000, PSA Rate: -$0.00267 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	-$1.23	$0.00	$0.00	$0.00	-$1.23
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$51..68	$41.86	$41.47	$44.31	$43.75
Franchise Fee	$0.61	$0.96	$0.95	$0.77	$0.76	$0.81	$0.80
Final Bill	$43.52	$53.20	$52.63	$42.62	$42.23	$45.12	$44.55
% Change in Final Bill From Today		22.2%	22.8%	-2.1%	-3.0%	3.7%	2.4%

Median Usage Scenario Twenty

Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $429,900,000
Annual Net Fuel and Purchased Power Costs: $706,100,000, PSA Rate: $0.00400 per kWh
Balancing Account after Application of $0.004 per kWh band: $64,050,904

June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Median Usage Scenario Twenty-One							
Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $496,800,000 Annual Net Fuel and Purchased Power Costs: $773,100,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $21,486,850							
June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Median Usage Scenario Twenty-Two							
Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $706,700,000 Annual Net Fuel and Purchased Power Costs: $982,900,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $210,306,850							
June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Median Usage Scenario Twenty-Three							
Gas Price: $8.22 per MMBtu Adjusted to AZ Prices ($7.60) Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $$653,400,000 Annual Net Fuel and Purchased Power Costs: $929,600,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $162,336,850							
June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Median Usage Scenario Twenty-Four							
Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $343,800,000 Annual Net Fuel and Purchased Power Costs: $620,100,000, PSA Rate: $0.00009 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$0.04	$0.00	$0.00	$0.00	$0.04
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$52.95	$41.86	$41.47	$44.31	$45.02
Franchise Fee	$0.61	$0.96	$0.97	$0.77	$0.76	$0.81	$0.82
Final Bill	$43.52	$53.20	$53.92	$42.62	$42.23	$45.12	$45.84
% Change in Final Bill From Today		22.2%	23.9%	-2.1%	-3.0%	3.7%	5.3%

Median Usage Scenario Twenty-Five							
Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $859,700,000 Annual Net Fuel and Purchased Power Costs: $1,135,900,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $348,006,850							
June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Median Usage Scenario Twenty-Six							
Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume: 57,527,000 MMBtu, Annual Gas Cost: $332,500,000 Annual Net Fuel and Purchased Power Costs: $608,700,000, PSA Rate: $0.00182 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$0.84	$0.00	$0.00	$0.00	$0.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$53.75	$41.86	$41.47	$44.31	$45.81
Franchise Fee	$0.61	$0.96	$0.98	$0.77	$0.76	$0.81	$0.84
Final Bill	$43.52	$53.20	$54.73	$42.62	$42.23	$45.12	$46.85
% Change in Final Bill From Today		22.2%	25.8%	-2.1%	-3.0%	3.7%	7.2%

Median Usage Scenario Twenty-Seven

Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case + 3 Percent Annual Load Growth

Annual Gas Volume: 57,527,000 MMBtu, Annual Gas Cost: $472,900,000
Annual Net Fuel and Purchased Power Costs: $749,100,000, PSA Rate: $0.00400 per kWh
Balancing Account after Application of $0.004 per kWh band: $67,960,956

June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Median Usage Scenario Twenty-Eight

Gas Price: $8.22 per MMBtu Adjusted to AZ prices (to $7.60) Gas Volume: APS Base Case + 3 Percent Annual Load Growth

Annual Gas Volume: 57.527,000 MMBtu, Annual Gas Cost: $437,200,000
Annual Net Fuel and Purchased Power Costs: $713,400,000, PSA Rate: $0.00400 per kWh
Balancing Account after Application of $0.004 per kWh band: $35,830,956

June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Median Usage Scenario Twenty-Nine

Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case + 3 Percent Annual Load Growth

Annual Gas Volume 57,527,000 MMBtu, Annual Gas Cost: $230,100,000
Annual Net Fuel and Purchased Power Costs: $506,300,000, PSA Rate: -$0.00163 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	-$0.75	$0.00	$0.00	$0.00	-$0.75
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$52.16	$41.86	$41.47	$44.31	$44.23
Franchise Fee	$0.61	$0.96	$0.95	$0.77	$0.76	$0.81	$0.81
Final Bill	$43.52	$53.20	$53.12	$42.62	$42.23	$45.12	$45.04
% Change in Final Bill From Today		22.2%	22.0%	-2.1%	-3.0%	3.7%	3.5%

Median Usage Scenario Thirty							
Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume 57,527,000 MMBtu, Annual Gas Cost: $575,300,000 Annual Net Fuel and Purchased Power Costs: $851,500,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $160,120,956							
June Usage of 460 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$42.56	$52.25	$52.25	$41.35	$40.84	$44.31	$44.31
% Change in Base Rates From Today		22.8%	22.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.16	$0.16	$0.16	$0.00	$0.16
PSA	$0	$0.00	$1.84	$0.00	$0.00	$0.00	$1.84
TCA	$0	$0.00	$0.04	$0.00	$0.04	$0.00	$0.04
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.12	$0.00	$0.08	$0.00	$0.12
Subtotal	$42.91	$52.25	$54.75	$41.86	$41.47	$44.31	$46.82
Franchise Fee	$0.61	$0.96	$1.00	$0.77	$0.76	$0.81	$0.86
Final Bill	$43.52	$53.20	$55.75	$42.62	$42.23	$45.12	$47.67
% Change in Final Bill From Today		22.2%	28.1%	-2.1%	-3.0%	3.7%	9.5%

Appendix A: Staff Assumptions

This Appendix lists the assumptions that underlie the various scenarios as well as further discussion as needed.

1. The most basic assumption is that except for the limited variables which are adjusted from scenario to scenario, the system is assumed to be static. Of course in real life many variables can and will change, but modeling a wide variety of variable changes would be difficult, unwieldy, and in Staff's view is unnecessary to assess the general impact which variations in APS' natural gas supply portfolio would have on customer bills. Many of these variables which are assumed to be static are listed below.
2. APS' hedging of natural gas prices is not directly taken into consideration. However, to the extent APS had hedged its natural gas prices, it would be less likely that the high cost scenarios would reflect what could happen in the future, subject to the details of APS' hedging activities.
3. For the scenarios using the $8.22 NYMEX value adjusted for basin differentials, a basic calculation was made to estimate the typical price differential between the Henry Hub, which is the basis for NYMEX futures, and the San Juan and Permian basins where APS buys natural gas. This was done by calculating the average differential between the basins for 2004 and then taking the average of those two numbers, assuming APS takes equal amounts of fuel from the San Juan and Permian basins. For daily spot market prices in 2004 as reported in Gas Daily, San Juan gas was typically $0.71 per MMBtu cheaper than Henry Hub gas and Permian gas was typically $0.53 per MMBtu cheaper than Henry Hub gas. The average of these two numbers is $0.62 per MMBtu. This number is subtracted from $8.22 to arrive at the $7.60 per MMBtu price used in the gas price scenario reflected the $8.22 NYMEX price adjusted for basin differentials.
4. It is assumed that there will be no changes in the cost of pipeline service from El Paso. There may not be significant changes in the cost of pipeline service through 2005, but with the pending El Paso rate proceeding in 2005 as well as other potential cost increases resulting from factors such as tighter balancing requirements, it seems likely that pipeline service costs will increase for APS in the future.
5. No modeling was done of how natural gas price changes would impact how APS manages its business including how various generating units are dispatched and possible shifting among fuel sources.
6. Future natural gas prices are unknown and projections of natural gas prices are notoriously inaccurate. A variety of uncertain factors, such as economic conditions, weather, and world petroleum markets, greatly impact natural gas prices both now and in the future. The variety of scenarios presented provides a spread of possible natural gas price cases.
7. There was no assessment of how much APS load may actually increase due to expanding demand for electricity from population and economic growth or decrease due to greater funding of energy-efficient demand side management efforts or other factors.
8. Staff's direct testimony does not contain specific rate element proposals for rate schedules, including rate schedule E-12, which is under consideration in this analysis.

Staff's direct testimony did contain a recommendation that residential rates be reduced by 4.04 percent. For purposes of this analysis, this 4.04 percent decrease is applied across all E-12 rate elements to provide an estimate of what E-12 rates would be under Staff's original case. Further, this 4.04 percent decrease was applied to Today's rates, so, as was done with Today's rates, the franchise fee was factored out of the rates for the purpose of calculating the base rate total. The franchise fee is later added back in as the final step in calculating the final customer bill. Franchise fees are discussed in more detail in Appendix B.

9. RUCO's direct testimony proposes a 2.84 percent decrease and indicates that residential customers should receive the same percentage decrease as other rate classes. So in a fashion similar to the application of Staff's 4.04 percent proposed decrease, the 2.84 percent decrease proposed by RUCO is applied evenly to all rate elements for Today's schedule E-12. And the franchise fee is also treated in the same fashion as previously described for Staff's original case. Franchise fees are discussed in more detail in Appendix B.
10. For the EPS, CRCC, DSM, TCA, and PSA adjustors, it is worthwhile to briefly discuss which are considered in each of the seven rate proposals considered, and why or why not.

A. Today's Rates - For the Today's rate proposal, only the $0.35 EPS surcharge is included, as that is the only such adjustor or surcharge currently being applied in APS' rates.

B. APS Original W/O Adjustors - For APS Original W/O Adjustors, no adjustors or surcharges are applied, as the title of this rate proposal suggests.

C. APS Original W/Adjustors – All Adjustors are applied consistent with levels proposed in the Settlement and as discussed in Appendix B. It should be noted that APS' original proposal included the PSA, the TCA, the EPS, and the CRCC. It did not contemplate a DSM adjustor.

D. RUCO Original - In RUCO's original position, they were against the PSA, the TCA, and a DSM adjustor, so these were not included in the RUCO Original rate proposal. RUCO was in favor of the EPS and the CRCC (as proposed by APS), so these are included.

E. Staff Original – Staff originally opposed a PSA so that is not included in the Staff Original rate proposal. Staff included an EPS, CRCC, and TCA, so these are included. Staff supported up to $4 million to be recovered through the DSM adjustor, so DSM funding at a $4 million level recovered through the DSM adjustor is included.

F. Settlement W/O Adjustors – For Settlement W/O Adjustors, none of the adjustors is applied, as suggested by the title of this rate proposal.

G. Settlement W/Adjustors – For Settlement W/Adjustors, all the adjustors are applied consistent with the provisions of the Settlement and as described in Appendix B.

11. APS' off-system sales amount contained in the base case ($29.2 million) is assumed to stay constant through all the scenarios.

Appendix B: Miscellaneous Adjustor and Franchise Fee Calculations

1. CRCC – The CRCC rate contained in the Settlement, $0.000338 per kWh, is applied to the number of kWh used in a given scenario. There were slightly different CRCC amounts included in Staff's direct testimony, APS' original testimony, and the Settlement. For purposes of these bill comparisons, the Settlement CRCC level is used, as the difference resulting from the other amounts is minimal.
2. TCA – The Settlement provides for the TCA to take effect when the transmission component of retail rates exceeds the test year base of $0.000476 per kWh by five percent. For use in the customer bill estimates, the TCA rate is assumed to exceed the test year base by 20 percent, resulting in a TCA rate of $0.0000952 per kWh.
3. EPS – The EPS surcharge is set at $0.35 per month, per the Settlement, which provides that the initial charge will be the same as contained in the current EPS surcharge tariff, including caps.
4. DSM – The DSM adjustor rate is set assuming that APS will spend at the full $16 million dollar level in 2005, with $10 million built into base rates and $6 million collected through the DSM adjustor, resulting in a $0.000256 per kWh, based on retail sales of 23,473,646,000 kWh.
5. Franchise fee – APS pays various percentage franchise fees to various municipalities in Arizona. Currently the franchise fees are built into APS' base rates, meaning in effect all APS customers are paying the same franchise fee, regardless of which municipality they reside or do business in. Under the Settlement, the franchise fee would be separated out of base rates and would be applied to the customer bill at the last stage of calculating the customer bill, after the various adjustor rates have been applied. This new way of applying the franchise fee is more accurate, as customers will now be paying the actual franchise fee in their location, rather than a system average built into rates. But this change in the franchise fee calculation adds a wrinkle to the comparison of customer bills today and under various rate proposals. To present today's rates and the various rate proposals on a consistent footing, Staff has removed the franchise fee from today's rates, as well as from the rates under Staff's original case and RUCO's original case, since these are calculated off today's rates. This results in the total base rates for all rate proposals not reflecting franchise fees. The franchise fees are then added back in to all the rate proposals at the appropriate point later in the customer bill calculations.

   The franchise fee used for all rate proposals other than today's rates is the Phoenix franchise fee of 1.83 percent. This franchise fee is slightly higher than the average franchise fee used in today's rates. This results in the franchise fee being applied to all the other rate proposals being a small amount higher than the franchise fee being applied to the today's rates calculation. In the scenarios the differential is generally between $0.15 and $0.40 extra being applied to the new rate proposals due to the higher franchise fees used.

Appendix C: Scenario PSA Bank Balance Calculations

Staff has run 30 scenarios, 15 with the 738 kwh June 2004 average usage level and 15 with the 460 kwh June 2004 median usage level. Shown below are two tables summarizing the basic balancing account calculations attendant with each scenario.

April 2006 PSA Balancing Account Calculations

Based upon 2003 APS data, adjusted for gas price and gas volume parameters. In cases where the gas volume is adjusted, the native load sales are adjusted correspondingly

Interest is not included in calculations. Off system sales are incorporated into the Net Fuel and PP Costs line.

base cost of fuel in settlement $0.020743 per kwh

	Scenario Numbers							
	1,16	2,17	3,18	4,19	5,20	6,21	7,22	8,23
Annual Gas Cost ($000)	$248,400	$353,300	$326,700	$171,900	$429,900	$496,800	$706,700	$653,400
Annual Gas Volume (000 MMBtu)	42,985	42,985	42,985	42,985	42,985	85,970	85,970	85,970
Average Cost of Gas ($/MMBtu)	$5.78	$8.22	$7.60	$4.00	$10.00	$5.78	$8.22	$7.60
Annual Native Load Sales (MWH)	25,208,287	25,208,287	25,208,287	25,208,287	25,208,287	29,746,000	29,746,000	29,746,000
2005 Net Fuel and PP Costs	$524,600,000	$629,500,000	$602,900,000	$448,100,000	$706,100,000	$773,100,000	$982,900,000	$929,600,000
2005 Costs Recovered Thru Base Cost	$522,895,497	$522,895,497	$522,895,497	$522,895,497	$522,895,497	$617,021,278	$617,021,278	$617,021,278
Over/Undercollection (negative = overcollected)	$1,704,503	$106,604,503	$80,004,503	-$74,795,497	$183,204,503	$156,078,722	$365,878,722	$312,578,722
Balance After 90/10 Application	$1,534,052	$95,944,052	$72,004,052	-$67,315,948	$164,884,052	$140,470,850	$329,290,850	$281,320,850
Balance per kwh of Native Load Sales	$0.00006	$0.00381	$0.00286	-$0.00267	$0.00654	$0.00472	$0.01107	$0.00946
Balance per kwh Captured Within $0.004 band	$0.00006	$0.00381	$0.00286	-$0.00267	$0.00400	$0.00400	$0.00400	$0.00400
Balance per kwh Remaining Outside $0.004 band	$0.00000	$0.00000	$0.00000	$0.00000	$0.00254	$0.00072	$0.00707	$0.00546
Balancing Account Balance	$0	$0	$0	$0	$64,050,904	$21,486,850	$210,306,850	$162,336,850
Amount Balancing Account Exceeds $50 million trigger	$0	$0	$0	$0	$14,050,904	$0	$160,306,850	$112,336,850

	Scenario Numbers						
	9,24	**10,25**	**11,26**	**12,27**	**13,28**	**14,29**	**15,30**
Annual Gas Cost ($000)	$343,800	$859,700	$332,500	$472,900	$437,200	$230,100	$575,300
Annual Gas Volume (000 MMBtu)	85,970	85,970	57,527	57,527	57,527	57,527	57,527
Average Cost of Gas ($/MMBtu)	$4.00	$10.00	$5.78	$8.22	$7.60	$4.00	$10.00
Annual Native Load Sales (MWH)	29,746,000	29,746,000	26,743,000	26,743,000	26,743,000	26,743,000	26,743,000
2005 Net Fuel and PP Costs	$620,100,000	$1,135,900,000	$608,700,000	$749,100,000	$713,400,000	$506,300,000	$851,500,000
2005 Costs Recovered Thru Base Cost	$617,021,278	$617,021,278	$554,730,049	$554,730,049	$554,730,049	$554,730,049	$554,730,049
Over/Undercollection (negative = overcollected)	$3,078,722	$518,878,722	$53,969,951	$194,369,951	$158,669,951	-$48,430,049	$296,769,951
Balance After 90/10 Application	$2,770,850	$466,990,850	$48,572,956	$174,932,956	$142,802,956	-$43,587,044	$267,092,956
Balance per kwh of Native Load Sales	$0.00009	$0.01570	$0.00182	$0.00654	$0.00534	-$0.00163	$0.00999
Balance per kwh Captured Within $0.004 band	$0.00009	$0.00400	$0.00182	$0.00400	$0.00400	-$0.00163	$0.00400
Balance per kwh Remaining Outside $0.004 band	$0.00000	$0.01170	$0.00000	$0.00254	$0.00134	$0.00000	$0.00599
Balancing Account Balance	$0	$348,006,850	$0	$67,960,956	$35,830,956	$0	$160,120,956
Amount Balancing Account Exceeds $50 million trigger	$0	$298,006,850	$0	$17,960,956	$0	$0	$110,120,956

ARIZONA CORPORATION COMMISSION STAFF
Unresolved Differences Between APS and Staff
Based Upon Regulatory Audit of Utilitech, Inc.

Line No.	Unresolved Differences Between APS and Staff	Remaining Unresolved Differences
1	Adjustments to Lead-Lag Study	(10,281)
2	Difference in Property Taxes	(9,184)
3	Disallowance of Economic Development Expenses	(1,856)
4	Disallowance of Advertising Expenses	(4,421)
5	Eliminate Amortization of Severance Costs	(6,181)
6	Incentive Compensation Adjustment	(2,906)
7	Reverse Regulatory Asset Amortization	(2,465)
8	Net Unamortized Loss on Reacquired Debt	(697)
9	Adjust Customer Annualization	(361)
10	Deferred PacifiCorp Gain	(1,231)
11	Total Remaining Difference Between APS & Staff	(39,583)

Admitted
EXHIBIT
Staff 22
12/1/09

Part A: April 2006 Customers Bills – June Average Usage Scenarios

This set of scenarios is based upon average June 2004 consumption by residential customers served on Schedule E-12.

Average Usage Scenario One							
Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case							
Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $248,400,000 Annual Net Fuel and Purchased Power Costs: $524,600,000, PSA Rate: $0.00006 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$0.04	$0.00	$0.00	$0.00	$0.04
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$77.17	$69.33	$68.67	$73.65	$74.56
Franchise Fee	$1.02	$1.40	$1.41	$1.27	$1.26	$1.35	$1.36
Final Bill	$72.10	$77.66	$78.58	$70.59	$69.93	$75.00	$75.92
% Change in Final Bill From Today		7.7%	9.0%	-2.1%	-3.0%	4.0%	5.3%

Average Usage Scenario Two							
Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case							
Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $353,300,000 Annual Net Fuel and Purchased Power Costs: $$629,500,000, PSA Rate: $0.00381 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.81	$0.00	$0.00	$0.00	$2.81
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$79.93	$69.33	$68.67	$73.65	$77.32
Franchise Fee	$1.02	$1.40	$1.46	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.40	$70.59	$69.93	$75.00	$78.74
% Change in Final Bill From Today		7.7%	12.9%	-2.1%	-3.0%	4.0%	9.2%

Average Usage Scenario Three							
Gas Price: $8.22 per MMBtu Adjusted to AZ prices (to $7.60) Gas Volume: APS Base Case							
Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $326,700,000 Annual Net Fuel and Purchased Power Costs: $602,900,000, PSA Rate: $0.00286 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.11	$0.00	$0.00	$0.00	$2.11
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$79.23	$69.33	$68.67	$73.65	$76.62
Franchise Fee	$1.02	$1.40	$1.45	$1.27	$1.26	$1.35	$1.40
Final Bill	$72.10	$77.66	$80.68	$70.59	$69.93	$75.00	$78.03
% Change in Final Bill From Today		7.7%	11.9%	-2.1%	-3.0%	4.0%	8.2%

EXHIBIT
Staff 23
LB 12/01/04
Admitted

Average Usage Scenario Four

Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $171,900,000
Annual Net Fuel and Purchased Power Costs: $448,100,000, PSA Rate: -$0.00267 per kWh
Balancing Account after Application of $0.004 per kWh band: $0

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	-$1.97	$0.00	$0.00	$0.00	-$1.97
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$75.15	$69.33	$68.67	$73.65	$72.54
Franchise Fee	$1.02	$1.40	$1.38	$1.27	$1.26	$1.35	$1.33
Final Bill	$72.10	$77.66	$76.53	$70.59	$69.93	$75.00	$73.87
% Change in Final Bill From Today		7.7%	6.1%	-2.1%	-3.0%	4.0%	2.4%

Average Usage Scenario Five

Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case

Annual Gas Volume: 42,985,000 MMBtu, Annual Gas Cost: $429,900,000
Annual Net Fuel and Purchased Power Costs: $706,100,000, PSA Rate: $0.00400 per kWh
Balancing Account after Application of $0.004 per kWh band: $64,050,904

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Six

Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case Doubled

Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $496,800,000
Annual Net Fuel and Purchased Power Costs: $773,100,000, PSA Rate: $0.00400 per kWh
Balancing Account after Application of $0.004 per kWh band: $21,486,850

June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Seven							
Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $706,700,000 Annual Net Fuel and Purchased Power Costs: $982,900,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $210,306,850							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Eight							
Gas Price: $8.22 per MMBtu Adjusted to AZ Prices ($7.60) Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $$653,400,000 Annual Net Fuel and Purchased Power Costs: $929,600,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $162,336,850							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Nine							
Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $343,800,000 Annual Net Fuel and Purchased Power Costs: $620,100,000, PSA Rate: $0.00009 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$0.07	$0.00	$0.00	$0.00	$0.07
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$77.19	$69.33	$68.67	$73.65	$74.58
Franchise Fee	$1.02	$1.40	$1.41	$1.27	$1.26	$1.35	$1.36
Final Bill	$72.10	$77.66	$78.60	$70.59	$69.93	$75.00	$75.94
% Change in Final Bill From Today		7.7%	9.0%	-2.1%	-3.0%	4.0%	5.3%

Average Usage Scenario Ten							
Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case Doubled							
Annual Gas Volume: 85,970,000 MMBtu, Annual Gas Cost: $859,700,000 Annual Net Fuel and Purchased Power Costs: $1,135,900,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $348,006,850							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Eleven							
Gas Price: APS Base Case of $5.78 Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume: 57,527,000 MMBtu, Annual Gas Cost: $332,500,000 Annual Net Fuel and Purchased Power Costs: $608,700,000, PSA Rate: $0.00182 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$1.34	$0.00	$0.00	$0.00	$1.34
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$78.47	$69.33	$68.67	$73.65	$75.86
Franchise Fee	$1.02	$1.40	$1.44	$1.27	$1.26	$1.35	$1.39
Final Bill	$72.10	$77.66	$79.90	$70.59	$69.93	$75.00	$77.24
% Change in Final Bill From Today		7.7%	10.8%	-2.1%	-3.0%	4.0%	7.1%

Average Usage Scenario Twelve							
Gas Price: $8.22 per MMBtu (2-05 NYMEX) Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume: 57,527,000 MMBtu, Annual Gas Cost: $472,900,000 Annual Net Fuel and Purchased Power Costs: $749,100,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $67,960,956							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Thirteen							
Gas Price: $8.22 per MMBtu Adjusted to AZ prices (to $7.60) Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume: 57.527,000 MMBtu, Annual Gas Cost: $437,200,000 Annual Net Fuel and Purchased Power Costs: $713,400,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $35,830,956							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

Average Usage Scenario Fourteen							
Gas Price: $4.00 per MMBtu Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume 57,527,000 MMBtu, Annual Gas Cost: $230,100,000 Annual Net Fuel and Purchased Power Costs: $506,300,000, PSA Rate: -$0.00163 per kWh Balancing Account after Application of $0.004 per kWh band: $0							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	-$1.20	$0.00	$0.00	$0.00	-1.20
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$75.92	$69.33	$68.67	$73.65	$73.31
Franchise Fee	$1.02	$1.40	$1.39	$1.27	$1.26	$1.35	$1.34
Final Bill	$72.10	$77.66	$777.31	$70.59	$69.93	$75.00	$74.65
% Change in Final Bill From Today		7.7%	7.2%	-2.1%	-3.0%	4.0%	3.5%

Average Usage Scenario Fifteen							
Gas Price: $10.00 per MMBtu Gas Volume: APS Base Case + 3 Percent Annual Load Growth							
Annual Gas Volume 57,527,000 MMBtu, Annual Gas Cost: $575,300,000 Annual Net Fuel and Purchased Power Costs: $851,500,000, PSA Rate: $0.00400 per kWh Balancing Account after Application of $0.004 per kWh band: $160,120,956							
June Usage of 738 kWh	Today	APS Original W/O Adjustors	APS Original With Adjustors	RUCO Original	Staff Original	Settlement W/O Adjustors	Settlement With Adjustors
Base Rate Total	$70.74	$76.26	$76.26	$68.73	$67.88	$73.65	$73.65
% Change in Base Rates From Today		7.8%	7.8%	-2.8%	-4.0%	4.1%	4.1%
CRCC	$0	$0.00	$0.25	$0.25	$0.25	$0.00	$0.25
PSA	$0	$0.00	$2.95	$0.00	$0.00	$0.00	$2.95
TCA	$0	$0.00	$0.07	$0.00	$0.07	$0.00	$0.07
EPS	$0.35	$0.00	$0.35	$0.35	$0.35	$0.00	$0.35
DSM	$0	$0.00	$0.19	$0.00	$0.13	$0.00	$0.19
Subtotal	$71.09	$76.26	$80.07	$69.33	$68.67	$73.65	$77.47
Franchise Fee	$1.02	$1.40	$1.47	$1.27	$1.26	$1.35	$1.42
Final Bill	$72.10	$77.66	$81.54	$70.59	$69.93	$75.00	$78.88
% Change in Final Bill From Today		7.7%	13.1%	-2.1%	-3.0%	4.0%	9.4%

EXHIBIT
ALL-STATE LEGAL®
S-24
LB 12/2/04
Admitted

Rate Comparison

State	Colorado	Nevada	California	New Mexico	Utah	Arizona
Utility	Xcel Energy/Public Service Company of Colorado	Nevada Power Compamy	PG&E	Public Service of New Mexico	Utah Power and Light	Arizona Public Service
Rate Schedule	Schedule R	Schedule RS	E-1 Residential Service	Residential	Residential Schedule No. 1	E-12 with Proposed Increase
kWh (APS E-12 Summer Average)	738	738	738	738	738	738
Monthly Service Charge	$6.60	$6.00	$4.50	$2.88	$0.98	$7.70
Energy Charge	$0.06095	$0.09306	$0.11430	$0.06942	$0.06630	$0.07570
			$0.12989	$0.08095	$0.07600	$0.10556
Base Rate	$51.58	$74.68	$91.24	$60.32	$53.19	$73.65
Base Rate on a per kWh basis	$0.07	$0.10	$0.12	$0.08	$0.07	$0.10

Rates Exclude adjustors and taxes where applicable

EXHIBIT
ALL-STATE LEGAL®
Staff 25
LB 12/2/04
Admitted

ARIZONA CORPORATION COMMISSION STAFF

Calculation of Fair Value Rate Base Included in Paragraph 5 of the Settlement Agreement
($000)

A.	Original Cost Rate Base:	$3,826,968
B.	Recontruction Cost New Depreciated Rate Base:	$6,281,885
C.	Fair Value Rate Base: (A. + B.) / 2	**$5,054,426**

EXHIBIT
ALL-STATE LEGAL®
S-26
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN TEHREON, TO APROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.

Docket No. E-01345A-03-0437

NOTICE OF FILING RESPONSES TO COMMISSIONER INQUIRIES

Commission Staff hereby gives Notice of Filing Responses to Commissioner Inquiries in connection with the Settlement discussions in this docket. These Responses were compiled by Staff and represent the collective positions of the participants in Settlement negotiations.

RESPECTFULLY SUBMITTED this 18th day of August, 2004.

Christopher C. Kempley

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Janet Wagner, Attorney
Arizona Corporation Commission
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Original and 13 copies of the foregoing filed this 18th day of August, 2004, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Copy of the foregoing mailed this 18th day of August, 2004, to:

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RESPONSES TO COMMISSIONER ISSUES IN CONNECTION WITH PROPOSED SETTLEMENT OF DOCKET NO. E-01345-03-0437, ARIZONA PUBLIC SERVICE COMPANY REQUEST FOR RATE ADJUSTMENT

The Commissioners have identified issues for the Parties to consider in settlement discussions. This memorandum addresses those issues. Each of the commissioners' questions are summarized below.

I. Commissioner Mundell's May 6, 2004 Memorandum

A. Bill Estimation Procedures

In Docket No. E-01345A-03-0775, APS has asked the Commission to address its bill estimation procedures. Since this rate case will determine what rates APS' customers will be paying, please discuss as part of this rate case how those same customers' bills may and/or can be estimated.

While Staff recognizes the importance of this issue, Staff believes that the public interest will be best served by a comprehensive analysis, instead of an analysis that is focused solely upon APS. With that end in mind, the Process Standardization Working Group ("PSWG") is in the process of developing a statewide standard for electric utility bill estimation procedures. The PSWG was founded in 1999 after the Commission's enactment of the retail electric competition rules. Its members include representatives from APS, TEP, SRP, and the cooperatives. The PSWG develops methods for standardizing utility systems in order to facilitate coordination among utilities during and after the transition to competition. Because the PSWG routinely develops standards for utility operations, Staff believes that the PSWG will be able to provide some useful information on this issue. The PSWG anticipates completing this project by the end of this calendar year.

In addition, Staff is also analyzing APS' bill estimation procedures independently of the PSWG's efforts. Staff's review is ongoing. In light of these ongoing efforts, the proposed settlement agreement does not address this issue. Staff will file a report in docket No. E-01345A-03-0437 (the APS rate case docket) for the Commission's review before the commencement of the hearing on the Proposed Settlement.

B. Changes in Break-Over Points for Tiered or Seasonal Rates

APS currently has tiered rates (i.e., the more you use, the more you pay) for several of its customer classes. Please discuss the break-over points for these tiers and consider whether they should be modified based on more current usage data and conservation goals. The parties should explain why there should be or should not be any modifications to these break-over points.

In general, break-over points, which are also referred to as "rate blocks," are established to reach a pricing goal, such as tracking marginal cost, or a social goal, such as conservation or customer equity. Reducing or shifting rate blocks can cause unintended rate impacts for existing customers. For example, a change in break-over points coupled with a rate increase could result in some customers receiving a rate increase that substantially exceeds the system average. In order to avoid these types of results, the Parties have been cautious about changing the break-over points for APS' rates.

APS currently has approximately five residential and nine general service or miscellaneous tariffs that feature tiered or seasonal rates. A list of these specific rates and the number of customers subscribing to each follows:

Rate Schedule	Description	Number of Customers (2003 Avg.)
Residential		
E-10	Seasonal/Tiered (Frozen)	90,880
E-12	Seasonal/Tiered	383,661
EC-1	Seasonal (Frozen)	24,002
ECT-1R	Seasonal/TOU	43,557
ET-1	Seasonal/TOU	286,266
General Service		
E-21	Seasonal/TOU (Frozen)	27
E-22	Seasonal/TOU	18
E-23	Seasonal/TOU	146
E-24	Seasonal/TOU	48
E-30	Seasonal	4,530
E-32	Seasonal/Tiered	95,388
E-20	Seasonal/TOU	339
E-38	Seasonal/Tiered/TOU Option	152
E-221	Tiered/TOU Option	1,384

Regarding residential rates, the Agreement provides for the current rate structure and break-over points to remain in place. On APS' most common residential rate, E-12, the first break point occurs at the first 400 kWh, the second break point occurs at the second 400 kWh; and the third applies to all additional usage above 800 kWh.

Based on test year usage data for the test year summer months (May – October), approximately 32% of E-12 bills fall in the first block (first 400 kWh), and 30% fall in the second block (second 400 kWh). The average E-12 customer with a consumption of 770 kWh per month will be billed on the second block. Above average use customers (usage above 800 kWh) account for 38% of customer bills. This structure provides a lower rate for customers with a lower than average usage and a higher rate for customers with a higher than average usage. The Parties believe that this rate structure encourages conservation.

As to APS' general service rates, the predominant schedule with breakpoint and seasonality features is E-32. The E-32 rate, which applies to general service customers with demand less than three MW, accounts for ninety-four percent of APS' general service customers and is responsible for eighty-one percent of current general service revenue. The current rate includes a relatively complex series of declining blocks and block expanders, which can be confusing to customers, and has both a demand charge and four energy blocks.

The settlement agreement proposes a number of changes to E-32. First, the Settlement rates simplify the rate by reducing the number of energy blocks to two, with two demand blocks for customers with loads over twenty kW. Staff and APS believe that a simpler, more understandable rate will allow customers to better manage their electric usage. Second, the Settlement rates incorporate higher demand charges, which will encourage customers to manage their monthly peak load. Third, the rate will include a 100 kW billing break point in the demand portion of the rate to provide for smoother rate transitions as customers' loads change over time. In addition, the Settlement rates block the energy billing elements of the rate based on the customer's load factor, which will encourage more efficient utilization of the utility's investment in generation, transmission, and distribution systems. Finally, Paragraph 57 of the Settlement Agreement requires APS to conduct a study analyzing rate design modifications to encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand.

C. Discounts for Automatic Customer Payments

Please discuss why APS does not offer a discount to its customers for automatic payment of their bills. Please discuss the possibility of including this type of discount in APS' tariffs as part of this rate case.

In Decision No. 61976, the Commission gave APS authority to provide for a one-time payment of $10.00 to customers choosing automatic payment. Commissioner Mundell correctly notes that APS' tariffs do not otherwise provide for discounts for customers who choose automatic payment.

Although APS has not elected to provide the one-time discount at this time, 12.6 percent of APS' residential customers, 8.5 percent of its general service customers, and 12.1 percent of all APS customers participate in Surepay, its automatic payment plan. According to APS, E-Source/Platts, an independent energy industry information service, reports that national participation rates in such programs average nine percent for residential customers and four percent for non-residential customers. APS also points to a 2003 report by Chartwell, an information technology management consulting firm, that estimates national participation in such programs to average between eight and twelve percent. These statistics suggest that APS' customer participation levels for its automatic payment program are at least comparable to national levels even in the absence of an ongoing discount.

At present, APS believes that discounts would be uneconomic. A discount might increase customer participation in the automatic payment program. APS believes, however, that any increase in cash flow and minor reduction in bill processing expenses resulting from such increased customer participation would be more than offset by the discount. In other words, the potential cost savings from increased customer participation would not cover the costs of ongoing discounts. As a result, customers who elect to forego the automatic payment option would end up paying for the ongoing discount enjoyed by those who choose automatic payment.

At this time, the Parties do not propose to require changes to the discounts for customers electing automatic payment.

D. School District Issue

At a public comment session, many school district representatives spoke of the hardship of incorporating any rate increase into their already approved budgets. Please discuss the possibility of phasing in any rate increase that would apply to school districts. The thought behind this request is to allow the school districts time to get any Commission approved rate increase incorporated into their budgets.

At the April 7, 2004 public comment session, several school districts stated that an increase in electric rates would be burdensome, especially because the state legislature was considering eliminating "excess utilities" funding. A.R.S. § 15-910 provides that excess utilities costs are exempt from a school district's revenue control limit for budgeting until at least the end of the 2008-09 budget year. Senate bill 1405 (46th Leg., 2d Sess. 2004) originally proposed to continue a cap on excess utilities funding that was enacted in prior legislation. This provision of S.B. 1405 was stripped out in a house floor amendment (Amendment No. 4570). As a result, the final version of the bill does not contain a cap on excess utilities funding. Accordingly, the excess utilities funding provided in A.R.S. § 15-910 will be available through the 2008-09 budget year.

Although the settlement agreement does not propose to phase in rates applicable to school districts, it does include several provisions that will benefit both schools and other general service customers. First, the agreement proposes a rate increase that is substantially lower than that originally proposed by APS. Second, the agreement's proposed changes to Rate E-32 will tend to reduce the rate impacts to lower load factor E-32 customers, such as schools. Finally, the Agreement proposes to substantially increase DSM funding, which will provide further opportunities for school districts to manage their electric utility costs. Specifically, the Preliminary Energy Efficiency Plan, Appendix "B" to the Agreement, includes the development of energy efficient schools, retrofitting schools, and financial incentives for schools to make energy efficient investments. Some school organizations joined AECC during the course of the Settlement negotiations. AECC actively participated in the negotiations.

II. Commissioner Gleason's May 10, 2004 Letter

A. Wholesale and Retail Competition

What principles should the parties include in any settlement that would promote wholesale and retail electric competition and would provide APS customers with a meaningful choice of suppliers of competitive services?

The settlement agreement provides a number of provisions that are designed to promote both wholesale and retail competition.

1. Section IX of the Agreement sets forth detailed provisions to encourage the development of the wholesale market:

a. The settlement agreement provides for restrictions on APS' ability to self-build new, large central station generation with an in-service date before 2015, subject to a safety mechanism that permits APS to seek an exemption from the Commission if the wholesale market cannot cost effectively meet the needs of APS' customers.

b. APS has also committed to issuing a broad "all sources" RFP no later than the end of 2005 seeking at least 1,000 MW of long-term resources from the market. Neither PWEC nor any other APS affiliate will participate in that procurement.

c. The Agreement also provides for Commission workshops on resource planning. These workshops will focus on both infrastructure development and wholesale competitive procurement.

2. Several provisions of the Agreement are designed to foster retail competition:

a. The Agreement prohibits APS from requesting recovery of stranded costs that may be associated with the acquisition and rate basing of assets presently owned by Pinnacle West Energy Corporation ("PWEC").

b. APS has also agreed to recognize the existence of any Commission-approved direct access programs in its resource planning process.

c. The rate design for general service customers, who are the customers most likely to seek direct access, establishes charges for competitive services, such as generation, billing, metering, and meter reading, at cost of service. Specifically, the revenue requirement resulting from the Agreement, other than those associated with the Competition Rules Compliance Charge ("CRCC") or System Benefits Charge, shall be first applied to generation charges to bring them to full cost of service and then next applied to revenue cycle services to bring them to cost of service. Setting rates for these potentially competitive services to better reflect cost is intended to create opportunities for competitors. After generation and revenue cycle services have been appropriately priced, the residual general service revenue requirement will be assigned to wires services.

d. The Agreement provides that West Phoenix CC-4 and West Phoenix CC-5 shall be deemed local generation. During must-run conditions, generation from those units shall be available at FERC-regulated cost of service prices to electric service providers serving direct access load in the Phoenix load pocket.

e. The Agreement also provides for the Electric Competition Advisory Group ("ECAG") or similar stakeholder process to consider other retail competition issues on an industry-wide basis.

B. Shopping Credits

How should the APS "shopping credit" for competitive services such as generation and metering be recalculated to better promote electric competition? Please address an alternative method for calculation of the "shopping credit" for generation and other competitive services as compared to the method approved in Decision No. 61973 approving the APS stranded cost settlement.

The Agreement's proposed rate design regarding the calculation of the "shopping credit" is addressed in part 2.c of the previous answer. The Parties believe that this rate design appropriately addresses these issues at this time. In addition, the competition transition charge ("CTC") for customers choosing direct access will terminate on December 31, 2004. The elimination of the CTC effectively increases the "shopping credit," thereby raising the "price to beat" and creating opportunities for competitors.

C. Ring Fencing

What structural and legal "ring fencing" mechanisms should the Commission consider to maintain APS' separate corporate identify? Would additional oversight of affiliated transactions, dividend policies, securities issuances, ownership changes, diversification investments, and asset transfers be in the public interest?

APS believes that existing Commission rules and decisions suitably address the specific issues raised in this question, given the overall structure of the settlement agreement. These include the Commission's code of conduct; the various APS financing orders issued in 1984, 1986, and 2003, which limit APS' issuance of debt and other financing activities; the secondary procurement protocols in Track B, which address ongoing wholesale power procurement; and the Commission's existing affiliated interest rules, A.A.C. R14-2-801, et seq., which address affiliated transactions, securities issuances, diversification investments, and asset transfers.

By contrast, Staff believes that additional Commission oversight of APS' affiliated interests may be appropriate. In the Track A decision, the Commission concluded that the existing codes of conduct need additional provisions in order to cover APS and all affiliates in energy-related fields, including affiliates that sell power. Decision No. 65154 at 25. In Decision No. 65434, the Commission indicated that it was concerned about the lack of "regulatory insulation" between APS and its affiliates. In Decision No. 65796, APS' most recent financing case, the Commission required APS to maintain a minimum common equity ratio of forty percent as a condition of approving the application. Ultimately, some of these issues will be addressed in APS' code of conduct proceeding, Docket No. E-00000A-02-0051, et. al., which is scheduled to resume at the conclusion of this proceeding.

Although the Agreement does not purport to comprehensively resolve these issues, it does contain several related provisions that address them:

1. The competitive procurement provisions in Section IX require an independent monitor for any competitive procurement process that involves an APS affiliate.

2. The Agreement also provides for an initial Request for Proposals ("RFP") for at least 1,000 MW in which APS affiliates will not participate.

3. The self-build restrictions in Section IX provide for additional Commission oversight of future APS construction of new generation.

4. The Agreement provides for the continuation of APS' Secondary Procurement Protocol

III. Chairman Spitzer's May 14, 2004 Letter

A. Demand Side Management

Please consider the subject of demand side management/energy efficiency.

Section VII of the settlement agreement contains a comprehensive energy-efficiency demand side management ("DSM") initiative. The Agreement includes the following features: $10 million for energy-efficiency DSM in base rates, Commission oversight and pre-approval of energy-efficiency DSM programs, an adjustment mechanism to fund at least $6 million annually for such programs above the base-rate amount, systematic reporting of DSM results, and a Preliminary DSM Plan for 2005 (Appendix B). The Agreement also provides for the creation of a collaborative working group to assist in implementation of DSM. Additionally, the competitive procurement provisions in Section IX specifically refer to DSM as a resource that is eligible to participate in the 1,000 MW RFP. In this competitive procurement, DSM bids will be evaluated consistently with other bids, including life-cycle costs.

B. Wind Energy

Please consider whether wind energy could be a component of purchased power contracts to serve load.

The Settlement Agreement expressly recognizes that the costs of wind energy (and other renewable resources that are near market price) may be recovered through the Power Supply Adjustor ("PSA"). Section VIII of the Settlement Agreement addresses the mechanics of cost recovery of such renewable resources through the PSA, which under the Settlement Agreement would be acquired through a separate RFP for at least 100 MW of renewable resources in 2005. It also includes a commitment by APS to seek ten percent of its incremental capacity needs from renewable resources. In addition, the 1,000 MW RFP in Section IX is open to renewable resources.

IV. Commissioner Hatch Miller's May 14, 2004 Memo

A. Enhancing Residential Time-of-Use Rates

Please examine the possibility of enhancing APS' time of use ("TOU") programs for residential customers.

In the settlement agreement, the Parties have included an experimental TOU program to allow up to ten thousand residential customers to choose a TOU rate with an alternative TOU period. For example, the experimental program will offer participating customers the option of selecting among two alternative on-peak periods, 7:00 a.m. to 7:00 p.m. or 8:00 a.m. to 8:00 p.m., instead of the standard on-peak period of 9:00 a.m. to 9:00 p.m. A pilot program is necessary to test both customer reaction to the program and to assess the administrative burden on APS, as APS has indicated that reprogramming meters for these experimental programs will be costly and time consuming. The Parties have not proposed additional TOU pilot programs at this time.

Approximately thirty-nine percent of APS' residential customers are on TOU rates, as compared with approximately twenty percent of SRP's residential customers and approximately three percent of TEP's customers. These numbers indicate that APS already has extensive customer participation in its TOU rates.

In addition to the expansion of its residential TOU program, the Parties are proposing a general service TOU rate to provide additional options to APS' general service TOU customers. This option will be open to any qualifying general service customer. Paragraph 57 of the Agreement also requires APS to conduct a study analyzing rate design modifications that could encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand.

B. Changing Off- and On-Peak Hours

Please consider changing the timeframes of "off-peak" and "on-peak" hours, extending the duration of "off peak" hours, and including weekday holidays in the off-peak hours' designation.

In its direct testimony, APS proposed significant changes to Rates ET-1 and ECT-1R, its TOU rates for residential customers. Specifically, APS proposed eliminating the on-peak/off-peak distinction during the winter months and charging a flat rate, which would be calculated by averaging the existing on-peak and off-peak rates. This change would have eliminated the off-peak/on-peak customer price signals during the winter months.

In developing its testimony, Staff concluded that it was opposed to APS' proposal. Although APS' winter peak is not as dramatic as its summer peak, the Company nonetheless experiences peak periods of use in the winter months. Staff concluded that, instead of eliminating the off-peak/on-peak distinction in the winter months, it would be better to simply change the off-peak and on-peak periods to better correspond to the Company's actual winter peak. Staff also believes that APS should classify weekday holidays as off-peak periods.

APS, however, has identified significant meter reprogramming costs associated with implementing this change. APS claims that it cannot reprogram its meters in the field, but must instead remove them, reprogram them in its shops, and then reinstall them. As a result, APS estimates that including weekday holidays in the off-peak designation would take eighteen to twenty-four months and cost over $30 million.

Staff believes that APS should develop metering systems that will allow it to be more flexible in designing its TOU rates. As a result, the Parties have agreed that APS shall conduct a study to determine how to resolve these meter programming issues so that APS can better accommodate its customers when designing its TOU rates. The study analyzing possible rate design modifications provided by Paragraph 57 of the Agreement, and referenced above in Section IV.A. will provide additional impetus to this effort.

C. Eliminating or Reducing Residential Demand Charges

Please consider eliminating or reducing any demand charges imposed on residential customers.

Only two of APS' five residential rates, optional ECT-1R and EC-1, include a demand charge. APS believes that it is important to have an optional demand rate that accurately reflects cost causation to provide an appropriate price signal to residential customers.

Eliminating demand charges may adversely affect customers who have invested in demand control or have altered their lifestyles to take advantage of a rate schedule with a demand component. These rate schedules are voluntary, so customers who prefer to avoid demand charges may elect an energy-only rate schedule. The Parties have not proposed to eliminate residential demand charges at this time.

EXHIBIT
S-27
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	DOCKET NO. E-01345A-03-0437

SUMMARY OF

WITNESS TESTIMONY

OF

ERNEST G. JOHNSON

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

NOVEMBER 5, 2004

TESTIMONY SUMMARY

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

Mr. Johnson provides policy level testimony which summarizes the Settlement process, provides reasons which support Staff's conclusions that the Settlement Agreement is in the public interest and addresses several general policy considerations.

Staff's remaining witnesses will provide a detailed summary for each applicable subject area; by contrast, Mr. Johnson's testimony addresses the Settlement from a policy perspective. Mr. Johnson concludes that the Settlement Agreement is fair, balanced and in the public interest. Mr. Johnson asserts the following as support for Staff's conclusion that the Settlement Agreement is in the public interest:

- Staff believes that the agreement is fair to ratepayers because it precludes inappropriate utility profits and results in just and reasonable rates for consumers.

- Staff believes that it is fair to the utility because it provides revenues necessary for the utility to provide reliable electric service along with an opportunity for a reasonable profit.

- Staff believes that this proposal balances many diverse interests including those of low-income customers, the renewable energy sector, DSM advocates, merchant generators and retail energy marketers.

- Staff believes that the Agreement is in the public interest because it allows APS to rate base the PWEC Assets, which are the generating plants originally built by APS' affiliate, Pinnacle West Energy Corporation, at a value significantly below their book value.

- Although the Agreement calls for rate basing the PWEC Assets, it also addresses potentially anti-competitive effects associated with such rate basing. The Agreement adopts a self-build moratorium, provides for a competitive solicitation in 2005, and requires Staff to conduct workshops to address future resource planning and acquisition issues. In addition, the rate design section encourages general service customers, which are the customers most attractive to new competitors, to shop for competitive services by adopting cost-based unbundling for generation and revenue cycle services. These provisions are intended to promote competition.

- Staff believes that the Settlement eliminates long, complex litigation by resolving issues associated with prior Commission decisions that are currently on appeal (Track A and certain rate case issues). If the Agreement is approved, these appeals will be dropped.

- Staff believes that the Agreement promotes the public interest by facilitating the provision of reliable electric service at the lowest reasonable rates.

- The Agreement provides additional discounts to low-income APS customers, increases funding for advertising these discounts, and increases funding for APS' low-income weatherization program.

- The Agreement sets forth a comprehensive DSM proposal, which is intended to foster the development of new DSM programs. Significantly, the DSM section of the Agreement also includes provisions to ensure that DSM expenditures will be reasonable and that the Commission will be able to maintain appropriate oversight.

In its application, APS requested a rate increase of almost 10 percent. This increase was largely associated with the Company's desire to rate base the PWEC assets. Staff opposed rate base treatment of the PWEC assets thereby eliminating approximately 6 percent of the overall percentage increase.

We did that because, in our opinion, APS had failed to demonstrate that its request to rate base the PWEC units at a value of $889 million was warranted. We also stated that; if the Commission were inclined to rate base the PWEC assets that the amount allowed in rate base should be no more than the current value of the units, which we suggested was below their book value adjusted to reflect the value lost in foregoing the PWEC Track B contract. Under the Settlement Agreement, the PWEC assets would be rate based at a value of $700 million which is substantially less than the $889 million valuation as of the end of the test year.

Staff's decision to support rate basing the PWEC units is largely the result of the reduced valuation of the generation units, the ability to retain the benefits associated with the Track B Contracts, and enhancement of competitive wholesale and retail opportunities. Additionally, Staff considered the rebuttal arguments advanced by APS, particularly the testimony and analysis of Mr. Ajit Bhatti concerning:

- Resource additions for APS
- Higher efficiency and off-system sales associated with the combined-cycle units
- Resource Planning
- Market value of PWEC units

While much more persuasive than APS' original arguments, absent the benefits identified previously, Staff would oppose rate base treatment of the PWEC assets.

In concluding that the Settlement Agreement is in the public interest, Mr. Johnson notes that the Agreement addresses and resolves all of the main rate case issues, provides sufficient revenues and return for APS to maintain reliable electric service and results in rates and charges which Staff believes are just and reasonable.

EXHIBIT
5-28
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	DOCKET NO. E-01345A-03-0437

SUMMARY OF

WITNESS TESTIMONY

OF

LINDA A. JARESS

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

NOVEMBER 5, 2004

TESTIMONY SUMMARY

ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO. E-01345A-03-0437

The proposed Settlement Agreement is in the public interest not only because it represents a consensus of the vast majority of the parties, but also because it provides long-term benefits to the customers of APS and the citizens of Arizona. The reduction in the value of the Pinnacle West Energy Corporation assets included in rate base is a permanent reduction that will benefit customers for many years, until the assets are fully depreciated. The proposed increase in Demand Side Management spending, if approved, will have long-term effects by reducing APS' need for new generation. The provision requiring APS to issue a special RFP for renewables in 2005 is a positive step toward providing long-term improvements to the natural environment in Arizona.

Among other reasons that the Settlement Agreement is in the public interest is the elimination of certain court cases and the end of the preliminary inquiry, allowing affected parties to shift their resources to more productive ends. Furthermore, if adopted, the Settlement Agreement will further define APS' role in electric competition in Arizona and creates opportunities for merchant plants to sell power to APS. Finally, the Settlement Agreement is in the public interest because it settles, once and for all, the issue of the $234 million write-off (and possibly more) and APS' request that ratepayers pay for its reversal.

APS' application requested an increase in revenues from its customers of $175.1 million including a proposed additional Competition Rules Compliance Charge ("CRCC") of $8.3 million. Staff's direct testimony recommended a net reduction of $142.7 million which included a $7.4 million CRCC surcharge. The direct testimony of the Residential Utility Consumer Office supported a decrease of $53.61 million. Arizonans for Choice and Competition recommended adjustments to APS' request that resulted in a revenue requirement increase of approximately $25.0 million. Ultimately, the parties agreed to a base rate increase of $67.6 million with an additional CRCC surcharge of $7.9 million, for a total increase of $75.5 million.

By supporting the Settlement Agreement and its benefits, Staff's movement from its recommended revenue requirement decrease in its direct case to the $75.5 million increase resulting from the Settlement Agreement is significant. The revenue requirement impact from ratebasing the Pinnacle West Energy Corporation assets at $700.0 million, by itself, increases Staff's recommended revenue requirement by approximately $76 million. The adoption by the Settlement Agreement of more current fuel and purchased power expenses increases the revenue requirement proposed by Staff by approximately $34 million. The negotiated capital structure and cost of debt and equity levels also had a significant effect, increasing the revenue requirement by approximately $35 million. Similarly, the resolution of depreciation issues and nuclear decommissioning expense issues results in an increase to

Staff's revenue requirement position of approximately $33 million. The main body of Ms. Jaress' testimony sets forth the rationale for Staff's adoption of these adjustments.

The listed amounts do not total the entire difference between the revenue requirement derived from the Settlement Agreement and the revenue requirement in Staff's direct testimony. It is important to remember that the revenue requirement reflected in the Settlement Agreement and adopted by Staff was derived as a result of consideration of specific revenue impacting adjustments <u>and</u> non-revenue impacting adjustments.

EXHIBIT
ALL-STATE LEGAL®
S-29
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATE MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT	DOCKET NO. E-01345A-03-0437

SUMMARY OF

SEPTEMBER 27, 2004 STAFF REPORT

OF

MATTHEW ROWELL

IN SUPPORT OF THE PROPOSED SETTLEMENT AGREEMENT

NOVEMBER 5, 2004

STAFF REPORT SUMMARY

ARIZONA PUBLIC SEVICE COMPANY

DOCKET NO. E-01345A-03-0437

On August 18, 2004, a proposed Settlement Agreement of Arizona Public Service Company's ("APS") pending rate case was docketed. That agreement contained proposed resolutions of issues regarding the treatment of Pinnacle West Energy Corporation's ("PWEC") Arizona generation assets. The agreement also contains several provisions that are pertinent to competition in the wholesale and retail electric markets in Arizona.

The PWEC Assets

The parties to the Settlement Agreement agreed that APS should be allowed to acquire and rate base the following PWEC generating units: West Phoenix CC-4, West Phoenix CC-5, Saguaro CT-3, Redhawk CC-1, and Redhawk CC-2 (collectively, the "PWEC Assets"). In order to recognize the ratepayer benefits associated with the Track B contract, $148 million of the PWEC Assets' value will be disallowed, which results in an original cost rate base value of $700 million as of December 31, 2004.

The Settlement's resolution of issues regarding the treatment of PWEC's Arizona generation assets represents a departure from the primary position taken in Staff's direct case laid out in Mr. Harvey Salgo's February 3, 2004 testimony. However, the Settlement's treatment of the PWEC assets is largely consistent with Staff's alternative recommendation (also laid out in Mr. Salgo's February 3, 2004 testimony.) Specifically, Staff's direct case suggested the alternative of rate basing the PWEC assets at a reduced value.

Staff's direct case was driven by our belief that APS did not put forward a case that would justify inclusion of the assets at full book value. APS' direct case justified inclusion of the PWEC assets based mainly on, what Staff would characterize as, an equity argument, i.e. that Pinnacle West Capital was damaged by the Track A Order and thus rate basing the PWEC assets was justified. Staff did not believe that such an equity argument was sufficient to support the inclusion of assets that would have a revenue requirement effect of approximately $100 million.

Mr. Salgo's testimony pointed to several deficiencies in APS' direct testimony, the most important of which was that APS' proposal did not account at all for the value of the Track B contract between PWEC and APS. Mr. Salgo also indicated that APS had not established that the PWEC assets were the most efficient option available for reliably serving APS' customers' needs. In APS' rebuttal case, witness Ajit Bhatti presented several economic studies that support APS' contention that the PWEC assets were in fact an economical choice. For example, Mr. Bhatti's rebuttal testimony demonstrated that the choice to build combined cycle plants rather than combustion turbine plants (in spite of the combustion turbines' lower capital costs) was justified by the greater efficiency of combined cycle plants. Additionally, the responses to APS' last formal request for proposal did not indicate to Staff that the market would provide a superior alternative to the rate basing of the PWEC plants.

What primarily drove Staff's decision to agree to the terms of the settlement regarding the PWEC assets was the agreed upon rate base value of $700 million. This represents a discount of $148 million from the assets' end of 2004 depreciated value. The $148 million is a reasonable estimate of the value of the Track B contract and represents a long term benefit to APS' customers. The $148 million adjustment will have a downward impact on APS' revenue requirement in every rate case the company will file with the Commission in the foreseeable future. Staff believes that rate basing the PWEC assets, within the context of the other provisions of the Settlement agreement, is a good deal for APS' customers in the long term.

Resolving the PWEC assets issues ends a long standing dispute between APS and the Commission which allows both APS and the Commission to spend time and resources on more positive endeavors such as DSM, the promotion of renewable resources, and the development of competition (all of which the Settlement agreement also supports.)

The $234 million write off

The Settlement Agreement provides that APS will not recover (now or in any subsequent proceeding) the $234 million write-off attributable to Decision No. 61973, the Commission order that approved the 1999 APS Settlement Agreement. This is not a deviation from the position taken in Staff's direct case.

Competitive Procurement of Power

The Settlement Agreement includes provisions intended to enhance the wholesale market in Arizona while still protecting retail customers. APS agrees that it will not pursue any self-build option having an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. This provision does not prevent APS from purchasing a generation plant from a merchant or a utility.

APS will issue an RFP or other competitive solicitation(s) no later than the end of 2005 seeking long-term future resources of not less than 1000 MW for 2007 and beyond.

The Commission Staff has agreed to schedule workshops on resource planning issues that focus on developing needed infrastructure and developing a flexible, timely, and fair competitive procurement process.

None of these provisions are inconsistent with Staff's positions put forth in its direct case. However, APS' commitment to these pro-competitive provisions did serve to mitigate Staff's concerns regarding the rate basing of the PWEC assets.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

SUMMARY OF

SEPTEMBER 27, 2004 STAFF REPORT ON

ADJUSTMENT MECHANISMS
CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

BY

ROBERT GRAY AND BARBARA KEENE

NOVEMBER 26, 2004

The proposed settlement agreement in the Arizona Public Service (APS) rate proceeding contains provisions for implementing various adjustment mechanisms. These include the Power Supply Adjustor (PSA), the Demand Side Management (DSM) Adjustor, the Environmental Portfolio Standard (EPS) Adjustor, the Competitive Rules Compliance Charge (CRCC), the Returning Customer Direct Access Charge (RCDAC), and the Transmission Cost Adjustor (TCA). The DSM Adjustor and EPS Adjustor are discussed in the Staff Report and panel on Demand-side Management, Renewables, and Distributed Generation.

The structure and features of the adjustors are the result of settlement negotiations on a wide variety of issues in this case. Staff believes that the PSA, through a variety of provisions, reasonably balances the interests of ratepayers and APS while providing a measure of both certainty and flexibility in the future treatment of the PSA. As part of the overall settlement agreement, the adjustor mechanisms are in the public interest.

Power Supply Adjustor

The implementation of an adjustor mechanism such as the PSA entails a wide range of considerations which must be weighed carefully to ensure that such a mechanism is in the public interest. Adjustor mechanisms by their nature attempt to balance a variety of possible goals, such as certainty, flexibility, price stability, sending a price signal as prices change, and providing a reasonable opportunity to recover prudently incurred costs. The PSA contained in the proposed settlement agreement contains a variety of provisions which addresses both the interests of ratepayers and APS in a reasonable fashion. While no adjustor mechanism can fully protect ratepayers from the underlying volatility of energy markets, the proposed PSA helps shield ratepayers from price volatility through the provision of regular adjustments of the adjustor rate, the inclusion of a bandwidth limiting the amount of automatic adjustment in the adjustor rate, and the provision of the opportunity for cost recovery of the costs of hedging fuel and purchased power costs. Further, APS is motivated to minimize the cost of fuel and purchased power through a 90/10 sharing mechanism.

In Staff's direct case, Staff was concerned about potential over recovery of fixed costs due to load growth. Staff was willing to support an adjustor that would include fuel costs and a credit for revenues associated with sales for resale (off-system sales) in addition to purchased power costs, but Staff also believed that the PSA should include features to address the potential over recovery of fixed costs due to load growth. In APS' rebuttal case, APS states that, over the last five years, the Company's fixed costs have increased at about the same rate as sales growth over the same period. The PSA in the proposed agreement recognizes fuel costs and off-system sales as recommended in Staff's direct case.

Also in Staff's direct case, Staff felt that there was a need for an incentive, such as a deadband, for APS to hedge and otherwise keep down fuel and purchased power costs. APS, in its rebuttal case, proposed the 90/10 sharing mechanism that gives APS such an incentive to keep down costs. The proposed settlement agreement includes the 90/10 sharing mechanism, a form of a deadband, among the features of the PSA.

The five-year life of the PSA and related provisions protect the public interest by providing the opportunity to review the PSA mechanism in the future for possible modification or termination while also providing APS with a level of certainty regarding the method of cost recovery for its substantial fuel and purchased power costs. Such flexibility is important given the new nature of the proposed PSA and the uncertainty regarding what future conditions will be in the electricity industry.

The settlement contains strong safeguards which enable the Commission to review costs which APS would be passing through to its customers via the PSA. The settlement provides a commitment by APS to provide a wide variety of information related to the operation of the PSA on a monthly basis, which will assist the Commission and other interested parties in monitoring and assessing the operation of the PSA. Additionally, the settlement agreement specifically recognizes that the Commission can review the prudence of fuel and purchased power costs at any time. In summary, Staff believes the adjustor provisions contained in the proposed settlement agreement are in the public interest, as they reasonably balance the interests of ratepayers and APS and provide a variety of incentives to the Company to manage the PSA in a manner which is beneficial to its ratepayers while also providing the opportunity to address any problems which may arise in the future operations of the PSA.

Competitive Rules Compliance Charge

The settlement agreement includes the CRCC, which would enable APS to recover costs related to the transition to retail competition. APS would recover a maximum of $47.7 million plus interest through a charge of $0.000338 per kWh over a five-year collection period.

In Staff's direct case, Staff recommended that APS' proposed $49.3 million for the CRCC be reduced by removing ISO/RTO expenses, payroll-related expenses, and Track B expenses. In APS' rebuttal case, APS explained why the payroll-related expenses were necessary. APS also stated that Track B expenses should not be excluded from the CRCC because the Track B process was a Commission-ordered program related to the electric competition rules. The proposed settlement agreement continues to exclude the ISO/RTO expenses from the CRCC because APS should seek recovery of those costs through FERC-jurisdictional rates.

Returning Customer Direct Access Charge

The settlement agreement provides for an RCDAC which would apply only to large customers who return to standard offer service from direct access service and otherwise would impose costs on other standard offer customers. Staff's support for the RCDAC is consistent with Staff's direct case.

Transmission Cost Adjustor

The proposed TCA would apply only to costs related to changes in APS' open access transmission tariff or the tariff of an RTO or similar organization. The TCA would not go into effect until APS' transmission component of retail rates exceeds the test year base of $0.000476 per kWh by five percent. Staff supported a TCA in its direct case.

EXHIBIT
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BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

SUMMARY OF

SEPTEMBER 27, 2004 STAFF REPORT ON

RATE DESIGN, LOW INCOME PROGRAMS, AND SERVICE SCHEDULES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

BY

ERINN ANDREASEN
AND
BARBARA KEENE

November 26, 2004

The proposed settlement agreement addresses certain rate design, service schedule and low income provisions. Staff believes that the provisions regarding rate design and service charges are in the public interest.

Revenue Allocations

Staff has supported a revenue allocation that reflects cost of service considerations. This cost of service consideration was reflected in both Staff's recommended revenue allocations in its direct case and in its settlement position. Under the proposed settlement, the system average increase to base rates would be 3.77 percent. Residential rates would be increased by 3.94 percent and general service rates would be increased by 3.56 percent.

Residential Rates

In its direct case, Staff supported APS' request to phase out frozen rates E-10 and EC-1 with certain conditions, including a one-year phase out period and providing notice to customers. Under the proposed settlement agreement, Schedule E-10 and EC-1 would remain frozen and be retained with the intent to eliminate these rates in APS' next rate case proceeding. APS would provide a Staff-approved notice to customers on E-10 and EC-1.

In its rate application, APS proposed to increase basic service charges on certain residential rate schedules. In its direct case, Staff recommended that basic service charges should reflect cost but that no residential basic service charges should be increased by more than 5 percent. In the proposed settlement, the basic service charges are maintained for residential service schedules with the exception of E-12 which has been increased by 2.61 percent.

In its rate application, APS proposed to eliminate its winter peak differentiated pricing for its residential time-of-use rates. In its direct case, Staff supported maintaining on- and off-peak price signals during the winter period. In addition, Staff supported adopting time-of-use periods that reflect the actual time of system peak. Under the proposed settlement, APS would maintain its current on- and off-peak rates for the winter billing period and submit a study to Staff regarding flexibility in implementing on-and off-peak periods.

Under the proposed settlement, APS' proposed residential experimental time-of-use periods are adopted. The experimental periods would provide a limited number of customers with the option of selecting alternative on-peak time periods. In its direct case, Staff supported the adoption of APS' proposed experimental time-of-use periods.

General Service and Classified Rates

Under the proposed settlement, rate E-32 has been redesigned in an effort to simplify the rate. When designing the rate, consideration was given to smoothing out the rate impacts across customers of varying sizes. Changes include the addition of an energy block for customers with loads under 20 kW and the addition of a demand billing block for customers with loads greater than 100 kW. In its direct case, Staff supported the simplification of rate E-32.

Under the proposed settlement agreement, a new rate schedule, E-32 TOU, would be adopted to provide general service customers with an additional time-of-use rate. This rate would include on- and off-peak pricing signals. In its direct case, Staff supported the adoption of E-32 TOU with the adoption of on- and off-peak winter rates.

Under the proposed settlement, frozen rates E-38 and E-38T would not be eliminated in this proceeding as APS proposed in its initial application. These rate schedules would be retained with the intent to eliminate these rates in APS' next rate case proceeding. A Staff-approved notice would be provided to customers.

Under the proposed settlement agreement, the changes to the rate structure for lighting tariffs E-47 and E-58 proposed in APS' application would be adopted.

Under the proposed settlement, the existing 11:00 a.m. to 9:00 p.m. on-peak time periods would remain in effect for general service time-of-use customers, and the summer rate period would begin in May and conclude in October.

In its rate application, APS proposed to eliminate experimental time-of-use rates E-21, E-22, E-23, and E-24. Under the proposed settlement, experimental time-of-use schedules E-22, E-23, and E-24, would be frozen. Experimental time-of-use schedule E-21, which had previously been frozen, and E-22, E-23, and E-24 would be retained with the intent to eliminate these rates in APS' next rate case proceeding. APS would provide a Staff-approved notice to customers on these schedules.

APS' current time-of-use rate schedule, E-20, would be frozen.

Under the proposed settlement, transmission and primary voltage discounts are provided for certain general service rates which include military base customers that are served directly from APS substations.

<u>Low Income Programs</u>

The discount levels were increased for both the E-3 and E-4 tariffs. In addition, APS would increase its annual funding for marketing its E-3 and E-4 tariffs to $150,000.

<u>Service Schedules</u>

Under the proposed settlement, Schedules 1, 3, 4, 7, 10, and 15 would be modified. These changes are consistent with Staff's position in its direct case.

EXHIBIT
S-32
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BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

SUMMARY OF

SEPTEMBER 27, 2004 STAFF REPORT ON

DEMAND-SIDE MANAGEMENT, RENEWABLES, AND DISTRIBUTED GENERATION ISSUES CONTAINED IN THE PROPOSED SETTLEMENT AGREEMENT

BY

BARBARA KEENE

NOVEMBER 26, 2004

The proposed settlement agreement contains provisions regarding demand-side management (DSM), renewables, and distributed generation. These provisions are the result of settlement negotiations on a wide variety of issues in this case. As part of the overall settlement agreement, these provisions are in the public interest.

The settlement agreement is in the public interest because of the following:

- The agreement provides for APS to implement considerably more DSM than is being done today, resulting in customer savings, utility cost reductions, and reduced impact on the environment.

- The agreement provides safeguards to ensure that the level of DSM expenditures will be reasonable, including Commission approval of programs, unspent amounts in base rates being returned to customers, and APS filing semi-annual reports on its DSM programs.

- The agreement provides for expenditures for low income weatherization and bill assistance to more than double over test-year expenditures.

- The agreement provides for the establishment of a collaborative DSM working group to provide APS with input on program development, implementation, and performance.

- The agreement changes the Environmental Portfolio Standard (EPS) surcharge into an adjustment mechanism to allow for flexibility in funding the EPS if the Commission were to approve a funding change.

- The agreement provides for APS to issue an RFP in 2005 seeking renewable resources that should help provide further diversity to APS' generation portfolio.

Demand-side Management

The settlement agreement provides for APS to spend $10 million each year through base rates for DSM, plus another $6 million per year through an adjustment mechanism. In Staff's direct case, Staff had wanted APS to do more DSM but had recommended a lower level of funding: a cap of $4 million per year to be collected through an adjustment mechanism. Staff had been most concerned about APS being able to ramp up to a higher level of spending in a short time. However, the settlement agreement provides that if APS does not spend the total $30 million in base rates from 2005 through 2007, the unspent amount would be returned to ratepayers through the DSM adjustor in 2008.

Environmental Portfolio Standard

In regard to the Environmental Portfolio Standard, APS would continue to recover $6 million annually in base rates as recommended by Staff in its direct case. The existing EPS surcharge, which provided $6.5 million during the test year, would be converted into an adjustment mechanism to allow for Commission-approved changes to APS' EPS funding. Although Staff had not contemplated in its direct case that the surcharge become an adjustor, Staff agrees with others that there is value in the flexibility of an adjustor because it would allow for Commission-approved changes in the amount of EPS revenue collected.

Special RFP

APS would issue a special RFP in 2005 for at least 100 MW and 250,000 MWh per year of renewable energy resources for delivery beginning in 2006. Either in this solicitation or in subsequent procurements, APS would seek to acquire at least 10 percent of its annual incremental peak capacity needs from renewable resources. Although Staff had not contemplated such an RFP in its direct case, Staff sees the value of the RFP in helping to provide APS with more diversification in its supply portfolio.

Distributed Generation

The settlement agreement provides for Staff to schedule workshops to consider outstanding issues concerning distributed generation. The workshops may be followed by rulemaking. Although Staff had not addressed the subject of distributed generation in its direct case, Staff understands that distributed generation can provide value and that these issues should be addressed.

SWEEP

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Attorneys for Southwest Energy Efficiency Project

BEFORE THE ARIZONA CORPORATION COMMISSION

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CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON
KRISTIN K. MAYES

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.	Docket No. E-01345A-03-0437 **NOTICE OF FILING SUMMARY OF TESTIMONY**

Southwest Energy Efficiency Project, through its undersigned counsel, hereby provides notice that it has this day filed the written summary of the testimony of Jeff Schlegel in connection with the above-captioned matter.

Admitted
EXHIBIT
SWEEP 1
LB 4/30/04

DATED this 23rd day of November, 2004.

ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST

By ______________________

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Attorneys for Southwest Energy Efficiency Project

ORIGINAL and 13 COPIES of the foregoing filed this 23rd day of November, 2004, with:

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Docket Control
Arizona Corporation Commission
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Phoenix, AZ 85007

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All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Summary of Settlement Testimony

Jeff Schlegel
Southwest Energy Efficiency Project (SWEEP)

November 23, 2004

Summary of Settlement Testimony
Jeff Schlegel, SWEEP

Arizona Public Service Company Rate Case Settlement
Docket No. E-01345A-03-0437

The Southwest Energy Efficiency Project (SWEEP) supports the APS rate case settlement agreement and recommends that the Commission adopt the settlement.

The settlement agreement was developed through a fair and inclusive negotiation process, with give and take among the parties and their positions. It represents a reasonable balancing of the issues in the case and the interests of the parties. The settlement agreement is supported by almost all parties to the case.

The increase in energy efficiency DSM efforts, funding, and programs will result in significant benefits for APS customers, the electric system, the economy, and the environment. Implementing the energy efficiency and DSM provisions set forth in the settlement agreement will result in meaningful positive net benefits (benefits that exceed costs) for APS customers, thereby demonstrating that the provisions are in the public interest.

Comparison of Settlement Position and Original Position

The key energy efficiency and DSM provisions in the settlement agreement, SWEEP's support for the provisions, and comparisons to SWEEP's original positions are summarized below.

<u>Original Position</u>:
The Commission should substantially increase energy efficiency in the APS service territory. Specifically, the Commission should set goals to achieve 7% of total energy resources needed to meet retail load in 2010 from energy efficiency, and 17% in 2020. The Commission should provide adequate funding to achieve the energy efficiency goals. SWEEP estimates that energy efficiency funding of $0.0015 per kWh of retail energy sales (1.5 mills), or about $35 million in the 2002 Test Year, is necessary to achieve the goals. A full portfolio of effective and cost-effective energy efficiency programs should be implemented in the APS service territory to achieve the energy efficiency goals.

<u>Settlement Agreement</u>:
The increase in energy efficiency DSM funding, to $16 million total annually and at least $48 million over 2005-2007, is reasonable and justified given the cost-effective benefits that will be achieved. While the funding level is less than SWEEP proposed originally, the increase is a valuable and meaningful step towards encouraging and supporting increased energy efficiency for APS customers. Therefore, SWEEP supports the proposed funding level set forth in the settlement agreement.

APS may request Commission approval for additional DSM program funding that exceeds $16 million annually, through the DSM adjustment mechanism, including for demand response and additional energy efficiency programs, thereby providing additional funding flexibility. This is an important provision that made it possible for SWEEP to accept a lower energy efficiency funding level in the settlement agreement.

The settlement agreement does not include goals for energy savings or peak demand reductions. After discussions during the settlement process and at the DSM Workshops, SWEEP now believes that the DSM plans would be an appropriate document in which to propose overall policy goals and program-specific goals for Commission review and consideration, partly because the plans will include supporting documentation. SWEEP plans to propose such goals in the DSM plans or in other forums before the Commission.

The Preliminary Energy Efficiency DSM Plan (Appendix B) summarizes a portfolio of effective and cost-effective energy efficiency programs to achieve meaningful energy savings and demand reductions. Implementing the portfolio of programs in the Preliminary Plan will ensure that all customers will have an opportunity to participate in and benefit directly from the energy efficiency programs. APS is required to develop a final plan for Commission review and approval before the programs can be implemented.

A collaborative working group will be implemented to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance. The collaborative working group will provide a valuable forum for stakeholder input and review, thereby increasing stakeholder support for the cost-effective programs ultimately proposed to the Commission. SWEEP plans to participate in the collaborative working group and views it as an additional opportunity to ensure effective and cost-effective DSM programs to benefit APS customers.

<u>Original Position</u>:
The Commission should act in a timely manner to increase energy efficiency in Arizona. Each day that passes without effective energy efficiency programs means more inefficient load is added to the electric system in this high load growth state, leading to higher total costs for customers, a less diverse and riskier energy resource mix, and increased damage to the environment.

<u>Settlement Agreement</u>:
SWEEP supports the settlement agreement as a meaningful step towards increasing energy efficiency in the APS service territory in a timely manner, given where we are now. At the time of settlement, SWEEP considered its support for the settlement agreement to be a less time consuming approach than returning to protracted litigation.

To ensure effective and appropriate Commission oversight, the settlement agreement requires that all energy efficiency and DSM programs be reviewed and pre-approved by the Commission. SWEEP is discussing potential programs and program designs with APS and other stakeholders informally in the hope that proposed energy efficiency programs could be submitted to the Commission reasonably soon after Commission approval of the settlement agreement.

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Attorneys for Western Resource Advocates

BEFORE THE ARIZONA CORPORATION COMMISSION

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

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.	Docket No. E-01345A-03-0437 **NOTICE OF FILING TESTIMONY**

Southwest Energy Efficiency Project, through its undersigned counsel, hereby provides notice that it has this day filed the written testimony of Jeff Schlegel in connection with the above-captioned matter.

Admitted
EXHIBIT
Sweep 2
LB 12/2/04

DATED this 27th day of September, 2004.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By [signature]
Timothy M. Hogan
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
Attorneys for Western Resource Advocates

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of September, 2004, with:

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Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing
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this 30th day of March, 2004, to:

All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Settlement Testimony of

Jeff Schlegel
Southwest Energy Efficiency Project (SWEEP)

September 27, 2004

Settlement Testimony of Jeff Schlegel, SWEEP
Docket No. E-01345A-03-0437

Table of Contents

Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom and in what capacity are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP). I am the Arizona Representative for SWEEP.

Q. Please describe the Southwest Energy Efficiency Project.

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection in the six states of Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming. SWEEP works on state energy legislation, analysis of energy efficiency opportunities and potential, expansion of state and utility energy efficiency programs as well as the design of such programs, building energy codes and appliance standards, and voluntary partnerships with the private sector to advance energy efficiency. SWEEP is funded primarily by foundations, the U.S. Department of Energy, and the U.S. Environmental Protection Agency.

Q. Did you file testimony in this matter previously?

A. Yes. I filed direct testimony on February 3, 2004, and I filed cross-rebuttal testimony on March 30, 2004. My qualifications are attached to my direct testimony.

Q. What is the purpose of your settlement testimony?

A. My testimony documents SWEEP's position on the settlement agreement, focusing primarily on the demand-side management (DSM) and energy efficiency provisions, particularly Section VII.

Q. Did you participate in the settlement negotiations?

A. Yes. I attended or participated in the settlement conferences, and I worked with APS, Commission Staff, RUCO, and the other parties to reach the settlement agreement filed with the Commission.

Summary of Testimony

Q. Does SWEEP support the settlement agreement?

A. Yes. The settlement agreement is in the public interest. The settlement was developed through a fair and inclusive negotiation process, and it represents a reasonable balancing of the issues in the case and the interests of the parties. The settlement agreement is supported by almost all parties to the case.

Q. Does SWEEP support the energy efficiency and DSM provisions in the settlement agreement?

A. Yes. The increase in energy efficiency efforts, funding, and programs will result in significant benefits for APS customers, the electric system, the economy, and the environment. Implementing the energy efficiency and DSM provisions set forth in the settlement agreement will result in meaningful positive net benefits (benefits that exceed costs) for APS customers, thereby demonstrating that the provisions are in the public interest.

Benefits of Increasing Energy Efficiency

Q. What are the benefits of increasing energy efficiency?

A. Increasing energy efficiency will provide significant and cost-effective benefits for APS customers (residential consumers and businesses), the electric system, the economy, and the environment. Increasing energy efficiency will save consumers and businesses money through lower electric bills, resulting in lower total costs for customers. Increasing energy efficiency will also reduce load growth, diversify energy resources, enhance the reliability of the electricity grid, reduce water use for power generation, reduce air pollution and carbon emissions, and create jobs and improve the economy. In addition, meeting load growth through increased energy efficiency can help to relieve system constraints in load pockets.

By reducing electricity demand, energy efficiency mitigates market and fuel price increases and reduces customer vulnerability to price volatility.

Energy efficiency is a reliable energy resource that costs less than other resources for meeting the energy needs of customers in the APS service territory. The total cost for energy efficiency savings is 2 to 3 cents per lifetime kWh saved, delivered to the customer. This is less than the cost of conventional generation, transmission, and distribution, and significantly less than the total delivered cost of energy from new natural gas-fired plants.

Energy Efficiency and DSM Provisions in the Settlement Agreement

Q. Please describe the key energy efficiency and DSM provisions in Section VII of the settlement agreement.

A. The key energy efficiency and DSM provisions in Section VII, and SWEEP's support for the provisions, are summarized below.

The increase in energy efficiency DSM funding, to $16 million total annually and $48 million over 2005-2007, is reasonable and justified given the cost-effective benefits that will be achieved. The increase in the funding level is a valuable and meaningful step towards encouraging and supporting increased energy efficiency for APS customers. The energy efficiency funding level of $16 million annually would be equivalent to about $0.65 per month for the average APS residential customer in 2005.

The $16 million in annual energy efficiency DSM funding will consist of $10 million in base rates plus at least $6 million through the DSM adjustment mechanism. APS may request Commission approval for additional DSM program funding that exceeds $16 million annually, including for demand response and additional energy efficiency programs, thereby providing additional funding flexibility.

The agreement requires low income weatherization funding of at least $1 million annually, as part of the $16 million of annual energy efficiency DSM funding (the low income funding is part of the $10 million of DSM funding in base rates). This is an increase of at least $500,000 above the current funding level of $500,000 annually.

The Preliminary Energy Efficiency DSM Plan (Appendix B) is a portfolio of effective and cost-effective energy efficiency programs to achieve meaningful energy savings and demand reductions. The programs will help consumers and businesses adopt cost-effective energy efficiency measures through education, financial incentives, training, technical assistance, and other mechanisms. Implementing the portfolio in the Preliminary Plan will ensure that all customers will have an opportunity to participate in and benefit directly from the energy efficiency programs. APS is required to develop a final plan for Commission review and approval before the programs can be implemented.

In general, I recommend a broad and diverse mix of energy efficiency strategies, not simply consumer rebates, and not just consumer information. The most effective energy efficiency programs employ a combination of strategies targeted to reduce or overcome the key barriers to energy efficiency in the marketplace. The Preliminary Energy Efficiency Plan (Appendix B) includes the comprehensive set of strategies that SWEEP recommends be considered in the detailed program planning process.

APS will have the opportunity to earn a performance incentive based on a share of net economic benefits (benefits minus costs) achieved by the energy efficiency programs, capped at 10% of total spending. This performance incentive is a positive mechanism to encourage APS to be effective and cost-efficient in administration, program design, and implementation. The settlement agreement does not provide for the recovery of net lost revenues, thereby reducing the cost of DSM to ratepayers relative to past Commission practice.

A collaborative working group will be implemented to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance. The collaborative working group will provide a valuable forum for stakeholder input and review, thereby increasing "buy-in" and stakeholder support for the cost-effective programs ultimately proposed to the Commission. SWEEP plans to participate in the collaborative working group.

Finally, to ensure effective and appropriate Commission oversight, the settlement agreement requires that all energy efficiency and DSM programs be reviewed and pre-approved by the Commission before APS may include program costs in any determination of total DSM costs incurred.

DSM and Rate Design

Q. Are there provisions in the settlement agreement that address DSM and rate design?

A. Yes. Paragraph 57 states that rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand are integral parts of an overall DSM strategy. The settlement agreement requires APS to conduct a study analyzing rate design modifications that could achieve these objectives, including, among others, consideration of mandatory TOU rates and/or expanded use of inclining block rates. If the study and analysis indicate that the rate design modifications are reasonable, cost-effective, and practical, APS is required to develop and propose to the Commission any appropriate rate design modifications.

SWEEP supports these improved rate design approaches as valuable complements to effective energy efficiency policies and programs, but not as replacements for cost-effective utility energy efficiency programs.

DSM and Competitive Procurement of Resources

Q. Are there additional provisions for DSM in the settlement agreement?

A. Yes. According to Section IX on Competitive Procurement of Power, paragraph 78, APS will issue an RFP or other competitive solicitation(s) seeking long-term future resources of not less than 1,000 MW for 2007 and beyond. DSM resources will be invited to compete in the RFP or competitive solicitation, and will be evaluated in a consistent and comparable manner. According to paragraph 79, Commission Staff will schedule resource planning workshops to develop the competitive procurement process and to consider whether and to what extent the competitive procurement should include an appropriate consideration of a diverse portfolio of DSM and other resources. SWEEP plans to participate in the workshops.

Conclusion

Q. Is the settlement agreement, including the DSM provisions in the agreement, in the public interest?

A. Yes. The settlement agreement is in the public interest, and SWEEP supports the settlement agreement.

Q. Does that conclude your settlement testimony?

A. Yes.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.	Docket No. E-01345A-03-0437 **NOTICE OF FILING CROSS-REBUTTAL TESTIMONY**

Southwest Energy Efficiency Project, through its undersigned counsel, hereby provides notice that it has this day filed the written cross-rebuttal testimony of Jeff Schlegel in connection with the above-captioned matter.

Admitted
EXHIBIT
SWEEP 3
CB 12/2/04

DATED this 30th day of March, 2004.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By
Timothy M. Hogan
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
Attorneys for Southwest Energy Efficiency Project

ORIGINAL and 13 COPIES of the foregoing filed this 30th day of March, 2004, with:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing transmitted electronically this 30th day of March, 2004, to:

All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Cross-Rebuttal Testimony of

Jeff Schlegel
Southwest Energy Efficiency Project (SWEEP)

March 30, 2004

Cross-Rebuttal Testimony of Jeff Schlegel, SWEEP
Docket No. E-01345A-03-0437

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom and in what capacity are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP). I am the Arizona Representative for SWEEP.

Q. Did you file direct testimony in this proceeding?

A. Yes, I filed direct testimony on February 3, 2004.

Q. What is the purpose of your cross-rebuttal testimony?

A. My cross-rebuttal testimony compares my direct testimony with positions taken by Staff regarding energy efficiency, focusing on the funding level for demand-side management (DSM) programs, the funding cap, and the funding and cost-recovery mechanism proposed by Staff.

Q. What is Staff's testimony on the benefits of DSM, and on DSM that APS should pursue?

A. Staff witness Barbara Keene, in her direct testimony on page 2 (starting at line 2) summarizes the benefits of DSM to APS customers, the APS electric system, and society. In her direct testimony (page 7, starting at line 1), Staff witness Barbara Keene recommends that APS should engage in DSM programs as long as the incremental societal benefits of the DSM programs are greater than the incremental cost of the DSM programs to society.

Q. What is Staff's recommendation regarding annual DSM costs?

A. Staff witness Barbara Keene, in her direct testimony on page 10 (starting at line 5), recommends that annual DSM funding be capped at $4 million.

Q. Is Staff's testimony on the benefits of and justification for DSM consistent with Staff's recommendation on the DSM funding cap?

A. No, there is a significant inconsistency between (1) Staff's summary of the benefits of and justification for DSM, and (2) the Staff-recommended DSM funding cap.

Q. What is the basis for Staff's recommended funding cap, and is the basis reasonable and sufficient for determining DSM funding in the future?

A. Apparently, the only basis for Staff's recommended funding cap is a review of past DSM expenditures (Barbara Keene direct testimony, page 10, line 5). No other basis is presented in Staff's testimony. A review of past DSM expenditures, by itself, is not a reasonable or sufficient basis for determining DSM funding in the future.

Q. Will $4 million of annual DSM funding be adequate to capture all cost-effective DSM in the APS service territory?

A. No. There is a large amount of cost-effective DSM that would not be achieved under a funding cap of $4 million.

Q. What would happen if cost-effective energy efficiency is not achieved because DSM funding is limited to $4 million annually?

A. If DSM funding is limited to $4 million annually, arbitrarily, by the Staff-recommended funding cap, then the total costs for customers will be higher, based on the fundamental definition of cost-effectiveness, and the other benefits of capturing the remaining cost-effective DSM will not be achieved.

Q. What funding level should be set for energy efficiency programs?

A. As stated in my direct testimony, the Commission should adopt a policy that would provide adequate energy efficiency program funding to achieve the energy efficiency goals recommended by SWEEP. SWEEP estimates that energy efficiency funding of $0.0015 per kWh of retail energy sales (1.5 mills), or about $35 million in the 2002 Test Year, is necessary to achieve the goals. SWEEP recommends that energy efficiency program spending ramp-up gradually in the first two years ($13 million in 2004 and $30 million in 2005).

Q. What funding and cost recovery mechanisms are recommended by Staff, and how does Staff's recommendation compare to your recommendation?

A. In her direct testimony (page 9, starting at line 2), Staff witness Barbara Keene recommends that APS recover its DSM costs through a separate DSM adjustment mechanism. SWEEP proposes a per-kWh SBC charge plus an SBC adjustment mechanism to reconcile actual expenditures that are higher than the base SBC charge of $0.0015 per kWh, if higher expenditures are necessary to achieve the goals. SWEEP also recommends that unexpended funds in a given year be carried over to future program years.

Q. Does that conclude your cross-rebuttal testimony?

A. Yes.

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Attorneys for Southwest Energy Efficiency Project

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BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
CHAIRMAN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
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In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.	Docket No. E-01345A-03-0437 **NOTICE OF FILING DIRECT TESTIMONY AND EXHIBITS**

Southwest Energy Efficiency Project, through its undersigned counsel, hereby provides notice that it has this day filed the written direct testimony and exhibits of Jeffrey A. Schlegel in connection with the above-captioned matter.

Admitted
EXHIBIT
SWEEP 4
CB 12/02/04

DATED this 3rd day of February, 2004.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By [signature]
Timothy M. Hogan
202 E. McDowell Rd., Suite 153
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Attorneys for Southwest Energy Efficiency Project

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COMMISSIONERS

MARC SPITZER, Chairman
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MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Direct Testimony of

Jeff Schlegel
Southwest Energy Efficiency Project (SWEEP)

February 3, 2004

Direct Testimony of Jeff Schlegel, SWEEP
Docket No. E-01345A-03-0437

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List of Exhibits

Introduction

Q. Please state your name and business address.

A. My name is Jeff Schlegel. My business address is 1167 W. Samalayuca Drive, Tucson, Arizona 85704-3224.

Q. For whom and in what capacity are you testifying?

A. I am testifying on behalf of the Southwest Energy Efficiency Project (SWEEP). I am the Arizona Representative for SWEEP.

Q. Please describe the Southwest Energy Efficiency Project.

A. SWEEP is a public interest organization dedicated to advancing energy efficiency as a means of promoting both economic prosperity and environmental protection in the six states of Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming. SWEEP works on state energy legislation, analysis of energy efficiency opportunities and potential, expansion of state and utility energy efficiency programs as well as the design of these programs, building energy codes and appliance standards, and voluntary partnerships with the private sector to advance energy efficiency. SWEEP is collaborating with utilities, state agencies, environmental groups, universities, and energy specialists in the region. SWEEP is funded primarily by foundations, the U.S. Department of Energy, and the U.S. Environmental Protection Agency.

Q. What are your professional qualifications?

A. I am an independent consultant specializing in policy analysis, evaluation and research, planning, and program design for energy efficiency and clean energy resources. I consult for public groups and government agencies, and I have been working in the field for over 20 years. In addition to my responsibilities with SWEEP, I am working or have worked extensively in many of the states that have effective energy efficiency programs, including California, Connecticut, Massachusetts, New Jersey, Vermont, and Wisconsin. In 1997, I received the Outstanding Achievement Award from the International Energy Program Evaluation Conference. Exhibit JS-1 summarizes my professional qualifications.

Summary of Testimony and Recommendations

Q. Please summarize your testimony.

A. I will testify that:

- The Commission should substantially increase energy efficiency in the Arizona Public Service Company (APS) service territory to achieve significant and cost-effective benefits for APS customers, the electric system, the economy, and the environment.

- Specifically, the Commission should set goals to achieve 7% of total energy resources needed to meet retail load in 2010 from energy efficiency, and 17% in 2020. The Commission should set parallel goals to reduce summer peak demand by at least 7% of total capacity resources needed to meet retail peak demand in 2010, and at least 17% in 2020.

- Achieving such goals would reduce average annual growth in retail energy and summer peak demand from over 4% to under 3%, eliminate the need for at least 1,100 MW of new power plants by 2020 and associated power line and pipeline infrastructure, save consumers and businesses over $1.9 billion during 2004-2020, reduce electricity price spikes and the risks of natural gas price volatility, and reduce emissions.

- Similar energy savings and peak demand reduction goals have been implemented by other states and utilities, and some have achieved or made progress towards achieving similar levels of energy savings.

- Energy efficiency costs less than other resources for meeting the energy needs of APS customers. Energy efficiency costs 2 to 3 cents per lifetime kWh saved, delivered to the customer. This is less than the cost of power from existing generation plants, and significantly less than the delivered cost of energy from new natural gas-fired plants.

- A full portfolio of effective and cost-effective energy efficiency programs should be implemented in the APS service territory to achieve the energy efficiency goals. All APS customers should have an opportunity to participate in and benefit directly from at least one energy efficiency program.

- The Commission should provide adequate funding to achieve the energy efficiency goals. SWEEP estimates that energy efficiency funding of $0.0015 per kWh of retail energy sales (1.5 mills), or about $35 million in the 2002 Test Year, is necessary to achieve the goals.

- Energy efficiency funding and cost recovery could be accomplished through a System Benefits Charge (SBC), expensing the energy efficiency expenditures, or rate-basing.

- Overall, the existing APS energy efficiency programs are insufficient and do not capture the vast majority of cost-effective energy efficiency opportunities for APS customers. APS appears to have a beneficial residential new construction program that is achieving meaningful results. However, APS energy efficiency efforts and achievements in all other markets are inadequate or nonexistent.

- The Commission should act in a timely manner to increase energy efficiency in Arizona. Each day that passes without effective energy efficiency programs means more inefficient load is added to the electric system in this high load growth state, leading to higher total costs for customers, a less diverse and riskier energy resource mix, and increased damage to the environment.

Increasing Energy Efficiency in the APS Service Territory

Q. In general, what do you recommend regarding energy efficiency?

A. The Commission should substantially increase energy efficiency in the APS service territory to achieve significant and cost-effective benefits for APS customers, the electric system, the economy, and the environment.

When compared to conventional generation and transmission, energy efficiency is more cost effective, cleaner, more distributed with no need for transmission or distribution lines, more diverse, less risky in terms of market and fuel price volatility, and less subject to security risks and interruptions – and it does not consume non-renewable resources or harm the environment. Energy efficiency provides financial and other direct benefits to consumers and businesses, and lowers the total cost of electric service for customers. Energy efficiency creates jobs and improves the economy. Finally, energy efficiency is a reliable energy resource that costs less than other resources for meeting the energy needs of customers in the APS service territory.

Q. Is energy efficiency an effective approach for diversifying the resource mix, increasing reliability, and mitigating price volatility and associated risks?

A. Yes, increasing energy efficiency will diversify the resource mix, increase reliability, and mitigate vulnerability to price volatility. Energy efficiency does not rely on any fuel and is not subject to shortages of supply or fuel price volatility. Energy efficiency is a distributed resource and does not rely on transmission or distribution systems, or natural gas pipelines. Meeting load growth through increased energy efficiency can help to relieve system constraints and pressure on load pockets. Energy efficiency is not threatened by operational interruptions (from terrorists or other threats to reliability) that central generation and transmission must address. In addition, by reducing total load, energy efficiency puts downward pressure on market prices for everyone purchasing power in the market.

Goals for Energy Savings and Peak Demand Reduction

Q. Specifically, what actions should the Commission take to increase energy efficiency in the APS service territory?

A. The Commission should set goals to achieve 7% of total energy resources needed to meet retail load in 2010 from energy efficiency, and 17% in 2020. The Commission should set parallel goals to reduce summer peak demand by at least 7% of total capacity resources needed to meet retail peak demand in 2010, and at least 17% in 2020. These goals are reasonable and achievable, and meeting the goals would provide cost-effective benefits to consumers, the electric system, the economy, and the environment.

Q. What benefits would result from achieving such goals?

A. Achieving the goals would reduce average annual growth in retail energy and summer peak demand from over 4% to under 3%, eliminate the need for at least 1,100 MW of new power plants by 2020 and associated power line and pipeline infrastructure, save consumers and businesses over $1.9 billion during 2004-2020, reduce electricity price spikes and the risks of natural gas price volatility, and reduce emissions.

Q. Have other states or utilities implemented similar goals?

A. Yes, other states and utilities have implemented similar goals. Examples include:

- Austin Energy, the Austin, Texas municipal utility, plans "investment in energy efficiency and peak load management to meet the target of achieving 15% of Austin's energy supply from energy efficiency efforts by 2020."[1]
- The Ft. Collins, Colorado municipal utility has implemented a goal to reduce per capita electric consumption 10%, from the baseline of 2002, by the year 2012. The 10% per capita consumption reduction target will reduce overall electric consumption approximately 17% by 2012. Ft. Collins has also set a goal to reduce per capita peak day electric demand 15%, from the baseline of 2002, by the year 2012.
- State agencies and universities in Arizona are required to reduce energy use 10% per square foot of floor area by 2008 and 15% by 2011, relative to 2001-02, per the savings goals in HB2324, passed by the Arizona Legislature last session.

Q. Have other states or utilities achieved energy savings and peak demand reductions similar to the goals SWEEP proposes?

A. Yes. According to a 2002 study by the American Council for an Energy Efficient Economy (ACEEE), based on data the utilities report to EIA, the top four states in terms of 2000 energy savings as a % of kWh retail sales saved energy equivalent to between 5.1% and 6.8% of their actual electricity sales to consumers that year.[2] All four of these states (Connecticut, Wisconsin, Minnesota, and Rhode Island) have continued their energy efficiency programs since 2000, therefore I estimate that several of the states have exceeded the level of 7% of total retail sales by now.

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[1] Austin Energy 2003 Strategic Plan. Note: Austin Energy is a large municipally owned utility with about 2,700 MW of generation capacity; it provides service to 355,000 customers.
[2] "State Scorecard on Utility and Public Benefit Energy Efficiency Programs: an Update" by D. York and M. Kushler; American Council for an Energy Efficient Economy, December 2002.

Two major investor-owned utilities in Connecticut, Connecticut Light & Power and United Illuminating, together spent about $87 million per year on energy efficiency and load management programs in 2001 and 2002 (approximately 2.8% of their overall revenues from retail electricity sales). The 2001 programs saved 314 GWh/yr (1.1% of sales) and the 2002 programs saved 246 GWh/yr (0.9% of sales).

Cumulative annual energy savings at Massachusetts Electric Company through 2002 were 1,721 GWh, equivalent to about 10% of retail energy sales in 2002.

Q. How does Arizona rank in national studies of energy efficiency?

A. In the 2002 ACEEE study previously cited, Arizona ranked 45th among the states, with 2000 energy efficiency savings equivalent to only 0.04% of retail sales. The leading energy efficiency states achieve energy savings about 150 times higher than Arizona. The ACEEE study also found that energy savings from utility energy efficiency programs in Arizona declined from 146 kWh per capita in 1993 to 4 kWh per capita in 2000.

Q. What is the potential for energy efficiency in Arizona?

A. In 2002, SWEEP completed a study of the potential for energy efficiency in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming. The study, "The New Mother Lode: The Potential for More Efficient Electricity Use in the Southwest," identified significant electricity savings, water conservation and other environmental benefits, and economic growth potential for Arizona through the pursuit of energy efficiency policies and programs.

The study analyzed electricity use in a "business-as-usual" Base Scenario and a High Efficiency Scenario that gradually increases the efficiency of electricity use in homes and work places. The study found the following benefits of the High Efficiency Scenario for Arizona:

- Reducing total electricity consumption 18% by 2010 and 34% by 2020;
- Reducing average annual load growth from 3% per year in the Base Scenario to 0.7% per year in the High Efficiency Scenario;
- Eliminating the need to construct twelve 500 megawatt power plants or their equivalent over the next 18 years, as well as transmission lines needed to serve these plants;
- Saving consumers and businesses $10.5 billion during 2003-2020, at a benefit-cost ratio of about 4.2, with a net benefit of $5,690 per household during this period;
- Increasing statewide personal income by $550 million per year and statewide employment by 24,100 jobs by 2020;

- Saving 9.0 billion gallons of water per year by 2010 and 22.4 billion gallons per year by 2020 (the latter equivalent to the water consumed by about 122,000 households); and
- Reducing carbon dioxide emissions, the main gas contributing to global warming, by 20% in 2010 and 36% in 2020 relative to the emissions of the Base Scenario.

The SWEEP study acknowledged that the High Efficiency future will not happen on its own. The study recommended new and expanded policies and initiatives to achieve the High Efficiency future and its benefits. In the report, SWEEP listed several energy efficiency policies that could be implemented in Arizona. Expanding utility energy efficiency programs is the most important policy for achieving energy savings. SWEEP also noted that not all of the potential energy savings are expected to be achieved from utility energy efficiency programs.

Q. How do the proposed goals compare to estimates of the potential for energy efficiency in Arizona?

A. Achieving the proposed goals would capture about half of the energy efficiency potential in Arizona estimated in the SWEEP New Mother Lode study.

Q. Are the goals reasonable and realistic?

A. Yes, the proposed goals are both reasonable and realistic. They are reasonable and realistic considering the low level of energy efficiency activities in Arizona in the recent past, the need to ramp up energy efficiency efforts in the early years, the high rate of load growth in the APS service territory, the significant energy efficiency potential in new construction, and the historical energy efficiency performance in leading states.

For comparison purposes, consider Integrated Resource Planning (IRP) principles applied in some states, including Arizona, during the 1990's. The IRP principles essentially stated that all cost-effective energy efficiency should be captured, as the least-cost resource, before making investments in higher cost resources. By definition, capturing less than the full amount of cost-effective energy efficiency potential leads to higher total costs for consumers. In proposing the goals of 7% in 2010 and 17% in 2020, SWEEP is acknowledging that only about half of the cost-effective energy efficiency potential identified in the SWEEP study (proportionally for APS) is going to be captured. Even more electricity could be saved, but SWEEP is being realistic about how much can be achieved and funded through utility programs given the current situation and recent history in Arizona. Additional energy savings could be achieved through other policies and programs, such as through the adoption and implementation of building energy codes and appliance standards.

Energy Efficiency Savings, Benefits, and Costs in Other States

Q. What has been the experience with energy efficiency in other states and at other utilities?

A. Based on results from other states and utilities, energy efficiency can provide substantial resources that are reliable and cost-effective. Below are several examples in addition to those summarized above:

- California: In 1999, the California Energy Commission stated: "Since 1975, a combination of State energy efficiency standards for buildings and appliances and utility energy efficiency programs have reduced electricity and natural gas consumption in California by over 470,000 gigawatt hours and over 50 billion therms. In 1998 alone, the savings from building and appliance standards totaled $1.4 billion per year. Utility distribution company energy efficiency programs achieved a similar amount of savings. The displaced energy from both standards and programs was roughly the equivalent of fourteen 700 megawatts power plants," or about 10,000 MW. Without sacrificing quality of life or productivity, electricity use per capita increased by only 5% in California during 1977-2001, compared to a nearly 50% increase in per capita electricity use in the other 49 states.[3]
- Connecticut: Two major investor-owned utilities in Connecticut, Connecticut Light & Power and United Illuminating, are responsible for over 90% of electricity sales in the state. Together they spent about $87 million per year on energy efficiency and load management programs in 2001 and 2002. This is approximately 2.8% of their overall revenues from retail electricity sales. The 2001 programs saved 314 GWh/yr (1.1% of sales); the 2002 programs saved 246 GWh/yr (0.9% of sales). The estimated peak load reductions are 66 MW from 2001 programs and 99 MW from 2002 programs.
- Vermont: The Vermont Public Service Board established a statewide energy efficiency program known as Efficiency Vermont in 1999. Efficiency Vermont spent $8.8 million (1.5% of electric utility revenues) in 2001 and $11.0 million (about 1.9% of revenues) in 2002. It is estimated that the programs in 2002 provided about 40 GWh/yr of electricity savings, equal to 0.7% of electricity sales in the state.
- Massachusetts: Massachusetts Electric is an investor-owned utility owned by National Grid USA. It spent $64 million on energy efficiency and DSM programs in 2001 (about 3.8% of revenues). The comprehensive energy efficiency programs run in 2001 saved 187 GWh/yr and 37 MW of peak load. The energy savings due to 2001 programs are equivalent to 1.0% of electricity sales.
- The Sacramento Municipal Utility District (SMUD) is a publicly-owned utility serving over 500,000 customers in California. SMUD spent about $17 million on

[3] "Energy Efficiency Leadership in California: Preventing the Next Crisis." Natural Resources Defense Council and Silicon Valley Manufacturing Group, San Francisco, CA, April 2003.

its energy efficiency programs in 2001 and nearly $21 million (2.3% of revenues) on these programs in 2002. The programs are comprehensive, including cash incentives for all types of efficiency measures. SMUD estimates the programs operated in 2002 reduced electricity use by 69 GWh/yr (0.72% of retail sales) and peak demand by 21.2 MW (0.76% of the peak demand registered that year).

- Minnesota: Xcel Energy is the main investor-owned utility in Minnesota and is responsible for about half of the electricity sold in the state. The utility spent about $37 million on energy efficiency and other DSM programs in 2001 and $38.5 million in 2002, slightly over 2% of revenues. The utility estimates it saved 254 GWh/yr and cut peak demand by 139 MW due to 2001 programs, and saved 267 GWh/yr and cut peak demand by 121 MW due to 2002 programs. The 2002 energy savings were equivalent to about 0.9% of retail sales. In addition, it is estimated that the programs operated in 2002 will generate net benefits of $233 million over the lifetime of measures installed that year.

Q. What does past experience say about the cost of energy efficiency?

A. Energy savings from energy efficiency programs cost less than other resources for meeting the energy needs of customers. Energy efficiency costs 2 to 3 cents per lifetime kWh saved, delivered to the customer. This is less than the cost of conventional power, and significantly less than the delivered cost of energy from natural gas fired plants.

In the Pacific Northwest, energy efficiency programs implemented by electric utilities working with businesses, local governments, and others in the region saved over 10,000 GWh/yr as of 1998, at an average cost of 2 to 2.5 cents per kWh saved.[4] In Vermont, energy efficiency measures installed in 2002 alone as a result of the Efficiency Vermont statewide program saved 574 GWh/yr, at a total cost of 2.9 cents per kWh saved over the lifetime of these measures.[5] In California, efficiency measures installed during 2001 exhibited an overall average cost of 3 cents per kWh saved over the lifetime of the measures.[6] Finally, a review article published in 2000 states, "Large-scale energy efficiency programs operated in a number of states during the 1990s were very cost-effective – saving energy at an average cost of $0.03/kWh or less, well below the cost of supplying electricity."[7]

[4] Revised Fourth Northwest Conservation and Electric Power Plan. Portland, OR: Northwest Power Planning Council, 1998.
[5] The Power of Efficient Ideas. Efficiency Vermont: Preliminary Report 2002. Burlington, VT: Efficiency Vermont. 2003.
[6] California Summary Study of 2001 Energy Efficiency Programs. Report prepared by Global Energy Partners, LLC, Lafayette, CA and submitted to Southern California Edison Co. and The California Measurement Advisory Council, March 2003.
[7] S. Nadel and M. Kushler. "Public Benefit Funds: A Key Strategy for Advancing Energy Efficiency." *The Electricity Journal 13*, Oct. 2000, pp. 74-84.

Q. Are similar results possible in the APS service territory?

A. Yes. Many of the states and utilities cited above have implemented fairly aggressive energy efficiency programs for a decade or more. There are more remaining opportunities for increased energy efficiency in the APS service territory, where energy efficiency programs have been much smaller (or nonexistent in some market segments), than there are in states and service territories where significant, effective programs have been operated for many years.

Q. Are other western states or utilities increasing their energy efficiency efforts?

A. Yes, several western states or utilities have increased their energy efficiency efforts and commitments recently, including:

- Xcel, Colorado: Planning to achieve 134 MW of peak demand reduction through DSM programs during 2001-05; 172 GWh/yr savings by 2005; spending $61 million over 5 years.[8]
- PacficCorp, Utah: Planning to spend $10 million on DSM in 2003, at least $17 million on currently-approved programs in 2004 ($17 million is about 1.8% of revenues). New DSM programs are under development.
- Nevada Power and Sierra Pacific Power: Began spending $11.2 million per year on DSM programs in 2003 (about 0.5% of revenues). Estimated energy savings of 37.5 GWh/yr; estimated peak load reduction of about 20 MW per program year. New energy efficiency programs are now being developed and analyzed.
- Texas Energy Efficiency Performance Standard: Energy efficiency goal requires that each utility acquire energy efficiency savings equivalent to at least 10% of its projected growth in demand. Utilities in Texas (both IOUs and municipals) are now spending around $100 million per year.

Energy Efficiency Programs and Strategies

Q. If energy efficiency is so beneficial, why doesn't it just happen in the marketplace?

A. Some of it does. However, cost-effective energy efficiency resources in Arizona are often untapped due to significant market failures and barriers faced by customers and other market participants (e.g., retailers, distributors, manufacturers, builders, contractors, and property managers). These market failures and barriers include lack of information, high transaction costs, low priority placed on energy issues by many consumers, lack of money or financing, misplaced or split incentives, institutional practices, and incomplete markets for energy efficiency.[9] Market intervention in the

[8] "Response to Issues Raised During the November 13, 2003 DSM Roundtable Discussion", memo distributed by Grey Staples, Xcel Energy, Minneapolis, MN, January 26, 2004.
[9] For one discussion of market failures and barriers, see M.A. Brown, "Market Failures and Barriers as a Basis for Clean Energy Policies," Energy Policy 29 (2001), pp. 1197-1207.

form of energy efficiency programs is necessary to reduce or eliminate the market failures and barriers to the adoption of cost-effective energy efficiency.

Q. What types of energy efficiency programs should be offered in the APS service territory?

A. A full portfolio of effective and cost-effective programs should be implemented in the APS service territory to achieve the energy efficiency goals proposed by SWEEP. All APS customers should have an opportunity to participate in and benefit directly from at least one energy efficiency program.

The energy efficiency programs should be market-oriented, thereby leveraging and focusing on naturally-occurring market opportunities, such as increasing energy efficiency when buying or building a new home, designing and building a new office building or facility, purchasing a new appliance, replacing old or failed equipment, modifying an industrial process, buying or replacing a heating or cooling system, or remodeling a home or business. The programs should work with the market by focusing on market opportunities, reducing market barriers, and increasing opportunities for and adoption of energy efficiency.

The energy efficiency programs should be focused on achieving energy savings as well as reducing summer peak demand, to ensure that the maximum economic and environmental benefits from energy savings are captured.

Q. Please provide a list of recommended energy efficiency programs.

A. Energy efficiency programs in the APS service territory should include:

- Commercial and Industrial (C&I) construction (new construction, renovation, and equipment replacement);
- C&I existing buildings including lighting, HVAC, motors/drives, compressed air, operations and maintenance, industrial process, and custom applications;
- Small business;
- Schools and local government;
- Residential new construction;
- Residential products including appliances, lighting, and windows;
- Residential existing buildings, with an emphasis on heating and cooling systems;
- Low/moderate income; and
- Targeted energy efficiency and distributed resources for T&D constrained areas.

These programs are being discussed in the DSM Workshops, ongoing in parallel at the Commission.

Q. What strategies should be employed in the energy efficiency programs listed above?

A. The following are effective program strategies, or tools in the toolbox:

- Promotion and marketing
- Consumer education
- Technical and design assistance
- Financial incentives (including rebates and financing for some markets and customer groups)
- Training for trade allies and vendors
- Coordination/initiatives with market actors in the distribution chain (manufacturers, distributors, retailers, builders, etc.)
- Product/service testing and RD&D
- Feedback on performance, and market tracking

As shown in the list above, I recommend a broad and diverse mix of strategies, not simply rebates or other financial incentives. In general, the most effective energy efficiency programs employ a combination of strategies targeted to reduce or overcome the key barriers to energy efficiency in the marketplace.

Q. Who should administer and deliver the energy efficiency programs?

A. The programs could be administered by APS or by an independent administrator, such as a contractor. Either option is viable. The important issue is to ensure effective administration of the programs to achieve the goals. Program delivery could be achieved through vendors, contractors, and other actors in the marketplace. Some programs could be delivered through partners such as the State Energy Office or low income weatherization agencies.

SWEEP Estimate of Energy Savings and Funding for the APS Service Territory

Q. Has SWEEP prepared an estimate of the impact of its proposed goals in terms of energy savings and associated funding in 2004 through 2020?

A. Yes. See Exhibit JS-2, which shows annual and cumulative annual energy savings, the impact of the energy savings on the forecast and load growth, and the funding necessary to achieve the goals. Total cumulative annual energy savings of 2,278 GWh are necessary to achieve the goal of 7% of total energy resources needed to meet retail load in 2010 from energy efficiency.

Funding to Achieve the Energy Efficiency Goals

Q. What funding level will be needed to achieve the energy efficiency goals proposed by SWEEP?

A. The Commission should adopt a policy that would provide adequate funding to achieve the energy efficiency goals. SWEEP estimates that energy efficiency funding of $0.0015 per kWh of retail energy sales (1.5 mills), or about $35 million in the 2002 Test Year, is necessary to achieve the goals (Exhibit JS-2).

The level of energy efficiency funding would increase over time as retail electricity sales increase. For example, funding would reach approximately $41 million in 2006, given recent and anticipated load growth. This level of funding should be adequate to achieve 1% electricity savings in 2006 and reduce load growth to 3% (Exhibit JS-2). SWEEP recommends that energy efficiency program spending ramp-up gradually in the first two years ($13 million in 2004 and $30 million in 2005).

Q. What would be the impact of this funding level on residential customers?

A. The energy efficiency funding level of $0.0015 per kWh of retail energy sales (1.5 mills) would amount to about $1.60 per month for the average APS residential customer.

Q. What funding and cost recovery mechanisms could be used?

A. Energy efficiency funding and cost recovery could be accomplished through a System Benefits Charge (SBC), expensing the energy efficiency expenditures, or rate-basing (capitalization).

Q. What should happen to under- or over-expenditures of energy efficiency funding in a given program year?

A. Unexpended funds should be carried over to future program years. An adjustor mechanism could be used to reconcile actual expenditures that are higher than $0.0015 per kWh, if higher expenditures are necessary to achieve the goals.

Existing APS Energy Efficiency Programs

Q. What energy efficiency programs does APS offer now?

A. In the 2002 Test Year, APS offered a residential new construction program; a low income weatherization program; a residential HVAC retrofit program; and a commercial energy information, analysis, and training program. APS also offered residential time-of-use rates and a C&I peak load reduction program (Power Partners). (APS response to Staff 5-13)

Q. Please summarize the findings of your assessment of the APS energy efficiency programs.

A. Overall, the existing APS energy efficiency programs are insufficient and do not capture the vast majority of cost-effective energy efficiency opportunities for APS customers. APS appears to have a beneficial residential new construction program that is achieving meaningful results. However, APS energy efficiency efforts and achievements in all other markets are inadequate or nonexistent.

Q. Please compare the overall level of APS spending and savings to the SWEEP proposal.

A. APS spent about $1.1 million on energy efficiency programs in 2002, about 0.05% of revenues (APS response to Staff 5-13). It appears that APS achieved annual savings equivalent to about 0.15% of retail sales.[10] These energy savings and spending levels are significantly lower than the levels recommended by SWEEP. The majority of cost-effective energy efficiency opportunities in the APS service territory are not being achieved at this very low level of program activity and funding.

Other DSM and Pricing Approaches

Q. Are there other approaches to achieving energy savings and peak demand reductions?

A. Yes. SWEEP supports complementary approaches such as DSM programs to encourage peak load reductions (load management and short-term demand response), and pricing and rate design (inclining block rates and critical peak pricing). SWEEP supports these approaches as complements to effective energy efficiency policies and programs, not as replacements for cost-effective utility energy efficiency programs.

---

[10] SWEEP plans to further document the performance and cost of APS energy efficiency programs prior to the hearings in April, either through the ongoing DSM Workshops at the Commission, or through discovery.

Development of an Energy Efficiency Plan for the APS Service Territory

Q. How should an energy efficiency plan for the APS service territory be developed?

A. SWEEP and others are working on a more detailed energy efficiency plan for APS as one part of the ongoing DSM workshops at the Commission. The Staff report on the DSM workshops is due in March 2004. SWEEP plans to submit its recommended plan for APS, based on the DSM workshop discussions, to the Commission prior to the April hearings. If the DSM workshops do not progress sufficiently to develop a plan for APS, SWEEP will either develop a plan for APS itself, or propose a process for developing a plan collaboratively, and SWEEP will file one or the other before the April hearings.

Timeliness of Commission Action

Q. Is timely action by the Commission on energy efficiency important?

A. Yes. The Commission should act in a timely manner to increase energy efficiency in Arizona and the APS territory. Each day that passes without effective energy efficiency programs means more inefficient load is added to the electric system in this high load growth state, leading to higher total costs for customers, a less diverse and riskier energy resource mix, and increased damage to the environment.

Q. Does that conclude your direct testimony?

A. Yes.

Qualifications of Jeff Schlegel

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Tucson, Arizona 85704
520-797-4392; 520-797-4393 (fax)
schlegelj@aol.com

Jeff Schlegel is an independent consultant specializing in policy analysis, planning, evaluation and research, and program design for energy efficiency, renewable energy, and low-income energy programs. Mr. Schlegel has more than 20 years of experience in the energy field. He works for public groups, collaboratives, and government agencies. Currently he is working with:

- The Southwest Energy Efficiency Project (SWEEP) on energy efficiency and distributed resources issues (2002-present);
- The State of Connecticut Energy Conservation Management Board, a public board appointed by the Connecticut legislature to oversee energy efficiency, demand response, and low income programs in the state (2000-present);
- The Massachusetts Energy Efficiency Collaboratives on behalf of the non-utility parties, providing policy analysis, planning, and evaluation oversight of energy efficiency and demand response programs (1992-present).

Summaries of Recent Projects: Policy Analysis, Planning, Program Design, and Measurement and Evaluation for Energy Efficiency and Renewable Energy Programs

- Arizona representative for the Southwest Energy Efficiency Project (SWEEP), a public interest organization devoted to advancing energy efficiency in Arizona, Colorado, Nevada, New Mexico, Utah, and Wyoming (2002-present). SWEEP was launched in 2001, and is working collaboratively with state governments, utilities, and other organizations. Represents SWEEP in Arizona, and coordinates with a coalition of environmental, consumer, and renewable energy groups in Arizona and the southwest on energy efficiency and distributed resource issues. Advocates and provides technical assistance regarding policies, programs, and market rules to advance energy efficiency.

- Policy and evaluation consultant for the Massachusetts non-utility parties in the New England energy efficiency collaboratives (1992-2003). Also provided policy analysis and evaluation support for the Conservation Law Foundation (CLF) in the early period of the collaboratives. Provides policy and technical support directly to the non-utility parties in the Massachusetts collaboratives (National Grid/Massachusetts Electric, NSTAR/Boston Edison, and Northeast Utilities/Western Massachusetts Electric), and coordinates with other collaboratives in New England. Mr. Schlegel's primary responsibilities include policy analysis, resource analysis and planning, evaluation and research, and program review for commercial and industrial (C&I) as well as residential programs.

- Policy, program, and evaluation consultant for the State of Connecticut Energy Conservation Management Board (ECMB), a public board appointed by the Connecticut legislature to oversee energy efficiency, demand response, and low income programs in the state (2000-present). Serves as the lead technical and policy consultant for the ECMB regarding the Conservation and Load Management (C&LM) programs in Connecticut, funded at $89 million annually.

- Technical consultant for the New England Demand Response Initiative (NEDRI). Assisted a 50-member stakeholder group from the six New England states in developing a comprehensive, coordinated set of demand response programs for the New England regional power markets (2002-2003).

- Policy, evaluation, and protocols consultant for the New Jersey Clean Energy Collaborative, a collaborative of the New Jersey electric and gas utilities and the Natural Resources Defense Council (NRDC) on energy efficiency and low income programs (2000-2003).

- From July 1997 to March 2000, Mr. Schlegel served as the lead technical consultant to the California Board for Energy Efficiency (CBEE). CBEE was a public advisory board that provided recommendations to the California Public Utilities Commission on the $275 to $300 million of energy efficiency programs operated in the State of California annually by the four largest investor-owned utilities. In this full-time position Mr. Schlegel served as the CBEE's technical coordinator and lead technical consultant; developed and drafted the energy efficiency policy rules adopted by the California Public Utilities Commission; assisted the CBEE in formulating policy and program recommendations for consideration by the Commission; examined policy initiatives proposed by utilities and parties; reviewed and prepared comments on three years of annual program plans proposed by the utilities; recommended new program concepts and alternatives to utility proposals based on compilation and assessment of ideas from other states and regions; tracked and monitored program performance and market progress; and developed an RFP for independent administration of energy efficiency programs. As part of this assignment Mr. Schlegel did extensive analysis of options for administration, management, and implementation of publicly-funded energy efficiency programs.

- Conducted a scoping study of market effects and market transformation due to California utility energy efficiency programs for the California PUC in conjunction with Lawrence Berkeley National Laboratory (1996). Reviewed the performance of C&I and residential programs in terms of how they have impacted and changed markets.

- Reviewed California demand-side management (DSM) measurement and evaluation activities for the California Public Utilities Commission (1994-1999), including the activities of the California Demand-Side Management Measurement Advisory Committee (CADMAC). This included independently reviewing the California measurement and evaluation protocols, providing independent assessments of utilities' requests for protocol waivers, and reviewing and commenting on evaluation studies and program performance.

- Participated in electric retail competition workshops and meetings, as part of the Arizona Corporation Commission's consideration of electric restructuring, on behalf of the Arizona Community Action Association (ACAA) (1994-1997). Represented low income customers and coordinated with consumer and environmental groups. Advocated and provided technical and policy support for energy efficiency and low income weatherization programs.

- Directed the evaluation of DSM shareholder incentive mechanisms for the California Public Utilities Commission (1992-1994). This study evaluated the effects of incentive mechanisms used for four California utilities and assessed the effectiveness of DSM incentives as a regulatory strategy. The evaluation also assessed the balance of risks and rewards for ratepayers and shareholders, evaluated market transformation, explored the role of measurement and evaluation in the regulatory process, and compared and contrasted various options for performance incentive mechanisms. As part of this study, Mr. Schlegel reviewed evaluation studies of DSM programs offered by the four major California utilities. Testified on these issues before the Commission in 1993-1994, and participated in a series of workshops on shareholder incentives in 1993.

- Reviewed the performance of DSM programs in New England for the Conservation Law Foundation and the Pew Charitable Trust (1994-1996). Compared evaluation results to planning estimates (costs, savings, and cost-effectiveness) to determine the overall performance and reliability of DSM.

- Conducted a verification audit of Pacific Gas and Electric Company's commercial and industrial custom rebate program as a consultant for the Commission Advisory and Compliance Division of the California Public Utilities Commission (CPUC) (1992-1993). As part of this project, designed the overall verification approach, developed the stratified sampling plan, reviewed the program results, and developed the procedures for adjusting engineering estimates based on the verification results.

- Executive Director (1990-1992) and Research Director (1985-1990) at Wisconsin Energy Conservation Corporation (WECC), a not-for-profit research, policy analysis, resource planning, and program design firm. Performed evaluations of utility, government, and public energy efficiency programs. Conducted research on new and emerging energy efficiency technologies, designed programs, and developed resource plans including portfolios of DSM and energy efficiency programs. As Executive Director, responsible for all operations of the not-for-profit corporation, with an annual budget of over $2 million. WECC grew from three to twenty-two employees during Mr. Schlegel's tenure.

Low-Income Program Experience

Mr. Schlegel has worked with utilities and government agencies to design, implement, and evaluate low-income programs. From October 1998 through May 2002 he worked with the Arizona Department of Economic Security on the REACH program, a low-income self-sufficiency program, performing evaluation, analysis, and reporting tasks. From 1994 to 1997 he worked with the Arizona Community Action Association (ACAA) on a series of energy affordability and weatherization/DSM programs. As part of this work he analyzed options, designed and evaluated different program approaches, and prepared comments for several rate cases. He has also represented ACAA on electric restructuring issues in workshops before the Arizona Corporation Commission.

Mr. Schlegel managed many projects with the State of Wisconsin Low Income Weatherization Assistance Program over an eight-year period from 1985 through 1993. He led the development of the integrated computerized energy audit system and other software used by the State of Wisconsin in its program. In 1989 he directed an evaluation and review of the use of the computerized energy audit system and infiltration procedures in the State of Wisconsin program. He also conducted an evaluation of the Wisconsin Gas Company low-income programs.

Awards

Mr. Schlegel is the winner of the 1997 Outstanding Achievement Award from the International Energy Program Evaluation Conference. The Outstanding Achievement Award was given to only four individuals nationwide between 1991 and 2002.

Publications and Presentations

Mr. Schlegel has presented at more than 60 major national, regional, and statewide energy conservation conferences, and is the author of many published papers and articles. He has presented papers at several major conferences including the National Association of Regulatory Utility Commissioners (NARUC) Conference, the International Conference on Energy Program Evaluation, the American Council for an Energy Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Buildings, the National Energy Services and DSM Conferences, the E-Source Conference, the Affordable Comfort Conference, the National Low-Income Energy Consortium Conference, the National Community Action Foundation Conference, the National Consumer Law Center Conference, and the National Department of Energy Weatherization Conference. He was a panel leader for the 1990 and 1996 ACEEE Summer Studies on Energy Efficiency.

SWEEP Energy Efficiency Goals of 7% by 2010 and 17% by 2020
APS Service Territory

Exhibit JS-2

SWEEP Proposal	Test Year		<----Ramp Up---->		<----------Full Implementation---------->				7% Goal										17% Goal
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case Retail Energy Sales (GWh)	23,373	24,495	25,670	26,902	27,979	29,098	30,262	31,472	32,731	34,040	35,402	36,818	38,291	39,822	41,415	43,072	44,795	46,586	48,450
Annual Growth Rate (%)		4.8%	4.8%	4.8%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Energy Savings Goal (% of forecast)			0.35%	0.75%	1.00%	1.15%	1.35%	1.50%	1.50%	1.50%	1.50%	1.45%	1.45%	1.45%	1.45%	1.45%	1.45%	1.45%	1.45%
Annual Energy Savings (GWh)			89.8	201.8	279.8	334.6	408.5	472.1	491.0	510.6	531.0	533.9	555.2	577.4	600.5	624.5	649.5	675.5	702.5
Cumulative Annual Savings (GWh)			89.8	291.6	571.4	906.0	1,314.6	1,786.6	2,277.6	2,788.2	3,319.2	3,853.1	4,408.3	4,985.7	5,586.3	6,210.8	6,860.3	7,535.8	8,238.3
Cumulative Annual % Savings (relative to the forecast)			0.4%	1.1%	2.0%	3.1%	4.3%	5.7%	7.0%	8.2%	9.4%	10.5%	11.5%	12.5%	13.5%	14.4%	15.3%	16.2%	17.0%
Revised Retail Energy Sales (GWh)	23,373	24,495	25,580	26,611	27,407	28,192	28,947	29,685	30,453	31,252	32,083	32,965	33,882	34,837	35,829	36,861	37,934	39,051	40,212
Revised Annual Growth Rate (%)		4.8%	4.4%	4.0%	3.0%	2.9%	2.7%	2.6%	2.6%	2.6%	2.7%	2.7%	2.8%	2.8%	2.8%	2.9%	2.9%	2.9%	3.0%
Annual Energy Efficiency Budget ($, 000)	*$35,059*		$13,477	$30,265	$41,111	$42,288	$43,421	$44,528	$45,680	$46,878	$48,124	$49,447	$50,823	$52,255	$53,743	$55,291	$56,901	$58,576	$60,317
	test year		*$38,371*	*$39,916*															

Assumptions:

Energy Forecast	Based on APS Schedules E-7 and F-4, APS Rate Case
Annual Growth Rate (%)	4.0% for 2006-2020; 4.8% for 2003-2005 per Schedule F-4
Energy Efficiency Funding Rate	$0.0015 /kWh of retail energy sales

WRA

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.	Docket No. E-01345A-03-0437 **NOTICE OF FILING THE SUMMARY OF THE TESTIMONY OF DAVID BERRY**

Western Resource Advocates hereby provides notice of filing the attached summary of the testimony of its witness, David Berry, in the above-captioned docket in connect with the Settlement Agreement.

Admitted
EXHIBIT
WRA 1
LB 11/30/04

DATED this 5th day of November, 2004.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By
Timothy M. Hogan
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
Attorneys for Western Resource Advocates

ORIGINAL and 13 COPIES of the foregoing filed this 5th day of November, 2004, with:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing transmitted electronically this 5th day of November, 2004, to:

All Parties of Record

Summary of Testimony
Arizona Public Service Company Rate Case Settlement
Docket No. E-01345A-03-0437

David Berry
Western Resource Advocates

Western Resource Advocates supports the Arizona Public Service Company (APS) rate case settlement agreement and recommends that the Commission adopt the settlement.

High natural gas prices have occurred in recent years and the settlement agreement includes a process for APS to hedge against continued high natural gas prices using low cost renewable energy resources with fixed or stable prices. In particular, the settlement agreement requires APS to obtain at least 100 MW of renewable resources with delivery of energy starting in 2006 and to obtain at least 10 percent of its growth in capacity needs from renewable resources. The agreement caps the cost of these renewable resources at 125 percent of APS' estimate of the market cost of similar conventional resources. The 25 percent premium incorporates environmental benefits of renewable resources and allows for errors in forecasting the benchmark price of conventional resources. Wind, biomass, and geothermal resources may beat the price cap. APS is encouraged to acquire Arizona renewable resources but may obtain resources from other states as well. If APS is unsuccessful in meeting the 100 MW goal, the Commission will have an opportunity to review the circumstances and decide what to do.

Acquisition of renewable energy resources is in the public interest. APS has a large exposure to high natural gas prices and the renewable resources will serve as a hedge against such prices, thereby lowering rates in years when gas prices are moderate or high.

Comparison with Original Position

In my direct testimony filed on February 3, 2004, I recommended that the Commission order APS to immediately acquire energy to meet at least 2 percent of its retail sales from low cost renewable energy resources and that the Commission undertake a process to establish a renewable portfolio standard well in excess of the current Environmental Portfolio Standard. I believe this settlement agreement captures the essence of that recommendation, but it couches the renewable resource goal in terms of MW and MWH and breaks the initial renewable energy goal into a 100 MW segment and subsequent segments. The settlement agreement also provides for Commission consideration of increasing APS' reliance on renewable energy beyond the amounts stated in the agreement by requiring that Staff initiate a rulemaking proceeding to modify the existing Environmental Portfolio Standard. The settlement agreement is also consistent with my direct testimony regarding recovery of renewable energy costs through the purchased power adjustor and regarding Commission review of circumstances if APS does not meet the renewable energy goals.

The settlement agreement does not incorporate specific recommendations I made in my direct testimony regarding funding of the Environmental Portfolio Standard or net metering options in APS' tariffs applicable to customers who generate electricity with photovoltaics. These issues primarily affect the deployment of solar energy and, after the Arizona Solar Energy Industries Association intervened during the settlement process, I deferred these issues to the judgment of the solar energy industry representatives.

Finally, I recommended that demand side management funding that was redirected to the Environmental Portfolio Standard be restored to demand side management programs. The settlement agreement greatly increases the level of demand side management.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.	Docket No. E-01345A-03-0437 **NOTICE OF FILING TESTIMONY**

Western Resource Advocates, through its undersigned counsel, hereby provides notice that it has this day filed the written testimony of David Berry in connection with the above-captioned matter.

Admitted
EXHIBIT
WRA 2
12/2/04 LB

DATED this 27th day of September, 2004.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By
Timothy M. Hogan
202 E. McDowell Rd., Suite 153
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Attorneys for Western Resource Advocates

ORIGINAL and 13 COPIES of the foregoing filed this 27th day of September, 2004, with:

Docketing Supervisor
Docket Control
Arizona Corporation Commission
1200 W. Washington
Phoenix, AZ 85007

COPIES of the foregoing transmitted electronically this 30th day of March, 2004, to:

All Parties of Record

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Testimony of

David Berry
Western Resource Advocates

September 27, 2004

Regarding the Proposed Settlement of

Docket No. E-01345A-03-0437

Arizona Public Service Company

Request for Rate Adjustment

Testimony of David Berry
Docket No. E-01345A-03-0437
September 27, 2004

Table of Contents

List of Exhibits

Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064.

Q. By whom are you employed?

A. I am Senior Policy Advisor with Western Resource Advocates (WRA).

Q. Did you previously file testimony in this matter?

A. Yes. I filed direct testimony on February 3, 2004 and cross-rebuttal testimony on March 30, 2004.

Q. What is the purpose of your testimony?

A. My testimony describes why the settlement agreement is in the public interest and in particular addresses Section VIII of the agreement (paragraphs 69 through 72) pertaining to renewable energy.

Q. Did you participate in the settlement negotiations?

A. Yes. I attended all settlement conferences and worked with other parties to the case to arrive at an agreement.

Q. Does WRA support the settlement agreement?

A. Yes.

Q. What is WRA's principal objective in this matter?

A. WRA's primary objective is to start Arizona Public Service Company (APS) on a path that will hedge the high and volatile prices of natural gas with low cost, stably priced renewable energy.

Hedging High Natural Gas Prices with Renewable Energy

Q. Please summarize your direct testimony with regard to hedging high natural gas prices with low cost renewable energy.

A. On pages 2 through 14 of my direct testimony, I found that APS relies on natural gas as a fuel for its intermediate and peaking power resources and that natural gas prices are volatile and increasing over time. As a result, rates will go up as gas prices go up. I further argued that APS should hedge against high natural gas prices by acquiring large amounts of low cost renewable energy to displace gas generation and that doing so would lower APS' fuel and purchased power costs in periods of moderate or high gas prices. I recommended that the Commission order APS to immediately acquire energy to meet at least 2 percent of its retail sales from low cost renewable energy resources and that the Commission undertake a process to establish a renewable portfolio standard well in excess of the current Environmental Portfolio Standard (EPS).

Q. Have you updated your exhibit on natural gas prices paid by electric utilities?

A. Yes. Exhibit DB-5 updates Exhibit DB-2 in my direct testimony, making use of more recent Energy Information Administration price data for 2003 and 2004 and more recent Gross Domestic Product Implicit Price deflators.[1] Exhibit DB-5 is presented in constant year 2004 dollars. Exhibit DB-5 shows the long run trend of increasing real gas prices (increasing at about 3 percent per year) and the volatility of gas prices paid by the US power industry.

Q. Has APS provided information about the effect of gas price increases on its costs?

A. Yes. Peter Ewen (page 5, lines 21 through 24 of his rebuttal testimony) states the following: "An upward move of $1/MMBTU in natural gas prices (with a corresponding increase in power prices of $8/MWH that maintains the average 'spark spread' at roughly current levels) translates into an additional cost to serve retail customers of about $55 million in 2004 and almost $65 million in 2005."

Q. What conclusions do you draw regarding natural gas costs?

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[1] Energy Information Administration, *Short Term Energy Outlook, August 2004*, Table 4. Energy Information Administration, *Annual Energy Review 2002*, Table 6.8. Energy Information Administration, *Natural Gas Annual 2002*, Table B2. Bureau of Economic Analysis, National Income and Product Accounts Table 1.1.4, Price Indexes for Gross Domestic Product, through 2004, Quarter II.

A. APS and its ratepayers have a significant exposure to high natural gas costs. Low cost, stably priced renewable energy is a readily available tool for hedging against higher gas prices over the long run.

Settlement Agreement Provisions Concerning Acquisition of Renewable Energy

Q. Does the settlement agreement foster the acquisition of low cost, stably priced renewable energy as a hedge against high natural gas prices?

A. Yes. According to paragraph 69, APS will issue a special request for proposals in 2005 seeking at least 100 MW and 250,000 MWh per year of energy from renewable resources (solar, biomass/biogas, wind, small hydro, hydrogen, and geothermal resources) with delivery beginning in 2006. APS will also seek to obtain at least 10 percent of its increases in peak capacity needs from renewable resources, using either the request for proposals or subsequent solicitations (¶ 69). APS' total peak requirements typically increase by about 300 to 350 MW per year. Meeting 10 percent of these increases with renewable resources would add about 30 to 35 MW of renewable resources per year.

Under the terms of the settlement agreement:

- Energy from renewable resources will be obtained via long term purchased power agreements of 5 to 30 year duration (¶ 69e).
- Energy from renewable resources must be deliverable to APS' system (¶ 69c).
- Proposals will be considered only if the products offered have fixed or relatively stable prices (¶ 69f).
- Proposals will be considered only if their costs, on a levelized basis per MWH, are less than 125 percent of the reasonably estimated market price of conventional resource alternatives (¶ 69g).
- APS will recover the costs of the renewable energy via the power supply adjustor and the Environmental Portfolio Standard adjustable surcharge. In particular, the only costs recovered through the EPS surcharge would be cost premiums, if any, above market price for EPS–eligible resources that do not exceed the EPS requirements and whose premiums do not exceed EPS funding. All other costs would be recovered through the power supply adjustor (¶¶ 69 h, i, j).
- Net proceeds from the sale of any environmental credits or tags attributable to the renewable resources shall be credited to the EPS account (¶ 69k).
- APS will allow comments on its draft request for proposals before sending out the request to potential bidders (¶ 70).

Q. How much energy would APS obtain from 100 MW of renewable resources?

A. An 85 MW wind facility with a 32 percent capacity factor would produce about 238,000 MWh of energy per year.[2] Geothermal plants with 10 MW of capacity would produce about 75,000 MWh of energy per year. Landfill gas projects in Arizona may exhibit a capacity factor of about 50 percent, so a 5 MW landfill gas project may produce about 22,000 MWh per year. If APS selected a mix of 85 MW of wind capacity, 5 MW of landfill gas capacity, and 10 MW of geothermal capacity, it would obtain about 335,000 MWh per year, for example.

Q. What is the relationship between resources acquired through the special request for proposals and the EPS?

A. The resources obtained through the special acquisition process described above may or may not be eligible to meet EPS requirements (¶ 69d). If the resources are EPS-eligible, they would count toward meeting APS' EPS goals (¶ 69m).

Further, APS' obligations under the EPS are <u>not</u> modified by the special renewable resource acquisition described above. APS will still have to meet EPS requirements as they exist now and as they may be modified by the Commission (¶ 72).

Q. Is the 100 MW renewable resource acquisition (and subsequent acquisitions to meet 10 percent of APS' increase in peak capacity needs) all that APS needs to adequately hedge against high natural gas prices?

A. The 100 MW goal incorporated into the settlement agreement is a reasonable initial, near-term objective. WRA anticipates that the Commission will consider modifications to the existing EPS and that these modifications can address additional goals for renewable energy, taking into account their hedge value, their environmental attributes, their cost, and their availability (¶ 68).

Q. Where would APS obtain the renewable resources to meet its obligations under the settlement agreement?

A. To meet its goals under the settlement agreement, APS would be seeking commercially available resources that could be deployed within about one year. The most likely resources would be wind, biomass, and geothermal resources.

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[2] Capacity factors of 32 percent have been achieved in other states. Arizona resources may not reach this level of production, however.

APS may obtain some or all of the resources from within Arizona. Arizona has the potential to supply at least 2000 to 3000 MW of wind energy[3] and may have some additional near term biomass potential. APS may also seek resources from neighboring states. New Mexico already has about 204 MW of wind resources and has the potential to generate about 56 million MWh per year from wind resources statewide.[4] California has geothermal resources whose energy could be sold to APS. Salt River Project is acquiring 25 MW of geothermal resources from a Salton Sea facility in California starting in 2004.[5]

The settlement agreement encourages APS to seek in-state resources (¶ 691, subject to ¶ 69n) but does not require APS to obtain all the renewable resources from within Arizona for two reasons:

a. Until APS receives price information from bidders, it is not known whether in-state resources would be more costly. The cost impact of an in-state requirement could be large. For example, if APS were required to obtain only in-state resources and if those resources cost $0.01 per kWh more than comparable out-of-state resources, the extra cost borne by ratepayers for 250,000 MWh per year would be $2.5 million per year. Further, in-state resources might exceed the cost cap while out of state resources might cost less than the cap.
b. A restriction requiring APS to buy only in-state resources may conflict with the commerce clause of the U.S. Constitution. A developer or ratepayer may sue the Commission, thereby jeopardizing the renewable energy program, and introducing uncertainty for APS and developers until the issue is resolved. Recent natural resource cases concerning the commerce clause, including Arizona cases, decided by either the Supreme Court or the U.S. Court of Appeals indicate that restrictions on interstate commerce to benefit local business at the expense of the national economy are unlawful unless the restriction is the only feasible way to promote a legitimate public purpose. In a recent review of these Supreme Court decisions, an article in the *Harvard Environmental Law Review* concluded that "the Court's avowed purpose is to prohibit 'economic protectionism,' defined as 'regulatory measures designed to benefit in-state economic interests by burdening out-of-state competitors'.... With only one exception, the (Supreme) Court has invalidated every natural resource

[3] Amanda Ormond, "Arizona Wind Energy Resource Potential," presentation to the Arizona Corporation Commission, June 25, 2004.

[4] Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, and Greeninfo Network, *Renewable Energy Atlas of the West*, Boulder, CO, 2002.

[5] Salt River Project, "SRP's Proposed Sustainable Portfolio Six-Year Plan," February 2004, p. 11.

protection regulation that it has considered between 1978 and 2001 in the context of a commerce clause challenge".[6]

Q. Is the price premium for renewable energy reasonable?

A. Yes. The agreement allows for a renewable energy price premium of 25 percent above APS' estimate of market costs for conventional generation (¶ 69g). This premium and its associated cap serve three purposes. First, the 125 percent cap allows renewable resources to be acquired while limiting APS' and ratepayers' exposure to high renewable resource costs relative to conventional energy costs.

To put the premium in perspective, the market price for energy only from a gas-fired combined cycle unit with an average heat rate of 8,000 Btu per kWh and a gas price of $6.18 per MMBtu[7] would be $0.04944 per kWh. Applying the premium, the renewable resources would have to have an energy price less than about $0.0618 per kWh at current natural gas prices (1.25 x $0.04944 = $0.0618). Renewable resources, including intermittent resources, also have capacity value and APS will have to add capacity values of specific resources to energy values to obtain the benchmark market price (¶ 69a).

Some resources are likely to beat the price cap. As indicated in my direct testimony, recent contracts for wind energy have been at prices less than $0.03 per kWh. When interconnection costs, transmission costs, and wind integration costs (costs associated with accommodating intermittent resources) are added in, the delivered price would be about $0.04 per kWh, which is clearly competitive. This price level assumes re-instatement of the federal production tax credit. Without the production tax credit, busbar costs might be around $0.049 to $0.052 per kWh (for Class IV and Class V wind resources)[8] plus about $0.01 per kWh for interconnection, transmission, and integration costs for a total of $0.059 to $0.062 per kWh which is still competitive. Geothermal resources may cost about $0.058 to $0.081 per kWh[9] and some of these projects might be competitive with respect to the price cap, especially as capacity

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6 Christine Klein, "The Environmental Commerce Clause," 27 *Harvard Environmental Law Review* 1, at 42 and 57.

7 This price is from the Energy Information Administration's estimate of 2004 gas prices paid by the electric power sector, *Short-Term Energy Outlook – September 2004*, Table 4. Note that the September 2004 gas price estimate is slightly higher than the August 2004 estimate used in Exhibits DB-5 and DB-6.

8 Western Resource Advocates, *A Balanced Energy Plan for the Interior West*, Boulder, CO, 2004, Appendix A.

9 Low value is average price paid by Sierra Pacific Power Company for geothermal energy as reported in its 2003 FERC Form 1. High value is estimate of levelized contract price paid by Imperial Irrigation District for geothermal energy from a Salton Sea project now under construction: John Sass and Sue Priest, "Geothermal California," *GRC Bulletin*, September/October 2002, pp. 183-187.

values are considered. Landfill gas projects in Arizona may cost about \$0.061 to \$0.075 per kWh,[10] so this technology may also be competitive, especially as capacity values are included in the benchmark price. In sum, the premium is reasonable because renewable resources are likely to be available at prices less than 125 percent of market prices for conventional generation and because APS' and ratepayers' exposure to high renewable energy costs is constrained.

Second, the 25 percent premium allows for implicit consideration of environmental benefits of renewable resources – reduced emissions of carbon dioxide, sulfur dioxide, and nitrogen oxides, depending on the conventional resources which are displaced. My direct testimony discusses environmental benefits and their valuation. Among these benefits is a reduction in APS' exposure to the costs of potential future regulation of carbon dioxide emissions. The environmental costs of conventional generation would not be included in the market analysis of conventional energy prices developed in accordance with paragraph 69g, so the environmental benefits of renewable energy can be considered to be included in the 25 percent premium allowed by the settlement agreement.

Third, the 25 percent premium allows for uncertainty inherent in the estimate of the long term market price of conventional resources prepared in accordance with paragraph 69g. Gas prices are very unstable (Exhibit DB-5) and so APS might misestimate the levelized cost of long term fixed price conventional energy resources. Indeed, gas price forecasts have exhibited significant underestimates in the recent past. Exhibit DB-6 shows Energy Information Administration Annual Energy Outlook (AEO) forecasts made in earlier years for natural gas prices paid by US electric generators.[11] Despite the detail and sophistication of the analyses, each forecast was significantly below actual prices in future years. Because the acquisition of renewable energy is intended to be a hedge against moderate and high gas prices, it is reasonable to allow for uncertainty in determining the market price of conventional generation.

Q. What happens if APS cannot acquire at least 100 MW of renewable resources for delivery starting in 2006?

A. Under paragraph 71 of the settlement agreement, APS would have to report to the Commission by January 31, 2007 if there is a shortfall. A shortfall could occur for any of several possible reasons. For example, no resources might meet the cost cap. Another circumstance might be that a developer is not be able to complete an

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[10] Estimated from data for SRP's Tri-Cities Landfill Project: *Salt River Project, Scope and Background Information for Participants in SRP's Sustainable Procurement Principles Development Process*, February 2004, p. 9, and *SRP's Proposed Sustainable Portfolio Six-Year Plan*, February 2004, p. 5. Estimate assumes a 50% capacity factor.

[11] Energy Information Administration, *Annual Energy Outlook 1996, Annual Energy Outlook 1999*, and *Annual Energy Outlook 2002*. Forecasts are reference case analyses.

otherwise desirable project by the end of 2006. Paragraph 71 enables the Commission to examine the situation and decide what to do.

Conclusions

Q. Are the renewable energy provisions in paragraphs 69 through 72 of the settlement agreement in the public interest?

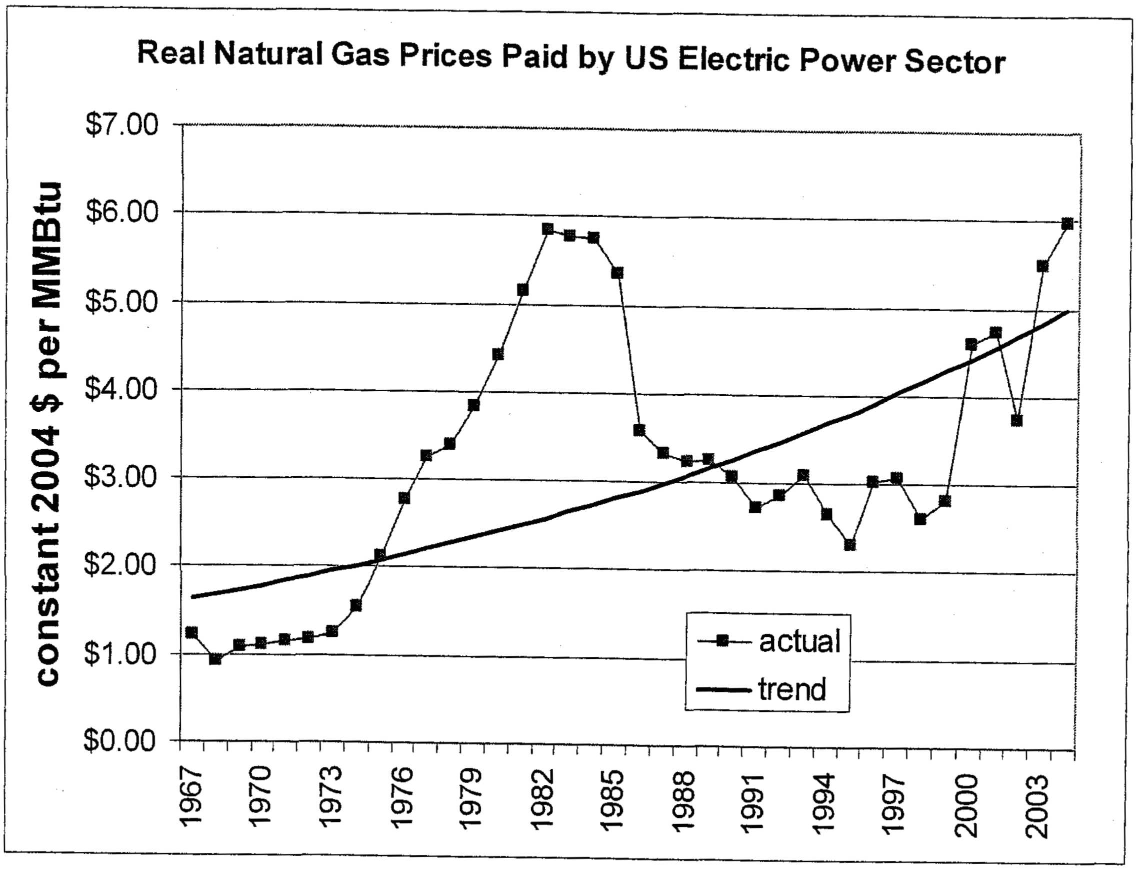
A. Yes. APS' acquisition of low cost, stably priced renewable energy resources will enable it to hedge against moderate and high natural gas prices in an economic manner and lower the price paid for electricity by retail consumers in periods of moderate and high gas prices. The renewable resources will also reduce the volatility of electricity prices and bring about environmental improvements.

More generally, the settlement agreement is a sea change.[12] Under the agreement, APS will carry out larger scale demand side management programs and renewable energy programs than it has in the past. As a result, APS' programs will lower the costs of meeting the demand for electric energy services and economically hedge against moderate and high gas prices.

Q. Does this conclude your testimony?

A. Yes.

[12] Full fathom five thy father lies; of his bones are coral made; those are pearls that were his eyes; nothing of him doth fade; but doth suffer a sea-change into something rich and strange. Shakespeare, The Tempest, Act I, Scene 2.


Real Natural Gas Prices Paid by US Electric Power Sector
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$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
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1970
1973
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1979
1982
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1991
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1997
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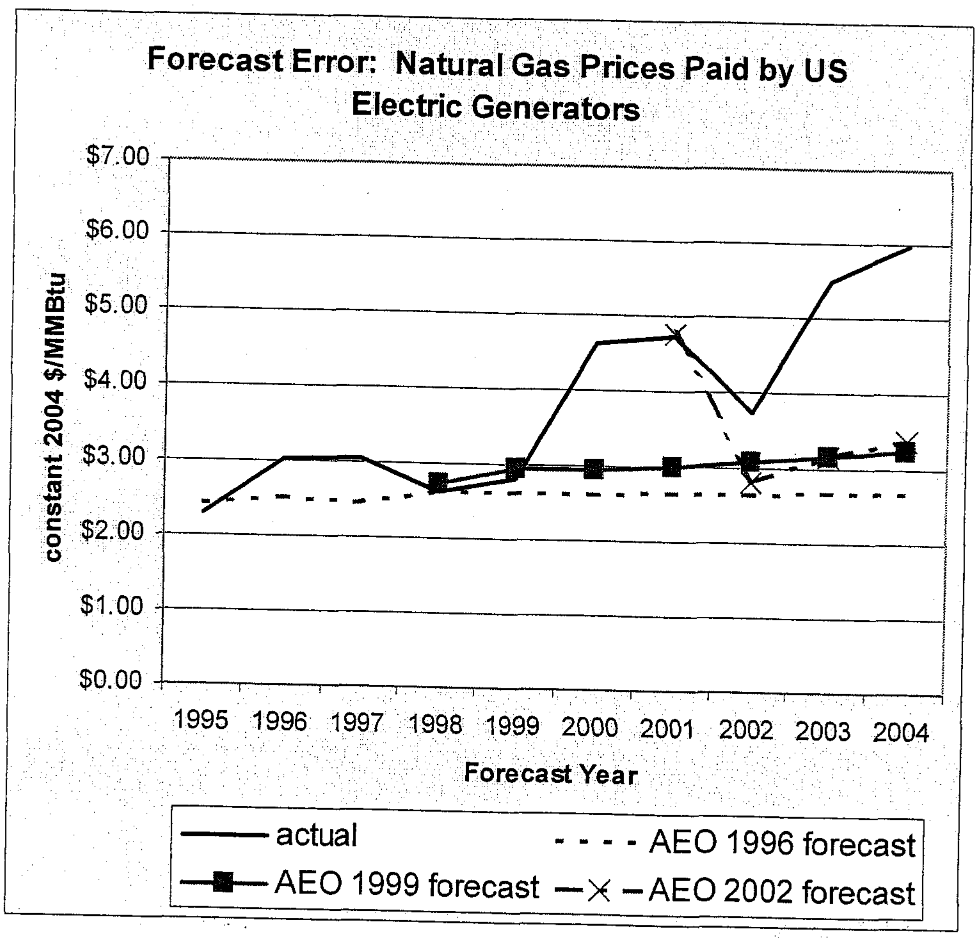
2003
actual
trend


Forecast Error: Natural Gas Prices Paid by US Electric Generators
$7.00
$6.00
$5.00
$4.00
$3.00
$2.00
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$0.00
constant 2004 $/MMBtu
1995
1996
1997
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1999
2000
2001
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Forecast Year
actual
AEO 1996 forecast
AEO 1999 forecast
AEO 2002 forecast

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.

Docket No. E-01345A-03-0437

NOTICE OF FILING CROSS-REBUTTAL TESTIMONY

Western Resource Advocates, through its undersigned counsel, hereby provides notice that it has this day filed the written cross-rebuttal testimony of David Berry in connection with the above-captioned matter.

Admitted
EXHIBIT
WRA-3
LB 12/2/04

DATED this 30th day of March, 2004.

ARIZONA CENTER FOR LAW IN
THE PUBLIC INTEREST

By______________________
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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Cross-Rebuttal Testimony of

David Berry

Western Resource Advocates

March 30, 2004

Cross-Rebuttal Testimony of David Berry
Docket No. E-01345A-03-0437

Table of Contents

Introduction

Q. Please state your name and business address and indicate whom you represent in this proceeding.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064. I represent Western Resource Advocates (WRA).

Q. Did you previously file testimony in this matter?

A. Yes. I filed direct testimony on February 3, 2004.

Q. What is the purpose of your cross-rebuttal testimony?

A. In the Amended Rate Case Procedural Order dated February 20, 2004, the Chief Administrative Law Judge ordered that any cross-rebuttal testimony to Staff/Intervenor testimony by parties other than Arizona Public Service Company (APS) should be filed by March 30, 2004. My cross-rebuttal testimony compares my direct testimony with positions taken by Staff, the Residential Utility Consumer Office (RUCO), and the Southwest Energy Efficiency Project (SWEEP) in their direct testimony. I address funding of the Environmental Portfolio Standard, the effect of natural gas prices on rates, and the role of energy efficiency as a complement to low cost renewable energy.

Funding of the Environmental Portfolio Standard

Q. What did you recommend regarding funding of the Environmental Portfolio Standard (EPS) in your direct testimony?

A. I recommended (page 17, starting at line 27) that the surcharge for the EPS be retained at its current level of $0.000875 per kWh, but that the caps be removed and that demand side management (DSM) funding that was redirected to support the implementation of the EPS be restored to DSM programs. My recommended funding level for the EPS was based on a calculation of the amount of money Arizona Public Service Company would need to meet the EPS kWh requirements by 2012. My recommendation also addressed the inequity created by the surcharge caps in which smaller commercial and residential customers pay a much higher effective surcharge rate for the EPS than large industrial customers.

Q. What is Staff's recommendation for funding the EPS?

A. On page 17 of her direct testimony (starting at line 15), Staff witness Barbara Keene recommends that the rate on EPS-1 remain at $0.000875 per kWh but with monthly caps of $0.99 for residential customers, $25.00 for non-residential customers, and $100.00 for non-residential customers with demands of 3,000 kW or more. It is my understanding that Staff recommends that the $6 million that previously funded DSM and was redirected to fund the EPS would continue to fund the EPS and would not be restored to DSM programs.

Q. Would Staff's recommended funding for the EPS be sufficient to pay for APS' resource acquisitions to meet the Commission's EPS requirements?

A. The Staff recommendation may fall short of covering the cost for APS to meet the EPS requirement by 2012. Staff identified ways for APS to lower its costs (direct testimony of Barbara Keene, page 18, starting at line 2), including an expanded buydown program and more large scale solar thermal electric projects. I estimated the costs of meeting the EPS solar electric requirement with 20 percent of the solar electric kWh coming from customer-sited photovoltaic projects for which APS pays a buydown of $3,100 per kW through 2005 and $300 per kW less each year after that. The rest of the EPS requirements are met with utility scale photovoltaic projects and a mix of non-solar resources. With this lower cost approach, the remaining cost of meeting the EPS requirements by 2012 would be about $207 million while the revenues from the surcharge as recommended by Staff, plus the annual $6 million of funding redirected from DSM programs, would bring in about $172 million from 2004 through 2012.

Q. Do Staff's recommended surcharge caps alleviate the fairness issue raised in your direct testimony?

Q. No. The surcharge portion of the revenues to pay for the EPS would still put most of the burden on smaller customers. The effective rates in the 2002 test year of Staff's capped surcharges would be as follows:

- $0.000622 per kWh for residential customers
- $0.000425 per kWh for non-residential customers under 3 MW
- $0.000031 per kWh for non-residential customers over 3 MW

Q. Did your direct testimony propose a method for alleviating hardships on larger customers stemming from the EPS surcharge other than surcharge caps?

A. Yes. I suggested an opt-out approach for large customers who would install their own renewable energy facilities in lieu of paying the surcharge.

Q. How does your recommended treatment of the EPS surcharge and redirection of the DSM funding compare with RUCO's direct testimony?

A. I believe RUCO and WRA have consistent recommendations. RUCO witness Marylee Diaz Cortez recommends that the DSM funding be restored to DSM (page 26, line 5) as I recommended. I also infer (direct testimony of Ms. Diaz Cortez, page 26, line 12) that RUCO believes that the EPS should continue to be funded at an adequate level through a surcharge.

Q. Are there uncertainties associated with the cost of meeting the EPS and with the amount of revenues from the surcharge, and, if so, how should they be addressed by the Commission?

A. There are uncertainties as indicated in my direct testimony (page 15, starting at line 43). I believe that the best way to address these uncertainties is to collect the EPS funding through an adjustable system benefit type of charge or surcharge in which the rate is reset regularly to deal with imbalances between costs and revenues.

The Effect of Natural Gas Prices on Rates

Q. What position did you take in your direct testimony regarding high natural gas prices?

A. On pages 2 through 14 of my direct testimony, I found that APS relies on natural gas as a fuel for its intermediate and peaking power resources and that natural gas prices are volatile and increasing over time. As a result, rates will go up as gas prices go up. I further argued that APS should hedge against high natural gas prices by acquiring large amounts of low cost renewable energy to displace gas generation and that doing so would lower APS' fuel and purchased power costs in periods of moderate or high gas prices. I recommended that the Commission order APS to immediately acquire energy to meet at least 2 percent of its retail sales from low cost renewable energy resources and that the Commission undertake a process to establish a renewable portfolio standard well in excess of the current EPS (and in addition to the EPS).

Q. Since you filed your direct testimony on February 3, 2004, what has happened to natural gas prices paid by electric utilities?

A. They are climbing even higher. In my direct testimony I used the Energy Information Administration's *Short Term Energy Outlook* December 2003 forecast price of $4.97 per MMBtu ($4.86 per MMBtu in 2002 dollars) for 2004 (direct testimony, page 11, line 39). The *Short Term Energy Outlook* of March 2004 forecasts a price of $5.75 per MMBtu for 2004 and $5.46 per MMBtu for 2005 in nominal dollars. The higher that natural gas prices are, the greater the savings from substituting low cost renewable energy for generation from the marginal fossil fuel plants.

Q. How does Staff's assessment of the natural gas situation compare with yours?

A. Our views are consistent. Douglas C. Smith observes (direct testimony, page 5, starting at line 17) that the average costs for gas-fired units are much higher than for APS' coal and nuclear plants and above the system average cost per MWh for fuel and purchased power. Mr. Smith estimated that gas-fired units provide about 25 percent of total system energy requirements (assuming the PWEC facilities are rate based) but represent a cost of about $299 million per year which is over half of APS' net fuel and purchased power cost. Mr. Smith concludes that changes in natural gas prices can significantly affect APS' total fuel and purchased power expense. On page 6, Mr. Smith states that natural gas prices have shown considerable variance in recent years and that gas and electricity market prices will continue to vary significantly in the foreseeable future.

Q. What did Staff conclude about the role of natural gas prices as a cause of APS' requested rate increase?

A. Mr. Smith indicates that high natural gas prices are a primary driver of APS' requested rate increase (page 6, starting at line 20).

Q. Does Staff recognize the role of hedging against high natural gas prices?

A. Yes. Mr. Smith states, on page 6, line 9 of his direct testimony, that APS' gas fuel costs and electricity market purchases, if not hedged, will represent a significant source of cost uncertainty in the future. Even with traditional hedging in place, Mr. Smith states that APS will not be able to eliminate all fuel cost uncertainty.

Q. In light of Staff's analysis, do you still believe that the Commission should order APS to acquire at least 2 percent of its retail sales from low cost renewable energy resources in the next two years?

A. Yes. Staff's assessment of the role of natural gas at APS and the high cost of natural gas reinforce the need to hedge against high gas prices with low cost renewable energy.

The Role of Energy Efficiency

Q. Mr. Schlegel, representing SWEEP, states that "increasing energy efficiency will diversify the resource mix, increase reliability, and mitigate vulnerability to price volatility. Energy efficiency does not rely on any fuel and is not subject to shortages of supply or fuel price volatility" (direct testimony, page 4, starting at line 24). How would energy efficiency and low cost renewable energy work together to hedge against the risk of continued high natural gas prices?

A. Both are cost effective means to reduce APS' reliance on expensive natural gas. Energy efficiency measures which reduce demand during peak and intermediate periods avoid the need to burn gas at APS' power plants and at natural gas fired power plants from which APS purchases energy. Low cost renewable energy displaces the marginal power plants that would otherwise be running at the time the renewable energy is available. During peak and intermediate periods, that renewable energy displaces electricity generated at gas-fired power plants.

Q. Mr. Schlegel proposes an ambitious energy efficiency program for APS and you have proposed that APS immediately acquire at least 2 percent of its retail energy sales from low cost renewable energy resources. Can ratepayers afford both of these programs?

A. Yes. By acquiring significant amounts of low cost renewable energy, APS' costs and rates will be lower than they would otherwise be. By acquiring significant amounts of cost effective energy efficiency resources, ratepayers' total costs will go down.

Q. Does this conclude your cross-rebuttal testimony?

A. Yes.

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BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
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JEFF HATCH-MILLER
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KRISTIN K. MAYES

In the matter of the Application of ARIZONA PUBLIC SERVICE COMPANY for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return, and for Approval of Purchased Power Contract.

Docket No. E-01345A-03-0437

NOTICE OF FILING DIRECT TESTIMONY AND EXHIBITS

Western Resource Advocates, through its undersigned counsel, hereby provides notice that it has this day filed the written direct testimony and exhibits of David Berry in connection with the above-captioned matter.

Admitted
EXHIBIT
WRA-4
CB 12/2/04

DATED this 3rd day of February, 2004.

ARIZONA CENTER FOR LAW IN
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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MARC SPITZER, Chairman
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MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND FOR APPROVAL OF PURCHASED POWER CONTRACT.	DOCKET NO. E-01345A-03-0437

Direct Testimony of

David Berry

Western Resource Advocates

February 3, 2004

Direct Testimony of David Berry
Docket No. E-01345A-03-0437

Table of Contents

List of Exhibits

Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064.

Q. By whom are you employed and in what capacity?

A. I am Senior Policy Advisor for Western Resource Advocates, formerly the Land and Water Fund of the Rockies.

Q. Please describe Western Resource Advocates.

A. Western Resource Advocates (WRA) works to protect and restore the natural environment of the Interior American West. Western Resource Advocates uses law, economics, and policy analysis to protect land and water resources, protect essential habitats for plants and animals, and assure that energy demands are met in environmentally sound and sustainable ways. We work with other environmental and community groups, taking into account the economic and cultural framework unique to the states of the Interior West. Western Resource Advocates has been involved in Arizona utility regulatory issues for over 12 years.

Q. What are your professional qualifications for presenting testimony in this docket?

A. Exhibit DB-1 summarizes my experience and education.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of WRA and I will address the following topics:

- hedging Arizona Public Service Company's (APS') exposure to increases in natural gas prices with low cost renewable energy so that ratepayers are less exposed to increases in natural gas prices,
- funding the Environmental Portfolio Standard, and
- improving APS' solar energy tariffs.

Hedging Natural Gas Price Increases

Q. Has Arizona Public Service Company indicated that natural gas price increases are an important component of its proposed rate increase?

A. Yes. Mr. Wheeler states on page 9 of his direct testimony that APS' fuel and purchased power costs have increased very significantly over the levels reflected in APS' current rates. In addition, on pages 10 and 11, Mr. Wheeler states that purchased power and gas generation components of APS' energy supply mix have exhibited volatile prices and that APS' average delivered cost of gas increased by 68 percent since the end of the test period. Mr. Robinson indicates (Attachment DGR-5, Page 7 of 27) that APS' normalized 2003 fuel and purchased power costs were $0.02371 per kWh and that the test year fuel and purchased power costs were $0.018033 per kWh, for an increase of $0.005137 kWh, which translates to an adjusted increase in costs of about $121 million.

Q. Has the electric industry generally faced natural gas price volatility?

A. Yes. Exhibit DB-2 shows prices paid by electric utilities nationally for natural gas. Historical data were taken from Energy Information Administration reports and forecasted prices for 2003 and 2004 were taken from the Energy Information Administration Short Term Energy Outlook for December 2003. Costs are presented in constant 2002 dollars, using the Gross Domestic Product Implicit Price Deflator. Gas prices have increased by as much as 60 percent from one year to the next. There is also a general upward trend in natural gas prices. The trend line shows an annual percentage price increase of about 3 percent per year in constant dollars. Of course the trend line does not account for the complexities of periods of great volatility.

Q. What has been APS' experience with natural gas consumption and prices?

A. The upper figure in Exhibit DB-3 shows natural gas generation (kWh) as a percentage of total APS kWh generation. Between 1997 and 2002, APS obtained, on average, 8 percent of its kWh generation from natural gas–fired power plants.[1] The lower figure in Exhibit DB-3 shows APS' natural gas costs from 1996 through September 2003.[2] For comparison, the prices paid by electric utilities for natural gas nationally are also

[1] *APS 2002 Statistical Supplement*, p. 122. APS also obtained electricity from purchased power, but the mix of generation resources underlying the purchased power is not reported. Some of the purchased power was likely to come from gas-fired resources. In 2002, APS purchased at least 2,315,000 MWH of energy from natural gas generation (APS response to WRA data request WRA 1-3).

[2] In response to WRA data request 1-7, APS indicated that it does not have gas price data prior to 1996.

shown in the figure. Prices paid by APS are similar to national prices except in 1996. APS is not immune to the volatility of natural gas prices.

Q. On January 27, 2004, APS submitted to the Commission a summary of responses to its power supply Request for Proposals dated December 3, 2003. What information does APS' summary provide about the role of natural gas in future generation and the price risk faced by APS and its customers?

A. APS' summary reinforces the concern that APS and its customers are and will be subject to natural gas price increases affecting the generation of a large portion of the electricity serving APS' retail customers. In particular, APS notes that:

- All of the asset-backed proposals involved natural gas-fired generation, and all the responses require APS and its customers to bear or assume gas price risk and gas transportation risk.
- The levelized prices (as calculated preliminarily by APS) range from $65 to $160 per MWH over the life of the proposed asset or purchased power agreement.
- None of the purchased power agreement proposals involves a fixed price bid.

Q. What are the impacts of continued exposure of APS and its ratepayers to natural gas price increases and price volatility?

A. Higher natural gas prices result in higher rates if the Commission permits APS to pass along to ratepayers increased electricity costs resulting from natural gas price increases. Highly volatile electricity prices make it harder for residential and non-residential consumers to budget for electricity expenditures and make it harder for those consumers to make decisions about energy efficiency.

Q. How can APS reduce its and its ratepayers' exposure to natural gas price volatility and price increases?

A. There are several ways a utility can protect itself and its ratepayers from natural gas price increases and price volatility. These include deployment of energy efficiency measures which reduce demand during periods when natural gas fired steam units, combustion turbines, and combined cycle units are running, fuel substitution, and financial hedges. In response to WRA data request 1-13, APS indicated that it uses both physical and financial contracts to manage the risks of natural gas price volatility. Such hedging mechanisms may be able to reduce volatility but, in general, they would not allow APS to avoid the trend in increases in natural gas prices over time. Further, even with its use of financial and physical hedges, APS still experienced price volatility (Exhibit DB-3).

Of particular interest is acquisition of significant quantities of energy from renewable resources which have stable prices. This energy could come from a variety of relatively low cost resources including landfill gas, geothermal projects, and wind resources. Such resources may be located in Arizona or elsewhere. Wind energy is the most rapidly growing renewable energy technology in the United States and wind energy contracts today exhibit prices around $0.03 per kWh or less[3] and typically incorporate stable prices.

Note that both energy efficiency and renewable energy resources, once installed, would not be subject to significant price increases because most of the cost is incurred as up-front capital costs or because contracts for purchases of renewable energy typically contain stable prices. In contrast, even well-hedged natural gas supplies would still be subject to long run price increases.

Q. Please describe how a wind energy resource could reduce APS' exposure to volatile natural gas prices.

A. Wind energy has stable costs and would displace APS' marginal gas-fired and coal-fired units that would otherwise be running at the time wind energy is available. If APS owns the wind project, most of the costs would be incurred up front. At present these costs are about $1,000 per kW. Variable operating and maintenance costs are very low. Thus APS would not be exposed to large fluctuations in costs from year to year. If APS purchases wind energy from a developer, the contract would probably resemble other contracts in the industry. These contracts typically have a fixed price or a price that varies according to a pre-determined schedule or a price that varies with inflation. Again, APS would not be exposed to large, unexpected fluctuations in costs from year to year.

Q. How much wind energy would APS need to acquire to provide a useful hedge against natural gas price increases?

A. In order to provide a significant hedge, capable of saving a million dollars or more per year during years of high natural gas prices, the amount of energy from renewable resources must be large. A small project would not provide a significant benefit.

For the three year period 2000 to 2002, APS' average annual sales to ultimate customers was 23,081 GWH (APS Standard Filing Requirements Schedule E-7). In an <u>initial</u> acquisition, at least about 2 percent of retail sales should be from stably priced renewable energy resources, or about 462 GWH. Assuming energy losses of 5

[3] These low prices are dependent on continuation of tax and other government incentives, including the production tax credit.

percent[4] a 175 MW wind energy project with a capacity factor of 32 percent could supply the target amount of energy on average. Subsequent acquisitions of wind or other renewable energy resources could increase the percentage, eventually perhaps reaching or exceeding 20 percent of APS' retail load.

Q. Wouldn't APS need to start with small demonstration projects before it could venture into larger acquisitions of wind energy?

A. No. There is significant experience with large wind energy projects in the Southwest. As of October 2003, the following wind generating capacity was in place in Southwestern states:

- California — 1,988 MW
- Texas — 1,096 MW
- Colorado — 61 MW plus 162 MW under construction (this project was completed in December 2003)
- New Mexico — 205 MW

In other western states, there were an additional 588 MW of wind generating capacity as of October 2003. The national total as of October 2003 was 5326 MW of wind generating capacity as reported on the American Wind Energy Association website.

With regard to recent or planned specific projects:

- Public Service Company of New Mexico (PNM) obtains about 200 MW of power from a wind project in east central New Mexico through a 25 year contract with the project developer. This project began operation during 2003. Previously PNM had little or no wind resources. Salt River Project purchases some of PNM's wind energy.
- A 162 MW wind project was under construction in late 2003 near Lamar, Colorado, with the energy to be purchased by Public Service Company of Colorado. The Lamar project was completed in December 2003.
- Texas-Caprock Wind, LP, an affiliate of Cielo Wind Power, announced plans in August 2003 to install up to 80 MW of wind generation capacity near Tucumcari, New Mexico within the next 12 months. Xcel Energy will purchase all the output of the turbines for at least 15 years.

Q. How large are utility wind projects in relation to utility peak demand?

4 APS 2002 FERC Form 1, page 401a, lines 27 and 28.

A. I estimated MW of wind generation capacity for Public Service Company of New Mexico, Public Service Company of Colorado, and PacifiCorp[5] as a percentage of 2002 peak demand as reported in the utilities' 2002 FERC Form 1, page 401b.[6] PNM's wind project capacity is about 14 percent of peak demand, Public Service Company of Colorado's wind project capacity is about 4 percent of peak demand, and PacifiCorp's wind project capacity is about 3.5 percent of peak demand.

Q. Did you prepare a calculation of the hedge value of wind energy for APS?

A. Yes, I examined a generic 175 MW wind project considering the following factors:

- The cost of wind energy plus the costs of integrating wind energy into the grid plus transmission and related costs for delivering wind energy to APS.
- Avoided conventional generation costs, including avoided fuel cost, avoided operating and maintenance cost, and avoided capacity cost.
- The benefits of reduced carbon dioxide, sulfur dioxide, and nitrogen oxide emissions due to displacement of fossil fuel generation by wind energy.

One could conduct a similar analysis for a specific project. To be a useful hedge, wind energy should be expected to be less costly to society than conventional generation in years when natural gas prices are high.

Q. Please describe how you estimated the cost of wind energy.

A. I reviewed costs of wind generation reported by Navigant Consulting, costs contained in several confidential contracts and costs for Texas wind projects.[7] For a good wind site, a long term contract price would be about $0.03 per kWh or less. In my analysis, I assumed a long term contract price of $0.028 per kWh in constant 2002 dollars. Thus, the assumed nominal price escalates at the rate of inflation.

[5] For Public Service Company of New Mexico, the wind resource is the 200 MW FPL project cited above. For Public Service Company of Colorado, the wind resource consists of the company's share of the Foote Creek Rim project, the Ponnequin project, the Peetz Table Wind Farm, and the Lamar project completed in December 2003. For PacifiCorp, the wind resource consists of PacifiCorp's share of the Foote Creek project in Wyoming plus the Stateline projects in Washington and Oregon. The energy output of these projects is not reported in a readily available form.

[6] Peak demand excludes non-requirements sales for resale and associated losses.

[7] Navigant Consulting, Inc., 2003. *The Changing Face of Renewable Energy*, http://www.navigantconsulting.com. R. Wiser, R. and O. Langniss, "The Renewables Portfolio Standard in Texas: An Early Assessment." Berkeley, CA: Lawrence Berkeley National Laboratory LBNL-49107, 2001.

Because wind energy is intermittent, there are wind integration costs. Wind integration refers to maintaining reliability given an intermittent resource by dealing with reserves and imbalances, rescheduling, and load following. I reviewed three studies which estimated wind integration operating costs as follows: about $2.00 per MWH for 200 MW of wind generation capacity with a 32 percent capacity factor (PacifiCorp); $1.90 to $2.92 per MWH reflecting a range of wind plant capacities from 250 MW to 2000 MW (We Energies); and $1.85 per MWH for Northern States Power's existing 280 MW wind plant.[8] I assumed a cost of $2.00 per MWH, reflecting a low initial quantity of wind generation in APS' system.

Transmission costs depend on the transmission service used. I assumed that APS' transmission and ancillary service costs (excluding imbalance costs, which are considered in integration costs, and assuming that all ancillary services are required) would apply.[9] Costs for any new transmission facilities and costs for interconnecting to the grid are site specific and will vary depending on the project location. To account for these costs generically, I assumed a five mile 230 kV transmission line from the wind facility to the grid plus the costs of interconnection with the grid.[10] The combined transmission-related costs are $24.13 per kW per year.

Q. Please describe the environmental benefits of wind energy.

A. As will be described below, wind energy displaces fossil fuel generation. APS would back off marginal gas and coal fired generation when wind energy is available and, in doing so, emissions of carbon dioxide, nitrogen oxides, and sulfur dioxide would be reduced. Carbon dioxide is the major anthropogenic contributor to greenhouse gases which affect long term climate change. Nitrogen oxides contribute to haze and smog and contribute to the formation of ozone which impairs respiratory health. Sulfur

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[8] PacifiCorp, *Integrated Resource Plan 2003.* Portland, OR, Appendix L, 2003. Electrotek Concepts, "We Energies Energy System Operations Impacts of Wind Generation Integration Study," Knoxville, TN, 2003. Electrotek Concepts, "Characterizing the Impacts of Significant Wind Generation Facilities on Bulk Power System Operations Planning," Arlington, VA, 2003 (study of Northern States Power).

[9] Arizona Public Service Company, 2002. Pro Forma Open Access Transmission Tariff, Revision No. 11. APS' transmission costs are neither the highest nor the lowest in the Southwest. In addition, provisions are being revised to recognize the intermittent nature of wind energy and to reduce the penalties for short term imbalances, thereby making ancillary service costs less onerous: California Independent System Operator, *Status Report in Compliance with March 27, 2003 Order,* Report submitted to the Federal Energy Regulatory Commission, July 28, 2003.

[10] Cost data from Energy Information Administration, *Renewable Energy Annual 1995*, Tables 32 and 33, inflated to 2002 dollars and annualized assuming a 25 year life and a 10 percent interest rate. Similar costs are reported in Iowa Department of Natural Resources, *Delivering 2,000 MW of Wind Energy to the Metropolitan Centers in the Midwest*, March 2002, pp. 15 - 16. The Midwest study uses cost estimates from the MidContinent Area Power Pool.

dioxide impairs respiratory function, is a cause of acid rain, and reduces visibility.[11] I subtracted the value of the environmental benefits from the costs of wind energy.[12,13]

Q. How did you monetize the environmental benefits?

A. To determine the volume of avoided emissions, I used APS' nitrogen oxide, sulfur dioxide, and carbon dioxide emissions rates for specific power plants.

As measures of the value to society of reducing air emissions, I applied market prices for tradable credits for emissions where there are air quality standards in place or where regulation may occur in the future. These market prices are intended to represent values to society. APS may be able to capture these values through the sale of emissions credits or allowances or through avoided purchases of credits and allowances.

Markets for carbon dioxide emissions reductions are currently developing and prices range from about $1 per metric ton of CO_2 to about $11 or more per metric ton of CO_2.[14] These prices discount the actual costs of complying with future carbon regulation because of uncertainty about what carbon credits will be acceptable to

[11] As an example of the benefits to society of reducing air emissions, the *Governor's Brown Cloud Summit Final Report* (January 16, 2001) found that nitrogen dioxide and sulfur dioxide gases from burning fossil fuels contribute to the brown cloud in the Phoenix area. Reduction of air emissions and the consequent reduction in the brown cloud would benefit society by improving visibility and reducing respiratory health effects.

[12] Alternately, one could add environmental costs to the costs of conventional generation.

[13] There may be other environmental benefits as well, such as reduced emissions of particulates and mercury and reduced water consumption. However, I did not include those benefits in the analysis. I also assumed that wind facilities would be located so as to minimize aesthetic and avian impacts.

[14] There are several markets for emissions reductions and not a single exchange in which credits are bought and sold. Price data are taken from the following sources. Natsource, "Assessment of Private Sector Anticipatory Response to Greenhouse Gas Market Development," prepared for Environment Canada, 2002. Cantor Environmental Brokerage reported that as of June 1, 2003, prices of project-based reductions in greenhouse gases for the United States were in the range of $1.00 to $3.00 per metric ton of carbon dioxide equivalent and increase up to $8.00 depending on vintage year, risk guarantees, volume, and contract structure. The Chicago Climate Exchange reported carbon financial instrument closing prices on December 16, 2003 of $1.00 per metric ton of carbon dioxide. However, the Chicago Climate Exchange began trading in December 2003 and there have been few trades so far. In a news release dated December 4, 2003, Natsource reported weighted average prices in 2003 as follows: $2.55 per ton of carbon dioxide equivalent for emissions reductions made for reasons other than complying with future regulation of greenhouse gas emissions; $3.64 per ton of carbon dioxide equivalent for emissions reductions that are Kyoto compliant (with buyer liability for shortfalls in delivery of contractual commitments); and $4.88 per ton of carbon dioxide equivalent for emission reductions that are Kyoto compliant with seller liability for failure to deliver contractual commitments. Natsource indicated that trades during the first three quarters of 2003 involved 71 million tons of carbon dioxide equivalents.

regulators in the future, uncertainty about future carbon regulation compliance costs, and other factors. I assumed a value of carbon dioxide emission reduction credits of $3.64 per metric ton which is the weighted average price during 2003 for emission reductions that will meet expected regulatory requirements but put the liability for shortfalls in delivery on the buyer.

For sulfur dioxide credits, I assumed the average value in 2002 reported in the literature, $170 per ton.[15]

For nitrogen oxides, there is a wide range of values. APS provided prices of sales and purchases which average $825 per ton. Nationally, credit prices averaged around $2000 per ton in 2002.[16] Cantor Environmental Brokerage reported prices for Maricopa County in October 2002 of $12,000 per ton. To be conservative, I used the average value reported by APS.

Q. What are the costs of conventional generation that could be avoided by wind energy?

A. If APS takes wind energy under a typical long term contract, it would take the wind energy produced from the project and back off its most expensive units running at the time the wind energy is available. If APS owns the wind project, the variable costs of the wind energy would be small and APS would back off its most expensive units running at the time the wind energy is available. To maximize the value of wind generation, APS should seek wind resources with as much generation as possible during peak seasons and hours.

To estimate the variable costs of the marginal units running when wind energy is available, I assumed that wind energy would be available year round with a capacity factor of 32 percent. I assumed that APS' marginal units would be as follows:[17]

- The Saguaro gas-fired combustion turbines and steam units. These are not as expensive as the Ocotillo combustion turbines, but the Ocotillo combustion turbines may be running when there is not sufficient transmission capacity to bring wind energy into the Phoenix load center. I assumed the heat rates and fuel costs reported by APS in its 2002 FERC Form 1.
- The West Phoenix gas-fired combined cycle units 1, 2, and 3. I assumed the heat rate and fuel cost reported by APS in its 2002 FERC Form 1. These units

[15] R. Richter, "Where's the Green in Green Emissions Trading?" *Power and Gas Marketing*, July/August, 2002, pp. 20-21, www.powerandgasmarketing.com.

[16] R. Richter, *op. cit.*

[17] The percentage of time that each unit is assumed to be the marginal unit is not reported in this testimony in order to preserve the confidentiality of other data provided by APS.

were considered to be the marginal units only during hours when they were running and there was sufficient transmission capacity to deliver energy from remote plants into the Phoenix area.

- The Four Corners coal-fired units 1, 2, and 3. I assumed the heat rate and fuel cost reported by APS in its 2002 FERC Form 1. These units are assumed to be the marginal units when the gas fired units listed above are not running.

For variable operating and maintenance costs, I used confidential costs provided by APS.

Q. Please describe your assumptions about avoided capacity costs attributable to wind energy.

A. Wind energy is an intermittent resource and its capacity value would depend on wind conditions and utility system characteristics. Thus, capacity value would be site specific. The National Renewable Energy Laboratory has analyzed the capacity value of wind projects and a study by the National Renewable Energy Laboratory suggests that a wind project at a good site may have a capacity value that is about 30 percent of the nameplate capacity of the wind project.[18] To the extent that wind resources have capacity value, APS could reduce its need for additional capacity[19] or could sell system capacity in the market.

I assumed that wind energy would enable APS to avoid capacity costs of $63.07 per kW per year for 30 percent of the nameplate capacity of the wind energy project. The cost was calculated as the annualized cost of a new combustion turbine using cost assumptions from the Energy Information Administration.[20]

Q. What do your calculations show when gas prices are at 2002 levels?

A. The relative costs of wind and conventional generation are project specific. I examined a generic project using reasonable assumptions about the costs of wind

[18] M. Milligan. "Variance Estimates of Wind Plant Capacity Credit." Boulder, CO, National Renewable Energy Laboratory, NREL/TP-440-21311, 1996. To analyze the capacity value of a specific wind energy resource in a specific utility system it is useful to systematically take into account the probabilities of wind generation occurring at specific times, demand reaching certain levels at those times, and the availability of other resources. Loss of load probability analysis is one way to prepare such an analysis.

[19] APS' summer supply and demand balance attached its response to the Arizona Competitive Power Alliance (December 24, 2003) shows APS needs considerable additional capacity in the next few years.

[20] Energy Information Administration, *Annual Energy Outlook 2003*. Washington, DC, Assumptions Section, Table 40, assuming a 25 year time horizon and 12 percent interest rate on capital. The costs include fixed operating and maintenance costs. Costs are inflated to 2002 dollars.

energy and the market prices of tradable credits in air emissions and assuming APS' costs of generating conventional energy in 2002. The analysis shows that, under these circumstances, wind energy is about $1.5 million less costly per year (in constant 2002 dollars) than conventional generation, including the environmental benefits of wind energy. Exhibit DB-4, columns a and b, shows the costs.

Q. What expectations about future natural gas prices are reasonable?

A. No one can be sure of the future price of natural gas, but the long run trend has been upward (Exhibit DB-2). The Energy Information Administration Annual Energy Outlook 2004 (Table A3) forecasts a real (inflation adjusted) average growth rate of 1.2 percent per year for the price of natural gas purchased by electric utilities over the period 2002 to 2025. As suggested by Exhibit DB-2, natural gas prices have also been volatile and they may very well continue to be volatile.

Q. Exhibit DB-3 shows that APS' gas prices increased in the first nine months of 2003 relative to 2002. What savings from wind energy would there have been if you substituted APS' 2003 gas prices for the 2002 gas prices used in the above analysis?

A. Applying the percentage increase from 2002 to 2003 in Exhibit DB-3 to the prices at individual power plants reported by APS in FERC Form 1 for 2002, wind energy would be about $2.8 million less costly per year than conventional generation, including environmental benefits (in constant 2002 dollars). The details are shown in Exhibit DB-4, columns a and c. When natural gas costs are high as they were in 2003, wind energy is less costly even when environmental benefits are not considered (avoided conventional generation costs are $19.0 million per year versus annual wind costs, excluding environmental benefits, of $18.9 million).

Q. Did you conduct any sensitivity analyses beyond that using 2003 natural gas prices?

A. Yes. I conducted sensitivity analyses to examine the robustness of the conclusions set forth above. Because wind energy could be used in the future as a hedge against natural gas price increases, I conducted the sensitivity analyses assuming that natural gas prices are at the 2004 level forecast by the Energy Information Administration in its December 2003 Short Term Energy Outlook, Table 4. Specifically, the fuel cost at each natural gas unit is assumed to be $4.86 per MMBtu in 2002 dollars.

To judge the sensitivity of the overall conclusion that wind energy is likely to be beneficial, on net, I changed one or a few variables at a time, leaving the other variables as specified above and assuming 2004 gas price levels. With gas prices changed to 2004 levels and changing no other assumptions, wind energy would be

$2.4 million per year less costly than conventional generation (Exhibit DB-4, columns a and d). Costs are presented in constant 2002 dollars, as above.

Of interest are cases where wind energy would be less advantageous than assumed above. For example, if the capacity value of wind energy were 15 percent of the nameplate capacity of the wind generation facility instead of 30 percent as assumed above, wind energy would be $0.8 million less costly per year than conventional generation. If the heat rate of the Saguaro combustion turbine were 10,000 Btu per kWh instead of 20,785 Btu/kWh as reported by APS in its 2002 FERC Form 1, wind energy would be $1.6 million less costly per year than conventional generation. If the wind integration cost were $4 per MWH instead of $2 per MWH as assumed above, wind energy would be $1.4 million less costly per year than conventional generation. If the environmental benefits were only half the values assumed above, wind energy would be $1.0 million less costly per year than conventional generation.

In light of the long term upward trend in natural gas prices, I conclude that the expectation of positive net benefits for wind energy is robust as long as the federal Production Tax Credit is continued.

Q. What do you conclude regarding the benefits and uses of wind energy?

A. Because of the long run historical tendency of natural gas prices to rise, wind energy is a useful hedge against natural gas price increases. Wind energy also provides price stability in lieu of the price volatility associated with generating electricity from natural gas. In addition, wind energy, and energy from renewable resources in general, have important environmental benefits.

Q. Does APS have any plans to acquire wind resources?

A. APS indicated, in response to WRA data request 2-18, that it is considering acquisition of wind energy from 15 MW of generating capacity that would be available in 2004. APS also indicated, in response to WRA data request 2-19 that it is not planning to acquire energy from renewable resources beyond that required by the Environmental Portfolio Standard unless such energy is cost competitive with conventional generation or until the Commission authorizes greater funding for renewable energy.

Q. Is the energy from 15 MW of wind generating capacity sufficient to provide a good hedge against natural gas prices increases?

A. No. It is much too small.

Q. What is the relationship between the use of renewable energy as a natural gas price hedge and the Environmental Portfolio Standard (EPS)?

A. The two renewable energy strategies serve different purposes. The natural gas price hedge requires large volumes of low cost renewable energy to displace conventional generation that is, in aggregate, higher cost much of the time. In contrast, the EPS is intended to promote development of environmentally friendly resources whose costs tend to be above market costs for conventional energy and capacity and it emphasizes development of solar energy projects. The EPS kWh requirements are too small to support an effective hedge against natural gas price volatility and price increases. WRA supports continuation of the EPS to foster solar energy projects.

Q. Is it in the public interest for APS to acquire large quantities of energy from renewable resources?

A. Yes. Renewable energy would provide the following benefits:

- It would provide a hedge against natural gas price increases and volatility.
- It would result in reduced air emissions, including carbon dioxide emissions which contribute to climate change.
- Along with energy efficiency, it would move APS toward a more diverse set of resources and technologies for meeting the demand for electric energy services.

Q. What do you recommend regarding renewable energy?

A. First, I recommend that the Commission order APS to immediately seek stably-priced energy from renewable resources amounting to at least 2 percent of APS' retail sales, with a target date of delivery of the energy no more than two years after the date of the decision in this Docket. APS should submit a written report to the Commission on its progress in acquiring such resources, with copies to all interested parties to this Docket, every six months, starting six months after the effective date of the Commission's order in this Docket. Two years after the decision in the Docket the Commission should review APS' progress and should conduct a hearing to determine how to proceed if APS believes that renewable energy cannot be practically used to hedge natural gas prices or has otherwise not obtained the recommended amount of energy from renewable resources. Note that this recommendation allows APS to bring to the Commission a recommendation that it not obtain at least 2 percent of its energy from renewable resources if the hedge value of that renewable energy is greatly diminished or to bring to the Commission a recommendation that the schedule for obtaining the targeted amount of renewable energy be modified. For example, if

Congress does not re-authorize the federal Production Tax Credit, the Commission may wish to reconsider the renewable energy schedule in a hearing.

Second, the Commission should address long term renewable energy goals that take into account the potential for low cost resources such as wind energy. In particular, the Commission should immediately open a docket to consider a renewable portfolio standard requiring that about 15 to 20 percent of retail kWh sales by jurisdictional electric utilities be met by energy from renewable resources by 2020.

Q. If the Commission adopts your recommendation that APS obtain large quantities of renewable energy immediately, how would APS recover the costs of that energy?

A. The costs of purchased energy from renewable resources would be recovered through the purchased power adjustor mechanism adopted in Decision No. 66567. Regardless of the cost recovery mechanism, revenues from the sale of environmental, renewable energy, or similar credits or allowances derived from renewable energy should be credited against the renewable energy cost.

Funding the Environmental Portfolio Standard

Q. How is the Environmental Portfolio Standard (EPS) currently funded?

A. A.A.C. R14-2-1618(A)(2) indicates that utilities are to use existing system benefit charges, including re-allocation of demand side management funding to EPS resources, plus a surcharge of $0.000875 per kWh. The surcharge is capped at $0.35 per month for residential customers, $13 per month for non-residential customers, and $39 per month for non-residential customers whose demand is 3 MW or more.

Q. What are the effective surcharge rates now being assessed?

A. The table below shows APS' 2002 revenues and MWH sales by class and the effective surcharge rates (revenues per kWh sold). Note that the surcharge caps result in the large industrial customers paying a much smaller effective rate than other customers.

Class	2002 Surcharge Revenues	2002 MWH Sales	Effective Rate $/kWh
Residential	$3,101,375	10,447,596	$0.0002969
Non-residential under 3 MW	$3,456,626	10,338,456	$0.0003343
Non-residential 3 MW +	$31,150	2,575,703	$0.0000121
Totals	$6,589,151	23,361,755	$0.0002820

Q. Is this sufficient revenue for APS to meet the EPS goals by 2011 or 2012?

A. No. In its June 30, 2003 report to the Commission, the Cost Evaluation Working Group indicated that there were insufficient surcharge revenues for APS to meet the Environmental Portfolio Standard by 2011 on the schedule set forth in A.A.C. R14-2-1618. Further, in response to data request WRA 1-16, APS indicated that it would need about $253 million to meet the 1.1 percent goal by 2011 but that it would receive only about $142 million over the period 2003 to 2011 from current funding sources (including revenues from redirection of demand side management programs to renewable energy).

Demand side management program funding that is now used to pay for EPS resources could and should be restored to demand side management programs. I, therefore, prepared an independent analysis of revenue needs for APS to meet the 1.1 percent goal in the EPS rule by 2012 that suggests that APS would need to spend about $222 million from 2004 through 2012 but would only obtain $71 million from the current surcharge (not including redirection of demand side management funds). To provide adequate funding from the surcharge alone, the caps would have to be removed from the current surcharge. That is, a surcharge rate of about $0.000875 per kWh with no caps would produce approximately the needed funding so that APS could meet the 1.1 percent goal, including the effects of the extra credit multipliers, by 2012.

Q. What do you recommend regarding funding for the EPS?

A. The current surcharge caps are inequitable and do not produce adequate revenue to fund the EPS. The simplest funding mechanism would be a surcharge of $0.000875 per kWh with no caps. The surcharge would be included in APS' proposed Schedule SBAC-1 or similar adjustor mechanism. The impact on major customer groups of the surcharge with no caps is as follows:

- $0.95 per month for the average residential customer
- $7.39 per month for the average commercial/industrial customer on Schedules E-32, E-32R, E-53, and E-54
- $2,977 per month for the average large industrial customer on Schedules E-34 and E-35.

The proposed surcharge would be about 1 percent of APS' proposed base rates plus the Competition Rules Compliance Charge for residential and general service customers.

Because the exact EPS costs and revenues are not known at this time, the EPS surcharge account in Schedule SBAC-1 should be reviewed by the Commission every three years to determine whether the surcharge rate should be adjusted. After 2012, any over- or under-collection should be addressed by the Commission to return excess funds to ratepayers or to reimburse APS for insufficiently funded projects.

I also recommend that demand side management program funding be restored to demand side management programs. Consistent with the proposed surcharge recommended above, any other funding for renewable energy currently in APS' rates, including Schedule SBAC-1, and used to help meet EPS requirements should be set to zero.

Q. What is WRA's position on mitigating the effect of the surcharge for some customer groups?

A. WRA does not object to surcharge caps or other mechanisms that would alleviate undue burdens on some customer groups while still pursuing the goals of the EPS. For example, large industrial customers (1 MW or larger) could be allowed by APS to opt out of the surcharge if the customer implements renewable energy projects such as solar hot water facilities, biomass facilities, or photovoltaic projects. APS should bring to the Commission, for Commission approval, all requests for opting out that it would like to grant. In their evaluations, APS and the Commission should consider the amount of surcharge revenue foregone, the amount of energy generated from the customer's renewable resource facilities, and the measurement and verification of that generation. APS should be able to count the energy and extra credit multipliers from these opt-out projects toward meeting its goal for renewable energy.

Improving Solar Energy Services

Q. Does APS propose to offer services to customers who generate their own electricity from solar energy?

A. Yes. APS proposes to continue its EPR-4 and EPR-2 tariffs. These schedules pertain to small power production facilities such as photovoltaic systems and set forth the rates for services purchased from APS and for sales of energy from the small power production facility to APS. Schedule EPR-2 is for qualifying facilities under 100 kW and Schedule EPR-4 is for renewable energy qualifying facilities 10 kW or less. In 2002, APS had no customers on Schedule EPR-2 and 10 customers on Schedule EPR-4.

Q. Do you have any recommendations regarding EPR-4 as filed by APS in this rate case docket?

A. Yes. Through the Environmental Portfolio Standard, the Commission is promoting solar energy, including solar energy projects on consumers' premises. APS' EPR-4 tariff should reinforce the Commission's policy by making customer-sited projects attractive. Therefore, I propose two changes to Schedule EPR-4:

- First, EPR-4 should apply to renewable energy systems up to 100 kW of DC capacity. Commercial customers interested in photovoltaic projects, for example, may wish to install facilities larger than the 10 kW limit in Schedule EPR-4. Such customers would now have to be served under Schedule EPR-2 which imposes a monthly service charge of between $7.34 and $18.31 while Schedule EPR-4 does not.
- Second, Schedule EPR-4 should incorporate a net metering option similar to that used in Tucson Electric Power Company's Pricing Plan PRS-101 approved by the Commission in Decision No. 65751, dated March 20, 2003. Under the parallel mode[21] inherent in Schedule EPR-4, any excess energy generated by the customer and delivered to APS would be carried forward and credited to the net kWh of the next billing cycle instead of being purchased by APS at the avoided cost rates shown in the Schedule EPR-4. All negative credits could be zeroed out annually to prevent a large build up of credits.

Summary of Recommendations

Q. Please summarize your recommendations.

A. APS and its ratepayers are exposed to natural gas price volatility and price increases. As a hedge against natural gas price increases, I recommend that the Commission order APS to immediately seek stably-priced energy from renewable resources amounting to at least 2 percent of APS' retail sales, with delivery of that energy starting within two years. I also recommend that APS report on its progress as described previously.

The Commission should immediately open a docket to consider a renewable portfolio standard requiring that about 15 to 20 percent of retail kWh sales by jurisdictional utilities be met by energy from renewable resources by 2020.

I recommend that a surcharge of $0.000875 per kWh without caps be included in APS' proposed Schedule SBAC-1 or similar adjustor mechanism to fully fund implementation of the Environmental Portfolio Standard. Because the exact EPS costs and revenues are not known at this time, the EPS surcharge account in Schedule SBAC-1 should be reviewed by the Commission every three years to determine whether the surcharge rate should be adjusted. After 2012, any over- or under-collection should be addressed by the Commission to return excess funds to

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[21] Decision No. 52345 defines parallel mode as a system configuration where the customer's self generation facilities first supply his or her own electric requirements with any excess power being sold to the utility.

ratepayers or to reimburse APS for insufficiently funded projects. Demand side management program funding that is now used to pay for EPS resources should be restored to demand side management programs.

I recommend that Schedule EPR-4 apply to systems up to 100 kW of DC capacity. I also recommend that Schedule EPR-4 incorporate a net metering option such that any excess energy generated by the customer and delivered to APS would be carried forward and credited to the net kWh of the next billing cycle instead of being purchased by APS at the avoided cost rates shown in the Schedule EPR-4.

Q. Does that conclude your direct testimony?

A. Yes.

Qualifications of David Berry

Education:

B.A. Syracuse University (Geography)
M.A. University of Pennsylvania (Regional Science)
Ph.D. University of Pennsylvania (Regional Science)

Employment History:

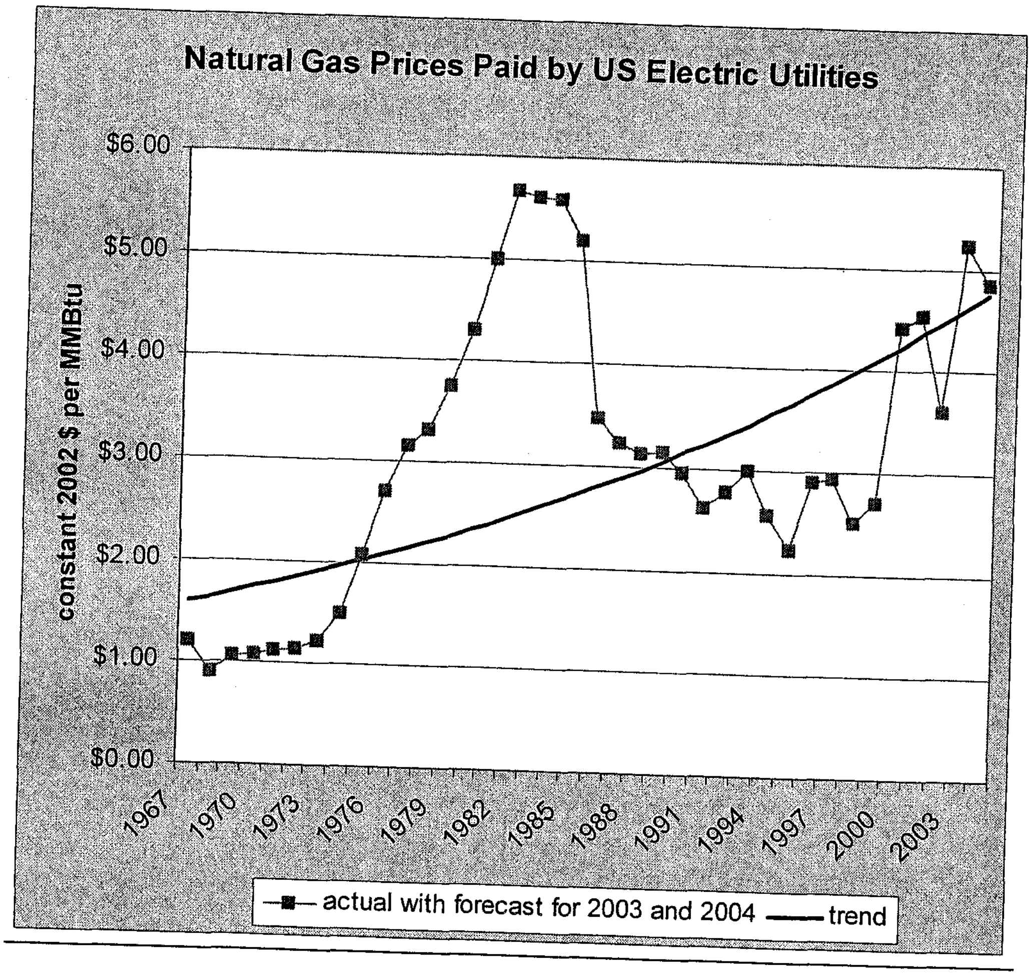
- Western Resource Advocates, Senior Policy Advisor (2001 - present)
- Navigant Consulting, Inc., Senior Engagement Manager (1997-2001)
- Arizona Corporation Commission, Chief Economist and Chief, Economics and Research (1985 – 1996)
- Boston University, Department of Urban Affairs and Planning, Lecturer (1981-1985)
- Abt Associates, Inc., Senior Analyst (1979-1985)
- University of Illinois, Department of Urban and Regional Planning, Visiting Assistant Professor (1977-1979)
- University of Pennsylvania, Regional Science Department, Lecturer (1974 –1977)
- Regional Science Research Institute, Research Associate (1972-1977)
- U.S. Army (1969-1971)

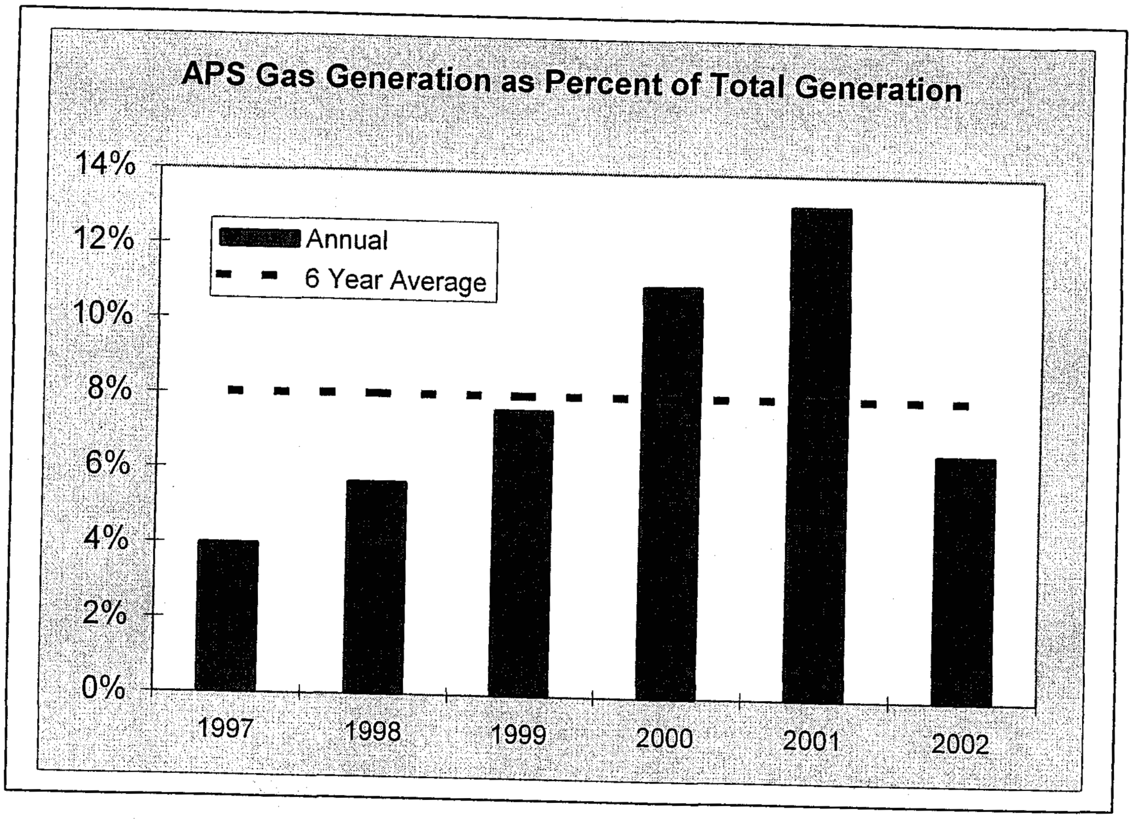
Testimony and Public Comment:

- Before the Maine Land Use Regulation Commission
- Before the Arizona Corporation Commission
- Before the New Mexico Public Regulation Commission

Publications in:

- *Ecological Economics*
- *Energy Policy*
- *Journal of the American Planning Association*
- *Business Economics*
- *Solar Today*
- *NRRI Quarterly Bulletin*
- *The Electricity Journal*
- *Journal of Economic Issues*
- *Public Utilities Fortnightly*
- *Journal of Environmental Management*
- *Public Management*
- *American Journal of Economics and Sociology*
- *Water Spectrum*
- *Geographical Perspectives*
- *Strategic Planning for Energy and the Environment*
- *National Tax Journal*
- *Policy Sciences*
- *Natural Resources Journal*
- *Water International*
- *Growth and Change*
- *Home Energy*
- *Professional Geographer*
- Chapters in books and proceedings


Natural Gas Prices Paid by US Electric Utilities
constant 2002 $ per MMBtu
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1967
1970
1973
1976
1979
1982
1985
1988
1991
1994
1997
2000
2003
actual with forecast for 2003 and 2004
trend


APS Gas Generation as Percent of Total Generation
14%
12%
10%
8%
6%
4%
2%
0%
Annual
6 Year Average
1997
1998
1999
2000
2001
2002

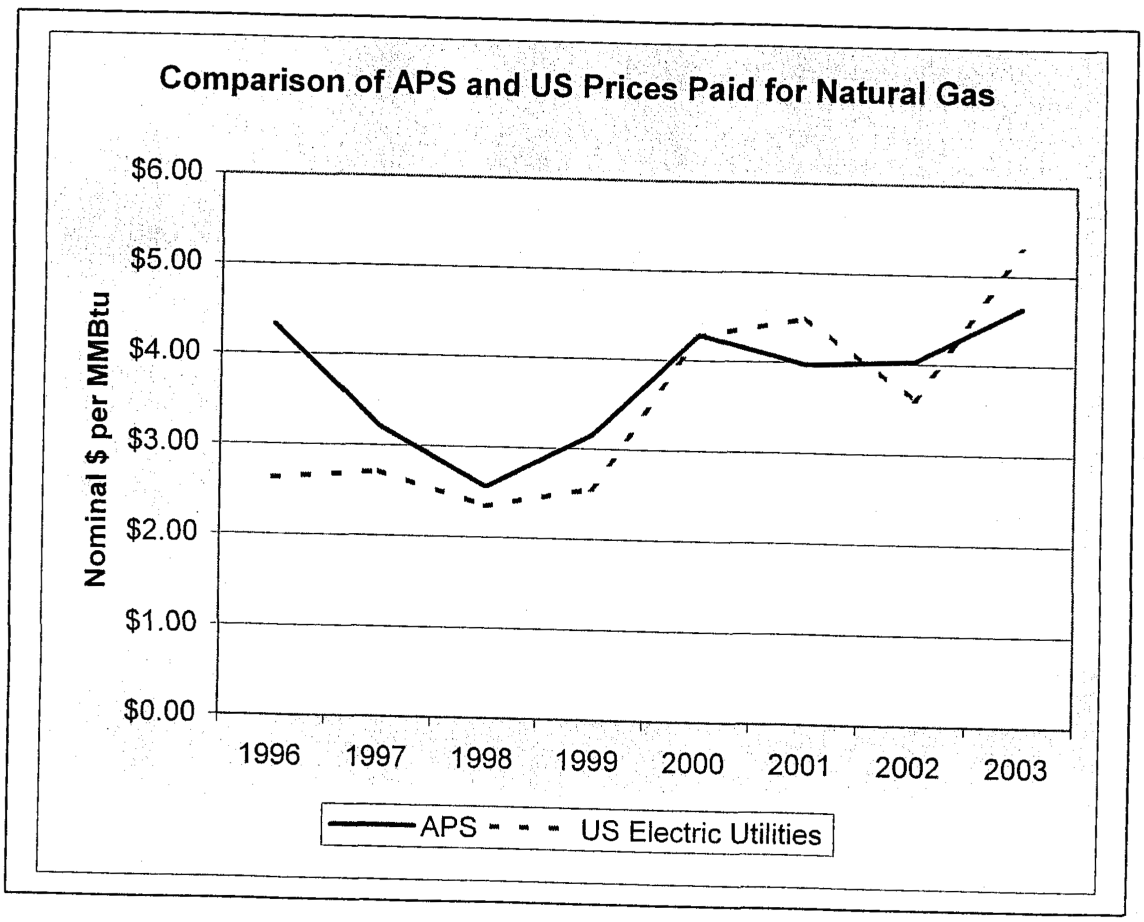

Comparison of APS and US Prices Paid for Natural Gas
Nominal $ per MMBtu
$6.00
$5.00
$4.00
$3.00
$2.00
$1.00
$0.00
1996
1997
1998
1999
2000
2001
2002
2003
APS
US Electric Utilities

EXHIBIT DB –4

SUMMARY OF COSTS AND BENEFITS OF WIND RESOURCES

(a) Component (all values in constant 2002 dollars)	(b) At 2002 Natural Gas Prices	(c) At 2003 Natural Gas Prices	(d) At 2004 Natural Gas Prices
1. Annual wind cost including transmission and integration	$18.9 million	$18.9 million	$18.9 million
2. Annual wind environmental benefits	$2.8 million	$2.8 million	$2.8 million
3. Annual net wind cost (= 1-2)	$16.2 million	$16.2 million	$16.2 million
4. Avoided annual conventional energy cost	$14.3 million	$15.7 million	$15.3 million
5. Avoided annualized conventional capacity cost	$3.3 million	$3.3 million	$3.3 million
6. Total annual avoided conventional generation cost (= 4 + 5)	$17.6 million	$19.0 million	$18.6 million
7. Annual wind energy savings (= 6 – 3)	**$1.5 million**	**$2.8 million**	**$2.4 million**

Notes to table

a. Components calculated assuming a 175 MW wind generation facility with a 32 percent capacity factor.

b. Because of rounding error, totals may differ from sums and differences of individual items shown in the table.