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DISPOSITION OF ORIGINAL EXHIBITS

FIRST CLASS MAIL

April 27, 2005

Arizona Corporation Commission
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AZ CORP COMMISSION
DOCUMENT CONTROL

Ms. Jane Rodda
Administrative Law Judge
ACC – HEARING DIVISION
400 West Congress
Tucson, AZ 85701

Case: AEPCO and SWTC
Number: E-01773A-04-0528, etc. E-04100A-04-0527
Date: April 14, 2005 E-01773A-04-0528

Dear ALJ Rodda:

With copy of this letter the original exhibits in this matter have been distributed, as follows:

Docket Control	AEPCO-1 through 7 SWTC-1 through 6 S-1 through 19, and 21 through 26
Returned to Mohave	M-1 and M-2
Returned to Staff	S-20

Exhibits M-1 and M-2 are being returned to Mohave Electric Cooperative because they were not moved for admission on the record either inadvertently or by design.

Exhibit S-20 is being returned to Staff because it was not utilized.

Please let us know if you have any questions or if we may be of any further assistance.

Very truly yours,

Marta T. Hetzer
Administrator/Owner

Enclosure

COPY FOR YOUR INFORMATION

Copy to: AEPCO and SWTC
Mohave Electric
Docket Control
Staff
Sulpher Springs
John Leonetti, Intervenor

PENGAD-Bayonne, N.J.
EXHIBIT
AEPCO-1
ADMITTED

DIRECT TESTIMONY OF DIRK MINSON
BEFORE THE ARIZONA CORPORATION COMMISSION
ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Dirk Minson and my business address is 1000 South Highway 80, Benson, Arizona, 85602.

Q. Mr. Minson, by whom are you employed and in what capacity?

A. I am the Chief Financial Officer of the Arizona Electric Power Cooperative, Inc. ("AEPCO"). As Chief Financial Officer, I serve as part of the Executive Management Team and report directly to the Chief Executive Officer. My specific responsibilities and duties include the accounting functions of the Cooperative, including establishing fiscal policy and procedure development and implementation of appropriate financial controls. Additional responsibilities include financial and corporate planning, rate design, development and implementation in addition to corporate treasury functions, as well as cash and working capital management, inventory control and risk management.

Q. Please briefly describe your educational background and work related experience.

A. I hold a B.S. Degree in Business Administration from Kansas State University and an M.B.A. from the University of Missouri. My entire 29-year career has been spent working directly or indirectly for electric

cooperative utilities. I began my employment with AEPCO in 1982 and was promoted to the position of Chief Financial Officer in May 1990.

Q. Mr. Minson, what is the purpose of your testimony?

A. I will provide the Commission information concerning AEPCO, its membership structure, its Board review and approval process for this rate filing and its rate history. I'll also describe generally the rate request and certain issues and other requests concerning it. In support of the rate application, Gary Pierson, our Manager of Financial Services, will testify more specifically concerning the A-H rate filing schedules. Steve Daniel of GDS Associates, Inc. will testify in support of our cost of service demand allocation methodology and Bill Edwards of the National Rural Utilities Cooperative Finance Corporation will provide information in support of AEPCO's Times Interest Earned Ratio ("TIER") and Debt Service Coverage Ratio ("DSCR") requirements.

BACKGROUND

Q. Mr. Minson, please describe AEPCO.

A. AEPCO is a non-profit, generation cooperative which serves the power needs of its five all requirements and one partial requirements Class A Member distribution cooperatives ("distribution cooperatives"). The distribution cooperatives provide the electricity at retail to their member owners which AEPCO generates or purchases at wholesale. We have one Class A Member in south-central California, the Anza Electric Cooperative, Inc. The other four Arizona all requirements distribution cooperatives are Duncan Valley Electric Cooperative, Inc. ("Duncan"), Graham County Electric Cooperative, Inc. ("Graham"), Sulphur Springs Valley Electric

Cooperative, Inc. ("SSVEC") and Trico Electric Cooperative, Inc. ("Trico"). Our partial requirements distribution cooperative member is the Mohave Electric Cooperative, Inc. ("Mohave"). The Arizona distribution cooperatives are also regulated by the Commission.

Q. What is the difference between an all requirements and a partial requirements member?

A. As the name implies, an all requirements member has a contract with AEPCO which requires it to buy and AEPCO to plan for and furnish all of its present and future power requirements. A partial requirements member, instead, has a contract with AEPCO to furnish only a portion of its retail electricity requirements and that member is obligated to plan for and secure from AEPCO or others the balance of its electricity needs. Mohave became a partial requirements member in 2001 as part of AEPCO's restructuring, which the Commission approved in Decision No. 63868. I would note that discussions are currently underway on SSVEC's notice to become, like Mohave, a partial requirements member. Once the necessary documents are prepared and approved by both the AEPCO and SSVEC Boards of Directors, that request must also be approved by the Rural Utilities Service ("RUS"). We will also seek the Commission's approval of SSVEC's new partial requirements agreement and any necessary related changes to SSVEC's rate and attendant changes to the all requirements distribution cooperative rates. However, for purposes of this Application, we have assumed that SSVEC is an all requirements member because that was its status in the test year and we are uncertain when the approvals necessary to accomplish its transition to a partial requirements member will be obtained.

1 Q. Does AEPCO have other members?

2 A. Yes. The City of Mesa is a Class B Member. It has a contract to purchase
3 15 MW from AEPCO through 2008. Finally, the Salt River Project
4 ("SRP") is a Class C AEPCO Member. It has a firm 100 MW electric
5 service agreement with AEPCO which will expire on December 31, 2010.
6

7 Q. Does AEPCO sell power to any non-members under long-term contracts?

8 A. Yes. Electrical District No. 2 purchases 8 MWs from AEPCO under a
9 contract which expires in 2012.
10

11 Q. How does AEPCO obtain the power and energy it supplies to its members
12 and for firm contract sales?

13 A. Most of the power is produced at our Apache Generating Station located
14 near Wilcox, Arizona. We have approximately 555 MWs of coal and
15 natural gas fired capacity. To meet our members' needs or where it is more
16 economical to do so, we also enter into other power purchase arrangements
17 including short- and long-term purchase agreements with other utilities.
18 Our current purchased power agreement consists of a 15 MW, year-round
19 contract with the Public Service Company of New Mexico which expires at
20 the end of 2008. AEPCO also has a five-year purchased power agreement
21 with Panda Gila River, LLC for summer peaking capacity and energy
22 which expires in 2007. The Panda Gila River agreement ranges from 30
23 MWs in 2003 to 85 MWs in 2007.
24

25 Q. How is AEPCO governed?

26 A. AEPCO's Board of Directors is comprised of 14 members, who oversee all
27 aspects of the Cooperative's operations. Twelve of the Board members

(two per Class A Member) are designated as the distribution cooperatives' representatives to the AEPCO Board by the distribution cooperative Boards, which in turn are elected by their retail member/consumers. The remaining two Board members represent the Class B and Class C Members.

Q. Did AEPCO's Board approve this rate filing and the other requests AEPCO is presenting in this application?

A. Yes. The process of Board analysis and review of the rate application began in November 2003. Between November 2003 and July 2004, several meetings were held with the Board of Directors discussing the need for and the elements of AEPCO's rate filing. In addition, during May and June 2004, meetings were also held with AEPCO's Class A Member Boards of Directors and their respective staffs to review the revenue requirement increase request. These meetings culminated in AEPCO's Board of Directors approving the filing of this rate case and associated revenue requirement increase during a July 2004 meeting.

Q. Mr. Minson, please describe AEPCO's rate history.

A. We are very proud of the fact that this requested rate increase will be the first general rate increase on the AEPCO system since 1984. In fact, since 1986, AEPCO has reduced its member rates by approximately 22% and, in addition, has either refunded or forgiven more than $27 million in fuel costs through the purchase power and fuel adjustment clause.

OVERVIEW OF FILING

Q. Please summarize AEPCO's rate request.

A. Mr. Pierson will testify in more detail concerning the specifics of the request. But, in general, AEPCO requests an overall 9.86% increase in its revenue requirements, which is a 7.8% increase in the tariffed rates for its all requirements members and a 14.0% increase in the partial agreement rates for Mohave.

Q. Why is there a difference between the rate requests?

A. Primarily because of the difference in the nature of the relationship between the all and partial requirements members. Under the partial requirements agreement which the Commission approved in the restructuring, its Rate Schedule A is very specific in assigning certain costs to be recovered from Mohave. In essence, Mohave has "purchased" a certain fixed percentage of AEPCO's assets and is entitled to receive the energy generated by those assets net of AEPCO's contract sales obligations. In turn, Mohave is assigned specific costs associated with financing and operating those assets as provided in the contract. The all requirements member tariff rate is determined after this process is complete and those members are assigned all remaining costs associated with the balance of AEPCO's cost of service. Mohave's effective percentage increase is higher than the all requirements members because the all requirements members have the advantage of increasing billing units. Whereas Mohave rates, as a partial requirements member, do not reflect an increase in billing units. It should be noted that, while the percentage increase is higher for Mohave, the relative contribution of Mohave's revenue to the total Class A Member revenue remains unchanged between existing AEPCO rates and proposed rates.

1

2 Q. Do all Class A Members get the benefit of whatever cost recoveries and
3 margins are made on sales to others by AEPCO?
4 A. Yes. The first step in our rate determination process is to credit to the
5 benefit of all members whatever cost recoveries and margins that AEPCO
6 has been able to achieve in its contract sales and economy sales to others.
7 Thus, the proceeds of these sales to others are used to reduce each
8 distribution cooperatives' cost of service and, in turn, the rates for
9 generation service which their retail members have to pay.
10
11 Q. Can you estimate the impact that AEPCO's proposed rate increase would
12 have on the retail member/owner's bill?
13 A. That is difficult because the distribution cooperatives have different retail
14 rates and varying rate structures. However, generation service generally
15 accounts for about 40% of the costs of the total delivered rate at retail.
16 Assuming a residential rate of $0.10 per kwh, on average four cents of that
17 rate would be attributable to AEPCO's generation service. Therefore, a
18 residential consumer using 750 kwh per month would see approximately a
19 $3.00 increase in the monthly bill as a result of this rate request.
20
21 Q. What are the primary reasons for the requested rate increase?
22 A. Obviously, AEPCO is subject to the same kind of inflationary pressures
23 which affect all utilities and businesses in general. But, generally there are
24 three primary cost areas which are driving this request. First, we have
25 recently seen higher coal costs and, in particular, much higher and very
26 volatile natural gas costs. Second, most of our generating assets at Apache
27 are now 25 or more years old. Although the embedded costs associated

with that plant are comparatively very low, as the units age, the overhaul and maintenance costs associated with them increase. Third, to meet increased demand and growth on the distribution cooperatives' systems, in October 2002, AEPCO brought on line Gas Turbine #4 at the Apache Station. This rate filing reflects the fixed costs associated with the interest, depreciation, insurance and property taxes associated with that new plant addition. It also reflects the fixed costs associated with a $10 million coal blending facility designed to reduce AEPCO's burned cost of coal. As a result, we have also reduced the burned cost of coal from approximately $1.65 MMBtu in the test year to $1.45 MMBtu.

Q. Has the restructuring of AEPCO led to increased costs?

A. Not really. Under the restructuring, existing transmission assets were moved to Southwest Transmission Cooperative, Inc. ("Southwest") and certain existing employees were permanently assigned to Southwest. Existing generation assets remained with AEPCO including certain existing employees. Most of AEPCO's employee base was moved to the third cooperative which was created in the restructuring--Sierra Southwest Cooperative Services, Inc. ("Sierra"). Sierra provides the balance of the labor force required to operate both Southwest and AEPCO, which was the same labor force which operated AEPCO prior to the reorganization. So, although the restructuring resulted in three cooperatives, no new labor force, debt or new assets were created as a result of it.

Q. Did the three primary factors you mentioned affect AEPCO's financial performance in 2003?

1 A. Yes--markedly so. Referring to Schedule A-2, AEPCO suffered an actual
2 net margin loss of slightly more than $7 million dollars in the 2003 test
3 year. Although approximately $3.8 million of this loss was attributable to a
4 one-time retirement write-off of certain ash pond facilities at Apache,
5 adjusted test year results still produced a net margin loss of $4.5 million
6 and a DSCR of only .70--far below our RUS mortgage minimum
7 requirement of 1.0. Our operating results and margin experience have not
8 improved for the first six months of 2004 and we expect another operating
9 margin loss this year.
10
11 Q. Mr. Minson, do these financial results emphasize the need for rapid rate
12 relief from the Commission?
13 A. Yes, for three primary reasons. First, as a non-profit cooperative, AEPCO
14 has no stockholder class which can absorb operating losses. We must move
15 quickly to bring our operating revenues back in line with our cost of
16 service. Second, the RUS requires both prospective and retrospective TIER
17 and DSCR results in determining AEPCO compliance under the terms of its
18 mortgage and 7 CFR 1710.114. Given last year's achieved results and this
19 year's expected performance, AEPCO will not meet those tests and must
20 move quickly to remedy that situation. Third, AEPCO has been making
21 steady progress in strengthening its equity position. Following a series of
22 financial setbacks in the 1980's, including the loss of 125 MWs of copper
23 industry load, AEPCO's negative equity position exceeded $51 million in
24 1990. While continuing to reduce member rates, we were able to improve
25 that position substantially through a series of aggressive cost cutting and
26 other cost saving measures to roughly $18 million in positive equity by

2002. Our losses in 2003 have reversed that trend and we would, in turn, like to reverse that direction as quickly as possible.

Q. Mr. Minson, the Commission in Decision Nos. 64227 and 65210 instructed AEPCO to file a Capital Plan by the end of 2002. Did AEPCO comply with that instruction?

A. Yes, we did. The Capital Plan described generally how AEPCO might achieve the membership capital or equity positions of 10% by 2006, 15% by 2010 and 30% by 2015 as Staff had recommended in its reports in those financing decisions.

Q. Will the current rate request allow AEPCO to continue advancing toward the recommended capital goals?

A. It certainly will improve the outlook for doing so. In 2002, our positive equity reached nearly 7%. Unfortunately, the 2003 experience and expected 2004 results I just discussed will drop that number to roughly 3%. We discussed with the Board and our distribution cooperative members the possibility of seeking a higher rate increase and a higher DSCR coverage ratio to make sure we would meet these capital targets. They decided, and I agree, that our best course of action was to moderate the current request at the 1.05 DSCR coverage level.

OTHER ISSUES

Q. Mr. Minson, is AEPCO requesting a change in its depreciation rates pursuant to A.A.C. R14-2-102 in this rate application?

1 A. Yes, we are. An exhibit describing the revised depreciation rates is
2 attached as Exhibit DCM-1. We would ask that the Commission approve
3 these revised rates.
4
5 Q. Why is AEPCO seeking a revision in the rates?
6 A. In evaluating the financing for the construction of Gas Turbine #4, AEPCO
7 commissioned a condition assessment study for its Apache Station Units 2
8 and 3 and associated common facilities. Prior to this study, their expected
9 life was only through the year 2020. That would have limited the length of
10 the loan we could have received for Gas Turbine #4 to roughly 15 years,
11 which would have increased the costs of the plant and financing
12 considerably. The Units have been well maintained and we believed their
13 condition would support an extended life assessment. Burns & McDonnell
14 conducted the condition assessment study and a copy of the Executive
15 Summary of their report is attached as Exhibit DCM-2. The report
16 concludes that the "units should provide service through the year 2035."
17 Therefore, we would ask that the Commission approve the revised
18 depreciation rates as reflected in Exhibit DCM-1.
19
20 Q. Do the revised depreciation rates have the effect of reducing the members'
21 overall cost of service?
22 A. Yes. As Mr. Pierson will testify, the revised depreciation rates lower costs
23 in the test year by slightly more than $1.47 million dollars.
24
25 Q. Mr. Minson, is AEPCO also requesting a purchased power and fuel
26 adjustment clause in this proceeding?

A. Yes. Mr. Pierson will discuss the details concerning and the reasons for that request in his testimony. I'd also note that in recent workshops on Demand Side Management ("DSM") and the Environmental Portfolio Standard ("EPS"), there has been some discussion of possible DSM and/or EPS adjustment clauses to allow the costs associated with such programs to be recovered on a current basis. Such clauses would have to be approved in the context of a general rate proceeding such as this one, but at the current time we have no specific proposal for such a clause(s) because we are not certain if the Commission or Staff want to pursue that course of action. We would, however, seek such clauses during the processing of this case if further developments on their desirability and design warrant.

CONCLUSION

Q. Do you have any concluding remarks?

A. I would ask that the Commission enter its order authorizing the all requirements member tariff rates and partial requirements contract rates. We'd also ask that the Commission order approve (1) revised depreciation rates as stated in Exhibit DCM-1 and (2) a purchased power and fuel adjustment clause as described in Mr. Pierson's testimony. Finally, we would ask that the Commission expedite the processing of this Application so AEPCO can reverse as quickly as possible its recent negative operating margin experience.

Q. Does that conclude your testimony?

A. Yes, it does.

16662-1/1183015v2

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Exhibit DCM-1

Analysis of effect of change in depreciation rates for ST2 and ST3 (life change to 2035)

	(a)	(b)	(c)	(d)	(e)	(f)
	Estimated Book Value 12/31/03	Estimated Accum. Prov. Depreciation 12/31/03	Estimated Net Book Value 12/31/03	Current Depreciation Rates **	Years Remaining 12/31/03 to 12/31/2035***	Calculated Proposed Depreciation Rates
Steam 2*	$134,034,371	$76,577,621	$57,456,750	2.09%	32	1.340%
Steam 3*	$127,122,671	$69,630,377	$57,492,294	1.81%	32	1.413%
	$261,157,041	$146,207,998	$114,949,043			

*: Includes common facilities allocated to each unit (excludes fully depreciated rail cars)
Also excludes furniture & equipment, rolling stock, etc, and general plant.

**: RUS approved these rates July 1995

***: Burns & McDonnell August 2003 Condition Assessment Report states "through 2035"

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
APACHE GENERATING STATION UNITS 2 & 3
Major Power Generation
And
Plant Electrical Equipment
Condition Assessment Report

EXECUTIVE SUMMARY

The scope of study by Burns & McDonnell is a summary assessment of the major thermal/electrical power generating equipment: i.e., boilers, fans, feedpumps, steam turbines, high energy piping, electric generators, and major plant electrical power distribution equipment (switchgear, motor control centers, and transformers).

Overall, Burns & McDonnell's general findings from the major condition assessment of the Apache Generating Station Units 2 & 3 reveal that the power generation and distribution equipment is well maintained. The maintenance and technical support practices and procedures in place appear to have recognized and addressed a combination of implemented and planned future repairs, replacements, and upgrades.

The major power generating and distribution equipment is expected to be capable of continued long-term service, with capacity and availability similar to recent performance. This is based on the continuation of current practices of base load operation, and plans for routine repairs, anticipated replacements, and upgrades. With these efforts, it is predicted that the units should provide service through the year 2035.

For long term planning Burns & McDonnell makes the following recommendations of equipment that may need to be refurbished due to normal time of service life. These recommendations are based on utility experience for similar units. It is recommended to have OEM inspections of major components such as the boiler, turbine/generator, boiler feed pumps and fans, and to perform an in-depth investigation prior to replacing and refurbishing existing equipment. The steam generators can be expected to have the lower water walls, the superheat and reheat sections changed out during the remaining life of the station. Steam turbine blades and bucket replacement, control valves, stop valves, and intercept valves could be expected to be refurbished, replaced, or upgraded. An overall plant controls system for Units 2 & 3 can be expected to replace the current controls of

the units. High pressure heaters No. 5 & 6 for Unit 2 and heater No. 6 for Unit 3 are recommended to be changed to stainless steel in the next five years. Condenser tubes for both units should be replaced in the future. The air preheater cold end baskets should be changed out in the future. Controls upgrade for the bottom ash and fly ash system should be done in the future. Both units cooling towers will need to have the fill, support structures, and drift eliminators replaced in the next five years. In the event that Powder River Basin coal is brought on site, it is strongly recommended to install a coal yard and bunker room wash down system and replace the existing coal dust collection system with high capacity dust collection system. The auxiliary transformers for both units are operating at close to their design temperatures at an altitude higher than design. It is recommended to replace these transformers in the next 10 to 15 years.

PENGAD-Bayonne, N.J.
EXHIBIT
AEPCO-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0528

REBUTTAL TESTIMONY OF

DIRK MINSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

MARCH 16, 2005

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INTRODUCTION

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

A. My name is Dirk Minson. I am the Chief Financial Officer of the Arizona Electric Power Cooperative, Inc. ("AEPCO") and my business address is 1000 South Highway 80, Benson, Arizona 85602.

Q. Did you file direct testimony in this matter?

A. Yes. I submitted direct testimony in support of AEPCO's rate application which was filed with the Commission on July 23, 2003.

Q. What is the purpose of this testimony?

A. I will summarize AEPCO's rebuttal position as well as respond to certain issues discussed in the testimony of Ms. Brown, Mr. Ramirez and Ms. Keene. In that regard, Gary Pierson, our Manager of Financial Services, is also presenting rebuttal testimony. I'll also update the Commission on AEPCO's current financial status and the progress of our discussions with Class A member Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC") concerning its request to become a partial requirements member of AEPCO.

UPDATE

Q. In your direct testimony, you discussed the fact that adjusted 2003 test year results had produced a net margin loss of $4.5 million and a DSCR of only .70, which is well below the RUS mortgage minimum requirement of 1.0. AEPCO expected another operating margin loss in 2004. Did that happen?

A. Unfortunately, yes. AEPCO's 2004 operating loss totaled $2.6 million. The loss would have been much greater but for a required reversal of a liability associated with non-member economy sales to certain California entities in 2001.

1 Q. What does this mean for AEPCO?

2 A. First, AEPCO is not in financial compliance under the terms of its mortgage as well as
3 the requirements of the RUS rules, primarily 7 CFR 1710.114. As a result, AEPCO is
4 required to notify RUS in writing of its non-compliance and develop a plan to achieve
5 compliance on a prospective basis. The plan will have to be acceptable to the RUS
6 Administrator. Short of that acceptance, AEPCO will be in technical default and will be
7 unable to secure loan funds for capital improvements or possibly not be able to draw
8 existing loan funds for capital expenses already incurred. This restriction will remain in
9 force until remedial action satisfactory to RUS is taken, such as implementation of the
10 new rates we propose. Second, unfortunately the 2004 results have further eroded
11 AEPCO's equity position after more than ten years of positive performance had
12 eliminated in excess of $51 million in negative equity. We estimate that our equity now
13 stands at $10.9 million or 4.3% of assets. At the end of 2002, it had reached almost 7%.
14 These developments emphasize the need for a rate order from the Commission as quickly
15 as possible.

16 Q. Have these developments impacted AEPCO's approach to this rebuttal testimony?

17 A. Yes. We felt it would assist Staff, the Administrative Law Judge and the Commission in
18 speeding further evaluation and action if we would narrow, to the maximum extent
19 possible, the issues in dispute and simplify our recommendations concerning revenue
20 recommendations, rates and procedures. Thus, as Mr. Pierson explains in greater detail,
21 we have limited our focus to a few major adjustment issues. We disagree with Staff on
22 several other adjustments, but if they don't materially impact AEPCO's financial health
23 we have elected not to contest them.

1 Q. Please update the Commission on the status of SSVEC's request to become a partial
2 requirements AEPCO member.
3 A. AEPCO and SSVEC have completed a draft partial-requirements agreement acceptable to
4 them. The RUS must approve the transition and, while we have communicated regularly
5 with RUS concerning it, we have received no firm indication on how long the RUS
6 review will take. Because the RUS might request changes to the agreement, we think it
7 best to delay formal submission to the Commission until that process is complete. When
8 RUS' approval is secured, we'll make a formal filing with the Commission for approval
9 of the SSVEC Partial Requirements Capacity and Energy Agreement and any required
10 partial- and all-requirements rate changes associated with it.
11 **SUMMARY OF REBUTTAL POSITION**
12 Q. Mr. Minson, please summarize AEPCO's reaction to the Staff's testimony.
13 A. Although we have disagreements with Staff on certain issues and details, we think the
14 Staff's analysis provides an excellent framework within which to structure an order
15 which allows AEPCO adequate rates and an opportunity to improve its financial position.
16 For example, Staff has recognized the need for and supports (1) a revenue requirements
17 increase, (2) adequate margins to support future necessary borrowing and positive equity
18 improvement and (3) a Fuel and Purchased Power Cost Adjustor ("FPPCA"). Staff also
19 agrees that all of our utility plant is used and useful. Staff's basic positions on these
20 issues are very constructive. We hope that our approach in response is equally
21 constructive and will allow rapid progress toward entry of a final rate decision.
22 Q. Please summarize AEPCO's revised requests.

A. Mr. Pierson provides greater detail on our positions. But, to summarize, we request that the Commission authorize: (1) an increase in operating revenues of approximately $9.446 million and a rate of return on rate base of 10.50%; (2) rates as set forth in Exhibit GEP-4; (3) an FPPCA; and (4) revised depreciation rates as set forth in Exhibit DCM-1. For convenience, I have attached as Exhibit DCM-3 proposed tariffs which reflect these requests and also include a proposed adjustor clause. It's important to stress that this will be the first rate increase for AEPCO since 1984. Indeed, in the past 20 years, AEPCO's rates to its member distribution cooperatives have declined approximately 22%. Thus, taking into account the generation and transmission rate requests, the average Class A member rates will still be about 17% below what they were in 1985.

COMMENTS ON SPECIFIC STAFF TESTIMONY

Ms. Brown's Testimony

Q. At page 4 of her testimony, Ms. Brown makes reference to a few customer comments received by the Commission on the rate application. Did you examine those materials?

A. Yes, I did. I think most of the concerns expressed grow out of a misunderstanding at the retail level of the impact of these wholesale rate requests by AEPCO as to generation and Southwest Transmission Cooperative, Inc. ("SWTC") as to transmission service. The Notice of Hearing which AEPCO and SWTC published and also circulated widely in member newsletters correctly stated that AEPCO and SWTC were requesting a combined approximately 24% revenue increase. A retail consumer reading that understandably assumes that means the end-use bill will increase 24% when, of course, that is not the case. Based on our revised rebuttal positions, we estimate that the average residential consumer would see approximately a $3.30 monthly increase attributable to AEPCO's

1 generation case and a $1.45 monthly increase attributable to SWTC's transmission
2 service case. We don't minimize any increase and our 20-year record of rate reductions
3 reinforces that. But, I hope that provides additional context to evaluate the handful of
4 comments which have been received.
5 Q. Please comment on Ms. Brown's testimony at pages 37-40 concerning redactions of
6 executive session Board minutes and legal invoices.
7 A. In an effort to narrow issues in dispute, we are not objecting to Ms. Brown's adjustment.
8 However, I do want to state the justifiable reasons for our redactions. Both before and
9 after filing, we supplied Staff with a tremendous amount of data and documents.
10 Multiple copies of about 16 bankers boxes of material were delivered in response to more
11 than 150 Staff data requests. The materials included all Board regular and executive
12 session minutes together with all legal invoices for a three-year period.
13 Q. What were the redactions?
14 A. Attorney discussions with the Board were redacted from executive session minutes and
15 narrative descriptions were initially detached from legal invoices to avoid any waiver of
16 the attorney-client privilege. Following discussions between our counsel and Staff's
17 attorneys, it was agreed that the attorney narrative descriptions would be supplied with
18 only minor redactions of entities which revealed specific privileged communications.
19 Thus, Staff was supplied with both matter and amount descriptions and, depending upon
20 how the firms reported their time, detailed descriptions of individual tasks performed.
21 We thought this had satisfactorily resolved this issue.
22 Q. Is it important to protect the attorney-client privilege?

1 A. Yes. While I am not an attorney, I'm told that the attorney-client privilege cannot be
2 selectively waived. Many of these matters involve ongoing litigation, other disputes
3 which may result in suits, contract negotiations and similar legal matters which have very
4 real cost and other impacts on AEPCO and the members we serve. If privileged
5 information is released to Staff and then adverse parties learn of the release, they can
6 demand access to our privileged discussions and attorneys' strategic advice. By way of
7 example, as the Commission knows, AEPCO has been deeply involved in a Surface
8 Transportation Board ("STB") rate case for several years. The result of the STB action
9 will determine AEPCO's annual cost to transport approximately 1.5 million tons of coal.
10 If the railroads had access to privileged information, AEPCO would be at a substantial
11 disadvantage in that rate case. We hope the Commission agrees that result would not be
12 in our member/consumers' best interests.
13 Q. Does AEPCO object to Ms. Brown's proposed $159,891 reduction in expenses
14 attributable to food and similar expenses at page 41 and Schedules CSB-12 and CSB-22
15 of her testimony?
16 A. Again, in an effort to narrow disputed issues, we do not. However, many of the expenses
17 are necessary to provide safe, reliable and adequate service. For example, the food
18 expense was primarily for annual Member Meetings, employee training sessions and
19 employee recruitment. The award expense was for employee safety awards. The
20 lobbying expenses are percentage estimates of the total membership dues paid to the
21 National Rural Electric Cooperative Association ("NRECA") and the Grand Canyon
22 Electric Cooperative Association ("Grand Canyon") concerning the time both spend on
23 lobbying. Federally, one of the NRECA's primary annual efforts is to try to assure

1 adequate RUS/FFB loan funds for cooperatives—an obviously critical issue to our efforts
2 to provide low-cost, reliable service. In Arizona, Grand Canyon monitors and, where
3 necessary, advocates in relation to a number of legislative issues which directly impact
4 cooperatives' cost and service abilities including property tax and other legislative
5 proposals.

6 Q. Does AEPCO agree with Ms. Brown's recommendation at pages 43-44 of her testimony
7 that the approximately $9.5 million in Commission-authorized legal and pension expense
8 deferrals not be included in rates?

9 A. Yes. We had looked at that issue prior to filing and decided not to seek rate recovery.
10 Because we were able to meet the expenses, but still hold down rates and build equity
11 over the deferral period, we did not want to pass that $9.5 million in expenses through to
12 our members.

13 Q. Finally, please comment on Ms. Brown's recommendation at pages 44-45 that AEPCO
14 be required to separate the revenues and expenses for Anza in future rate filings.

15 A. We do not support the recommendation. Anza has been a Class A member of AEPCO
16 since 1979. The Commission has never required in any of our previous cases a separate
17 cost of service study for it. Anza's load was 1.5% of our total energy sales in 2003. Cost
18 of service differences for Anza, if any, would be *de minimis* and would not justify either
19 our expense in performing such a study, nor the Staff and Commission effort required to
20 evaluate it.

1 Mr. Ramirez' Testimony

2 Q. Mr. Minson, at page 7 of his testimony, Mr. Ramirez expresses concern that AEPCO's
3 proposed revenues as adjusted by Staff would not be sufficient to service its debt
4 obligations. Do you agree?

5 A. Yes. That is why we are recommending that the revenue levels approved by the
6 Commission be sufficient to produce the 1.05 DSCR level which our Board of Directors
7 approved and we requested in our filing. Consistent with Mr. Ramirez' testimony, our
8 recommendations will allow us to cover our debt service obligations and support
9 additional debt financing which is necessary to meet service reliability and adequacy
10 needs.

11 Q. Do you disagree with Mr. Ramirez' recommendation that AEPCO continue to improve
12 its equity position?

13 A. Not at all. The rates that we propose would generate $8.2 million in net margins on an
14 annual basis. Absent other changes, this level of margins would build AEPCO's equity
15 ratio to 30% in about eight years.

16 Q. Do you have anything else to add in response to Mr. Ramirez' testimony?

17 A. Yes. I'd like to comment briefly on (1) his recommended target capital structure of 30%
18 and (2) his recommendation that the Commission restrict future patronage distributions
19 until 30% equity has been achieved.

20 Q. Please do so.

21 A. First, we strongly agree that AEPCO should continue to build equity and our record over
22 the past 15 years demonstrates that. Following economic events of the 1980s which were
23 beyond our control, such as a recession and losses of 125 MW in copper mining loads

1 (about 25% of Apache Station's then total generating capacity), from 1991 to 2002
2 AEPCO's equity as a percentage of assets increased from a negative 14.9% to a positive
3 7%. Notably, we accomplished this substantial equity improvement through a variety of
4 measures, including aggressive cost control, while simultaneously reducing member rates
5 by 22% after 1986. We do not agree, however, that the Commission should establish
6 30% or any other firm percentage as a target equity goal in this decision.
7 Q. Why not?
8 A. For a number of reasons. First, as the past 20 years amply demonstrate, economic,
9 financial and other conditions change. Locking in a target number unnecessarily binds
10 both AEPCO and future Commissions' ability to react to those changes. For example,
11 changes in environmental regulations impacting the timing and amount of necessary
12 capital improvements are very difficult to predict. Second, balancing the sometimes
13 competing goals of building equity, but also controlling member rates is an ongoing
14 process requiring constant evaluation which is inconsistent with a fixed target. Third,
15 moving to higher rates simply to keep pace with a predetermined equity goal may defeat
16 the purpose. For example, increasing rates at the wrong time economically may, in fact,
17 produce lower revenues and reduced margins. Finally, in my opinion, the 30% target is
18 simply too high. Mr. Ramirez' Schedule AXR-2 demonstrates that. Only two of the 13
19 rated cooperatives listed have patronage equity levels above 30%. The rest range from
20 roughly 26% to as low as 8%. The average is only 19%, which is consistent with an
21 R.W. Beck 2002 survey which indicated that, of G&T cooperatives surveyed which had
22 an equity ratio goal, the median goal was 17.5%. For all of these reasons, we recommend
23 that the Commission not order an improvement in AEPCO's equity position to 30%.

1 Q. What's your response to Mr. Ramirez' recommendation that future patronage
2 distributions by AEPCO be restricted until it has achieved a 30% capital structure?
3 A. Initially, let me clearly state that AEPCO has no plans for the foreseeable future to make
4 any patronage distributions. As Mr. Ramirez notes, we already have RUS and CFC
5 mortgage restrictions which control us in that regard and we see no reason for the
6 Commission to act in this area. However, if the Commission wants to impose a
7 patronage distribution restriction, we would ask that it simply order compliance by
8 AEPCO with its mortgage restrictions.
9 Ms. Keene's Testimony
10 Q. Ms Keene recommends that the Commission authorize an FPPCA as requested by
11 AEPCO. Do you have any comments on that recommendation?
12 A. Yes. We appreciate Staff's support of the concept and feel it will help considerably in
13 stabilizing and improving AEPCO's financial position. We disagree only with
14 Ms. Keene's recommendation to include in the FPPCA all revenue from non-Class A
15 sales as an offset to costs in the clause.
16 Q. Why?
17 A. We do not support that suggestion for several reasons. We do propose to credit to the
18 clause and the members' benefit any fuel costs recovered through non-Class A member
19 economy sales. So, our disagreement is only over crediting the FPPCA with the margins
20 received from those sales. The primary reason why is that a credit would actually result
21 in a double recovery of these margins. All margins received from such sales in the test
22 year have already been credited to reduce the members' cost of service in the rates we are
23 requesting here. So, for example, more than $2.2 million in margins from economy sales

in the test year have already been applied to reduce the members' cost of service and, therefore, the rates we are requesting here (Filing Schedule G-6, p. 2). If the margins from future economy sales are also credited to members through the FPPCA, the members will recover those margins twice. Second, crediting margins from economy sales also will distort the true price signal concerning fuel and purchase power costs sent to the members through the adjustor. Finally, margins from non-member economy sales are a primary way AEPCO can build equity with funds which don't have to be supplied by the members and their retail consumers. This enhances financial stability and also increases equity which the members and their member/consumers do not have to supply. Including those margins in the FPPCA would remove that source of margins. It would actively work against our attempts to gradually build equity which are supported by Staff.

Q. Does the Cooperative agree with Ms. Keene's proposal at pages 8-14 of her testimony to establish a Demand Side Management ("DSM") program for AEPCO?

A. No, it does not. AEPCO supports the efficient use and conservation of energy and is participating in the DSM evaluation effort currently ongoing at the Commission. However, as we have stated there, it is not appropriate as a wholesale generator for AEPCO to have a DSM program for several reasons. First, DSM programs are designed to affect end-use energy consumption. All of AEPCO's customers are distribution cooperatives that purchase wholesale electricity to supply at retail. DSM programs should be developed, delivered and financed by the local distribution cooperative, not the wholesale generator. Second, in addition to the distribution cooperative, if AEPCO were also required to provide DSM programs there would likely be a great deal of confusion by the end-use customer and a duplication of administrative costs. To require AEPCO to

have a DSM program on top of the programs of its distribution cooperatives is akin to requiring the generation divisions and distribution divisions of APS or TEP to have separate DSM programs for the same set of retail customers or requiring the wholesale energy suppliers of UniSource Energy Services to provide a DSM program for the customers of UES. These programs are simply better left to the "retail" arm of the utility to maximize the opportunity for successful implementation. Finally, there is wide geographic, climate, economic and size diversity among the distribution cooperatives served by AEPCO. In addition, this diversity now includes the partial-requirement nature of one and soon to be two of our distribution cooperatives. This diversity creates the need for different DSM programs or, at the very least, variations in DSM programs depending on the need and opportunities in each service area. While AEPCO stands ready to assist our members in developing DSM programs, these differing needs can best be addressed and managed by the individual distribution cooperatives.

REVISED DEPRECIATION RATES

Q. Mr. Minson, please comment on AEPCO's request that the Commission approve revised, lower depreciation rates.

A. Staff did not directly address that subject in its testimony, but I assume that was just an oversight. I discussed the request in my direct testimony and would ask that the Commission approve the new lower rates as set forth in Exhibit DCM-1.

CONCLUSION

Q. Mr. Minson, please summarize AEPCO's requests.

A. We would request that the Commission approve the rates and FPPCA as set forth in Exhibit DCM-3 and revised, lower depreciation rates as set forth in Exhibit DCM-1. We

would also ask that a proposed opinion be forwarded to the Commission for final approval as soon as possible.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

10421-36/1255529v2

EXHIBIT DCM-3

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

TARIFF

PERMANENT

Effective Date: _____

AVAILABILITY

Available to all cooperative associations which are or shall be all requirements Class A members of the Arizona Electric Power Cooperative, Inc. ("AEPCO").

MONTHLY RATE (BILLING PERIOD)

Electric power and energy furnished under this tariff will be subject to the following rates and terms:

Demand Charge
$13.98 per kW of billing demand, plus

Energy Charge
$0.02073 per kWh used during billing period, plus

Base Power Cost Adjustor
$0.00000 per kWh used during billing period

Billing Demand – The billing demand shall be that thirty minute integrated Class A member metered demand coincident at the hour of the AEPCO monthly peak. Contracts specifying demand levels and billing parameters are not included in this Class A member definition of billing demand and are billed separately.

Billing Month – The first calendar month preceding the month the bill is rendered.

Additional Charges – Service is also subject to the rates and charges stated in AEPCO's Regulatory Assets and Competition Transition Charge Supplemental Tariff. The demand and energy rates stated herein include no allowance for recovery of regulatory assets. Pursuant to Decision No. 62758, the regulatory assets and RAC have been assigned to Southwest Transmission Cooperative, Inc. AEPCO will pass through to its Class A members the RAC assessed by Southwest Transmission Cooperative, Inc.

Power Factor – Each member shall maintain power factor at the time of maximum demand as close to unity as possible. In the event the power factor measured at the time of the maximum demand is less than 95% lagging or leading, the maximum demand shall be adjusted for billing purposes by dividing the maximum measured demand by the measured power factor multiplied by .95. The provisions of the power factor adjustment will be waived if power factor is

detrimentally impacted as a direct result of system improvements or a change in operational procedure by AEPCO to reduce transmission losses and/or improve system reliability.

Taxes – Bills rendered are also subject to adjustment for all federal, state and local government taxes or levies on such sales and any assessments that are or may be imposed by federal or state regulatory agencies on electric utility gross revenues.

Transmission and Ancillary Service Charges – Each Class A member will also be billed by AEPCO for charges it incurs for the transmission of energy to the Class A member's delivery point(s). Such charges will be assessed to the Class A member at the rates actually charged AEPCO by the transmission provider and others for transmission service and the provision of ancillary services.

Base Power Cost Adjustor - The monthly bill computed under this schedule will, on the procedures stated herein, be increased or decreased by an amount equal to the result of multiplying the kWh used by the Adjustor where:

F = (PC + BA) - $0.01777

F = Adjustment factor in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

PC = The Commission allowed pro forma fuel, purchased power and wheeling costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BA = The "Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over or under collected in the past.

Allowable fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's own plants as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis. Included therein may be such costs as that charged for economy energy purchases and the charges as a result of scheduled outage. All such kinds of energy being purchased by AEPCO to substitute for its own higher cost energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of energy as recorded in RUS Account 565 and less

E. The demand and energy costs recovered through non-tariff contractual firm sales of power and energy as recorded in RUS Account 447, less

F. The energy costs recovered through inter-system sales including the incremental fuel and/or purchased energy costs related to economy energy sales and other energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Base Power Cost Adjustor as specified herein based upon a rolling twelve month average and file on September 1 or March 1 of the month preceding the effective date of the Base Power Cost Adjustor (i.e., October 1 or April 1): (1) calculations supporting the revised Adjustor with the Director, Utilities Division and (2) a tariff reflecting the revised Adjustor with the Commission which shall be effective for billings after the 1st day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

10421-36/1257338

Arizona Electric Power Cooperative, Inc.

Partial Requirements Member
Rates and Fixed Charge
(Effective as of _____)

Fixed Charge Mohave Electric Cooperative, Inc.	$761,245 per month
O&M Rate	$7.07 per kW/month
Energy Rate	$0.02073 per kWh used during the billing period
Base Power Cost Adjustor	$0.00000 per kWh used during billing period

Base Power Cost Adjustor - The monthly bill computed under this schedule will on the procedures stated herein be increased or decreased by an amount equal to the result of multiplying the kWh used by the Adjustor where:

F = (PC + BA) - $0.01694

F = Adjustment factor in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

PC = The Commission allowed pro forma fuel, purchased power and wheeling costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001).

BA = The "Bank Account" represents allowable accumulated fuel and purchased energy costs in dollars per kWh, rounded to the nearest one-thousandth of a cent ($0.00001) over or under collected in the past.

Allowable fuel, purchased power and wheeling costs include:

A. The costs of fossil fuel and natural gas consumed in AEPCO's own plants as recorded in RUS Accounts 501 and 547, plus

B. The actual costs associated with power purchased for reasons other than identified in paragraph (C) below as recorded in RUS Account 555, plus

C. The cost of energy purchased when such energy is purchased on an economic dispatch basis. Included therein may be such costs as that charged for economy energy purchases and the charges as a result of scheduled outage. All such kinds of energy being purchased by AEPCO to substitute for its own higher cost energy as recorded in RUS Account 555, plus

D. The firm and non-firm wheeling expenses associated with the delivery of energy as recorded in RUS Account 565 and less

E. The demand and energy costs recovered through non-tariff contractual firm sales of power and energy as recorded in RUS Account 447, less

F. The energy costs recovered through inter-system sales including the incremental fuel and/or purchased energy costs related to economy energy sales and other energy sold on an economic dispatch basis as recorded in RUS Account 447.

On a calendar semi-annual basis, AEPCO shall compute the Base Power Cost Adjustor as specified herein based upon a rolling twelve month average and file on September 1 or March 1 of the month preceding the effective date of the Base Power Cost Adjustor (i.e., October 1 or April 1): (1) calculations supporting the revised Adjustor with the Director, Utilities Division and (2) a tariff reflecting the revised Adjustor with the Commission which shall be effective for billings after the 1st day of the following month and which shall continue in effect until revised pursuant to the procedures specified herein.

10421-36/1256863

PENGAD-Bayonne, N.J.
EXHIBIT
AEPCO-3
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0528

REBUTTAL TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

MARCH 16, 2005

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INTRODUCTION

Q. Mr. Pierson, are you the same Gary E. Pierson who sponsored direct testimony for the Arizona Electric Power Cooperative, Inc. ("AEPCO") in this matter?

A. Yes, I am.

Q. Have you reviewed the direct testimony of Staff witnesses Crystal Brown, Barbara Keene, Alejandro Ramirez and Jerry Smith filed February 23, 2005 in this matter?

A. Yes, I have. As Mr. Minson discusses in his testimony, in order to narrow the issues in dispute and reduce complexity, for rebuttal purposes AEPCO accepts all seven of the Rate Base Adjustments proposed by Ms. Brown at pages 8-22 of her testimony. Further, AEPCO accepts nine of the twelve Operating Income Adjustments proposed by Ms. Brown as follows:

Adjustment No 1 – PTY Revenue and Expense	Schedule CSB-13
Adjustment No 3 – Asset Retirement Obligation	Schedule CSB-15
Adjustment No 6 – Transmission Expense Annualization	Schedule CSB-18
Adjustment No 7 – Normalized Legal Expense	Schedule CSB-19
Adjustment No 8 – Fuel Expense	Schedule CSB-20
Adjustment No 9 – Advertising Expense	Schedule CSB-21
Adjustment No 10 – Contributions & Other Expenses	Schedule CSB-22
Adjustment No 11 – ACC Gross Revenue Assessment	Schedule CSB-23
Adjustment No 12 – Interest on Long Term Debt	Schedule CSB-24

Thus, my rebuttal testimony will primarily address the remaining three proposed adjustments:

<u>Operating Income Adjustments</u>

Adjustment No 2 – Revenue and Expense Annualization	Schedule CSB-14
Adjustment No 4 – Tracker Mechanism (Base Power Cost)	Schedule CSB-16
Adjustment No 5 – Overhaul Accrual Expense	Schedule CSB-17

In addition, I am sponsoring Exhibits GEP-2 through GEP-10 in support of AEPCO's rebuttal position in this matter.

RATE BASE – AEPCO REBUTTAL POSITION

Q. Have you reviewed the Staff's testimony on the original cost/fair value rate base for this proceeding?

A. Yes, I have. As I indicated, AEPCO accepts the Staff's proposed rate base of $189,637,810 for purposes of determining its fair value rate base.

OPERATING INCOME – AEPCO REBUTTAL POSITION

Q. Please summarize AEPCO's rebuttal position based upon the Staff's direct testimony.

A. As shown on Exhibits GEP-5, column D and GEP-6, AEPCO proposes test year revenues of $138,951,691 and expenses of $128,494,283. This produces operating margins before interest on long-term debt of $10,457,408 and a net margin loss of $1,235,695. As I'll explain, the test year revenues we propose are $336,455 less than the Staff's position and the expenses are $187,911 greater. Thus, the operating margins before interest on long-term debt and the net margin loss amounts are $524,366 lower in our rebuttal position. The three rebuttal adjustments we propose and my exhibits which explain them are:

Adjustment No 1 – Revenue and Expense Annualization	Exhibit GEP-7
Adjustment No 2 – Overhaul Accrual Expense	Exhibit GEP-8
Adjustment No 3 – Tracker Mechanism (Base Power Cost)	Exhibit GEP-9

Rebuttal Adjustment No. 1 – Revenue and Expense Annualization

Q. Please describe the growth adjustment which is proposed by Ms. Brown to AEPCO's revenues and expenses.

A. Ms. Brown made a growth annualization adjustment in order to achieve a matching of revenues and expenses with the year-end rate base (Brown Testimony, pp. 25-26). Staff

computed the adjustment by applying one-half of the customer load growth percentage of AEPCO's Class A Members or 1.65% to the demand and energy revenues as well as the variable expenses. As a result, Staff proposes an increase in revenues of $1,271,908 and an increase in expenses of $264,376.

Q. Please describe the Company's position on the growth adjustment.

A. We will not object to the concept, but Ms. Brown's adjustment does not take into account the fact that Mohave Electric Cooperative, Inc. ("Mohave") is a partial requirements customer of AEPCO. As such, its customer load growth does not result in increased power deliveries by and increased revenues to AEPCO. Therefore, the adjustment is somewhat overstated due to the inclusion of Mohave's test year customer load growth.

Q. Have you prepared an exhibit which explains AEPCO's rebuttal position?

A. Yes, I have. Exhibit GEP-7 takes Ms. Brown's adjustment, as set forth in her Schedule CSB-14, and modifies it by excluding Mohave's customer growth for 2003 from the calculation of the annualization factor. That decreases the factor from 1.65% to 1.61%. Our adjustment reduces the Staff proposed revenue adjustment by $336,455 and the Staff proposed expense adjustment by $5,658.

Rebuttal Adjustment No. 2 – Overhaul Accrual Expense

Q. Please describe the adjustment which Ms. Brown proposes to overhaul accrual expense at pages 31-32 of her testimony.

A. Staff proposes an adjustment to reflect overhaul accrual expense based upon an eight-year historic average of overhaul cost incurred during the years 1996 through 2003. Staff proposes a reduction of $657,788, which decreases the total expense to $4,129,720.

Q. What is AEPCO's position on this adjustment?

A. While we are confident that our overhaul accruals method is and will be representative of our experience, in order to reduce issues in dispute, we will not object to Staff's alternate approach. However, Ms. Brown's adjustment does not provide an adequate accrual for a Gas Turbine 4 major overhaul. Gas Turbine 4 is a 38 MW aero-derivative combustion turbine that was very recently placed into commercial service in October 2002. Therefore, it was not in service for almost all of the historic 1996-2003 period. In September 2003, it was determined, based upon operating characteristics, that a major overhaul of Gas Turbine 4 will be required in October 2010. Based upon engineering estimates of the cost of that major overhaul, AEPCO began accruing approximately $19,000 per month starting October 2003 based upon the remaining 84 months of the eight-year cycle. However, only $57,354 of expense, as shown on Schedule CSB-17, line 10, would be accrued for a Gas Turbine 4 overhaul based upon Ms. Brown's historic approach. That obviously will not adequately cover the $1.6 million cost of the overhaul.

Q. Have you prepared an adjustment setting forth AEPCO's rebuttal position?

A. Yes, I have. Exhibit GEP-8 takes Ms. Brown's adjustment and modifies it by incorporating an adjustment to recognize the monthly accrual for the Gas Turbine 4 major overhaul which began in the test year. An annual accrual in the amount of $200,738 ($1,605,900/8 years) for Gas Turbine 4 less the amount included in the Staff's adjustment of $7,169 ($57,354/8 years) should be added to Staff's proposed adjustment. As shown on line 16, this increases the Staff proposed adjustment by $193,569.

Rebuttal Adjustment No. 3 – Tracker Mechanism (Base Power Cost)

Q. Please describe Ms. Brown's adjustment in relation to AEPCO's Base Power Cost at pages 29-30 of her testimony.

1 A. Ms. Brown takes AEPCO's filed position on the base cost of power of $41,276,155 and
2 reduces it by $7,716,227 which lowers the adjustor base rate from $0.02038/kWh to
3 $0.01657/kWh.
4 Q. Please describe the Company's position on the adjustments contained in Schedule CSB-16.
5 A. The company accepts the fuel expense adjustment that Ms. Brown made to column B, l. 11
6 of Schedule CSB-16, but does not accept the purchased power adjustment set forth in
7 column B, l. 27. The Staff adjustment "annualizing savings from a new contract that was in
8 effect for only half of the test year" is not a reduction in the purchased power energy costs
9 of the Public Service Company of New Mexico ("PNM") (Direct Testimony of
10 Ms. Brown, p. 30, ll. 21-22). Rather, the adjustment is an annualization of the payment for
11 a 2 MW contract demand reduction in the AEPCO/PNM contract. Therefore, it should not
12 be deducted from the purchased power energy costs of PNM. To clarify, we agree with
13 Staff's proposed adjustment of $250,000, but the adjustment should be made against
14 purchased power demand costs, not purchased power energy costs. In addition to the fuel
15 expense and purchased power adjustment, Ms. Brown has also made adjustments to add
16 certain fixed fuel costs, purchased/demand costs, firm wheeling expenses and credits for
17 non-tariff sales fuel recovery/demand based upon the recommendations of Ms. Keene.
18 AEPCO agrees to including the gas reservation charges, demand charges for purchased
19 power, firm wheeling costs and certain credits for non-tariff sales fuel recovery. But, as
20 explained in Mr. Minson's rebuttal testimony, AEPCO does not agree that revenue credits
21 reflecting the margins on economy energy sales should be included in the determination of
22 the base power cost and adjustor base rate.
23 Q. Have you prepared an adjustment setting forth this position?

A. Yes, I have. Exhibit GEP-9, page 1 makes certain adjustments to Ms. Brown's Schedule CSB-16 to reflect our rebuttal position. Column [D] sets forth these rebuttal adjustments. On line 5, test year sales are adjusted to reflect the energy billing units associated with the revenue annualization that the Company proposed in Schedule GEP-6. Line 27 removes the Staff adjustment to reduce PNM purchased power energy costs that should be made instead to PNM purchased power demand costs. Line 31 correspondingly adds the Staff adjustment to reduce PNM purchased power demand costs. Line 51 removes the $2,215,834 in margins associated with economy energy sales from the Staff adjustment for the non-tariff demand related revenues. As a result of these adjustments, the base cost of power should be $35,776,234, which translates to an adjustor base of $0.01748/kWh as shown on line 6, page 2 of Exhibit GEP-9.

Q. Are there any further modifications to the base power costs determination that AEPCO is proposing?

A. Yes. There are certain purchased demand costs and wheeling costs that are applicable to our all-requirements members, but are not applicable to our partial-requirements member Mohave. These costs represent purchased capacity charges and associated wheeling expenses for the Panda Gila River purchased power agreement that Mohave elected not to participate in. These costs have been excluded from the calculation of Mohave's fixed charge and operations and maintenance rate and should be excluded as well from Mohave's base cost of power. Page 2, line 6 of Exhibit GEP-9 shows this differential calculation of the base power cost for the all-requirement and partial-requirement members. Therefore, AEPCO recommends that the all-requirements adjustor base be set at $0.01777/kWh and that the partial-requirements adjustor base be set at $0.01694/kWh.

1 **REBUTTAL POSITION – REVENUE REQUIREMENTS AND RATES**

2 Q. Please state the Company's rebuttal position on revenue requirements and rates.

3 A. The Board of Directors instructed AEPCO to seek Commission approval for revised rates
4 designed to achieve a 2003 test year result equal to a Debt Service Coverage Ratio
5 ("DSCR") of 1.05. A copy of this resolution, adopted on July 14, 2004, is attached as
6 Exhibit GEP-10. The Board of Directors determined that this level of increase was
7 necessary to ensure that AEPCO satisfies its mortgage requirements and maintains a
8 satisfactory level of financial integrity while simultaneously building cooperative equity.
9 As Mr. Ramirez notes in his testimony at page 2, the Staff's minimum recommended
10 operating income would produce a DSCR of only .91, which is below RUS minimum
11 requirement. We agree with his statements at page 7 of his testimony that this level of
12 revenue would not be sufficient to service current debt, build equity or support new debt
13 financing. Therefore, applying the 1.05 DSCR to AEPCO's proposed test year revenues of
14 $138,951,691, expenses of $128,494,283, operating margins before interest on long-term
15 debt of $10,457,408 and the net margin loss of $1,235,695, operating revenues should be
16 increased by $9,446,032 as shown in column E, Exhibit GEP-5.

17 Q. Have you prepared exhibits which summarize AEPCO's rebuttal position?

18 A. Yes. Exhibit GEP-2 sets forth AEPCO's rebuttal position in column [C]. We request
19 that the Commission enter its order approving an increase of $9,446,032 in operating
20 revenue and a rate of return of 10.50% on the fair value rate base of $189,637,810.
21 Exhibit GEP-3 is the rate base summary. Exhibit GEP-4 sets forth the proposed rates
22 based on AEPCO's rebuttal position in column [C]. Exhibit GEP-5 summarizes

1 Operating Income – Test Year. Finally, Exhibit GEP-6 sets forth our rebuttal adjustments
2 to the Staff's Test Year – As Adjusted.
3 Q. Why are the rebuttal rates requested in column C of Exhibit GEP-4 higher than those
4 originally requested in AEPCO's filing?
5 A. Primarily because in preparing our original schedules, the fourth quarter 2003 test year
6 debt principle payment in the approximate amount of $2.2 million was overlooked.
7 AEPCO had attempted to make the payment on December 31, 2003, but the wire transfer
8 to the U.S. Treasury failed. It was successfully made on the first business day of 2004,
9 but several months later when the rate case schedules were being prepared, the fact that
10 the payment was attributable to the 2003 test year was overlooked. Taking this payment
11 into account, the original rate request should have been approximately $2.3 million higher
12 to cover the principle payment and the 1.05 DSCR associated with it.
13 Q. How was this omission discovered?
14 A. We learned of it in early January 2005 while researching the answer to a Staff data
15 request. We promptly advised Staff of the situation. In February, we also discussed the
16 matter and the fact that the original rate request should have been higher with the AEPCO
17 Board of Directors.
18 Q. Does this conclude your rebuttal testimony?
19 A. Yes, it does.
20 10421-36/1257424

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-2

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL FILING	[B] STAFF DIRECT POSITION	[C] COMPANY REBUTTAL POSITION
1	Adjusted Operating Income (Loss)	$ 7,972,676	$ 10,981,774	$ 10,457,408
2	Depreciation and Amortization	$ 7,608,735	$ 7,539,289	$ 7,539,289
3	Income Tax Expense	-	-	-
4	Long-term Interest Expense	$ 13,547,749	$ 13,313,164	$ 13,313,164
5	Principal Repayment	$ 10,344,950	$ 14,360,494	$ 14,360,494
6a	Recommended Increase in Operating Revenue	$ 8,450,016	$ 6,773,320	$ 9,446,032
6b	Percent Increase (Line 6a / Line 7b) - Per Staff	N/A	4.86%	6.80%
6c	Percent Increase (Line 6a / Line 7a) - Per Coop	9.86%	7.80%	10.92%
7a	Adjusted Class A Member Revenue	$ 85,685,624	$ 86,810,386	$ 86,473,931
7b	Adjusted Test Year Operating Revenue	$ 137,611,450	$ 139,288,146	$ 138,951,691
8	Recommended Annual Operating Revenue	$ 146,061,466	$ 146,061,466	$ 148,397,723
9a	Recommended Operating Margin Before Interest	$ 16,422,692	$ 17,755,094	$ 19,903,440
9b	Recommended Margins(Loss) After Interest	$ 1,959,955	$ 4,099,540	$ 6,247,886
9c	Recommended Net Margin	$ 3,922,406	$ 6,061,991	$ 8,210,337
10a	Staff TIER (L3+L9a)/L4 - Per Staff	N/A	1.33	1.50
10b	TIER (L9c+L4)/L4 - Per Coop (RUS Definition)	1.29	1.46	1.62
11a	Staff DSC (L2+L3+L9b)/(L4+L5) - Per Staff	N/A	0.91	0.99
11b	DSC (L2+L4+L9c)/(L4+L5) - Per Coop (RUS Definition)	1.05	0.97	1.05
12	Adjusted Rate Base	$ 222,147,011	$ 189,637,810	$ 189,637,810
13	Rate of Return (L9a / L12)	7.39%	9.36%	10.50%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules CSB-2, CSB-11, Testimony Alejandro Ramirez
Column [C]: Exhibits GEP-3, GEP-5

Arizona Electric Power Cooperative, Inc.
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Exhibit GEP-3

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[C] STAFF DIRECT POSITION	[C] COMPANY REBUTTAL POSITION
1	Plant in Service	$ 389,603,749	$ 377,675,263	$ 377,675,263
2	Less: Acc Depreciation & Amortization	(186,190,519)	(185,936,636)	(185,936,636)
3	Net Plant in Service	203,413,230	191,738,627	191,738,627
	LESS:			
4	Advances in Aid of Construction (AIAC)	-	-	-
5	Contributions in Aid of Construction (CIAC)	-	-	-
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	-	-	-
9	Member Advances	-	(11,982,081)	(11,982,081)
	ADD:			
10	Working Capital	16,778,408	9,881,264	9,881,264
11	Plant Held for Future Use	-	-	-
12	Deferred Debits	1,955,373	-	-
13	Total Rate Base	$ 222,147,011	$ 189,637,810	$ 189,637,810

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Staff Schedule CSB-2, Column C
Column [C]: Rebuttal Testimony Gary Pierson

Arizona Electric Power Cooperative, Inc.

Exhibit GEP-4

Docket No. E-01773A-04-0528

Test Year Ended December 31, 2003

SUMMARY OF PROPOSED RATES

Line No.	Description	[A] Company Original Filing	[B] Staff Direct Position	[C] Company Rebuttal Position
1	All Requirements Members:			
2	Demand Rate - $/kW Month	$ 13.79	$ 12.90	$ 13.98
3	Energy Rate - $/kWh	$ 0.02071	$ 0.02079	$ 0.02073
4	Power Cost Adjustor Base - $/kWh	$ 0.02038	$ 0.01657	$ 0.01777
5	Partial Requirements Members:			
6	Fixed Charge - $/Month	$ 705,795	$ 707,392	$ 761,245
7	O&M Rate - $/kW Month	$ 7.25	$ 7.48	$ 7.07
8	Energy Rate - $/kWh	$ 0.02071	$ 0.02079	$ 0.02073
9	Power Cost Adjustor Base - $/kWh	$ 0.02038	$ 0.01657	$ 0.01694
10	Proposed Revenue Increase - ($000's):			
11	Anza	$ 147.9	$ 79.4	$ 167.5
12	Duncan Valley	90.1	47.5	101.2
13	Graham County	470.8	246.9	527.0
14	Mohave	4,001.3	4,421.2	4,432.9
15	Sulphur Springs	2,148.5	1,158.0	2,415.0
16	Trico	1,591.4	826.9	1,802.4
17	Total Class A	$ 8,450.0	$ 6,779.9	$ 9,446.0
18	Proposed Revenue Increase - Percent:			
19	Anza	7.73%	4.08%	8.60%
20	Duncan Valley	7.77%	4.07%	8.64%
21	Graham County	7.82%	4.07%	8.69%
22	Mohave	14.00%	15.30%	15.53%
23	Sulphur Springs	7.69%	4.09%	8.52%
24	Trico	7.94%	4.05%	8.83%
25	Total Class A	9.86%	7.81%	10.92%

References:

Column A - Company Original Filing, Schedules G2A & H-2

Column B - Staff Witness Keene Testimony and Workpapers

Column C - Gary Pierson Rebuttal Testimony and Workpapers

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-5

OPERATING INCOME - TEST YEAR, STAFF ADJUSTED AND COMPANY PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR AS ADJUSTED	[C] COMPANY REBUTTAL TEST YEAR ADJUSTMENTS	[D] COMPANY REBUTTAL TEST YEAR AS ADJUSTED	[E] COMPANY REBUTTAL PROPOSED CHANGES	[F] COMPANY REBUTTAL RECOMMENDED
	REVENUES:						
1	Class A Members, Non-Base Cost of Power Revenue	$ 44,409,469	$ 37,818,004	$ 12,879,693	$ 50,697,697	$ 9,446,032	$ 60,143,729
2	Class A Members, Base Cost of Power Revenue	41,276,155	48,992,382	(13,216,148)	35,776,234		35,776,234
3	Total Class A Member Electric Revenue	85,685,624	86,810,386	(336,455)	86,473,931	9,446,032	95,919,963
4	Non-Class A, Non-Firm, & Non-Member	50,444,504	50,996,438	-	50,996,438	-	50,996,438
5	Total Electric Revenue	136,130,128	137,806,824	(336,455)	137,470,369	9,446,032	146,916,401
6	Other Operating Revenue	1,481,322	1,481,322	-	1,481,322	-	1,481,322
7	Total Revenues	137,611,450	139,288,146	(336,455)	138,951,691	9,446,032	148,397,723
	EXPENSES:						
8	Operations - Production, Fuel	59,803,425	59,014,728	(264,376)	58,750,352	-	58,750,352
9	Operations - Production, Steam	8,764,555	8,764,555	258,718	9,023,273	-	9,023,273
10	Operations - Production, Other	1,335,333	1,743,316	-	1,743,316	-	1,743,316
11	Operations - Other Pwr Supply, Demand	5,769,587	5,769,587	(250,000)	5,519,587	-	5,519,587
12	Operations - Other Pwr Supply - Energy	12,420,888	12,170,888	250,000	12,420,888	-	12,420,888
13	Operations - Transmission	8,036,486	8,036,486	-	8,036,486	-	8,036,486
14	Operations - Administrative and General	9,191,902	9,525,759	-	9,525,759	-	9,525,759
15	Maintenance - Production, Steam	10,170,045	9,512,258	193,569	9,705,827	-	9,705,827
16	Maintenance - Production, Other	2,809,881	2,809,881	-	2,809,881	-	2,809,881
17	Maintenance - Transmission	28,388	8,828	-	8,828	-	8,828
18	Maintenance - General Plant	63,958	63,958	-	63,958	-	63,958
19	Depreciation and Amortization	7,608,735	7,539,289	-	7,539,289	-	7,539,289
20	ACC Gross Revenue Taxes	288,752	-	-	-	-	-
21	Taxes	3,346,839	3,346,839	-	3,346,839	-	3,346,839
22	Total Operating Expenses	129,638,774	128,306,372	187,911	128,494,283	-	128,494,283
23	Operating Margin Before Interest on L.T.- Debt	7,972,676	10,981,774	(524,366)	10,457,408	9,446,032	19,903,440
24	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS:***						
25	Interest on Long-term Debt	13,547,749	13,313,164	-	13,313,164	-	13,313,164
26	Other Interest & Other Deductions	914,988	342,390	-	342,390	-	342,390
27	Total Interest & Other Deductions	14,462,737	13,655,554	-	13,655,554	-	13,655,554
28	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	(6,490,061)	(2,673,780)	(524,366)	(3,198,146)	9,446,032	6,247,886
29	***NON-OPERATING MARGINS***						
30	Interest Income	582,014	582,014	-	582,014	-	582,014
31	Other Non-operating Income	1,380,437	1,380,437	-	1,380,437	-	1,380,437
32	Total Non-Operating Margins	1,962,451	1,962,451	-	1,962,451	-	1,962,451
33	***EXTRAORDINARY ITEMS***	-	-	-	-	-	-
34	***NET MARGINS (LOSS)***	$ (4,527,610)	$ (711,329)	$ (524,366)	$ (1,235,695)	$ 9,446,032	$ 8,210,337

35 References:
36 Column [A]: Cooperative Schedule C-1, Pages 1 and 2
37 Column [B]: Schedule CSB-11, Column C
38 Column [C]: Exhibit GEP-5

References:
Column [D]: Column [B] + Column [C]
Column [E]: Exhibit GEP-2
Column [F]: Column [D] + Column [E]

Arizona Electric Power Cooperative, Inc.
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Exhibit GEP-6

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] STAFF TEST YEAR AS Adjusted	[B] ADJ #1 Revenue and Expense Annualizations Ref: Sch GEP-7	[C] ADJ #2 Overhaul Accrual Expense Ref: Sch GEP-8	[D] ADJ #3 Tracker Mechanism (Base Power Cost) Ref: Sch GEP-9	[E] COMPANY REBUTTAL AS ADJUSTED
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 37,818,004	$ (336,455)	$ -	$ 13,216,148	$ 50,697,697
2	Class A Members, Base Cost of Power Revenue	48,992,382	-	-	(13,216,148)	35,776,234
3	Total Class A Member Electric Revenue	86,810,386	(336,455)	-	-	86,473,931
4	Non-Class A, Non-Firm, & Non-Member	50,996,438	-	-	-	50,996,438
5	Total Electric Revenue	137,806,824	(336,455)	-	-	137,470,369
6	Other Operating Revenue	1,481,322	-	-	-	1,481,322
7	Total Revenues	139,288,146	(336,455)	-	-	138,951,691
8	*OPERATING EXPENSES:*					
9	Operations - Production, Fuel	59,014,728	(264,376)	-	-	58,750,352
10	Operations - Production, Steam	8,764,555 [1]	258,718	-	-	9,023,273
11	Operations - Production, Other	1,743,316 [2]		-	-	1,743,316
12	Operations - Other Pwr Supply, Demand	5,769,587	-	-	(250,000)	5,519,587
13	Operations - Other Pwr Supply - Energy	12,170,888 [3]	-	-	250,000	12,420,888
14	Operations - Transmission	8,036,486	-	-	-	8,036,486
15	Operations - Administrative and General	9,525,759	-	-	-	9,525,759
16	Maintenance - Production, Steam	9,512,258 [4]	-	193,569	-	9,705,827
17	Maintenance - Production, Other	2,809,881	-	-	-	2,809,881
18	Maintenance - Transmission	8,828	-	-	-	8,828
19	Maintenance - General Plant	63,958	-	-	-	63,958
20	Depreciation and Amortization	7,539,289	-	-	-	7,539,289
21	ACC Gross Revenue Taxes	-	-	-	-	-
22	Taxes	3,346,839	-	-	-	3,346,839
23	Total Operating Expenses	128,306,372	(5,658)	193,569	-	128,494,283
24	Operating Margin Before Interest on L.T.- Debt	10,981,774	(330,797)	(193,569)	-	10,457,408
25	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*					
26	Interest on Long-term Debt	13,313,164	-	-	-	13,313,164
27	Other Interest & Other Deductions	342,390	-	-	-	342,390
28	Total Interest & Other Deductions	13,655,554	-	-	-	13,655,554
29	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(2,673,780)	(330,797)	(193,569)	-	(3,198,146)
30	*NON-OPERATING MARGINS*					
31	Interest Income	582,014	-	-	-	582,014
32	Other Non-operating Income	1,380,437	-	-	-	1,380,437
33	Total Non-Operating Margins	1,962,451	-	-	-	1,962,451
34	*EXTRAORDINARY ITEMS*	-	-	-	-	-
35	*NET MARGINS (LOSS)*	$ (711,329)	$ (330,797)	$ (193,569)	$ -	$ (1,235,695)

Footnote Explanations

[1] Includes account nos. 500, 5 includes account nos. 555 to 557

[2] Includes account nos. 546, 5 includes account nos. 510 to 515

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-7**

Docket No. E-01773A-04-0528

Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 1 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY REBUTTAL ADJUSTMENTS	[C] COMPANY REBUTTAL AS ADJUSTED
1	Class A Member Demand Revenues	$ 36,990,731	$ 6,922,455	$ 30,068,276
2	Class A Member Energy Revenues	$ 40,285,075	$ 14,260,705	$ 26,024,370
3	Class A Member ACC Assessment Rev	$ -	$ -	$ -
4	Class A Member Fixed Charge Revenues	$ -	$ -	$ -
5	Total Class A Member Base Rate Revenues	$ 77,275,806	$ 21,183,160	$ 56,092,646
6	Factor to Annualize Revenues to End of Test Year	1.65%		1.67%
7	Revenue Annualization Adjustment	$ 1,271,908	$ (336,455)	$ 935,453
8	Variable Expenses Not Recovered Through Fuel Adj	$ -		$ 16,062,410
9	Factor to Annualize Revenues to End of Test Year	1.65%		1.61%
10	Adjustment to Expenses	$ 264,376	$ (5,658)	$ 258,718

	Calculation of Annualization Factor						
	Number of Customers						
	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
2002	3,702	2,446	7,481	N/A	43,113	27,631	84,373
2003	3,824	2,484	7,623	N/A	44,431	28,729	87,091
Increase	122	38	142	N/A	1,318	1,098	2,718
% Increase	3.30%	1.55%	1.90%	0.00%	3.06%	3.97%	3.22%
2003 Growth Rate							3.22%
Annualization Factor - 2003 Growth Rate divided by 2							
	1.65%	0.78%	0.95%	0.00%	1.53%	1.99%	1.61%

Calculation of Variable Expenses Not Recovered Through Fuel Adjustor			
Account No.	Description	Amount	
500	Operation Supervision and Engineering	$ 1,999,908	
501&547	Fuel - Steam Power & Other	$ 59,803,425	
502	Steam Expenses	$ 2,710,803	
505	Electric Expenses	$ 1,437,524	
510	Maintenance Supervision & Engineering	$ 840,774	
512	Maintenance of Boiler Plant	$ 6,433,681	
513	Maintenance of Electric Plant	$ 264,759	
514	Maintenance of Miscellaneous Steam Plant	$ 2,374,961	
555	Purchased Power - Demand	$ 5,769,587	
555	Purchased Power - Energy	$ 10,085,538	
	Total Variable Expenses	$ 91,720,960	
501&547	Fuel - Steam Power & Other	$ (59,803,425)	Recovered through Fuel Adj
555	Purchased Power - Demand	$ (5,769,587)	Recovered through Fuel Adj
555	Purchased Power - Energy	$ (10,085,538)	Recovered through Fuel Adj
		$ 16,062,410	
	2003 Growth Rate	1.61%	
	Adjustment to Expenses	$ 258,718	

References:

Column A: Cooperative Data Request Response CSB 6-1

Column B: Testimony, CSB

Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Exhibit GEP-8

REBUTTAL ADJUSTMENT NO. 3 - OVERHAUL ACCRUAL EXPENSE

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY REBUTTAL ADJUSTMENTS	[C] COMPANY REBUTTAL AS ADJUSTED
1	Overhaul Accrual Expense	$4,129,720	$ 193,569	$ 4,323,289

2		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 57,354	$ 3,206,259
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 57,354	$ 33,037,763
12								Divided by	8
13	ADJUSTMENT TO ANNUALIZE GT4 OVERHAUL ACCRUALS								$ 4,129,720
14	ANNUAL GT4 MAJOR OVERHAUL ACCRUAL - $1,605,900 / 8 YEARS =						$ 200,738		
15	LESS: AMOUNT INCLUDED IN TOTAL, LINE 10 - $57,354 / 8 YEARS=						7,169		
16	ADDITIONAL GT4 ACCRUAL								193,569
17									$ 4,323,289
18									

19 * Per response to CSB 1-38, there has been no actual overhaul expense
20 for generating GT2 for the period 1990 to 2004.

21 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.

22 <u>References:</u>

23 Column A: Staff Exhibit CSB -17, Column C
24 Column B: Gary Pierson Rebuttal Testimony
25 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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REBUTTAL ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED	[D] COMPANY REBUTTAL ADJUSTMENTS	[E] COMPANY REBUTTAL AS ADJUSTED
1	Base Cost of Power Revenue					
2	Test Year Sales (In kWhs)	2,025,326,533	-	2,025,326,533	-	2,025,326,533
3	Base Cost of Power (Col A, per Dec 58405)	$ 0.01714	$ 0.00324	$ 0.02038	$ (0.00381)	$ 0.01657
4	Adjustment to match Coop proposed power expense to revenue	$ 34,714,097	$ 6,562,058	$ 41,276,155	$ (7,715,755)	$ 33,560,400
5	Test Year Sales (In kWhs)	2,025,326,533		2,025,326,533	21,063,927	2,046,390,460
6	Base Cost of Power (Col C, Line 53/Line 5)	$ 0.02038	$ (0.00381)	$ 0.01657	$ 0.00091	$ 0.01748
7	Adjustment to reflect Staff's adjustments to power costs	$ 41,276,627	$ (7,716,227)	$ 33,560,400	$ 2,215,834	$ 35,776,234
8	Total	$ 34,714,097	$ (1,153,697)	$ 33,560,400	$ 2,215,834	$ 35,776,234
9	Base Cost of Power Expense					
10	Coal Fired Steam Plant Costs:					
11	Fuel, Coal ($1,534,274 Coop Adj No. 5 - $1,030,873 legal exp)	$ 42,029,531	$ 503,401	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-	-	-
14	Less: Fixed Fuel Costs	(549,137)	253,272	(295,865)	-	(295,865)
15	Subtotal	$ 43,789,748	$ 756,673	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:					
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809	-	9,809
19	Less: Fixed Fuel Costs	(1,435,208)	1,435,208	-	-	-
20	Subtotal	$ 14,029,332	$ 1,435,208	$ 15,464,540	$ -	$ 15,464,540
21	Total Fuel Costs	$ 57,819,080	$ 2,191,881	$ 60,010,961	$ -	$ 60,010,961
22	Purchased Power Energy Costs					
23	Firm Purchases					
24	CRSP	$ 309,547	$ -	$ 309,547	$ -	$ 309,547
25	PacifiCorp	-	-	-	-	-
26	Parker Davis	217,629	-	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061	(250,000)	1,713,061	250,000	1,963,061
28	Panda Gila River	1,134,573	-	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-	-	-
30	Subtotal Firm Purchases	$ 3,624,810	$ (250,000)	$ 3,374,810	$ 250,000	$ 3,624,810
31	Firm Purchases, Demand	$ -	5,769,587	$ 5,769,587	(250,000)	5,519,587
32	Nonfirm Purchases, Demand and Energy	6,460,728	-	6,460,728	-	6,460,728
33	Total Purchased Power Costs	$ 10,085,538	$ 5,519,587	$ 15,605,125	$ -	$ 15,605,125
34	Firm Wheeling Expenses	$ -	7,939,635	$ 7,939,635	-	$ 7,939,635
35	Non-firm Wheeling Expenses	77,291	-	77,291	-	77,291
36	Total Firm and Non-Firm Wheeling Expenses	$ 77,291	$ 7,939,635	$ 8,016,926	$ -	$ 8,016,926
37	TOTAL FUEL COSTS & PURCHASED ENERGY	$ 67,981,909	$ 15,651,103	$ 83,633,012	$ -	$ 83,633,012
38	Less:					
39	Non-tariff Sales Fuel Recovery					
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-	-	-
42	City of Mesa (PSA)	2,657,351	(90,879)	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,376,189	(20,185)	1,356,004	-	1,356,004
44	SRP	13,039,105	(260,828)	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921	-	142,921
47	Subtotal	$ 18,311,016	$ (371,892)	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:					
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,705,282	$ (371,892)	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ -	$ 23,739,222	$ 23,739,222	$ (2,215,834)	$ 21,523,388
52	Total Non-Tariff Sales Fuel Recovery, Energy and Demand	$ 26,705,282	$ 23,367,330	$ 50,072,612	$ (2,215,834)	$ 47,856,778
53	Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)	$ 41,276,627	$ (7,716,227)	$ 33,560,400	$ 2,215,834	$ 35,776,234

54 References:
55 Column [A]: Cooperative Application Schedule H-2A
56 Column [B]: Testimony Crystal Brown
57 Column [C]: Column [A] + Column [B]
57 Column [D] - Rebuttal Testimony Gary Pierson
57 Column [E]: Column [C] + Column [D]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY REBUTTAL AS ADJUSTED	[B] LESS: ALL-REQ. COST ADJUSTMENTS	[C] BASE REQ. ADJUSTOR BASE CALCULATION	[D] PLUS: ALL-REQ..COST ADJUSTMENTS	[E] POWER COST ADJUSTOR BASE CALCULATION
1	Partial Requirements Customers:					
2	Test Year Sales (In kWhs)					716,978,668
3	Base Cost of Power - $/kWh					$ 0.01694
4	Base Cost of Power					$ 12,148,074
	All Requirements Customers:					
5	Test Year Sales (In kWhs)	2,046,390,460	-	2,046,390,460		1,329,411,792
6	Base Cost of Power - $/kWh	$ 0.01748	$ (0.00054)	$ 0.01694	$ 0.00083	$ 0.01777
7	Base Cost of Power	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 23,628,160
8	Total Base Cost of Power	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 35,776,234
9	Base Cost of Power Expense					
10	Coal Fired Steam Plant Costs:					
11	Fuel, Coal	$ 42,532,932	$ -	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-	-	-
14	Less: Fixed Fuel Costs	(295,865)	-	(295,865)	-	(295,865)
15	Subtotal	$ 44,546,421	$ -	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:					
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809	-	9,809
19	Less: Fixed Fuel Costs	-	-	-	-	-
20	Subtotal	$ 15,464,540	$ -	$ 15,464,540	$ -	$ 15,464,540
21	Total Fuel Costs	$ 60,010,961	$ -	$ 60,010,961	$ -	$ 60,010,961
22	Purchased Power Energy Costs					
23	Firm Purchases					
24	CRSP	$ 309,547	$ -	$ 309,547	$ -	$ 309,547
25	PacifiCorp	-	-	-	-	-
26	Parker Davis	217,629.00	-	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061.00	-	1,963,061	-	1,963,061
28	Panda Gila River	1,134,573.00	-	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-	-	-
30	Subtotal Firm Purchases	$ 3,624,810	$ -	$ 3,624,810	$ -	$ 3,624,810
31	Firm Purchases, Demand	5,519,587	(1,000,872)	$ 4,518,715	1,000,872	$ 5,519,587
32	Nonfirm Purchases, Demand and Energy	6,460,728.0	-	6,460,728	-	6,460,728
33	Total Purchased Power Costs	$ 15,605,125	$ (1,000,872)	$ 14,604,253	$ 1,000,872	$ 15,605,125
34	Firm Wheeling Expenses	$ 7,939,635	(102,500)	$ 7,837,135	102,500	$ 7,939,635
35	Non-firm Wheeling Expenses	77,291	-	77,291	-	77,291
36	Total Firm and Non-Firm Wheeling Expenses	$ 8,016,926	$ (102,500)	$ 7,914,426	$ 102,500	$ 8,016,926
37	TOTAL FUEL COSTS & PURCHASED ENERGY	$ 83,633,012	$ (1,103,372)	$ 82,529,640	$ 1,103,372	$ 83,633,012
38	Less:					
39	Non-tariff Sales Fuel Recovery					
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-	-	-
42	City of Mesa (PSA)	2,566,472	-	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,356,004	-	1,356,004	-	1,356,004
44	SRP	12,778,277	-	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921	-	142,921
47	Subtotal	$ 17,939,124	$ -	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:					
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,333,390	$ -	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ 21,523,388	$ -	$ 21,523,388	$ -	$ 21,523,388
52	Total Non-Tariff Sales Fuel Recovery, Energy and Demand	$ 47,856,778	$ -	$ 47,856,778	$ -	$ 47,856,778
53	Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 35,776,234

54 References:
55 Column [A]: Exhibit GEP-9, Page 1, Column [E]
56 Column [B]: Rebuttal Testimony Gary Pierson
57 Column [C]: Column [A] + Column [B]
58 Column [D]: Rebuttal Testimony Gary Pierson

Exhibit GEP-10

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

The following resolution was adopted at a **regular meeting** of the Board of Directors of Arizona Electric Power Cooperative, Inc. (AEPCO), held in Benson, Arizona on July 14, 2004.

RESOLUTION

WHEREAS, *the Management of Arizona Electric Power Cooperative, Inc., (AEPCO) has presented additional information to the Directors which supports and recommends the need to modify the rates and tariffs for generation service in such a manner that will result in an overall increase in AEPCO's annual operating revenue; and*

WHEREAS, *the increase in AEPCO's annual operating revenue is necessary to ensure that AEPCO satisfies its mortgage requirements with the Rural Utilities Service (RUS), maintains a satisfactory level of financial integrity, while simultaneously building cooperative equity; and*

WHEREAS, *Management has prepared and reviewed with the Directors certain financial results culminating in the proposed rates and tariffs which are based on achieving an annual Debt Service Coverage Ratio (DSCR) of 1.05 for the 2003 test year;*

NOW, THEREFORE BE IT RESOLVED, *that the Board of Directors of Arizona Electric Power Cooperative Inc., hereby authorizes Management to file the required schedules, testimony, applications and other items as may be necessary including a request to implement a fuel and purchased energy adjustor with the appropriate regulatory body, including the Arizona Corporation Commission and the Rural Utilities Service, which will effectuate such rates and tariffs resulting in an increase in annual revenues designed to achieve a 2003 test year financial result equal to a DSCR of 1.05; and*

BE IT FURTHER RESOLVED, *that the Board of Directors hereby authorizes the Executive Vice President and Chief Executive Officer, or his designee, to sign or otherwise take any and all necessary actions which may be required to cause the new rates and tariffs to become implemented which are designed to achieve the objective of an annual DSCR of 1.05.*

I, Lyn R. Opalka, do hereby certify that I am Secretary of AEPCO, and that the foregoing is a true and correct copy of the Resolution adopted by the Board of Directors at a **regular meeting** held on July 14, 2004.

Secretary

(seal)

PENGAD-Bayonne, N.J.
EXHIBIT
AEPCo-4
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-04-0528

REBUTTAL TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

MARCH 16, 2005

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REVENUE REQUIREMENTS AND RATES	7

INTRODUCTION

Q. Mr. Pierson, are you the same Gary E. Pierson who sponsored direct testimony for the Arizona Electric Power Cooperative, Inc. ("AEPCO") in this matter?

A. Yes, I am.

Q. Have you reviewed the direct testimony of Staff witnesses Crystal Brown, Barbara Keene, Alejandro Ramirez and Jerry Smith filed February 23, 2005 in this matter?

A. Yes, I have. As Mr. Minson discusses in his testimony, in order to narrow the issues in dispute and reduce complexity, for rebuttal purposes AEPCO accepts all seven of the Rate Base Adjustments proposed by Ms. Brown at pages 8-22 of her testimony. Further, AEPCO accepts nine of the twelve Operating Income Adjustments proposed by Ms. Brown as follows:

Adjustment No 1 – PTY Revenue and Expense	Schedule CSB-13
Adjustment No 3 – Asset Retirement Obligation	Schedule CSB-15
Adjustment No 6 – Transmission Expense Annualization	Schedule CSB-18
Adjustment No 7 – Normalized Legal Expense	Schedule CSB-19
Adjustment No 8 – Fuel Expense	Schedule CSB-20
Adjustment No 9 – Advertising Expense	Schedule CSB-21
Adjustment No 10 – Contributions & Other Expenses	Schedule CSB-22
Adjustment No 11 – ACC Gross Revenue Assessment	Schedule CSB-23
Adjustment No 12 – Interest on Long Term Debt	Schedule CSB-24

Thus, my rebuttal testimony will primarily address the remaining three proposed adjustments:

<u>Operating Income Adjustments</u>

Adjustment No 2 – Revenue and Expense Annualization	Schedule CSB-14
Adjustment No 4 – Tracker Mechanism (Base Power Cost)	Schedule CSB-16
Adjustment No 5 – Overhaul Accrual Expense	Schedule CSB-17

In addition, I am sponsoring Exhibits GEP-2 through GEP-10 in support of AEPCO's rebuttal position in this matter.

RATE BASE – AEPCO REBUTTAL POSITION

Q. Have you reviewed the Staff's testimony on the original cost/fair value rate base for this proceeding?

A. Yes, I have. As I indicated, AEPCO accepts the Staff's proposed rate base of $189,637,810 for purposes of determining its fair value rate base.

OPERATING INCOME – AEPCO REBUTTAL POSITION

Q. Please summarize AEPCO's rebuttal position based upon the Staff's direct testimony.

A. As shown on Exhibits GEP-5, column D and GEP-6, AEPCO proposes test year revenues of $138,951,691 and expenses of $128,494,283. This produces operating margins before interest on long-term debt of $10,457,408 and a net margin loss of $1,235,695. As I'll explain, the test year revenues we propose are $336,455 less than the Staff's position and the expenses are $187,911 greater. Thus, the operating margins before interest on long-term debt and the net margin loss amounts are $524,366 lower in our rebuttal position. The three rebuttal adjustments we propose and my exhibits which explain them are:

Adjustment No 1 – Revenue and Expense Annualization	Exhibit GEP-7
Adjustment No 2 – Overhaul Accrual Expense	Exhibit GEP-8
Adjustment No 3 – Tracker Mechanism (Base Power Cost)	Exhibit GEP-9

Rebuttal Adjustment No. 1 – Revenue and Expense Annualization

Q. Please describe the growth adjustment which is proposed by Ms. Brown to AEPCO's revenues and expenses.

A. Ms. Brown made a growth annualization adjustment in order to achieve a matching of revenues and expenses with the year-end rate base (Brown Testimony, pp. 25-26). Staff

computed the adjustment by applying one-half of the customer load growth percentage of AEPCO's Class A Members or 1.65% to the demand and energy revenues as well as the variable expenses. As a result, Staff proposes an increase in revenues of $1,271,908 and an increase in expenses of $264,376.

Q. Please describe the Company's position on the growth adjustment.

A. We will not object to the concept, but Ms. Brown's adjustment does not take into account the fact that Mohave Electric Cooperative, Inc. ("Mohave") is a partial requirements customer of AEPCO. As such, its customer load growth does not result in increased power deliveries by and increased revenues to AEPCO. Therefore, the adjustment is somewhat overstated due to the inclusion of Mohave's test year customer load growth.

Q. Have you prepared an exhibit which explains AEPCO's rebuttal position?

A. Yes, I have. Exhibit GEP-7 takes Ms. Brown's adjustment, as set forth in her Schedule CSB-14, and modifies it by excluding Mohave's customer growth for 2003 from the calculation of the annualization factor. That decreases the factor from 1.65% to 1.61%. Our adjustment reduces the Staff proposed revenue adjustment by $336,455 and the Staff proposed expense adjustment by $5,658.

Rebuttal Adjustment No. 2 – Overhaul Accrual Expense

Q. Please describe the adjustment which Ms. Brown proposes to overhaul accrual expense at pages 31-32 of her testimony.

A. Staff proposes an adjustment to reflect overhaul accrual expense based upon an eight-year historic average of overhaul cost incurred during the years 1996 through 2003. Staff proposes a reduction of $657,788, which decreases the total expense to $4,129,720.

Q. What is AEPCO's position on this adjustment?

A. While we are confident that our overhaul accruals method is and will be representative of our experience, in order to reduce issues in dispute, we will not object to Staff's alternate approach. However, Ms. Brown's adjustment does not provide an adequate accrual for a Gas Turbine 4 major overhaul. Gas Turbine 4 is a 38 MW aero-derivative combustion turbine that was very recently placed into commercial service in October 2002. Therefore, it was not in service for almost all of the historic 1996-2003 period. In September 2003, it was determined, based upon operating characteristics, that a major overhaul of Gas Turbine 4 will be required in October 2010. Based upon engineering estimates of the cost of that major overhaul, AEPCO began accruing approximately $19,000 per month starting October 2003 based upon the remaining 84 months of the eight-year cycle. However, only $57,354 of expense, as shown on Schedule CSB-17, line 10, would be accrued for a Gas Turbine 4 overhaul based upon Ms. Brown's historic approach. That obviously will not adequately cover the $1.6 million cost of the overhaul.

Q. Have you prepared an adjustment setting forth AEPCO's rebuttal position?

A. Yes, I have. Exhibit GEP-8 takes Ms. Brown's adjustment and modifies it by incorporating an adjustment to recognize the monthly accrual for the Gas Turbine 4 major overhaul which began in the test year. An annual accrual in the amount of $200,738 ($1,605,900/8 years) for Gas Turbine 4 less the amount included in the Staff's adjustment of $7,169 ($57,354/8 years) should be added to Staff's proposed adjustment. As shown on line 16, this increases the Staff proposed adjustment by $193,569.

Rebuttal Adjustment No. 3 – Tracker Mechanism (Base Power Cost)

Q. Please describe Ms. Brown's adjustment in relation to AEPCO's Base Power Cost at pages 29-30 of her testimony.

A. Ms. Brown takes AEPCO's filed position on the base cost of power of $41,276,155 and reduces it by $7,716,227 which lowers the adjustor base rate from $0.02038/kWh to $0.01657/kWh.

Q. Please describe the Company's position on the adjustments contained in Schedule CSB-16.

A. The company accepts the fuel expense adjustment that Ms. Brown made to column B, l. 11 of Schedule CSB-16, but does not accept the purchased power adjustment set forth in column B, l. 27. The Staff adjustment "annualizing savings from a new contract that was in effect for only half of the test year" is not a reduction in the purchased power energy costs of the Public Service Company of New Mexico ("PNM") (Direct Testimony of Ms. Brown, p. 30, ll. 21-22). Rather, the adjustment is an annualization of the payment for a 2 MW contract demand reduction in the AEPCO/PNM contract. Therefore, it should not be deducted from the purchased power energy costs of PNM. To clarify, we agree with Staff's proposed adjustment of $250,000, but the adjustment should be made against purchased power demand costs, not purchased power energy costs. In addition to the fuel expense and purchased power adjustment, Ms. Brown has also made adjustments to add certain fixed fuel costs, purchased/demand costs, firm wheeling expenses and credits for non-tariff sales fuel recovery/demand based upon the recommendations of Ms. Keene. AEPCO agrees to including the gas reservation charges, demand charges for purchased power, firm wheeling costs and certain credits for non-tariff sales fuel recovery. But, as explained in Mr. Minson's rebuttal testimony, AEPCO does not agree that revenue credits reflecting the margins on economy energy sales should be included in the determination of the base power cost and adjustor base rate.

Q. Have you prepared an adjustment setting forth this position?

A. Yes, I have. Exhibit GEP-9, page 1 makes certain adjustments to Ms. Brown's Schedule CSB-16 to reflect our rebuttal position. Column [D] sets forth these rebuttal adjustments. On line 5, test year sales are adjusted to reflect the energy billing units associated with the revenue annualization that the Company proposed in Schedule GEP-6. Line 27 removes the Staff adjustment to reduce PNM purchased power energy costs that should be made instead to PNM purchased power demand costs. Line 31 correspondingly adds the Staff adjustment to reduce PNM purchased power demand costs. Line 51 removes the $2,215,834 in margins associated with economy energy sales from the Staff adjustment for the non-tariff demand related revenues. As a result of these adjustments, the base cost of power should be $35,776,234, which translates to an adjustor base of $0.01748/kWh as shown on line 6, page 2 of Exhibit GEP-9.

Q. Are there any further modifications to the base power costs determination that AEPCO is proposing?

A. Yes. There are certain purchased demand costs and wheeling costs that are applicable to our all-requirements members, but are not applicable to our partial-requirements member Mohave. These costs represent purchased capacity charges and associated wheeling expenses for the Panda Gila River purchased power agreement that Mohave elected not to participate in. These costs have been excluded from the calculation of Mohave's fixed charge and operations and maintenance rate and should be excluded as well from Mohave's base cost of power. Page 2, line 6 of Exhibit GEP-9 shows this differential calculation of the base power cost for the all-requirement and partial-requirement members. Therefore, AEPCO recommends that the all-requirements adjustor base be set at $0.01777/kWh and that the partial-requirements adjustor base be set at $0.01694/kWh.

1 **REBUTTAL POSITION – REVENUE REQUIREMENTS AND RATES**

2 Q. Please state the Company's rebuttal position on revenue requirements and rates.

3 A. The Board of Directors instructed AEPCO to seek Commission approval for revised rates
4 designed to achieve a 2003 test year result equal to a Debt Service Coverage Ratio
5 ("DSCR") of 1.05. A copy of this resolution, adopted on July 14, 2004, is attached as
6 Exhibit GEP-10. The Board of Directors determined that this level of increase was
7 necessary to ensure that AEPCO satisfies its mortgage requirements and maintains a
8 satisfactory level of financial integrity while simultaneously building cooperative equity.
9 As Mr. Ramirez notes in his testimony at page 2, the Staff's minimum recommended
10 operating income would produce a DSCR of only .91, which is below RUS minimum
11 requirement. We agree with his statements at page 7 of his testimony that this level of
12 revenue would not be sufficient to service current debt, build equity or support new debt
13 financing. Therefore, applying the 1.05 DSCR to AEPCO's proposed test year revenues of
14 $138,951,691, expenses of $128,494,283, operating margins before interest on long-term
15 debt of $10,457,408 and the net margin loss of $1,235,695, operating revenues should be
16 increased by $9,446,032 as shown in column E, Exhibit GEP-5.

17 Q. Have you prepared exhibits which summarize AEPCO's rebuttal position?

18 A. Yes. Exhibit GEP-2 sets forth AEPCO's rebuttal position in column [C]. We request
19 that the Commission enter its order approving an increase of $9,446,032 in operating
20 revenue and a rate of return of 10.50% on the fair value rate base of $189,637,810.
21 Exhibit GEP-3 is the rate base summary. Exhibit GEP-4 sets forth the proposed rates
22 based on AEPCO's rebuttal position in column [C]. Exhibit GEP-5 summarizes

1 Operating Income – Test Year. Finally, Exhibit GEP-6 sets forth our rebuttal adjustments
2 to the Staff's Test Year – As Adjusted.
3 Q. Why are the rebuttal rates requested in column C of Exhibit GEP-4 higher than those
4 originally requested in AEPCO's filing?
5 A. Primarily because in preparing our original schedules, the fourth quarter 2003 test year
6 debt principle payment in the approximate amount of $2.2 million was overlooked.
7 AEPCO had attempted to make the payment on December 31, 2003, but the wire transfer
8 to the U.S. Treasury failed. It was successfully made on the first business day of 2004,
9 but several months later when the rate case schedules were being prepared, the fact that
10 the payment was attributable to the 2003 test year was overlooked. Taking this payment
11 into account, the original rate request should have been approximately $2.3 million higher
12 to cover the principle payment and the 1.05 DSCR associated with it.
13 Q. How was this omission discovered?
14 A. We learned of it in early January 2005 while researching the answer to a Staff data
15 request. We promptly advised Staff of the situation. In February, we also discussed the
16 matter and the fact that the original rate request should have been higher with the AEPCO
17 Board of Directors.
18 Q. Does this conclude your rebuttal testimony?
19 A. Yes, it does.
20 10421-36/1257424

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-2

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL FILING	[B] STAFF DIRECT POSITION	[C] COMPANY REBUTTAL POSITION
1	Adjusted Operating Income (Loss)	$ 7,972,676	$ 10,981,774	$ 10,457,408
2	Depreciation and Amortization	$ 7,608,735	$ 7,539,289	$ 7,539,289
3	Income Tax Expense	-	-	-
4	Long-term Interest Expense	$ 13,547,749	$ 13,313,164	$ 13,313,164
5	Principal Repayment	$ 10,344,950	$ 14,360,494	$ 14,360,494
6a	Recommended Increase in Operating Revenue	$ 8,450,016	$ 6,773,320	$ 9,446,032
6b	Percent Increase (Line 6a / Line 7b) - Per Staff	N/A	4.86%	6.80%
6c	Percent Increase (Line 6a / Line 7a) - Per Coop	9.86%	7.80%	10.92%
7a	Adjusted Class A Member Revenue	$ 85,685,624	$ 86,810,386	$ 86,473,931
7b	Adjusted Test Year Operating Revenue	$ 137,611,450	$ 139,288,146	$ 138,951,691
8	Recommended Annual Operating Revenue	$ 146,061,466	$ 146,061,466	$ 148,397,723
9a	Recommended Operating Margin Before Interest	$ 16,422,692	$ 17,755,094	$ 19,903,440
9b	Recommended Margins(Loss) After Interest	$ 1,959,955	$ 4,099,540	$ 6,247,886
9c	Recommended Net Margin	$ 3,922,406	$ 6,061,991	$ 8,210,337
10a	Staff TIER (L3+L9a)/L4 - Per Staff	N/A	1.33	1.50
10b	TIER (L9c+L4)/L4 - Per Coop (RUS Definition)	1.29	1.46	1.62
11a	Staff DSC (L2+L3+L9b)/(L4+L5) - Per Staff	N/A	0.91	0.99
11b	DSC (L2+L4+L9c)/(L4+L5) - Per Coop (RUS Definition)	1.05	0.97	1.05
12	Adjusted Rate Base	$ 222,147,011	$ 189,637,810	$ 189,637,810
13	Rate of Return (L9a / L12)	7.39%	9.36%	10.50%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules CSB-2, CSB-11, Testimony Alejandro Ramirez
Column [C]: Exhibits GEP-3, GEP-5

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-3**
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[C] STAFF DIRECT POSITION	[C] COMPANY REBUTTAL POSITION
1	Plant in Service	$ 389,603,749	$ 377,675,263	$ 377,675,263
2	Less: Acc Depreciation & Amortization	(186,190,519)	(185,936,636)	(185,936,636)
3	Net Plant in Service	203,413,230	191,738,627	191,738,627
	LESS:			
4	Advances in Aid of Construction (AIAC)	-	-	-
5	Contributions in Aid of Construction (CIAC)	-	-	-
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	-	-	-
9	Member Advances	-	(11,982,081)	(11,982,081)
	ADD:			
10	Working Capital	16,778,408	9,881,264	9,881,264
11	Plant Held for Future Use	-	-	-
12	Deferred Debits	1,955,373	-	-
13	Total Rate Base	$ 222,147,011	$ 189,637,810	$ 189,637,810

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Staff Schedule CSB-2, Column C
Column [C]: Rebuttal Testimony Gary Pierson

Arizona Electric Power Cooperative, Inc.

Exhibit GEP-4

Docket No. E-01773A-04-0528

Test Year Ended December 31, 2003

SUMMARY OF PROPOSED RATES

Line No.	Description	[A] Company Original Filing	[B] Staff Direct Position	[C] Company Rebuttal Position
1	All Requirements Members:			
2	Demand Rate - $/kW Month	$ 13.79	$ 12.90	$ 13.98
3	Energy Rate - $/kWh	$ 0.02071	$ 0.02079	$ 0.02073
4	Power Cost Adjustor Base - $/kWh	$ 0.02038	$ 0.01657	$ 0.01777
5	Partial Requirements Members:			
6	Fixed Charge - $/Month	$ 705,795	$ 707,392	$ 761,245
7	O&M Rate - $/kW Month	$ 7.25	$ 7.48	$ 7.07
8	Energy Rate - $/kWh	$ 0.02071	$ 0.02079	$ 0.02073
9	Power Cost Adjustor Base - $/kWh	$ 0.02038	$ 0.01657	$ 0.01694
10	Proposed Revenue Increase - ($000's):			
11	Anza	$ 147.9	$ 79.4	$ 167.5
12	Duncan Valley	90.1	47.5	101.2
13	Graham County	470.8	246.9	527.0
14	Mohave	4,001.3	4,421.2	4,432.9
15	Sulphur Springs	2,148.5	1,158.0	2,415.0
16	Trico	1,591.4	826.9	1,802.4
17	Total Class A	$ 8,450.0	$ 6,779.9	$ 9,446.0
18	Proposed Revenue Increase - Percent:			
19	Anza	7.73%	4.08%	8.60%
20	Duncan Valley	7.77%	4.07%	8.64%
21	Graham County	7.82%	4.07%	8.69%
22	Mohave	14.00%	15.30%	15.53%
23	Sulphur Springs	7.69%	4.09%	8.52%
24	Trico	7.94%	4.05%	8.83%
25	Total Class A	9.86%	7.81%	10.92%

References:

Column A - Company Original Filing, Schedules G2A & H-2

Column B - Staff Witness Keene Testimony and Workpapers

Column C - Gary Pierson Rebuttal Testimony and Workpapers

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-5

OPERATING INCOME - TEST YEAR, STAFF ADJUSTED AND COMPANY PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR AS ADJUSTED	[C] COMPANY REBUTTAL TEST YEAR ADJUSTMENTS	[D] COMPANY REBUTTAL TEST YEAR AS ADJUSTED	[E] COMPANY REBUTTAL PROPOSED CHANGES	[F] COMPANY REBUTTAL RECOMMENDED
	REVENUES:						
1	Class A Members, Non-Base Cost of Power Revenue	$ 44,409,469	$ 37,818,004	$ 12,879,693	$ 50,697,697	$ 9,446,032	$ 60,143,729
2	Class A Members, Base Cost of Power Revenue	41,276,155	48,992,382	(13,216,148)	35,776,234		35,776,234
3	Total Class A Member Electric Revenue	85,685,624	86,810,386	(336,455)	86,473,931	9,446,032	95,919,963
4	Non-Class A, Non-Firm, & Non-Member	50,444,504	50,996,438	-	50,996,438	-	50,996,438
5	Total Electric Revenue	136,130,128	137,806,824	(336,455)	137,470,369	9,446,032	146,916,401
6	Other Operating Revenue	1,481,322	1,481,322	-	1,481,322	-	1,481,322
7	Total Revenues	137,611,450	139,288,146	(336,455)	138,951,691	9,446,032	148,397,723
	EXPENSES:						
8	Operations - Production, Fuel	59,803,425	59,014,728	(264,376)	58,750,352	-	58,750,352
9	Operations - Production, Steam	8,764,555	8,764,555	258,718	9,023,273	-	9,023,273
10	Operations - Production, Other	1,335,333	1,743,316	-	1,743,316	-	1,743,316
11	Operations - Other Pwr Supply, Demand	5,769,587	5,769,587	(250,000)	5,519,587	-	5,519,587
12	Operations - Other Pwr Supply - Energy	12,420,888	12,170,888	250,000	12,420,888	-	12,420,888
13	Operations - Transmission	8,036,486	8,036,486	-	8,036,486	-	8,036,486
14	Operations - Administrative and General	9,191,902	9,525,759	-	9,525,759	-	9,525,759
15	Maintenance - Production, Steam	10,170,045	9,512,258	193,569	9,705,827	-	9,705,827
16	Maintenance - Production, Other	2,809,881	2,809,881	-	2,809,881	-	2,809,881
17	Maintenance - Transmission	28,388	8,828	-	8,828	-	8,828
18	Maintenance - General Plant	63,958	63,958	-	63,958	-	63,958
19	Depreciation and Amortization	7,608,735	7,539,289	-	7,539,289	-	7,539,289
20	ACC Gross Revenue Taxes	288,752	-	-	-	-	-
21	Taxes	3,346,839	3,346,839	-	3,346,839	-	3,346,839
22	Total Operating Expenses	129,638,774	128,306,372	187,911	128,494,283	-	128,494,283
23	Operating Margin Before Interest on L.T.- Debt	7,972,676	10,981,774	(524,366)	10,457,408	9,446,032	19,903,440
24	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS:***						
25	Interest on Long-term Debt	13,547,749	13,313,164	-	13,313,164	-	13,313,164
26	Other Interest & Other Deductions	914,988	342,390	-	342,390	-	342,390
27	Total Interest & Other Deductions	14,462,737	13,655,554	-	13,655,554	-	13,655,554
28	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	(6,490,061)	(2,673,780)	(524,366)	(3,198,146)	9,446,032	6,247,886
29	***NON-OPERATING MARGINS***						
30	Interest Income	582,014	582,014	-	582,014	-	582,014
31	Other Non-operating Income	1,380,437	1,380,437	-	1,380,437	-	1,380,437
32	Total Non-Operating Margins	1,962,451	1,962,451	-	1,962,451	-	1,962,451
33	***EXTRAORDINARY ITEMS***	-	-	-	-	-	-
34	***NET MARGINS (LOSS)***	$ (4,527,610)	$ (711,329)	$ (524,366)	$ (1,235,695)	$ 9,446,032	$ 8,210,337

35 References:
36 Column [A]: Cooperative Schedule C-1, Pages 1 and 2
37 Column [B]: Schedule CSB-11, Column C
38 Column [C]: Exhibit GEP-5

References:
Column [D]: Column [B] + Column [C]
Column [E]: Exhibit GEP-2
Column [F]: Column [D] + Column [E]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-6

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] STAFF TEST YEAR AS Adjusted	[B] ADJ #1 Revenue and Expense Annualizations Ref: Sch GEP-7	[C] ADJ #2 Overhaul Accrual Expense Ref: Sch GEP-8	[D] ADJ #3 Tracker Mechanism (Base Power Cost) Ref: Sch GEP-9	[E] COMPANY REBUTTAL AS ADJUSTED
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 37,818,004	$ (336,455)	$ -	$ 13,216,148	$ 50,697,697
2	Class A Members, Base Cost of Power Revenue	48,992,382	-	-	(13,216,148)	35,776,234
3	Total Class A Member Electric Revenue	86,810,386	(336,455)	-	-	86,473,931
4	Non-Class A, Non-Firm, & Non-Member	50,996,438	-	-	-	50,996,438
5	Total Electric Revenue	137,806,824	(336,455)	-	-	137,470,369
6	Other Operating Revenue	1,481,322	-	-	-	1,481,322
7	Total Revenues	139,288,146	(336,455)	-	-	138,951,691
8	*OPERATING EXPENSES:*					
9	Operations - Production, Fuel	59,014,728	(264,376)	-	-	58,750,352
10	Operations - Production, Steam	8,764,555 [1]	258,718	-	-	9,023,273
11	Operations - Production, Other	1,743,316 [2]		-	-	1,743,316
12	Operations - Other Pwr Supply, Demand	5,769,587	-	-	(250,000)	5,519,587
13	Operations - Other Pwr Supply - Energy	12,170,888 [3]	-	-	250,000	12,420,888
14	Operations - Transmission	8,036,486	-	-	-	8,036,486
15	Operations - Administrative and General	9,525,759	-	-	-	9,525,759
16	Maintenance - Production, Steam	9,512,258 [4]	-	193,569	-	9,705,827
17	Maintenance - Production, Other	2,809,881	-	-	-	2,809,881
18	Maintenance - Transmission	8,828	-	-	-	8,828
19	Maintenance - General Plant	63,958	-	-	-	63,958
20	Depreciation and Amortization	7,539,289	-	-	-	7,539,289
21	ACC Gross Revenue Taxes	-	-	-	-	-
22	Taxes	3,346,839	-	-	-	3,346,839
23	Total Operating Expenses	128,306,372	(5,658)	193,569	-	128,494,283
24	Operating Margin Before Interest on L.T.- Debt	10,981,774	(330,797)	(193,569)	-	10,457,408
25	*INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS*					
26	Interest on Long-term Debt	13,313,164	-	-	-	13,313,164
27	Other Interest & Other Deductions	342,390	-	-	-	342,390
28	Total Interest & Other Deductions	13,655,554	-	-	-	13,655,554
29	*MARGINS (LOSS) AFTER INTEREST EXPENSE*	(2,673,780)	(330,797)	(193,569)	-	(3,198,146)
30	*NON-OPERATING MARGINS*					
31	Interest Income	582,014	-	-	-	582,014
32	Other Non-operating Income	1,380,437	-	-	-	1,380,437
33	Total Non-Operating Margins	1,962,451	-	-	-	1,962,451
34	*EXTRAORDINARY ITEMS*	-	-	-	-	-
35	*NET MARGINS (LOSS)*	$ (711,329)	$ (330,797)	$ (193,569)	$ -	$ (1,235,695)

Footnote Explanations

[1] Includes account nos. 500, 5 includes account nos. 555 to 557

[2] Includes account nos. 546, 5 includes account nos. 510 to 515

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-7**
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 1 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY REBUTTAL ADJUSTMENTS	[C] COMPANY REBUTTAL AS ADJUSTED
1	Class A Member Demand Revenues	$ 36,990,731	$ 6,922,455	$ 30,068,276
2	Class A Member Energy Revenues	$ 40,285,075	$ 14,260,705	$ 26,024,370
3	Class A Member ACC Assessment Rev	$ -	$ -	$ -
4	Class A Member Fixed Charge Revenues	$ -	$ -	$ -
5	Total Class A Member Base Rate Revenues	$ 77,275,806	$ 21,183,160	$ 56,092,646
6	Factor to Annualize Revenues to End of Test Year	1.65%		1.67%
7	Revenue Annualization Adjustment	$ 1,271,908	$ (336,455)	$ 935,453
8	Variable Expenses Not Recovered Through Fuel Adj	$ -		$ 16,062,410
9	Factor to Annualize Revenues to End of Test Year	1.65%		1.61%
10	Adjustment to Expenses	$ 264,376	$ (5,658)	$ 258,718

	Calculation of Annualization Factor						
	Number of Customers						
	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
2002	3,702	2,446	7,481	N/A	43,113	27,631	84,373
2003	3,824	2,484	7,623	N/A	44,431	28,729	87,091
Increase	122	38	142	N/A	1,318	1,098	2,718
% Increase	3.30%	1.55%	1.90%	0.00%	3.06%	3.97%	3.22%
2003 Growth Rate							3.22%
Annualization Factor - 2003 Growth Rate divided by 2							
	1.65%	0.78%	0.95%	0.00%	1.53%	1.99%	1.61%

Calculation of Variable Expenses Not Recovered Through Fuel Adjustor			
Account No.	Description	Amount	
500	Operation Supervision and Engineering	$ 1,999,908	
501&547	Fuel - Steam Power & Other	$ 59,803,425	
502	Steam Expenses	$ 2,710,803	
505	Electric Expenses	$ 1,437,524	
510	Maintenance Supervision & Engineering	$ 840,774	
512	Maintenance of Boiler Plant	$ 6,433,681	
513	Maintenance of Electric Plant	$ 264,759	
514	Maintenance of Miscellaneous Steam Plant	$ 2,374,961	
555	Purchased Power - Demand	$ 5,769,587	
555	Purchased Power - Energy	$ 10,085,538	
	Total Variable Expenses	$ 91,720,960	
501&547	Fuel - Steam Power & Other	$ (59,803,425)	Recovered through Fuel Adj
555	Purchased Power - Demand	$ (5,769,587)	Recovered through Fuel Adj
555	Purchased Power - Energy	$ (10,085,538)	Recovered through Fuel Adj
		$ 16,062,410	
	2003 Growth Rate	1.61%	
	Adjustment to Expenses	$ 258,718	

<u>References:</u>
Column A: Cooperative Data Request Response CSB 6-1
Column B: Testimony, CSB
Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc. **Exhibit GEP-8**
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 3 - OVERHAUL ACCRUAL EXPENSE

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY REBUTTAL ADJUSTMENTS	[C] COMPANY REBUTTAL AS ADJUSTED
1	Overhaul Accrual Expense	$4,129,720	$ 193,569	$ 4,323,289

2		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 57,354	$ 3,206,259
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 57,354	$ 33,037,763
12								Divided by	8
13									$ 4,129,720

13	ADJUSTMENT TO ANNUALIZE GT4 OVERHAUL ACCRUALS	
14	ANNUAL GT4 MAJOR OVERHAUL ACCRUAL - $1,605,900 / 8 YEARS =	$ 200,738
15	LESS: AMOUNT INCLUDED IN TOTAL, LINE 10 - $57,354 / 8 YEARS=	7,169
16	ADDITIONAL GT4 ACCRUAL	193,569
17		$ 4,323,289
18		

19 * Per response to CSB 1-38, there has been no actual overhaul expense
20 for generating GT2 for the period 1990 to 2004.

21 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.

22 <u>References:</u>

23 Column A: Staff Exhibit CSB -17, Column C
24 Column B: Gary Pierson Rebuttal Testimony
25 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED	[D] COMPANY REBUTTAL ADJUSTMENTS	[E] COMPANY REBUTTAL AS ADJUSTED
1	Base Cost of Power Revenue					
2	Test Year Sales (In kWhs)	2,025,326,533	-	2,025,326,533	-	2,025,326,533
3	Base Cost of Power (Col A, per Dec 58405)	$ 0.01714	$ 0.00324	$ 0.02038	$ (0.00381)	$ 0.01657
4	Adjustment to match Coop proposed power expense to revenue	$ 34,714,097	$ 6,562,058	$ 41,276,155	$ (7,715,755)	$ 33,560,400
5	Test Year Sales (In kWhs)	2,025,326,533		2,025,326,533	21,063,927	2,046,390,460
6	Base Cost of Power (Col C, Line 53/Line 5)	$ 0.02038	$ (0.00381)	$ 0.01657	$ 0.00091	$ 0.01748
7	Adjustment to reflect Staff's adjustments to power costs	$ 41,276,627	$ (7,716,227)	$ 33,560,400	$ 2,215,834	$ 35,776,234
8	Total	$ 34,714,097	$ (1,153,697)	$ 33,560,400	$ 2,215,834	$ 35,776,234
9	Base Cost of Power Expense					
10	Coal Fired Steam Plant Costs:					
11	Fuel, Coal ($1,534,274 Coop Adj No. 5 - $1,030,873 legal exp)	$ 42,029,531	$ 503,401	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-	-	-
14	Less: Fixed Fuel Costs	(549,137)	253,272	(295,865)	-	(295,865)
15	Subtotal	$ 43,789,748	$ 756,673	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:					
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809	-	9,809
19	Less: Fixed Fuel Costs	(1,435,208)	1,435,208	-	-	-
20	Subtotal	$ 14,029,332	$ 1,435,208	$ 15,464,540	$ -	$ 15,464,540
21	Total Fuel Costs	$ 57,819,080	$ 2,191,881	$ 60,010,961	$ -	$ 60,010,961
22	Purchased Power Energy Costs					
23	Firm Purchases					
24	CRSP	$ 309,547	$ -	$ 309,547	$ -	$ 309,547
25	PacifiCorp	-	-	-	-	-
26	Parker Davis	217,629	-	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061	(250,000)	1,713,061	250,000	1,963,061
28	Panda Gila River	1,134,573	-	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-	-	-
30	Subtotal Firm Purchases	$ 3,624,810	$ (250,000)	$ 3,374,810	$ 250,000	$ 3,624,810
31	Firm Purchases, Demand	$ -	5,769,587	$ 5,769,587	(250,000)	5,519,587
32	Nonfirm Purchases, Demand and Energy	6,460,728	-	6,460,728	-	6,460,728
33	Total Purchased Power Costs	$ 10,085,538	$ 5,519,587	$ 15,605,125	$ -	$ 15,605,125
34	Firm Wheeling Expenses	$ -	7,939,635	$ 7,939,635	-	$ 7,939,635
35	Non-firm Wheeling Expenses	77,291	-	77,291	-	77,291
36	Total Firm and Non-Firm Wheeling Expenses	$ 77,291	$ 7,939,635	$ 8,016,926	$ -	$ 8,016,926
37	TOTAL FUEL COSTS & PURCHASED ENERGY	$ 67,981,909	$ 15,651,103	$ 83,633,012	$ -	$ 83,633,012
38	Less:					
39	Non-tariff Sales Fuel Recovery					
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-	-	-
42	City of Mesa (PSA)	2,657,351	(90,879)	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,376,189	(20,185)	1,356,004	-	1,356,004
44	SRP	13,039,105	(260,828)	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921	-	142,921
47	Subtotal	$ 18,311,016	$ (371,892)	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:					
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,705,282	$ (371,892)	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ -	$ 23,739,222	$ 23,739,222	$ (2,215,834)	$ 21,523,388
52	Total Non-Tariff Sales Fuel Recovery, Energy and Demand	$ 26,705,282	$ 23,367,330	$ 50,072,612	$ (2,215,834)	$ 47,856,778
53	Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)	$ 41,276,627	$ (7,716,227)	$ 33,560,400	$ 2,215,834	$ 35,776,234

54 References:
55 Column [A]: Cooperative Application Schedule H-2A
56 Column [B]: Testimony Crystal Brown
57 Column [C]: Column [A] + Column [B]
57 Column [D] - Rebuttal Testimony Gary Pierson
57 Column [E]: Column [C] + Column [D]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REBUTTAL ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY REBUTTAL AS ADJUSTED	[B] LESS: ALL-REQ. COST ADJUSTMENTS	[C] BASE REQ. ADJUSTOR BASE CALCULATION	[D] PLUS: ALL-REQ..COST ADJUSTMENTS	[E] POWER COST ADJUSTOR BASE CALCULATION
1	Partial Requirements Customers:					
2	Test Year Sales (In kWhs)					716,978,668
3	Base Cost of Power - $/kWh					$ 0.01694
4	Base Cost of Power					$ 12,148,074
	All Requirements Customers:					
5	Test Year Sales (In kWhs)	2,046,390,460	-	2,046,390,460		1,329,411,792
6	Base Cost of Power - $/kWh	$ 0.01748	$ (0.00054)	$ 0.01694	$ 0.00083	$ 0.01777
7	Base Cost of Power	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 23,628,160
8	Total Base Cost of Power	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 35,776,234
9	Base Cost of Power Expense					
10	Coal Fired Steam Plant Costs:					
11	Fuel, Coal	$ 42,532,932	$ -	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-	-	-
14	Less: Fixed Fuel Costs	(295,865)	-	(295,865)	-	(295,865)
15	Subtotal	$ 44,546,421	$ -	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:					
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809	-	9,809
19	Less: Fixed Fuel Costs	-	-	-	-	-
20	Subtotal	$ 15,464,540	$ -	$ 15,464,540	$ -	$ 15,464,540
21	Total Fuel Costs	$ 60,010,961	$ -	$ 60,010,961	$ -	$ 60,010,961
22	Purchased Power Energy Costs					
23	Firm Purchases					
24	CRSP	$ 309,547	$ -	$ 309,547	$ -	$ 309,547
25	PacifiCorp	-	-	-	-	-
26	Parker Davis	217,629.00	-	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061.00	-	1,963,061	-	1,963,061
28	Panda Gila River	1,134,573.00	-	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-	-	-
30	Subtotal Firm Purchases	$ 3,624,810	$ -	$ 3,624,810	$ -	$ 3,624,810
31	Firm Purchases, Demand	5,519,587	(1,000,872)	$ 4,518,715	1,000,872	$ 5,519,587
32	Nonfirm Purchases, Demand and Energy	6,460,728.0	-	6,460,728	-	6,460,728
33	Total Purchased Power Costs	$ 15,605,125	$ (1,000,872)	$ 14,604,253	$ 1,000,872	$ 15,605,125
34	Firm Wheeling Expenses	$ 7,939,635	(102,500)	$ 7,837,135	102,500	$ 7,939,635
35	Non-firm Wheeling Expenses	77,291	-	77,291	-	77,291
36	Total Firm and Non-Firm Wheeling Expenses	$ 8,016,926	$ (102,500)	$ 7,914,426	$ 102,500	$ 8,016,926
37	TOTAL FUEL COSTS & PURCHASED ENERGY	$ 83,633,012	$ (1,103,372)	$ 82,529,640	$ 1,103,372	$ 83,633,012
38	Less:					
39	Non-tariff Sales Fuel Recovery					
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-	-	-
42	City of Mesa (PSA)	2,566,472	-	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,356,004	-	1,356,004	-	1,356,004
44	SRP	12,778,277	-	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921	-	142,921
47	Subtotal	$ 17,939,124	$ -	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:					
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,333,390	$ -	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ 21,523,388	$ -	$ 21,523,388	$ -	$ 21,523,388
52	Total Non-Tariff Sales Fuel Recovery, Energy and Demand	$ 47,856,778	$ -	$ 47,856,778	$ -	$ 47,856,778
53	Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)	$ 35,776,234	$ (1,103,372)	$ 34,672,862	$ 1,103,372	$ 35,776,234

54 References:
55 Column [A]: Exhibit GEP-9, Page 1, Column [E]
56 Column [B]: Rebuttal Testimony Gary Pierson
57 Column [C]: Column [A] + Column [B]
58 Column [D]: Rebuttal Testimony Gary Pierson

Exhibit GEP-10

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

The following resolution was adopted at a **regular meeting** of the Board of Directors of Arizona Electric Power Cooperative, Inc. (AEPCO), held in Benson, Arizona on July 14, 2004.

RESOLUTION

***WHEREAS**, the Management of Arizona Electric Power Cooperative, Inc., (AEPCO) has presented additional information to the Directors which supports and recommends the need to modify the rates and tariffs for generation service in such a manner that will result in an overall increase in AEPCO's annual operating revenue; and*

***WHEREAS**, the increase in AEPCO's annual operating revenue is necessary to ensure that AEPCO satisfies its mortgage requirements with the Rural Utilities Service (RUS), maintains a satisfactory level of financial integrity, while simultaneously building cooperative equity; and*

***WHEREAS**, Management has prepared and reviewed with the Directors certain financial results culminating in the proposed rates and tariffs which are based on achieving an annual Debt Service Coverage Ratio (DSCR) of 1.05 for the 2003 test year;*

***NOW, THEREFORE BE IT RESOLVED**, that the Board of Directors of Arizona Electric Power Cooperative Inc., hereby authorizes Management to file the required schedules, testimony, applications and other items as may be necessary including a request to implement a fuel and purchased energy adjustor with the appropriate regulatory body, including the Arizona Corporation Commission and the Rural Utilities Service, which will effectuate such rates and tariffs resulting in an increase in annual revenues designed to achieve a 2003 test year financial result equal to a DSCR of 1.05; and*

***BE IT FURTHER RESOLVED**, that the Board of Directors hereby authorizes the Executive Vice President and Chief Executive Officer, or his designee, to sign or otherwise take any and all necessary actions which may be required to cause the new rates and tariffs to become implemented which are designed to achieve the objective of an annual DSCR of 1.05.*

I, Lyn R. Opalka, do hereby certify that I am Secretary of AEPCO, and that the foregoing is a true and correct copy of the Resolution adopted by the Board of Directors at a **regular meeting** held on July 14, 2004.

Secretary

(seal)

PENGAD-Bayonne, N.J.
EXHIBIT
AEPCO-5
ADMITTED

DIRECT TESTIMONY AND EXHIBITS

OF

STEPHEN PAGE DANIEL

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

July, 2004

BEFORE THE
ARIZONA CORPORATION COMMISSION

Direct Testimony And Exhibits
Of
Stephen Page Daniel

On Behalf Of
Arizona Electric Power Cooperative, Inc.

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen Page Daniel. My business address is 1850 Parkway Place, Suite 800, Marietta, Georgia 30067.

Q. By whom are you employed and in what capacity?

A. I am Executive Vice President and a founding principal of GDS Associates, Inc. ("GDS Associates"), a multi-disciplined engineering and consulting firm.

Q. Please outline your formal education.

A. I received a Bachelor of Industrial Engineering degree from Georgia Institute of Technology in 1970. I received a Master of Business Administration degree with a major in finance from Georgia State University in 1978.

Q. To what professional organizations do you belong?

A. I am a member of the Institute of Electrical and Electronics Engineers.

Q. What are your duties and responsibilities with GDS Associates?

A. My primary responsibilities involve providing rate and regulatory services related to electric utility industry matters and consulting services with regard to electric system power

1 supply planning, including strategic planning for transmission resources and access and electric
2 industry restructuring/deregulation matters.

3 **Q. Please briefly describe your professional experience.**

4 A. Prior to founding GDS Associates in early 1986, I worked for approximately fifteen (15)
5 years with another consulting engineering firm. During that time, my positions and
6 responsibilities changed from initially a rate analyst to Assistant Vice President, Rate and
7 Analytical Services.

8 As an engineering consultant over the last thirty-four (34) years, I have had primary
9 responsibility for assignments pertaining to wholesale rates, retail rates, financial planning,
10 power supply planning for electric utilities, transmission access, and electric industry
11 restructuring/deregulation policy development and implementation. My various assignments
12 have been on behalf of more than one hundred and seventy-five (175) cooperative and municipal
13 electric systems, several industrial clients, several investor-owned utilities, and several
14 regulatory commissions in thirty-six (36) states. My responsibilities have included the
15 preparation of allocated cost-of-service studies, retail and wholesale rate design studies, financial
16 forecasts, revenue requirements evaluations, and analyses of alternative power supply resources.

17 I also have analyzed cost-of-service studies filed by others with the Federal Energy
18 Regulatory Commission and various state regulatory commissions.

19 My responsibilities also have included assignments in the specialized areas of rate design
20 for unusual loads, evaluation of financing alternatives, acquisition and merger feasibility and
21 market power related issues, and regulatory rulemaking.

22 I have attached a copy of my current resume as Exhibit SPD-1 for further reference to my
23 professional experience.

Q. Have you previously testified before regulatory commissions?

A. Yes. I have testified before numerous state utility commissions, including the Arizona Corporation Commission ("Commission" or "ACC"). I also have testified before the Federal Energy Regulatory Commission ("FERC") in numerous cases.

Q. Have you testified as an expert in court proceedings?

A. Yes. I have testified or filed affidavits in Federal District Courts, Federal Bankruptcy Courts, the Supreme Court of the State of New York and several other state courts.

Q. On whose behalf are you appearing in this proceeding?

A. The Arizona Electric Power Cooperative, Inc. ("AEPCO").

Q. Have you previously provided consulting services to AEPCO?

A. Yes. I have provided revenue requirements, allocated cost-of-service, rate design and other services to AEPCO on many occasions since the mid-1970s.

Q. Are you familiar with AEPCO's resources, cost structure and operations as they have evolved over the years?

A. Yes.

II. NATURE AND PURPOSE OF TESTIMONY

Q. What was your firm retained to do in support of AEPCO's rate filing in this proceeding?

A. GDS was asked to analyze the AEPCO system, including its relevant characteristics, for the purpose of determining the appropriate demand cost allocation methodology to be used to allocate AEPCO's power supply fixed costs to its Class A Members. The recommended demand allocation methodology was to be used to support the fully allocated embedded cost-of-service study to be filed by AEPCO as part of its rate request.

Q. Did your firm prepare an analysis and report documenting the recommended demand cost allocation methodology for AEPCO?

A. Yes. That study is attached as Exhibit SPD-2.

Q. Was this study prepared by you or under your supervision?

A. Yes.

Q. What types of information did you examine in preparing the demand cost allocation analysis?

A. I reviewed various information such as the following:

- Historical AEPCO monthly system peak load data for five years (*i.e.*, 1998-2002);
- Member distribution cooperative and other load data for the same period;
- Patterns of scheduled generation maintenance; and
- Timing of the commercial operation of AEPCO's new power supply resources.

III. COST CLASSIFICATION AND ALLOCATION

Q. Describe in general terms the process for developing a fully allocated cost-of-service study.

A. For allocated cost-of-service study purposes, a utility's costs, both investments (*i.e.*, rate base related items) and operating expenses, generally are separated by function (*i.e.*, production, transmission, distribution and general), and such functional costs are then separated into four classifications: (1) demand-related or fixed costs; (2) energy-related or variable costs; (3) customer-related costs; and (4) revenue-related costs. Of course, after its restructuring, AEPCO's role is solely as a power supplier, so its costs are limited to production, from both generation resources and purchased power arrangements, together with general or indirect costs. Each of these functional categories and classifications of costs must then be allocated to

customers based on the cost-causal relationships (*i.e.*, allocation factors) that best reflect the "drivers" that explain the incurrence of each such cost component of providing service.

The bulk of a utility's production-related costs will be either fixed costs or variable costs. Fixed costs generally do not change in the short-run as the result of short-run changes in the demand for power and the power output to meet that demand. Such costs reflect the long-term advance commitment of power supply resources necessary to meet a utility's firm load obligation, including adequate planning reserves for contingency purposes. Installed generating capacity investments, fixed operation and maintenance expenses and the capacity-related (or demand-related) components of long-term purchased power costs are examples of fixed power supply costs. Fixed costs should be allocated based on the cost-causation principles which consider relevant system characteristics.

Variable costs, on the other hand, are those costs which will change as a result of short-run incremental changes in system output. The most common examples of variable power supply costs are fuel costs, variable operation and maintenance expenses for generation, and the energy-related components (*e.g.*, fuel, variable operation and maintenance charges, and tolling charges) of purchased power rates. Generally, variable costs are allocated based on energy usage.

IV. RELEVANT FACTORS FOR CONSIDERATION IN SELECTION OF APPROPRIATE DEMAND ALLOCATION METHODOLOGY

Q. Please explain generally how utilities such as AEPCO develop power supply resources to supply their firm load obligations.

A. Electric utilities plan and construct generation facilities and enter into firm purchased power contracts to meet their capacity requirements (*i.e.*, firm load obligations), including adequate planning reserves, at the time of system peaks. The system planning and operations

decisions also consider interchange capabilities with other entities. The planning, construction (or purchase implementation) and operation of the system is influenced by many factors, including: the types and sizes of units; daily, weekly, monthly and seasonal load variations; scheduled maintenance of facilities and necessary planning and operating reserves for contingencies; and unscheduled (or forced) outages.

The system characteristics and capacity requirements of each utility must be examined independently to determine the critical peak demand periods associated with firm load obligations and the amount and types of resources necessary to serve those loads reliably. Even though a utility must have adequate capacity to serve its single annual highest load, this does not mean, however, that other peak loads on the system are not important (or are necessarily less important) for planning purposes and for determining the appropriate demand-related (or fixed) cost allocation methodology for a particular system.

Q. What factors did you examine in evaluating the appropriate demand allocation methodology for AEPCO?

A. One or more of the following factors regarding the planning and operating realities of a system, such as AEPCO, provide guidance in selecting the appropriate demand allocation methodology:

- The pattern of monthly peak loads both in absolute MWs and with each monthly peak expressed as a percentage of the annual peak;
- The relationship of the monthly peaks in the non-peak months to the monthly peak(s) in any discernible peak season;
- The ratio of the lowest monthly peak to the annual system peak;
- The pattern of scheduled maintenance;

- Monthly generating reserves (*i.e.*, percentages of reserves remaining available to the utility after factoring in pre-scheduled maintenance and firm opportunity sales to and firm purchases from other entities); and

- Timing of the commercialization of new power supply resources.

V. AEPCO SYSTEM ASSESSMENT

Q. Describe in general terms the process used to analyze AEPCO system characteristics as part of your assessment of the appropriate method for allocating fixed costs.

A. Data for the most recently available five (5) calendar years (*i.e.*, 1998-2002) was analyzed for AEPCO. As I noted previously, the analysis focused on the total firm obligation load served by AEPCO, since this is the load for which AEPCO plans its long-term power supply resources. Even though the contractual status of certain AEPCO firm loads has changed over time, AEPCO still served this load and was obligated to plan for it as part of its member systems' firm loads, and, therefore, it was included in our analysis. The 100-MW sale to Morenci terminated May 31, 2002, and was not renewed or replaced with other non-Class A Member sales due to AEPCO's increasing capacity needs to serve its existing Class A Members. The load data for 2002, therefore, excludes the partial-year, 100-MW sale to Morenci so as not to skew the statistics for 2002. This is the only adjustment we made to AEPCO's actual monthly system peaks load data for the 5-year period analyzed. At the time this analysis was undertaken, complete 2003 data were not available. However, given that the data utilized in the analysis spanned five (5) years, the addition of one year and the deletion of an earlier year, in keeping with using a 5-year trend, was not considered necessary to assess the load characteristics of the AEPCO system.

The AEPCO total system monthly peak demands for the 5-year period examined were then subjected to various statistical tests to assess the nature of those peaks and the importance of those peaks for demand cost allocation purposes. In addition, the characteristics of the system's monthly reserve margins (*i.e.*, available capacity minus firm load) were examined to determine the relative relationships among the twelve months of the annual load cycle. Finally, the timing of the commercialization of new power supply resources was considered in assessing the proper demand allocation method for the system.

A. System Load Data

Q. Describe your analysis of the AEPCO system load data and characteristics.

A. Attachment A of Exhibit SPD-2 shows AEPCO's monthly total peak loads for 1998-2002 and the composition of that load by entity served. Attachment B to Exhibit SPD-2 restates the monthly system peak loads for each of the five (5) years analyzed and expresses the monthly peaks of each year as a percent of the annual peak for that year. Attachment B also calculates 5-year average monthly peak loads in MWs and expresses those 5-year averages as a percentage of the annual peak.

Attachment C of Exhibit SPD-2 is a series of bar graphs that plot the monthly peaks in MWs for each year (pp. 1-5) and for the 5-year average (p. 6). Finally, Attachment D is a series of bar graphs that plot the monthly peaks expressed as a percentage of the annual peak for each year (pp. 1-5) and for the 5-year average (p. 6).

These load data in both the tabular and graphic forms were prepared to develop a general understanding of the relative load characteristics for the AEPCO system.

Q. Please describe the results of your load analysis.

A. As can be seen from this data, AEPCO's highest peak occurs in the summer months (*i.e.*, June-September). While the monthly peak loads do indicate a summer peaking characteristic,

1 the data does not indicate, however, that this summer peaking characteristic is sufficiently
2 pronounced to warrant a summer-based demand allocation factor (*e.g.*, 1-coincident peak ("CP"),
3 2-CP, 3-CP or 4-CP methodology). This conclusion is reached by examining the relative
4 relationships of the non-summer month (*i.e.*, October-May) peaks and the summer month peaks
5 using the percentage statistics presented on Attachment B of Exhibit SPD-2.

6 As you can see, the non-summer month peaks for each year are at or above 70% of the
7 annual system peak, and for the 5-year period average 77% of the 5-year average peak. The
8 average summer month peak to annual peak ratio is 96.5%. Many of the non-summer month
9 peaks in a given year are 75% to 95% of the annual peaks for the year.

10 These statistics are important because they compare the non-summer month peaks with
11 the summer month peaks to test the importance of each month's peak to AEPCO's need to plan
12 adequate capacity to serve its firm load obligation. Monthly peaks that are at or above 70% of
13 the annual peak should be considered significant in the power supply resources planning process
14 and, therefore, in the selection of the appropriate cost-of-service demand allocation methodology
15 for the system. The greater the non-peak loads relative to the annual peak load, the greater the
16 likelihood of a higher annual load factor system. This influences not only the magnitude of
17 capacity required, but also the type of resource mix (*e.g.*, base, intermediate and peaking units).

18 **Q. What do you conclude from this load analysis for the AEPCO system?**

19 A. A utility, such as AEPCO, must plan sufficient capacity to serve its annual peak load and
20 also to maintain adequate planning reserves. But, for cost allocation purposes other monthly
21 peaks that are relatively high compared to the annual system peak should be considered relevant
22 as well. For example, there may be significant diversity among the individual distribution
23 cooperative loads that creates the monthly peaks throughout the year. Such diversity is

beneficial to AEPCO and its members because it means less capacity is required to serve their composite loads than the sum of their individual maximum loads. Arbitrarily selecting the single annual peak or a seasonal average peak (*e.g.*, 2 CP, 3 CP or 4 CP) methodology may unduly allocate fixed cost responsibility to the contributors to such peak(s) and unfairly relieve those contributors to the other, equally significant monthly peaks from an appropriate allocation of power supply resources fixed cost responsibility. Selection of the appropriate cost allocation methodology should focus on the load characteristics of the AEPCO system and the members' contributions to such characteristics, and not on the individual member's load characteristics, to properly recognize and encourage load diversity which benefits all members through reduced costs.

B. <u>System Reserves</u>

Q. Describe the analysis of system reserves which was prepared as part of the demand allocation factor assessment.

A. AEPCO's system reserves at the time of its monthly peaks, based on actual loads (Attachment A of Exhibit SPD-2) and resources (Attachment E of Exhibit SPD-2) as well as annual pre-scheduled maintenance, were calculated and examined for the 1998-2002 period. The monthly system reserves were expressed as a percentage of both adjusted net load (*i.e.*, firm peak load obligation less firm purchases) and available capacity. Similarity of the reserve percentages for each month is an indicator of the relative significance of such monthly peaks. As shown by the reserve percentages on page 2 of Attachment F, there are a number of non-summer months with reserve percentages that are similar to percentages for the summer months where the annual system peak occurs. These data certainly indicate that certain of the non-summer peaks as well as the summer peaks are critical and hence relevant in establishing the most appropriate demand allocation methodology for AEPCO's power supply resources.

C. Commercialization of Installed Generating Capability and Long-Term Purchases

Q. Describe the analysis of the commercialization of power supply resources.

A. The nature and timing of the implementation of installed generating capability and effective dates of the long-term capacity purchases also offer some insight as to the appropriate demand cost allocation methodology for a system. AEPCO's power supply resources history for 1998-2002 is set forth in Attachment E of Exhibit SPD-2. A review of this information shows that AEPCO has brought on-line only one new generating resource during this 5-year period – Apache GT-4 in October 2002. Since the timing of the unit's commercialization was not set to coincide with the beginning of the summer season, this suggests that while this resource would ultimately be needed to serve the annual peak occurring in the summer, it was also needed to serve non-summer load.

In addition, AEPCO's purchases tend to be year-round in nature as indicated on Attachment E. During the 5-year period analyzed, AEPCO did have one seasonal peaking purchase from PacifiCorp which, based on its magnitude, appears to be directed at economically matching such resource to the peaking component of AEPCO's summer load. This transaction, however, does not appear to support a conclusion that AEPCO's summer peaking requirements are of such magnitude that a strong seasonal-based demand allocation methodology would be appropriate.

AEPCO also has two (2) hydro-based purchased power resources that have a summer-season characteristic to the scheduled deliveries. But, this characteristic is a function of the associated project marketing plans which take into account water availability for the hydro resources. These seasonal purchased power characteristics, therefore, should not be considered

strong indicators of an AEPCO summer peaking characteristic warranting a seasonal-based demand allocation methodology.

VI. APPROPRIATE COST OF SERVICE DEMAND ALLOCATION METHODOLOGY

Q. Describe your conclusions with regard to the appropriate demand allocation methodology for the AEPCO system.

A. The following conclusions flow from the analysis of the AEPCO system load and resource characteristics, which I described previously:

- AEPCO's system peak occurs during the summer (*i.e.*, June-September) months.
- AEPCO's monthly non-summer peak loads are at or above 70% of its annual peak load and in many of those non-summer months are 85-95% of the annual system peak.
- AEPCO's summer-seasonal peaking characteristic is not sufficiently pronounced to warrant a seasonal-based demand cost allocation methodology (*e.g.*, 1-CP, 2-CP, 3-CP or 4-CP).
- The nature of AEPCO's generation capability and purchased power arrangements reflect the importance of all monthly AEPCO peaks, particularly when considering pre-scheduled maintenance of resources.
- AEPCO's seasonal long-term purchases are relatively modest and appear directed at meeting the portion of the annual peak in the summer that exceeds the non-summer peaks or are based upon resource availability, or both.
- Although AEPCO has installed only one new generator in the last six (6) years, that unit was placed in commercial operation in October 2002, rather than at the beginning of the summer season, thus indicating that the summer peak is not the sole driver of new resource installations.

In light of these factors, AEPCO's monthly system peaks are all sufficiently important with regard to the planning and operation of the AEPCO system to be considered in the demand cost allocation methodology to be selected for cost-of-service purposes. Based on our analysis

of all AEPCO loads and individual member distribution system loads, we have recommended that AEPCO adopt the 12-CP demand cost allocation methodology as the most appropriate for determining its cost of service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

16662-1/1183048v3

Stephen Page Daniel
Executive Vice President

EDUCATION: Master of Business Administration in Finance, Georgia State University (1978)
Bachelor of Industrial Engineering, Georgia Institute of Technology (1970)

PROFESSIONAL MEMBERSHIP: Institute of Electrical and Electronics Engineers

EXPERIENCE:

2/86-Present

Executive Vice President and principal of GDS Associates, Inc.

1/71-2/86

Mr. Daniel served as rate analyst (1971-1974), project manager (1975-1981), Group Manager - Rate and Analytical Services (1982-1984), and Assistant Vice President - Rate and Analytical Services (1985-1986) with Southern Engineering Company. Mr. Daniel was also Coordinator - Load and Energy Management Services from 1978 to 1981.

During his thirty-four (34) years experience in the electric utility industry, Mr. Daniel has consulted with utilities, government agencies, and industrial clients in thirty-six (36) states in the following areas:

- Policy evaluations regarding electric industry restructuring and retail competition.
- Mergers and Acquisitions, including market power related issues.
- Power supply planning for generation and transmission utility systems and distribution systems.
- Transmission access/pricing issues:
  - Negotiation of transmission arrangements (including OATT service)
  - Policy advocacy/rulemaking, including RTO development
  - Open-access transmission implementation/compliance
  - Transmission rate case litigation
  - Strategic Planning
- Negotiation of wholesale (sales-for-resale) power supply contracts on behalf of cooperative and municipal electric power systems involving:
  - Full and partial requirements services
  - Interchange services
  - Generation support services
  - Joint ownership arrangements
- Preparation of pooling rates for cooperative generation and transmission systems.
- Preparation of financial forecasts and forecasts of operations for rural electric distribution and generation and transmission systems.
- Preparation of cost-of-service studies and sales-for-resale rate studies for cooperative generation and transmission systems.
- Preparation of retail rate studies and cost-of-service studies for rural electric distribution systems and municipal electric systems.
- Analysis of cost-of-service studies filed by others with the Federal Energy Regulatory Commission (formerly Federal Power Commission) and various state regulatory commissions.

- Preparation of revenue requirements studies for cooperative and municipal power systems.
- Facilities valuation studies for property sales and condemnations.
- Assignments in specialized areas of:
  - Industry Restructuring/Wholesale Competition/Retail Competition
  - Rate design for special loads
  - Financial requirements analyses
  - Evaluation of financing alternatives
  - Acquisition, merger and divestiture evaluations
  - Regulatory rulemaking
  - Public Utility Regulatory Policies Act of 1978
  - Cogeneration and Small Power Production
  - Territorial Integrity

REGULATORY EXPERIENCE:

Federal Energy Regulatory Commission (formerly Federal Power Commission) [1/]
Alabama Public Service Commission [3/]
Alaska Public Utilities Commission [1/]
Arizona Corporation Commission [1/]
Arkansas Public Service Commission
Public Utilities Commission of the State of Colorado
Florida Public Service Commission [2/]
Georgia Public Service Commission
Indiana Regulatory Commission (formerly Public Service Commission of Indiana)
Kansas Corporation Commission
Louisiana Public Service Commission
Mississippi Public Service Commission [2/] [3/]
Nevada Public Utilities Commission
North Carolina Utilities Commission
Pennsylvania Public Utility Commission
South Carolina Public Service Commission
Texas Public Utility Commission [1/]
Utah Public Service Commission
Virginia State Corporation Commission
West Virginia Public Service Commission [2/]

[1/] Including Regulatory Rulemaking
[2/] Including Generic Hearings
[3/] Including Restructuring and Deregulation Proceedings

EXPERT TESTIMONY IN COURT PROCEEDINGS:

(1) Clay County Superior Court, Clay County, Florida
(2) United States Federal District Court, District of Nebraska
(3) United States Federal District Court, Anderson, South Carolina
(4) United States Bankruptcy Court, Opelousas, Louisiana

AFFIDAVITS IN COURT PROCEEDINGS:

(1) United States Federal District Court, Middle District – Alabama, Northern Division
(2) Supreme Court of New York, Niagara County, Index No. 081556, Judge Joslin, Affidavit in Appellate Proceeding

OTHER EXPERT APPEARANCES:

(1) Kansas Legislature Electric Industry Restructuring Task Force

PUBLICATIONS

"Joint Ownership of Transmission" - CFC Power Review - Spring 1989 (with Robert M. Gross)
"Long-Term Transmission Access Strategy - Do You Have One?" – TransActions, Vol. No. 198

LECTURES/SEMINARS:

- Retail Competition/Restructuring: Framing the Debate
  Florida Utility Industry Restructuring Task Force, June 9, 1998
- NRECA Restructuring Forum
  Technical Advisor to Roundtable Discussion (January 28, 1998)
- Missouri Retail Competition
  Missouri REC Managers' Conference, June 5, 1997
- Southeast Power Markets Outlook
  Southeast Power Markets, Atlanta, GA, May 21, 1997
- Open-Access Transmission: A Key to Competitive Bulk Power Markets
  1996 Strategic Planning Program, Strategic Planning Process for 1997 and Beyond, Alabama Electric Cooperative, Inc., July 2, 1996
- Open-Access Transmission: A Key to Competitive Bulk Power Markets
  1996 Annual Engineers Conference
  Florida Electric Cooperatives Association, May 15, 1996
- The Future: Transmission Open-Access Update; Industry Restructuring; and Strategic Planning
  SMEPA Board of Trustees Forum (1996)
  Open-Access Transmission -- The Path to Competitive Bulk Power Markets
- Status of Utility Restructuring in the U.S. and Implications for Georgia
  Georgia Public Service Commission Staff Meeting, December 18, 1995
- Unbundling Services and Rates: A Choice or a Necessity?
  Public Power: Preparing for Competition
  Infocast, Washington, D.C., November 17, 1995
- Trends in Power Supply: What's All the Change About?
  The FERC MEGA-NOPR, Privatization & Regulatory Jurisdictional Issues
  15th Annual Southeastern Electric & Natural Gas Conference, October 10, 1995
- Transmission Access: The Path to Competition
  The Electric Cooperatives of South Carolina, Engineering & Purchasing Association Meeting, May 1995

- Transmission Access: The Path to Competition
  SMEPA Board of Trustees Forum (1994)
- The Changing Structure of Electric Utilities
  G&T Accounting and Finance Association 1994 Annual Meeting
- Surviving and Thriving as Rural (Cooperative) Energy Systems in the 90's and Beyond,
  Southeastern Power Administration Integrated Resource Planning Conference (1993)
- Transmission Access and Pricing Policies of the FERC
  National G&T Managers Association Meeting (1993)
- G&T Rate Theory: Competitive Positioning
  NRECA G&T Rate Seminar (1993)
- Transmission Strategies In A Changing Regulatory And Access Environment
  Electric Systems Planning and Operations Conference (1992)
- A Wholesale Rate Case: The Consultant's Role
  Seminole Electric Cooperative, Inc., June 1992 Employee Meeting
- The Economic Impact of Annexation On Rural Electric Systems: The Technical Perspective; and Price Alone May Not Be Good Enough! (Workshop)
  NRECA Territorial Integrity Conference (1990)
- Regulation After Refunding: Life At The FERC
  National G&T Managers Association Meeting (1989)
- Joint Ownership: A Transmission Access Alternative
  Executive Enterprises Third Annual Transmission Access And Pricing Conference (1989)
- FERC, IPPS, Etc.
  NRECA Transmission Forum (1989)
- FERC Regulation of G&Ts: Prospect and Impact
  NRECA G&T Legal Seminar (1989)
- A Review of Reality -- Cooperative/Creative Ratemaking
  NRECA 1985 Directors' Update (1985)
- Electric Rates: The Impact on Load and Energy Management
  NRECA Load Management Workshop (1980)
- AEPCO Rates: Past, Present & Future
  Grand Canyon State Electric Cooperative, Inc. Annual Meeting (1979)
- Fuel Adjustment Clauses and Rates
  Georgia Rural Electric Managers Association (1979)
- How to Distribute the Benefits of Load Management
  NRECA Load Management Conference (1979)
- Fuel Adjustments and Power Rates
  South Carolina Electric Cooperative Managers Association (1979)
- Load Management and Rates
  Indiana Statewide REC, Inc. (1978)
- The Philosophy of Setting Rates
  Cooperative Power Association (1978)
- Strategies For Load and Energy Management
  Northwest Public Power Association 1978 Directors Conference (1978)
- Capital Budgeting to Meet System Planning Needs
  APPA Accounting & Finance Workshop (1974)

Appropriate Cost of Service Demand Allocation Methodology
For
Arizona Electric Power Cooperative, Inc.
Power Supply Resources Fixed Costs

I. INTRODUCTION

The Arizona Electric Power Cooperative, Inc. ("AEPCo") asked GDS Associates, Inc. ("GDS") to determine the appropriate cost of service demand allocation methodology to be used to allocate AEPCo power supply resources fixed costs to its Class A Members. AEPCo plans to file a rate case with the Arizona Corporation Commission ("Commission") and has been instructed in prior Commission decisions to include with such filing a fully allocated embedded cost of service study. The following discussion sets forth the analyses undertaken, the conclusions reached, and the recommended cost of service demand allocation methodology for AEPCo power supply resources fixed costs.

AEPCo supplies long-term power (both capacity and energy) to five (5) Class A Members,[1] one (1) Class B Member,[2] one (1) Class C Member,[3] and, from time-to-time, several

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1 Anza Electric Cooperative, Inc. (Anza"); Duncan Valley Electric Cooperative, Inc. ("Duncan"); Graham County Electric Cooperative, Inc. ("Graham"); Sulphur Springs Valley Electric Cooperative, Inc. ("Sulphur"); and Trico Electric Cooperative, Inc. ("Trico").

2 Mesa Electric Utility ("Mesa"). During 1999-2000 AEPCo also supplied power to Morenci Water & Electric Company ("Morenci"), which supply superceded services to Phelps-Dodge, a large industrial customer served by Duncan prior to 1999. For purposes of the analyses set forth in this report, all such load either through Morenci or Duncan was included as part of AEPCo's firm load obligation.

3 Salt River Project ("SRP").

non-members.[4] AEPCo supplies full requirements power to its Class A Members,[5] partial requirements power to its Class B Member, unit power to its Class C Member and various firm power products to its non-members. Since AEPCo must plan its power supply resources, including both generation and purchases, to meet its total firm load obligation, the composite AEPCo firm load has been determined to be the appropriate load to examine as part of the analyses to select the appropriate demand allocation methodology for AEPCo's power supply resources fixed costs. Even though the service arrangements and pricing mechanisms associated with services to the Class B Member, Class C Member, and non-members are distinct from the service arrangement and pricing mechanism for the Class A Members, AEPCo nonetheless must plan its system to meet its total firm load obligation. Thus, all firm load should be considered in the cost of service assessment.

II. COST CLASSIFICATION

For allocated cost-of-service purposes, a utility's costs, whether investment or rate-base related or expense related, generally are separated by function (*i.e.*, generation, transmission, distribution, general) and such functional costs are then separated into four classifications: (1) demand-related or fixed costs; (2) energy-related or variable costs; (3) customer-related costs; and (4) revenue-related costs. The bulk of a utility's generation and purchased power costs will be fixed costs and variable costs.

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4 Cyprus Twin Buttes Mine, ("Cyprus"); Electrical District No. 2 ("ED-2"); and the City of Safford, Arizona Electric Dept. ("Safford") (now Gila Resources). Previously, AEPCo also has supplied power to Thatcher Municipal Utilities ("Thatcher"). For purposes of the analyses set forth in this report, all such loads were included as part of AEPCo's firm load obligation.

5 Mohave has exercised its option to become a partial requirements customer, but for purposes of this analysis, its total requirements load has been included.

Fixed costs do not change in the short-run as the result of short-run changes in power output. Such costs reflect the long-term advance commitment of power supply resources necessary to meet a utility's firm load obligation, including adequate planning reserves for contingency purposes. Installed capacity investments, fixed operation and maintenance expenses and the capacity-related components of long-term purchased power costs are examples of fixed power supply costs.

Variable costs are those costs which will change as a result of short-run incremental changes in system output. The most common examples of variable power supply costs are fuel costs, variable operation and maintenance expenses for generation and the energy-related components (*e.g.*, fuel, variable operation and maintenance charges and tolling costs) of purchased power contracts.

The generation and transmission functions of power supply have been unbundled into the separate corporate entities of AEPCo and Southwest Transmission Cooperative, Inc. ("Southwest"), respectively. AEPCo is responsible for planning and procuring adequate power supply resources to meet its long-term firm load obligation. AEPCo secures transmission services from Southwest to deliver the necessary power supply resources to its Members and the non-members for which AEPCo is responsible for the transmission component of power sold. Such transmission services are secured and priced pursuant to Southwest's Open Access Transmission Tariff ("Southwest Tariff"). Thus, the allocation of costs related to transmission are dealt with through the establishment of the rates and charges for services under the Southwest Tariff and are not part of this assessment of the appropriate cost of service method of fixed cost allocation related to AEPCo's power supply resources.

III. FACTORS FOR EVALUATION

Electric utilities plan and construct generation facilities and enter into firm purchased power arrangements to meet their capacity requirements, including planning reserves, at the time of system peaks. The system planning and operations decisions also consider interchange capabilities with other entities. The planning, construction (or purchase implementation) and operation of the system is influenced by many factors, including: the types and sizes of units; daily, weekly, monthly and seasonal load variations; scheduled maintenance of facilities and necessary reserves for emergencies; and unscheduled outages and other contingencies. The system characteristics and capacity requirements of each utility must be examined independently to determine the critical peak demand periods and to establish the appropriate demand allocation methodology. Even though AEPCo must have adequate capacity to serve its single annual highest load, this does not mean that other peak loads are not important (or less important) in determining the appropriate cost of service methodology for the AEPCo system.

One or more of the following factors regarding the planning and operating realities of the AEPCo system provide guidance in selecting the appropriate demand allocation methodology:

The pattern of monthly peak loads both in absolute MWs and with each monthly peak expressed as a percentage of the annual peak;

The relationship of the monthly peaks in the non-peak months to the monthly peak(s) in any discernible peak season;

The ratio of the lowest monthly peak to the annual system peak;

The pattern of scheduled maintenance;

Monthly generating reserves (*i.e.*, percentages of reserves remaining available to the utility after factoring in pre-scheduled maintenance and firm opportunity sales to and firm purchases from other entities); and

Timing of the commercialization of new power supply resources.

The various factors are examined and discussed in Section IV, below.

IV. AEPCo SYSTEM ASSESSMENT

Data for the most recently available five (5) calendar years (*i.e.*, 1998-2002) was analyzed for AEPCo. As noted in the introduction, the analysis focused on the total firm obligation load served by AEPCo since this is the load for which AEPCo plans its long-term power supply resources. Even though the contractual status of certain AEPCo firm loads have changed over time (*e.g.*, the Phelps-Dodge load has migrated from the Duncan system to the Morenci system), AEPCo still served this load and was obligated to plan for it, and, therefore, it has been included in the analysis. The 100-MW sale to Morenci terminated May 31, 2002, and was not renewed or replaced with other sales due to AEPCo's increasing capacity needs to serve its Class A, B and C Members. The load data for 2002, therefore, excludes the partial-year, 100-MW sale to Morenci so as not to skew the statistics for 2002. This is the only adjustment to AEPCo's actual monthly system peaks load data for the five-year period analyzed.

A. System Load Data

Attachment A shows AEPCo's monthly total peak loads for 1998 2002 and the composition of that load by entity served. The only adjustment to actual data was the above-noted elimination of the partial-year (*i.e.*, five-month) sales to Morenci in 2002. Attachment B restates the monthly system peak loads for each of the five (5) years analyzed and expresses the monthly peak of each year as a percent of the annual peak for that year. Attachment B also calculates five-year average monthly peak loads in MWs and expresses those five-year averages as a percentage of the peak.

Attachment C is a series of bar graphs that plot the monthly peaks in MWs for each year (pp. 1-5) and for the five-year average (p. 6). Attachment D is a series of bar graphs that plot the monthly peaks expressed as a percentage of the annual peak for each year (pp. 1-5) and for the five-year average (p. 6).

These load data in both the tabular and graphic forms were prepared to develop a general understanding of the relative load characteristics for the AEPCo system. As can be seen from this data, AEPCo's highest peak occurs in the summer months (*i.e.*, June-September). While the monthly peak loads do indicate a summer peaking characteristic, the data does not indicate that this summer peaking characteristic is sufficiently pronounced, however, to warrant a summer-based demand allocation factor (*e.g.*, 1-coincident peak ("CP"), 2-CP, 3-CP or 4-CP methodology). This conclusion is reached by examining the relative relationships of the non-summer month (*i.e.*, October-May) peaks and the summer-month peaks using the percentage statistics presented on Attachment B.

As shown on Attachment B, the non-summer month peaks for each year are at or above 70% of the annual system peak, and for the five-year period, average 77% of the five-year average peak. The average summer-month peak to annual peak ratio is 96.5%. While the lowest monthly non-summer-month peak to annual peak ratio is 70.1%, many of the non-summer months are 75% to 95% of the annual peaks.

These statistics are important because they compare the non-summer month peaks with the summer month peaks to test the importance of each to AEPCo's need to plan adequate capacity to serve its firm load obligation. Monthly peaks that tend to be at or above 70% of the annual peak should be considered significant in the power supply resources planning process and, therefore, in the selection of the appropriate cost of service demand allocation methodology

for the system. The greater the non-peak loads relative to the peak load, the greater the likelihood of a higher annual load factor system. This influences not only the magnitude of capacity required, but also the type of resource mix (*e.g.*, base, intermediate and peaking units).

A utility, such as AEPCo, must plan sufficient capacity to serve its annual peak load and also to maintain adequate planning reserves. But, for cost allocation purposes other monthly peaks that are relatively high compared to the annual system peak should be considered relevant as well. For example, there may be significant diversity among the customers that create the monthly peaks throughout the year. Such diversity is beneficial to AEPCo and its members because it means less capacity is required to serve their composite loads than the sum of their individual maximum loads. Arbitrarily selecting the single annual peak or a seasonal average peak (*e.g.*, 2 CP, 3 CP or 4 CP) methodology may unduly allocate fixed cost responsibility to the contributors to such peak(s) and unfairly relieve those contributors to the other, equally significant monthly peaks from an appropriate allocation of power supply resources fixed cost responsibility. Selection of the appropriate cost allocation methodology should focus on the load characteristics of the AEPCo system and the members' contributions to such characteristics, and not on the individual member's load characteristics, to properly recognize and encourage load diversity which benefits all members through reduced costs.

B. System Reserves

AEPCo's system reserves at the time of its monthly peaks, based on actual loads (Attachment A) and resources (Attachment E) and annual pre-scheduled maintenance also were calculated and examined for the 1998-2002 period. The monthly system reserves are expressed as a percentage of both adjusted net load (*i.e.*, peak load less firm purchases) and available capacity. Similarity of the reserve percentages for each month is an indicator of the relative

significance of such monthly peak. As shown by the reserve percentages on page 2 of Attachment F, there are a number of non-summer months with reserve percentages that are similar to percentages for the summer months where the annual system peak occurs. This data certainly indicates that at least certain of the non-summer peaks as well as the summer peaks are critical and hence relevant in establishing the most appropriate demand allocation methodology for AEPCo's power supply resources.

C. Installed Generating Capability and Long-Term Purchases

The nature and timing of implementation of installed generating capability and long-term capacity purchases also offers some insight as to the appropriate demand cost allocation methodology for a system. AEPCo's power supply resources history for 1998-2002 is set forth in Attachment E. A review of this information shows that AEPCo has brought on-line only one new generating resource during this five-year period – Apache GT-4 in October 2002. Since the timing of commercialization of this unit was not set to coincide with the beginning of the summer season, this suggests that while this resource would ultimately be needed to serve the annual peak occurring in the summer, it was also needed to serve non-summer load.

AEPCo's purchases tend to be year around in nature as indicated on Attachment E. During the five-year period analyzed, AEPCo did have one seasonal peaking purchase from PacifiCorp which, based on its magnitude, appears to be directed at economically matching such resource to the peaking component of AEPCo's summer load. This transaction, however, does not appear to support a conclusion that AEPCo's summer peaking requirements are of such magnitude that a strong seasons-based demand allocation methodology would be appropriate.

It should be noted that AEPCo also has two (2) hydro-based purchased power resources that have a summer-season characteristic to the scheduled deliveries. This characteristic is a

function of the associated project marketing plans which take into account the water availability from the hydro resources. These seasonal purchased power characteristics, therefore, should not be considered strong indicators of an AEPCo summer peaking characteristic warranting a seasonal-based demand allocation methodology.

V. APPROPRIATE COST OF SERVICE DEMAND ALLOCATION METHODOLOGY

The following conclusions flow from these analyses of the AEPCo system load and resource characteristics.

> AEPCo's system peak occurs during the summer (*i.e.*, June-September) months.
>
> AEPCo's summer-seasonal peaking characteristic is not sufficiently pronounced to warrant a seasonal-based demand cost allocation methodology (*e.g.*, 1-CP, 2-CP, 3-CP or 4-CP).
>
> AEPCo's monthly non-summer peak loads are at or above 70% of its annual peak load and in many of those non-summer months are 85-95% of the annual system peak.
>
> The nature of AEPCo's generation capability and purchased power arrangements reflect the importance of all monthly AEPCo peaks, particularly when considering pre-scheduled maintenance of resources.
>
> AEPCo's seasonal long-term purchases are relatively modest and appear directed at meeting the portion of the annual peak in the summer that exceeds the non-summer peaks.
>
> Although AEPCo has installed only one new generator in the last six (6) years, that unit was placed in commercial operation in October 2002, rather than at the beginning of the summer season, thus indicating that the summer peak is not the sole driver of new resource installations.

In light of the above observations, it is reasonable to conclude that AEPCo's monthly system peaks are all sufficiently important with regard to the planning and operation of the AEPCo system to be considered in the demand cost allocation methodology to be selected for

cost-of-service purposes. Under the circumstances, it is recommended that AEPCo adopt the 12-CP demand cost allocation methodology as the most appropriate for determining the cost of service on the AEPCo system.

Attachment A

Summary of AEPCO's Total Coincident Actual Loads - MW

Member ---> Status		Class A AR	Class A AR	Class A AR	Class A Partial	Class A AR	Class A AR	Non Member	Non Member	Class B Member	Non Member	Class C Member	Class B Member	Class B Member	Non Member	Non Member	Non Member	Non Member			
Year	Month	Anza Peak MW	Duncan Peak MW	Graham Peak MW	Mohave Peaks MW	Sulphur Peak MW	Trico Peak MW	75 MW Phelps Dodge MW	50 MW Phelps Dodge MW	MWE 75/100 MWE (1)	ED-2 Peak MW	SRP Peak MW	Mesa 15 Peak MW	Mesa 17.5 Peak MW	Safford Peak MW	Town Of Thatcher MW	Cyprus Cont Well MW	Cyprus Firm Peak MW	AEPCO Total Load MW	AEPCO Losses % 2.97%	AEPCO Peak Demand MW
1998	1	4.728	3.300	13.356	61.406	76.752	42.731	75.000	50.000	0.000	0.000	100.000	0.000	0.000	0.000	0.815	1.940	5.000	435.028	13.316	448.344
1998	2	5.796	3.340	13.544	57.698	82.414	44.195	75.000	50.000	0.000	0.000	100.000	0.000	0.000	0.000	0.881	1.940	5.000	439.808	13.462	453.270
1998	3	4.788	2.760	14.063	54.325	63.394	34.691	75.000	50.000	0.000	0.000	100.000	0.000	0.000	0.000	0.713	2.060	5.000	406.794	12.452	419.246
1998	4	3.708	2.760	14.062	66.559	62.149	36.419	75.000	50.000	0.000	8.000	100.000	15.191	17.588	0.333	0.798	1.880	5.000	459.447	14.063	473.510
1998	5	3.864	3.820	17.970	72.178	71.080	44.019	75.000	50.000	0.000	8.000	100.000	15.191	17.588	0.833	0.936	1.980	5.000	487.459	14.921	502.380
1998	6	5.616	4.800	26.971	109.323	91.643	60.141	75.000	50.000	0.000	8.000	100.000	15.191	17.588	3.523	1.885	1.980	5.000	576.661	17.651	594.312
1998	7	7.656	4.480	26.420	129.489	88.367	66.470	81.759	50.000	0.000	8.000	100.000	15.191	17.588	2.891	1.496	1.960	5.000	606.767	18.573	625.340
1998	8	8.376	3.940	23.212	127.106	89.067	63.525	75.000	50.000	0.000	8.000	100.000	15.191	17.588	3.421	1.863	2.020	5.000	593.309	18.161	611.470
1998	9	6.672	4.120	23.393	107.817	85.284	56.911	75.000	50.000	0.000	8.000	100.000	15.191	17.588	3.241	2.112	2.040	5.000	562.369	17.214	579.583
1998	10	4.032	3.400	17.250	68.848	71.480	49.972	75.000	50.000	0.000	8.000	100.000	15.191	17.588	2.292	1.898	2.020	5.000	491.971	15.059	507.030
1998	11	5.388	3.160	13.083	52.320	66.259	37.529	75.000	50.000	0.000	8.000	100.000	15.191	17.588	0.259	0.864	1.900	5.000	451.541	13.821	465.362
1998	12	6.336	3.460	15.141	62.356	81.240	49.662	75.000	50.000	0.000	8.000	100.000	15.191	17.588	0.000	0.958	1.920	5.000	491.852	15.055	506.907
1999	1	4.716	3.380	13.510	61.210	76.737	44.588	0.000	0.000	75.000	8.000	100.000	15.191	17.588	0.000	0.646	1.940	5.000	427.506	13.086	440.592
1999	2	6.048	3.060	14.418	59.652	74.460	47.154	0.000	0.000	75.000	8.000	100.000	15.244	17.588	0.000	0.835	1.940	5.000	428.399	13.113	441.512
1999	3	5.976	3.140	16.891	50.317	66.540	39.878	0.000	0.000	75.000	8.000	100.000	15.244	17.588	0.007	0.678	1.960	5.000	406.219	12.434	418.653
1999	4	4.272	2.980	16.174	71.488	63.973	37.131	0.000	0.000	75.000	8.000	100.000	15.244	17.588	0.000	0.880	1.840	5.000	419.570	12.843	432.413
1999	5	5.256	4.040	21.964	101.593	75.014	54.828	0.000	0.000	75.000	8.000	100.000	15.244	17.588	1.719	1.164	2.080	5.000	488.490	14.952	503.442
1999	6	7.392	5.460	28.908	126.199	96.510	69.157	0.000	0.000	75.000	8.000	100.000	15.244	17.588	4.044	2.361	1.960	5.000	562.823	17.227	580.050
1999	7	7.368	5.460	29.041	126.817	97.553	72.658	0.000	0.000	75.000	8.000	100.000	15.244	17.588	4.146	2.336	1.660	5.000	567.871	17.382	585.253
1999	8	7.740	4.480	25.924	126.413	90.508	67.337	0.000	0.000	75.000	8.000	100.000	15.244	17.588	3.983	2.750	1.500	5.000	551.467	16.880	568.347
1999	9	6.852	4.380	22.370	112.657	85.532	61.140	0.000	0.000	75.000	8.000	100.000	15.244	17.588	3.207	2.420	1.560	5.000	520.950	15.946	536.896
1999	10	5.844	3.140	16.350	91.346	75.780	56.305	0.000	0.000	75.000	8.000	100.000	15.244	17.588	1.507	1.825	1.660	5.000	474.589	14.527	489.116
1999	11	5.124	3.140	15.139	52.851	69.920	40.397	0.000	0.000	75.000	8.000	100.000	15.244	17.588	0.004	0.696	1.500	5.000	409.603	12.538	422.141
1999	12	6.444	3.740	16.271	64.747	79.440	49.111	0.000	0.000	75.000	8.000	100.000	15.244	17.588	0.000	0.980	1.940	5.000	443.505	13.575	457.080
2000	1	5.532	3.560	15.006	60.999	81.660	49.589	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.000	0.560	1.620	5.000	464.464	14.217	478.681
2000	2	5.100	3.220	13.152	57.597	76.516	41.224	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.000	0.528	1.660	5.000	444.935	13.619	458.554
2000	3	6.564	3.160	15.961	53.346	74.520	49.011	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.000	0.063	1.900	5.000	450.463	13.788	464.251
2000	4	4.716	4.260	22.098	98.871	82.082	56.968	0.000	0.000	100.000	8.000	100.000	15.350	17.588	2.505	2.040	1.980	5.000	521.458	15.961	537.419
2000	5	6.708	5.540	27.033	120.854	102.064	74.569	0.000	0.000	100.000	8.000	100.000	15.350	17.588	4.149	1.689	1.820	5.000	590.364	18.071	608.435
2000	6	7.776	5.620	30.193	131.904	98.312	73.712	0.000	0.000	100.000	8.000	100.000	15.350	17.588	3.289	1.971	1.780	5.000	600.495	18.381	618.876
2000	7	8.208	5.640	32.285	137.416	102.995	77.524	0.000	0.000	100.000	8.000	100.000	15.350	17.588	5.994	2.260	1.800	5.000	620.060	18.979	639.039
2000	8	7.320	5.620	32.889	138.975	102.294	77.059	0.000	0.000	100.000	8.000	100.000	15.350	17.588	6.219	2.425	2.040	5.000	620.779	19.001	639.780
2000	9	7.176	5.060	23.295	118.524	98.017	74.968	0.000	0.000	100.000	8.000	100.000	15.350	17.588	3.688	2.666	2.020	5.000	581.352	17.795	599.147
2000	10	5.604	4.460	23.023	105.457	88.715	67.776	0.000	0.000	100.000	8.000	100.000	15.350	17.588	5.364	2.495	2.100	5.000	550.932	16.864	567.796
2000	11	5.844	3.500	13.739	54.178	87.017	49.981	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.570	0.887	2.040	5.000	463.694	14.193	477.887
2000	12	5.136	3.520	16.079	65.141	79.536	49.820	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.059	0.406	2.100	5.000	467.735	14.317	482.052
2001	1	5.868	3.480	16.118	62.350	87.675	54.313	0.000	0.000	100.000	8.000	100.000	15.355	17.588	1.284	0.461	2.020	5.000	479.512	14.677	494.189
2001	2	5.916	3.320	14.999	64.787	90.478	54.025	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.990	0.607	1.840	5.000	482.900	14.781	497.681
2001	3	5.652	3.040	13.046	56.680	75.600	45.194	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.905	0.739	1.540	5.000	448.334	13.723	462.057
2001	4	4.368	3.480	17.311	86.734	70.532	53.362	0.000	0.000	100.000	8.000	100.000	15.350	17.588	3.311	1.686	1.620	5.000	488.342	14.948	503.290
2001	5	6.504	4.640	23.524	115.927	93.940	75.871	0.000	0.000	100.000	8.000	100.000	15.350	17.588	7.031	2.119	0.000	10.400	580.894	17.781	598.675
2001	6	7.260	5.080	30.008	134.236	99.850	83.932	0.000	0.000	100.000	8.000	100.000	15.350	17.588	6.956	1.890	0.000	10.540	620.690	18.999	639.689
2001	7	7.764	3.600	30.726	147.125	111.945	90.749	0.000	0.000	100.000	8.000	100.000	15.350	17.588	7.896	1.579	0.000	9.320	651.642	19.946	671.588
2001	8	7.764	5.160	29.069	120.600	104.404	86.829	0.000	0.000	100.000	8.000	100.000	15.350	17.588	7.682	2.711	0.000	9.800	614.957	18.823	633.780
2001	9	6.432	4.880	24.667	111.100	98.670	80.759	0.000	0.000	100.000	8.000	100.000	15.350	17.588	5.553	2.041	0.000	9.740	584.780	17.900	602.680
2001	10	4.524	3.380	16.293	95.977	75.408	57.493	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.479	0.619	0.000	9.120	504.231	15.434	519.665
2001	11	6.300	3.640	15.740	60.665	86.200	50.818	0.000	0.000	100.000	8.000	100.000	15.350	17.588	0.346	0.945	0.000	8.740	474.332	14.519	488.851
2001	12	6.504	3.880	17.242	64.236	98.960	61.370	0.000	0.000	100.000	8.000	100.000	15.350	17.588	1.423	0.000	0.000	8.360	502.913	15.394	518.307
2002	1	6.432	3.320	14.758	71.793	94.849	60.048	0.000	0.000	0.000	8.000	100.000	15.350	17.588	0.449	0.000	0.000	8.000	400.587	12.262	412.849
2002	2	6.084	2.360	15.023	71.893	93.072	59.913	0.000	0.000	0.000	8.000	100.000	15.350	17.588	0.132	0.000	0.000	7.880	397.295	12.161	409.456
2002	3	5.472	3.440	15.662	62.190	82.413	51.292	0.000	0.000	0.000	8.000	100.000	15.323	17.588	0.670	0.000	0.000	7.880	369.930	11.323	381.253
2002	4	5.496	3.780	20.461	94.674	71.220	61.409	0.000	0.000	0.000	8.000	100.000	15.341	17.588	0.000	0.000	0.000	7.620	405.589	12.415	418.004
2002	5	6.660	5.320	27.751	110.200	103.544	79.649	0.000	0.000	0.000	8.000	100.000	15.341	17.588	4.921	0.000	0.000	7.360	486.334	14.886	501.220
2002	6	7.068	6.040	33.126	99.000	110.561	96.441	0.000	0.000	0.000	8.000	100.000	15.341	17.588	5.615	0.000	0.000	6.920	505.700	15.479	521.179
2002	7	8.628	5.240	33.349	116.000	112.009	94.660	0.000	0.000	0.000	8.000	100.000	15.341	17.588	5.796	0.000	0.000	7.320	523.931	16.037	539.968
2002	8	8.400	5.340	30.972	115.000	107.663	92.968	0.000	0.000	0.000	8.000	100.000	15.341	17.588	6.327	0.000	0.000	6.740	514.339	15.743	530.082
2002	9	7.812	4.840	28.798	96.000	102.241	90.421	0.000	0.000	0.000	8.000	100.000	15.341	17.588	6.103	0.000	0.000	6.700	483.844	14.810	498.654
2002	10	5.112	2.900	16.583	79.000	76.651	62.274	0.000	0.000	0.000	8.000	100.000	15.341	17.588	0.880	0.000	0.000	6.760	391.089	11.971	403.060
2002	11	6.324	3.080	14.149	76.000	75.788	45.742	0.000	0.000	0.000	8.000	100.000	15.341	17.588	0.000	0.000	0.000	6.700	368.712	11.286	379.998
2002	12	6.912	3.460	16.503	79.000	92.659	58.683	0.000	0.000	0.000	8.000	100.000	15.341	17.588	0.019	0.000	0.000	6.740	404.905	12.394	417.299

AEPCO
2003 Analysis of Monthly Peak Demands

Attachment B

Relationship of Total System Monthly Peaks to Annual Peak

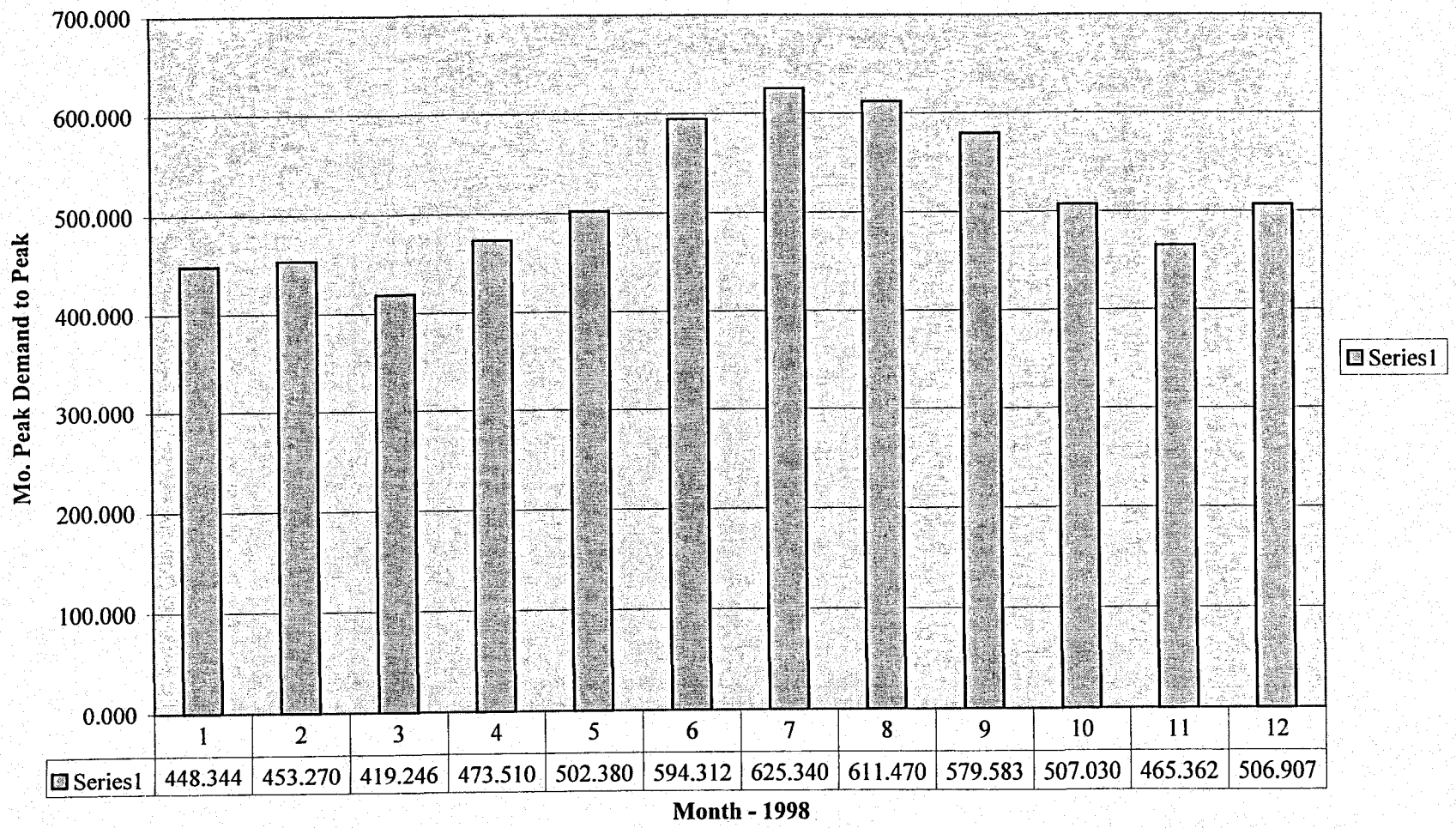
Line No.		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average %
1	1998	448.344	453.270	419.246	473.510	502.380	594.312	**625.340**	611.470	579.583	507.030	465.362	506.907	
2	% of peak	71.7%	72.5%	67.0%	75.7%	80.3%	95.0%	100.0%	97.8%	92.7%	81.1%	74.4%	81.1%	82.4%
3	1999	440.592	441.512	418.653	432.413	503.442	580.050	**585.253**	568.347	536.896	489.116	422.141	457.080	
4	% of peak	75.3%	75.4%	71.5%	73.9%	86.0%	99.1%	100.0%	97.1%	91.7%	83.6%	72.1%	78.1%	83.7%
5	2000	478.681	458.554	464.251	537.419	608.435	618.876	**639.039**	639.780	599.147	567.796	477.887	482.052	
6	% of peak	74.8%	71.7%	72.6%	84.0%	95.1%	96.7%	99.9%	100.0%	93.6%	88.7%	74.7%	75.3%	85.6%
7	2001	494.189	497.681	462.057	503.290	598.675	639.689	**671.588**	633.780	602.680	519.665	488.851	518.307	
8	% of peak	73.6%	74.1%	68.8%	74.9%	89.1%	95.3%	100.0%	94.4%	89.7%	77.4%	72.8%	77.2%	82.3%
9	2002	412.849	409.456	381.253	418.004	501.220	521.179	**539.968**	530.082	498.654	403.060	379.998	417.299	
10	% of peak	76.5%	75.8%	70.6%	77.4%	92.8%	96.5%	100.0%	98.2%	92.3%	74.6%	70.4%	77.3%	83.5%
11	Five-year % average (simple avg)	74.4%	73.9%	70.1%	77.2%	88.7%	**96.5%**	**100.0%**	**97.5%**	**92.0%**	81.1%	72.9%	77.8%	83.5%
12	Five year peak Mw average	454.931	452.095	429.092	472.927	542.830	590.821	**612.238**	596.692	563.392	497.333	446.848	476.329	
13	% of peak (weighted average)	74.3%	73.8%	70.1%	77.2%	88.7%	**96.5%**	**100.0%**	**97.5%**	**92.0%**	81.2%	73.0%	77.8%	83.5%

Test based upon Line 13:
5-Year Average Data

Test 1	**Average June-September Peaks**	**96.5%**
	Average All-Other Months	**77.0%**
	Difference	**19.5%**
Test 2	**Lowest Average Peak to Peak**	**70.1%**
Test 3	**Average 12 Peaks to Peak**	**83.5%**

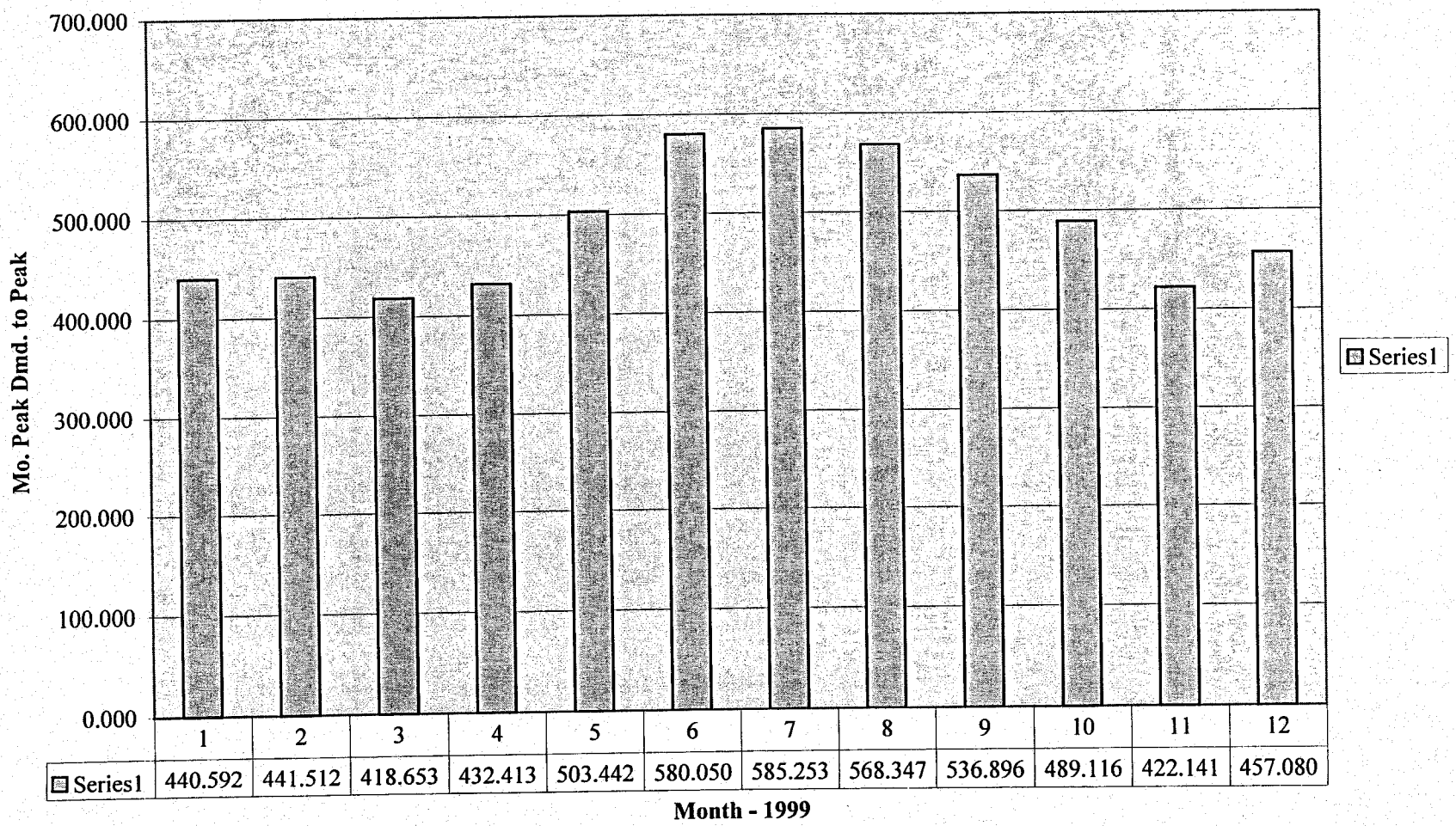
(1) Monthly loads taken from Attachment A.

AEPCO - 1998 Peak Demands



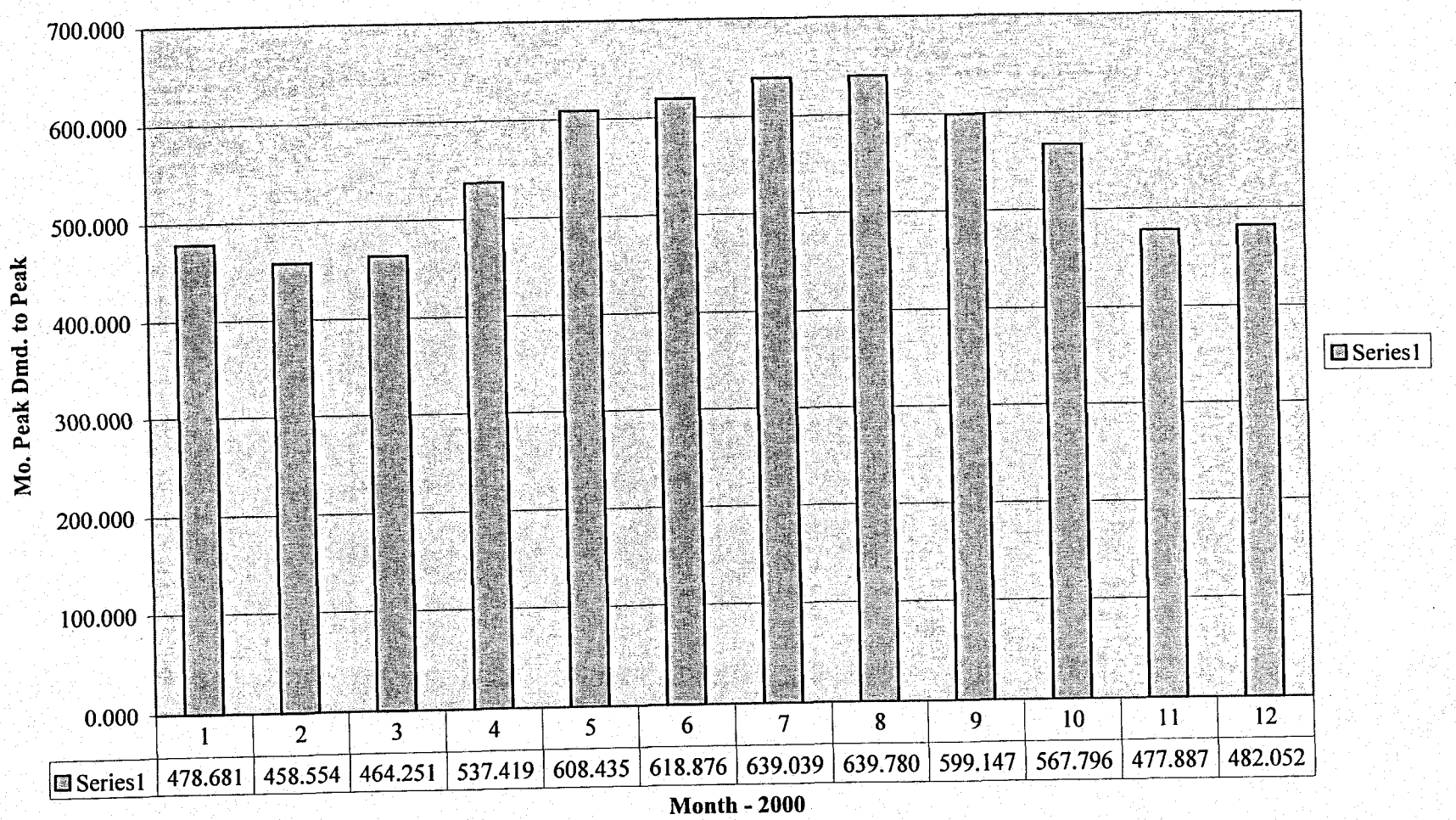
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	448.344	453.270	419.246	473.510	502.380	594.312	625.340	611.470	579.583	507.030	465.362	506.907

AEPCO - 1999 Peak Demands



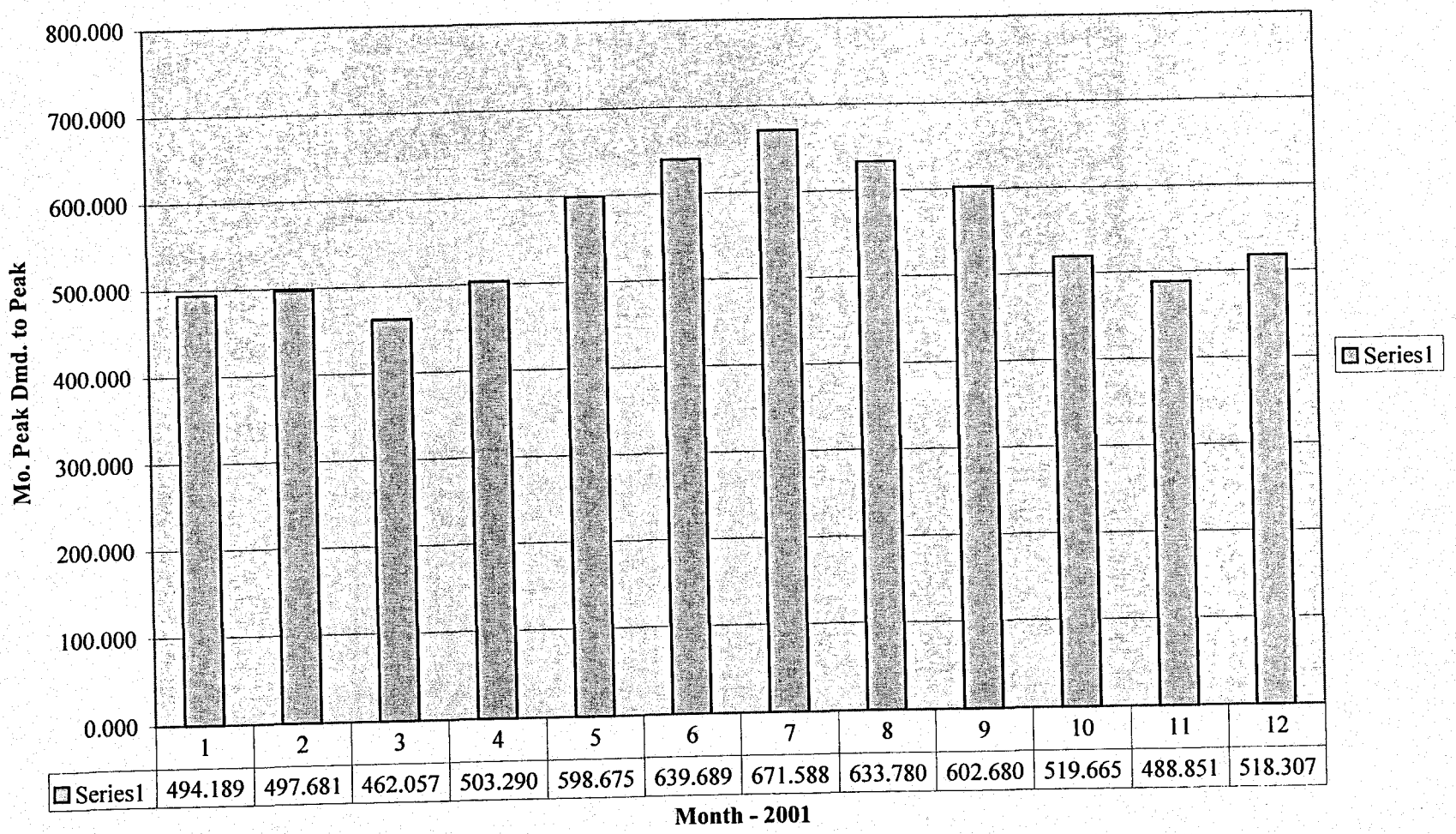
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	440.592	441.512	418.653	432.413	503.442	580.050	585.253	568.347	536.896	489.116	422.141	457.080

AEPCO - 2000 Peak Demands



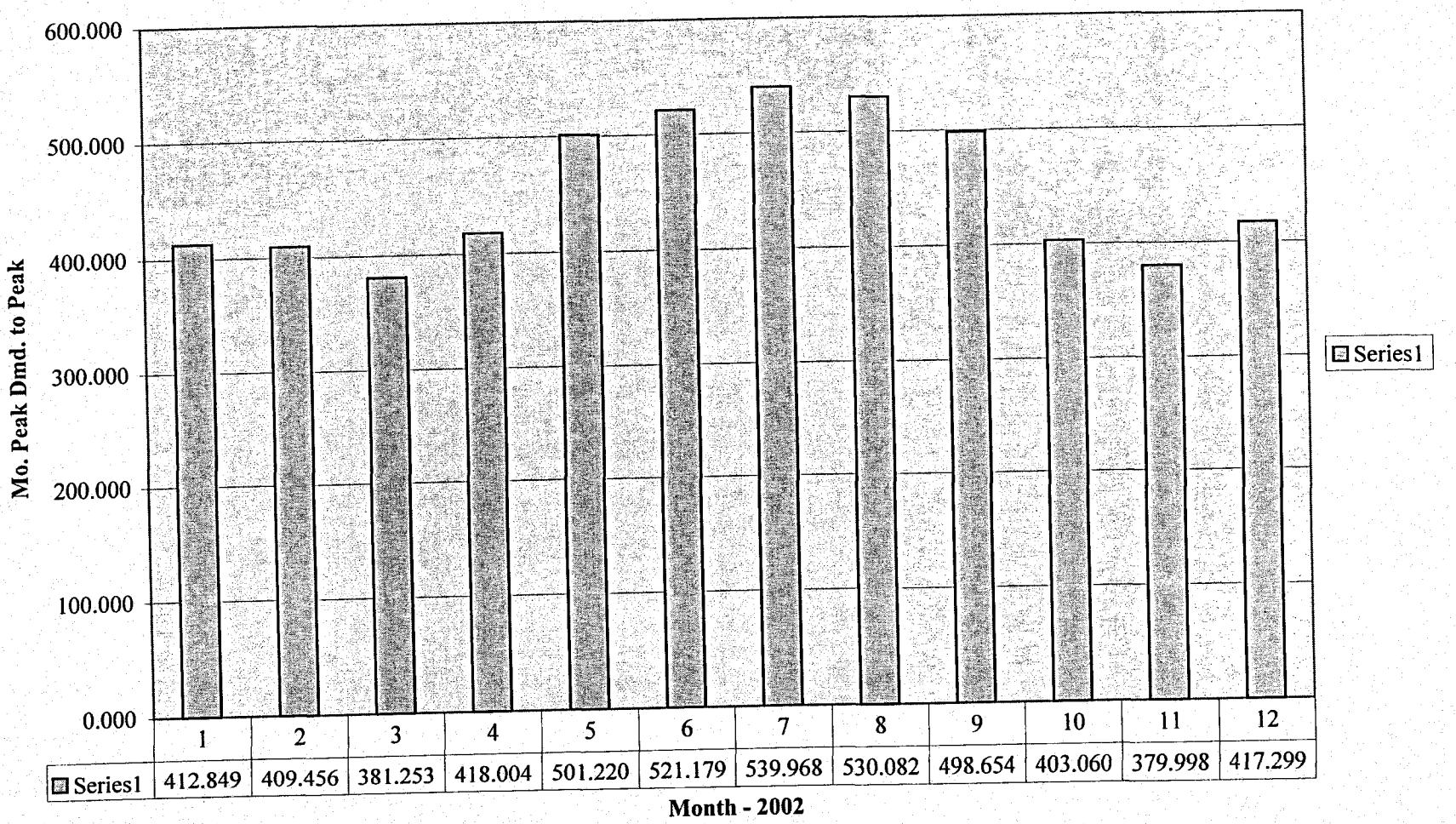
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	478.681	458.554	464.251	537.419	608.435	618.876	639.039	639.780	599.147	567.796	477.887	482.052

AEPCO - 2001 Peak Demands



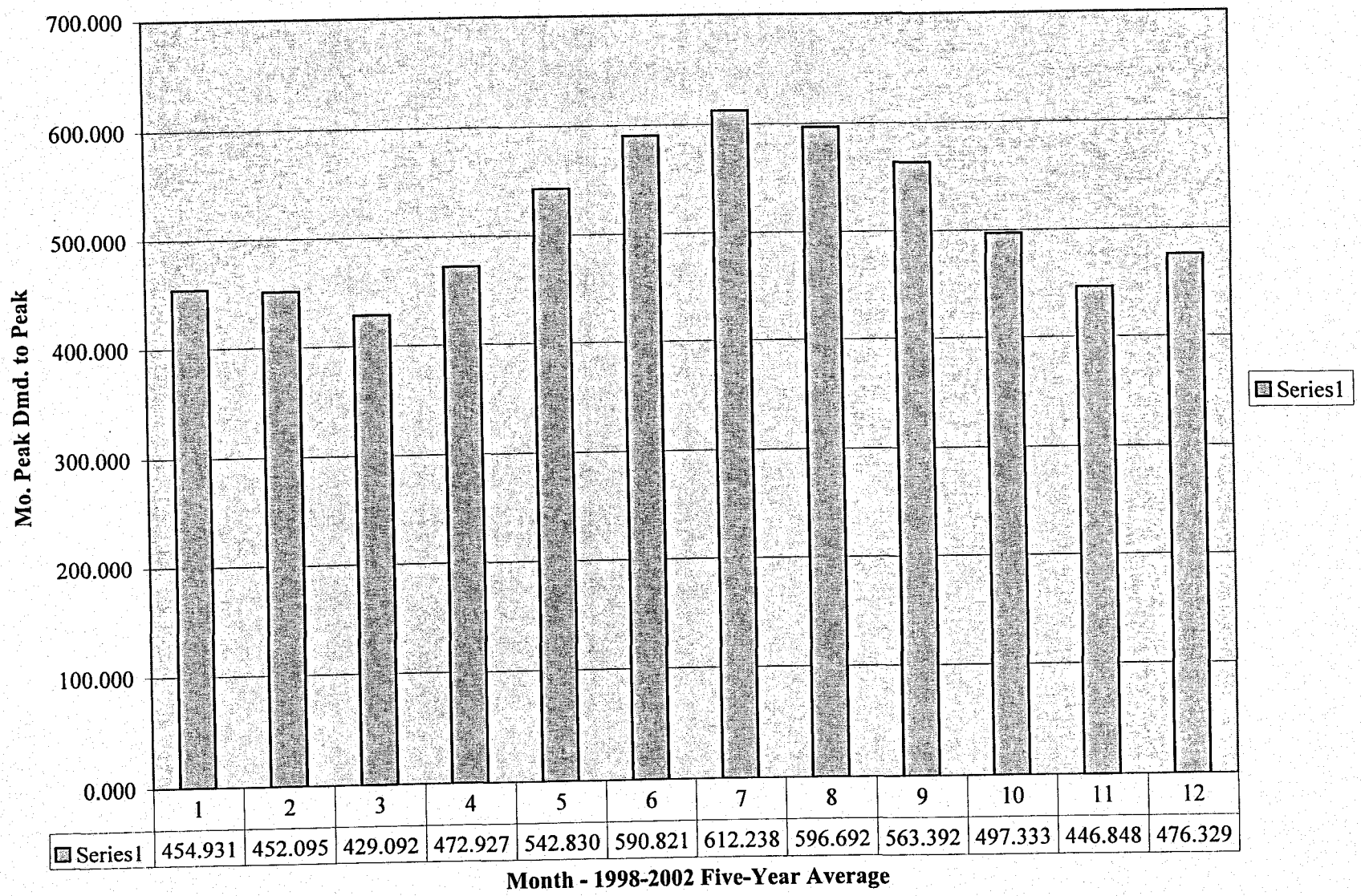
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	494.189	497.681	462.057	503.290	598.675	639.689	671.588	633.780	602.680	519.665	488.851	518.307

AEPCO - 2002 Peak Demands



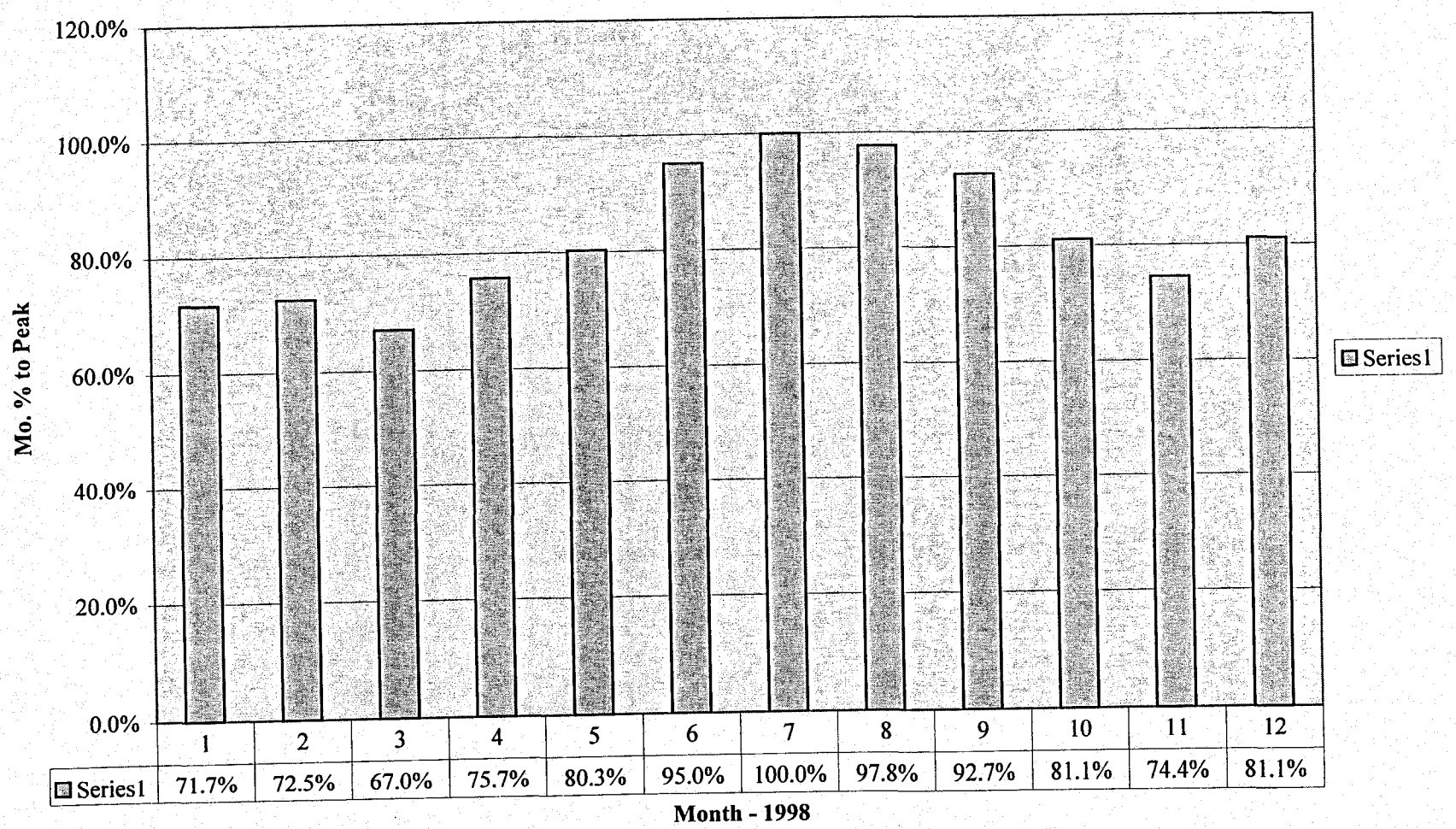
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	412.849	409.456	381.253	418.004	501.220	521.179	539.968	530.082	498.654	403.060	379.998	417.299

AEPCO Five-Year Avg. 1998-2002
Peak Demands



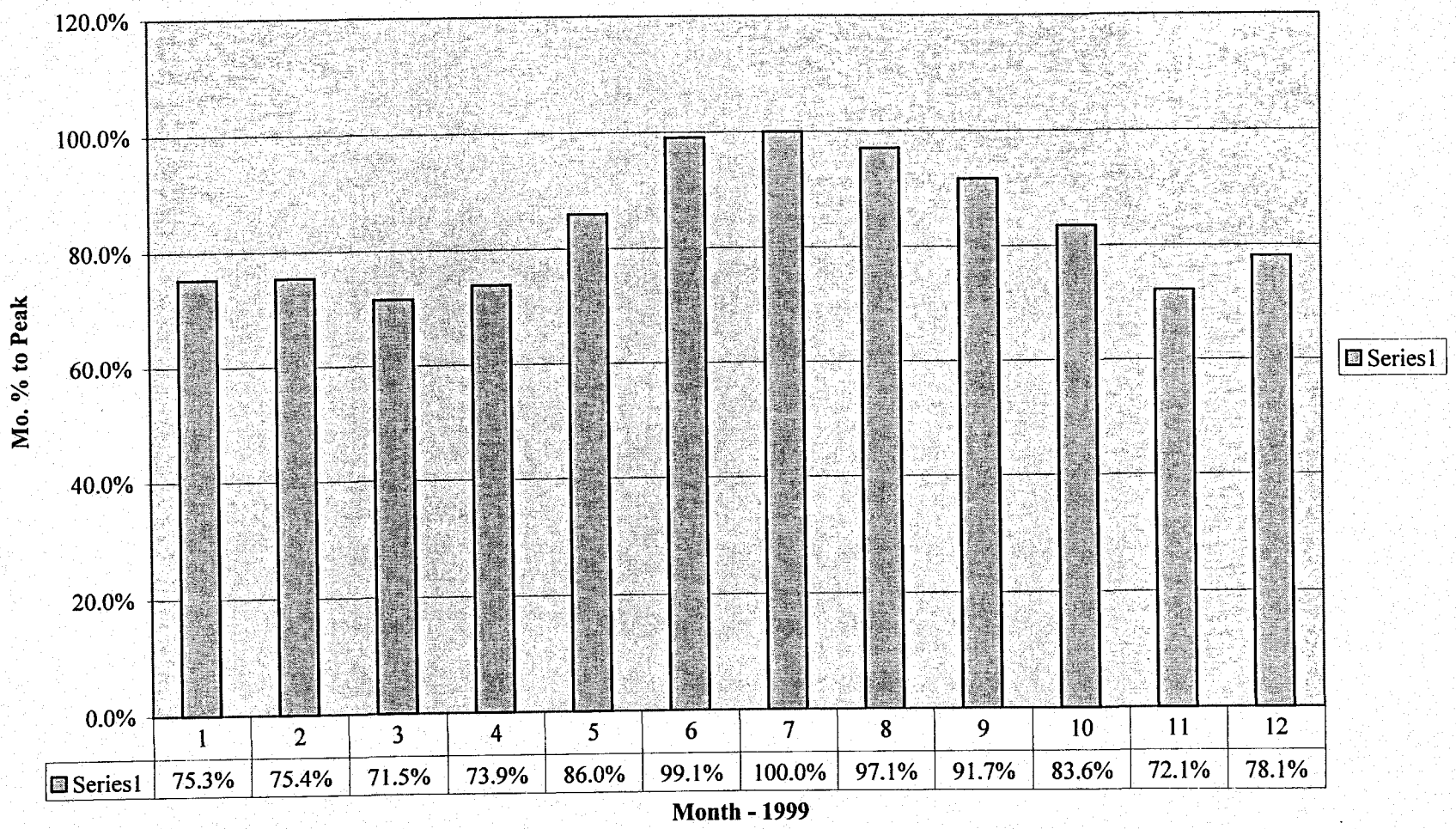
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	454.931	452.095	429.092	472.927	542.830	590.821	612.238	596.692	563.392	497.333	446.848	476.329

AEPCO 1998 - Peak %s



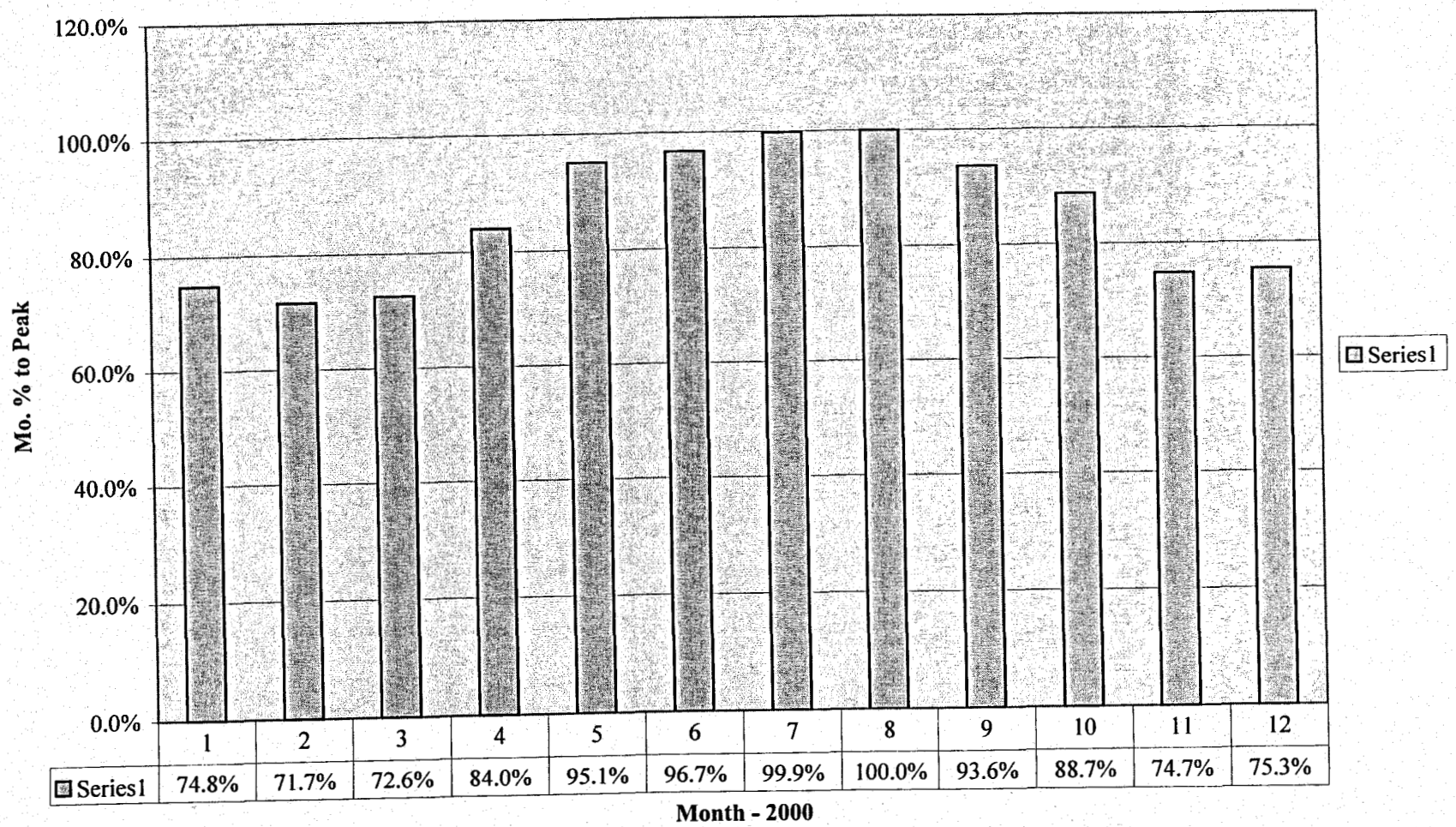
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	71.7%	72.5%	67.0%	75.7%	80.3%	95.0%	100.0%	97.8%	92.7%	81.1%	74.4%	81.1%

AEPCO - 1999 Peak %s



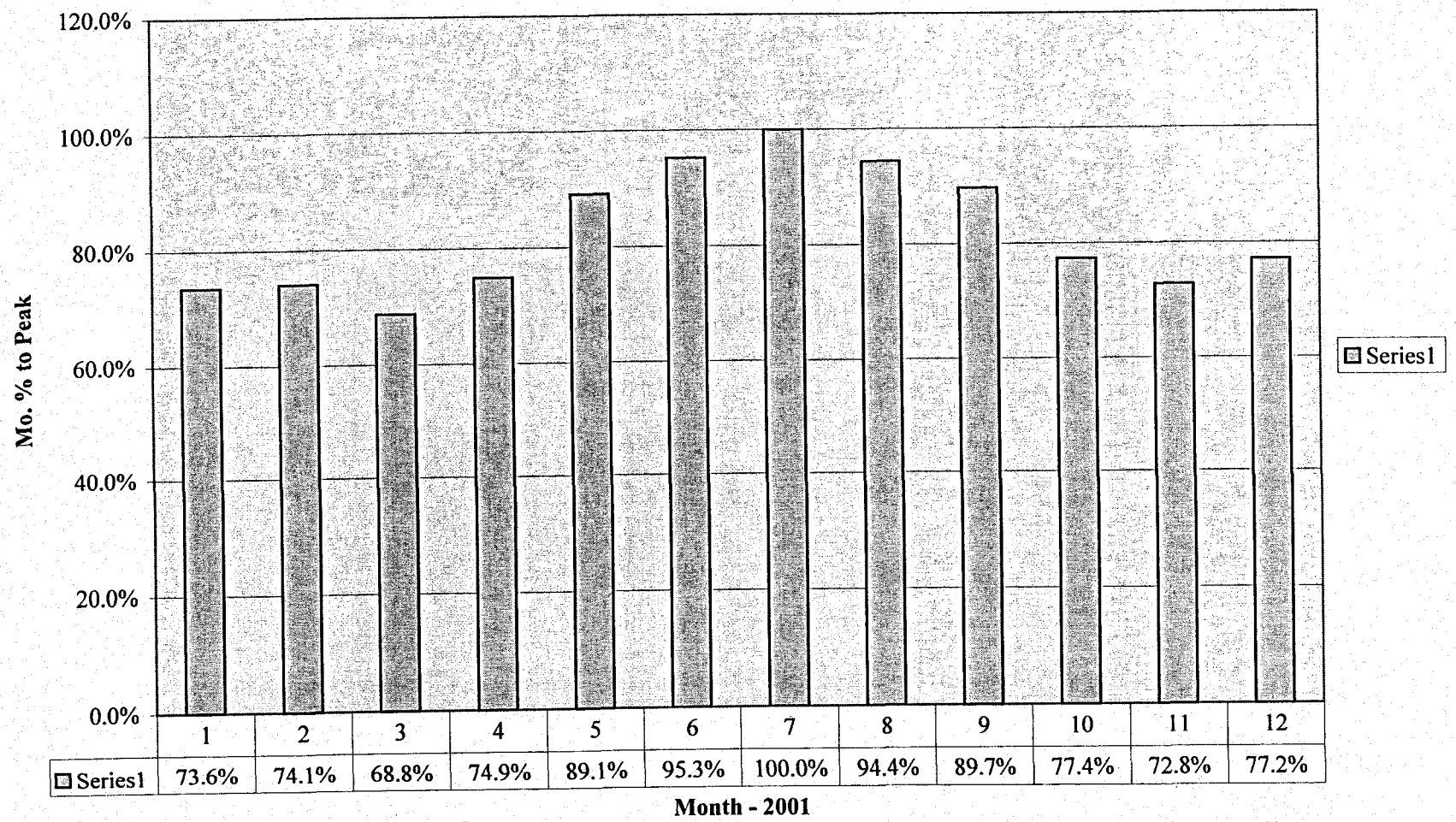
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	75.3%	75.4%	71.5%	73.9%	86.0%	99.1%	100.0%	97.1%	91.7%	83.6%	72.1%	78.1%

AEPCO - 2000 Peak %s



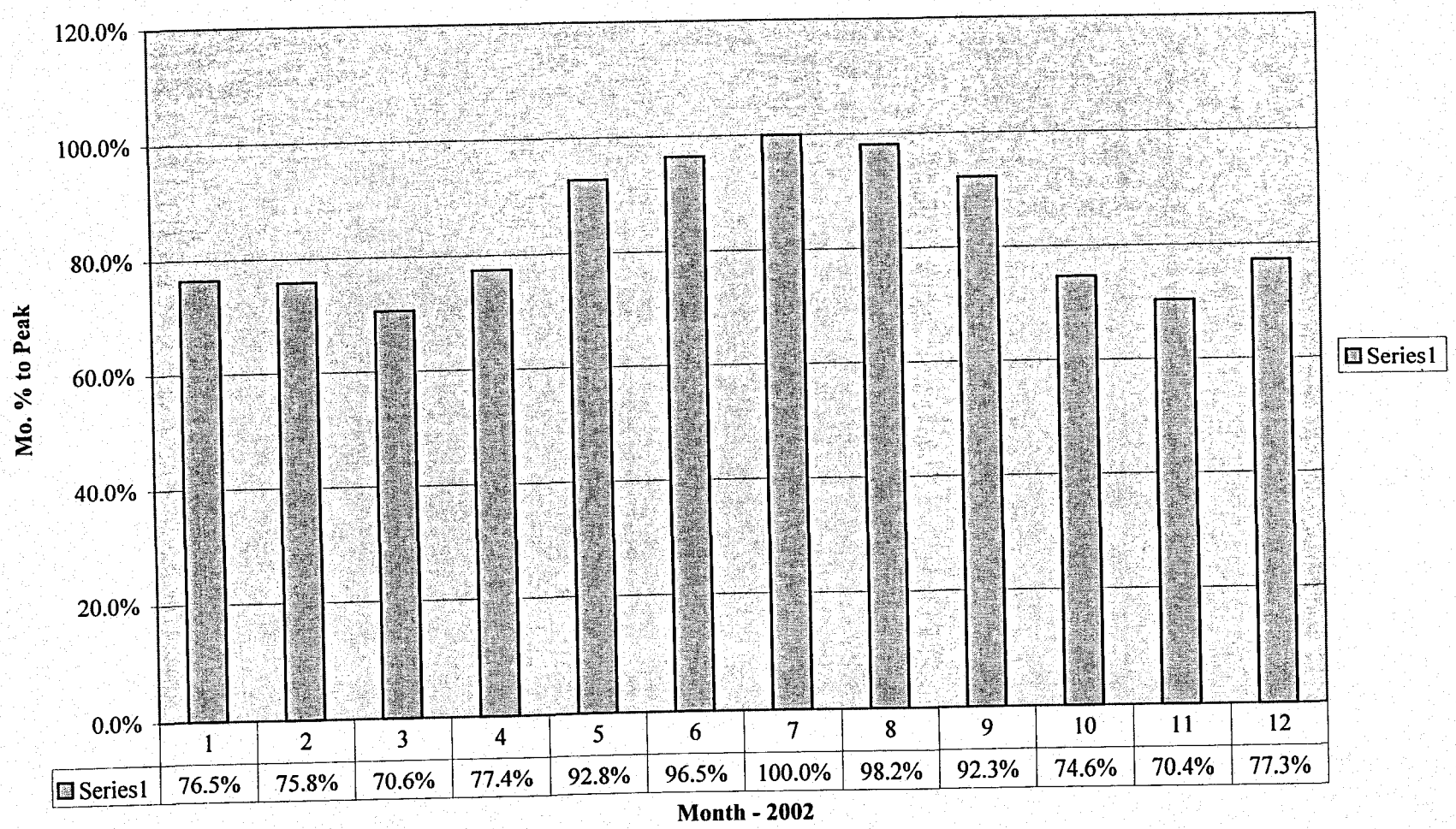
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	74.8%	71.7%	72.6%	84.0%	95.1%	96.7%	99.9%	100.0%	93.6%	88.7%	74.7%	75.3%

AEPCO - 2001 Peak %s



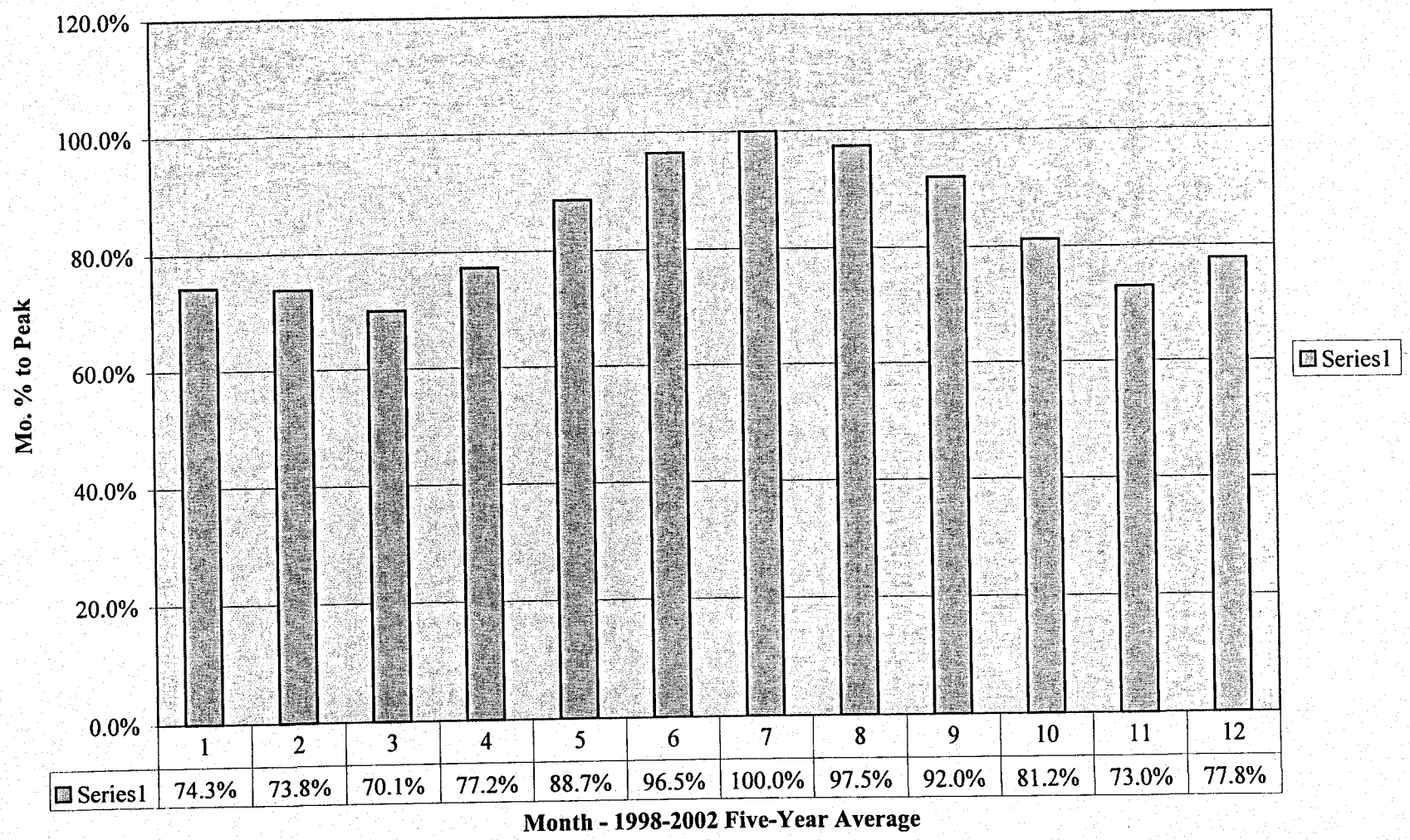
	1	2	3	4	5	6	7	8	9	10	11	12
Series1	73.6%	74.1%	68.8%	74.9%	89.1%	95.3%	100.0%	94.4%	89.7%	77.4%	72.8%	77.2%

AEPCO - 2002 Peak %s



	1	2	3	4	5	6	7	8	9	10	11	12
Series1	76.5%	75.8%	70.6%	77.4%	92.8%	96.5%	100.0%	98.2%	92.3%	74.6%	70.4%	77.3%

AEPCO Five-Year Avg. 1998-2002
Peak %s



	1	2	3	4	5	6	7	8	9	10	11	12
Series1	74.3%	73.8%	70.1%	77.2%	88.7%	96.5%	100.0%	97.5%	92.0%	81.2%	73.0%	77.8%

AEPCO's Installed Generating Capability and Long-Term Purchases by Month, 1998-2002

Month	Year	Installed Generation Apache CC-1 Capacity MW	Installed Generation Apache ST-2 Capacity MW	Installed Generation Apache ST-3 Capacity MW	Installed Generation Apache GT-2 Capacity MW	Installed Generation Apache GT-3 Capacity MW	Installed Generation Apache GT-4 Capacity MW	Firm Purchased Power PacifiCorp MW	Contingent Purchased Power Public Service of New Mexico MW	Firm Purchased Power SLC-IP Hydro MW	Firm Purchased Power Parker-Davis Hydro MW	Total Resources MW	Total Firm Purchases MW
January	1998	81.0	175.0	175.0	20.0	69.0	0.0	0.0	74.0	1.7	18.8	614.5	20.5
February	1998	81.0	175.0	175.0	20.0	69.0	0.0	0.0	74.0	1.3	12.6	607.9	13.9
March	1998	81.0	175.0	175.0	20.0	69.0	0.0	0.0	74.0	2.5	23.6	620.1	26.1
April	1998	81.0	175.0	175.0	20.0	69.0	0.0	0.0	74.0	7.4	23.8	625.2	31.2
May	1998	81.0	175.0	175.0	20.0	69.0	0.0	20.0	74.0	11.0	24.0	649.0	55.0
June	1998	81.0	175.0	175.0	20.0	69.0	0.0	61.0	73.0	12.0	24.0	690.0	97.0
July	1998	81.0	175.0	175.0	20.0	69.0	0.0	61.0	73.0	13.0	24.0	691.0	98.0
August	1998	81.0	175.0	175.0	20.0	69.0	0.0	61.0	73.0	14.0	24.0	692.0	99.0
September	1998	81.0	175.0	175.0	20.0	69.0	0.0	25.0	73.0	10.0	24.0	652.0	59.0
October	1998	81.0	175.0	175.0	20.0	69.0	0.0	0.0	74.0	2.0	12.0	608.0	14.0
November	1998	81.0	175.0	175.0	20.0	69.0	0.0	0.0	74.0	2.0	15.0	611.0	17.0
December	1998	81.0	175.0	175.0	20.0	69.0	0.0	0.0	74.0	3.0	19.0	616.0	22.0
January	1999	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.2	18.4	606.6	20.6
February	1999	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.2	18.4	606.6	20.6
March	1999	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.1	23.8	611.9	25.9
April	1999	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	8.6	23.8	618.4	32.4
May	1999	81.0	175.0	175.0	20.0	69.0	0.0	10.0	66.0	9.5	23.8	629.3	43.3
June	1999	81.0	175.0	175.0	20.0	69.0	0.0	42.0	66.0	11.1	23.8	662.9	76.9
July	1999	81.0	175.0	175.0	20.0	69.0	0.0	42.0	66.0	11.6	23.8	663.4	77.4
August	1999	81.0	175.0	175.0	20.0	69.0	0.0	42.0	66.0	11.6	23.8	663.4	77.4
September	1999	81.0	175.0	175.0	20.0	69.0	0.0	20.0	66.0	10.5	23.8	640.3	54.3
October	1999	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.1	18.4	606.5	20.5
November	1999	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.0	18.4	606.4	20.4
December	1999	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.3	18.4	606.7	20.7
January	2000	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.2	18.4	606.6	20.6
February	2000	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.2	18.4	606.6	20.6
March	2000	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.1	23.8	611.9	25.9
April	2000	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	8.6	23.8	618.4	32.4
May	2000	81.0	175.0	175.0	20.0	69.0	0.0	21.0	66.0	9.5	23.8	640.3	54.3
June	2000	81.0	175.0	175.0	20.0	69.0	0.0	57.0	66.0	11.1	23.8	677.9	91.9
July	2000	81.0	175.0	175.0	20.0	69.0	0.0	57.0	66.0	11.6	23.8	678.4	92.4
August	2000	81.0	175.0	175.0	20.0	69.0	0.0	57.0	66.0	11.6	23.8	678.4	92.4
September	2000	81.0	175.0	175.0	20.0	69.0	0.0	30.0	66.0	10.5	23.8	650.3	64.3
October	2000	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.1	18.4	606.5	20.5
November	2000	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.0	18.4	606.4	20.4
December	2000	81.0	175.0	175.0	20.0	69.0	0.0	0.0	66.0	2.3	18.4	606.7	20.7
January	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	66.0	2.6	18.4	604.0	21.0
February	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	66.0	2.6	18.4	604.0	21.0
March	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	66.0	2.6	23.8	609.4	26.4
April	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	66.0	2.6	23.8	609.4	26.4
May	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	66.0	12.5	23.8	619.3	36.3
June	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	12.5	23.8	643.3	36.3
July	2001	82.0	175.0	175.0	20.0	65.0	0.0	35.0	90.0	12.5	23.8	678.3	71.3
August	2001	82.0	175.0	175.0	20.0	65.0	0.0	35.0	90.0	12.5	23.8	678.3	71.3
September	2001	82.0	175.0	175.0	20.0	65.0	0.0	5.0	90.0	12.5	23.8	648.3	41.3
October	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	2.6	18.4	628.0	21.0
November	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	2.6	18.4	628.0	21.0
December	2001	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	2.6	18.4	628.0	21.0
January	2002	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	2.6	18.4	628.0	21.0
February	2002	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	2.6	18.4	628.0	21.0
March	2002	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	2.6	23.8	633.4	26.4
April	2002	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	2.6	23.8	633.4	26.4
May	2002	82.0	175.0	175.0	20.0	65.0	0.0	0.0	90.0	12.5	23.8	643.3	36.3
June	2002	82.0	175.0	175.0	20.0	65.0	0.0	0.0	15.0	12.5	23.8	568.3	36.3
July	2002	82.0	175.0	175.0	20.0	65.0	0.0	15.0	15.0	12.5	23.8	583.3	51.3
August	2002	82.0	175.0	175.0	20.0	65.0	0.0	15.0	15.0	12.5	23.8	583.3	51.3
September	2002	82.0	175.0	175.0	20.0	65.0	0.0	0.0	15.0	12.5	23.8	568.3	36.3
October	2002	82.0	175.0	175.0	20.0	65.0	38.0	0.0	15.0	2.6	18.4	591.0	21.0
November	2002	82.0	175.0	175.0	20.0	65.0	38.0	0.0	15.0	2.6	18.4	591.0	21.0
December	2002	82.0	175.0	175.0	20.0	65.0	38.0	0.0	15.0	2.6	18.4	591.0	21.0

Arizona Electric Power Cooperative, Inc.
2003 Analysis of $Monthly Loads

Attachment F

5-Year Average Reserves as % of Load and Capacity

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AEPCo Total Resources (Mw)												
1998	614.500	607.900	620.100	625.200	649.000	690.000	691.000	692.000	652.000	608.000	611.000	616.000
1999	606.600	606.600	611.900	618.400	629.300	662.900	663.400	663.400	640.300	606.500	606.400	606.700
2000	606.600	606.600	611.900	618.400	640.300	677.900	678.400	678.400	650.300	606.500	606.400	606.700
2001	603.978	603.978	609.378	609.378	619.347	643.347	678.347	678.347	648.347	627.978	627.978	627.978
2002	627.978	627.978	633.378	633.378	643.347	568.347	583.347	583.347	568.347	590.978	590.978	590.978
Maintenance Capacity												
1998				175.000								
1999			175.000	175.000								
2000		81.000		175.000								
2001				175.000								
2002				175.000								
Firm Purchases												
1998	20.500	13.900	26.100	31.200	55.000	97.000	98.000	99.000	59.000	14.000	17.000	22.000
1999	20.600	20.600	25.900	32.400	43.300	76.900	77.400	77.400	54.300	20.500	20.400	20.700
2000	20.600	20.600	25.900	32.400	54.300	91.900	92.400	92.400	64.300	20.500	20.400	20.700
2001	20.978	20.978	26.378	26.378	36.347	36.347	71.347	71.347	41.347	20.978	20.978	20.978
2002	20.978	20.978	26.378	26.378	36.347	36.347	51.347	51.347	36.347	20.978	20.978	20.978
Available Capacity												
(Total capacity less maintenance capacity less firm purchases)												
1998	594.000	594.000	594.000	419.000	594.000	593.000	593.000	593.000	593.000	594.000	594.000	594.000
1999	586.000	586.000	411.000	411.000	586.000	586.000	586.000	586.000	586.000	586.000	586.000	586.000
2000	586.000	505.000	586.000	411.000	586.000	586.000	586.000	586.000	586.000	586.000	586.000	586.000
2001	583.000	583.000	583.000	408.000	583.000	607.000	607.000	607.000	607.000	607.000	607.000	607.000
2002	607.000	607.000	607.000	432.000	607.000	532.000	532.000	532.000	532.000	570.000	570.000	570.000
5-yr avg. avail. Capacity	591.200	575.000	556.200	416.200	591.200	580.800	580.800	580.800	580.800	588.600	588.600	588.600
AEPCo Total Load At Generation (Mw)												
1998	448.344	453.270	419.246	473.510	502.380	594.312	625.340	611.470	579.583	507.030	465.362	506.907
1999	440.592	441.512	418.653	432.413	503.442	580.050	585.253	536.896	536.896	489.116	422.141	457.080
2000	478.681	458.554	464.251	537.419	608.435	618.876	639.039	639.780	599.147	567.796	477.887	482.052
2001	494.189	497.681	462.057	503.290	598.675	639.689	671.588	633.780	602.680	519.665	488.851	518.307
2002	412.849	409.456	381.253	418.004	501.220	521.179	539.968	530.082	498.654	403.060	379.998	417.299
Firm Purchases												
1998	20.500	13.900	26.100	31.200	55.000	97.000	98.000	99.000	59.000	14.000	17.000	22.000
1999	20.600	20.600	25.900	32.400	43.300	76.900	77.400	77.400	54.300	20.500	20.400	20.700
2000	20.600	20.600	25.900	32.400	54.300	91.900	92.400	92.400	64.300	20.500	20.400	20.700
2001	20.978	20.978	26.378	26.378	36.347	36.347	71.347	71.347	41.347	20.978	20.978	20.978
2002	20.978	20.978	26.378	26.378	36.347	36.347	51.347	51.347	36.347	20.978	20.978	20.978

Arizona Electric Power Cooperative, Inc.
2003 Analysis of $Monthly Loads

Attachment F

5-Year Average Reserves as % of Load and Capacity

Adjusted Net Load												
(AEPCO total load minus firm purchases)												
1998	427.844	439.370	393.146	442.310	447.380	497.312	527.340	512.470	520.583	493.030	448.362	484.907
1999	419.992	420.912	392.753	400.013	460.142	503.150	507.853	459.496	482.596	468.616	401.741	436.380
2000	458.081	437.954	438.351	505.019	554.135	526.976	546.639	547.380	534.847	547.296	457.487	461.352
2001	473.211	476.703	435.679	476.912	562.328	603.342	600.241	562.433	561.333	498.687	467.873	497.329
2002	391.871	388.478	354.875	391.626	464.873	484.832	488.621	478.735	462.307	382.082	359.020	396.321
5-year average load	434.200	432.683	402.961	443.176	497.771	523.122	534.139	512.103	512.333	477.942	426.897	455.258
Reserves												
(Available capacity minus adjusted load)												
1998	166.156	154.630	200.854	-23.310	146.620	95.688	65.660	80.530	72.417	100.970	145.638	109.093
1999	166.008	165.088	18.247	10.987	125.858	82.850	78.147	126.504	103.404	117.384	184.259	149.620
2000	127.919	67.046	147.649	-94.019	31.865	59.024	39.361	38.620	51.153	38.704	128.513	124.648
2001	109.789	106.297	147.321	-68.912	20.672	3.658	6.759	44.567	45.667	108.313	139.127	109.671
2002	215.129	218.522	252.125	40.374	142.127	47.168	43.379	53.265	69.693	187.918	210.980	173.679
5-year average reserves	157.000	142.317	153.239	-26.976	93.429	57.678	46.661	68.697	68.467	110.658	161.703	133.342
Reserves as % of Adjusted Net Load												
1998	38.84%	35.19%	51.09%	-5.27%	32.77%	19.24%	12.45%	15.71%	13.91%	20.48%	32.48%	22.50%
1999	39.53%	39.22%	4.65%	2.75%	27.35%	16.47%	15.39%	27.53%	21.43%	25.05%	45.87%	34.29%
2000	27.93%	15.31%	33.68%	-18.62%	5.75%	11.20%	7.20%	7.06%	9.56%	7.07%	28.09%	27.02%
2001	23.20%	22.30%	33.81%	-14.45%	3.68%	0.61%	1.13%	7.92%	8.14%	21.72%	29.74%	22.05%
2002	54.90%	56.25%	71.05%	10.31%	30.57%	9.73%	8.88%	11.13%	15.08%	49.18%	58.77%	43.82%
5-yr avg. reserves/adj. load	36.16%	32.89%	38.03%	-6.09%	18.77%	11.03%	8.74%	13.41%	13.36%	23.15%	37.88%	29.29%
Reserves as % of Available Capacity												
1998	27.97%	26.03%	33.81%	-5.56%	24.68%	16.14%	11.07%	13.58%	12.21%	17.00%	24.52%	18.37%
1999	28.33%	28.17%	4.44%	2.67%	21.48%	14.14%	13.34%	21.59%	17.65%	20.03%	31.44%	25.53%
2000	21.83%	13.28%	25.20%	-22.88%	5.44%	10.07%	6.72%	6.59%	8.73%	6.60%	21.93%	21.27%
2001	18.83%	18.23%	25.27%	-16.89%	3.55%	0.60%	1.11%	7.34%	7.52%	17.84%	22.92%	18.07%
2002	35.44%	36.00%	41.54%	9.35%	23.41%	8.87%	8.15%	10.01%	13.10%	32.97%	37.01%	30.47%
5-yr avg. reservs/Avail Cap.	26.56%	24.75%	27.55%	-6.48%	15.80%	9.93%	8.03%	11.83%	11.79%	18.80%	27.47%	22.65%

PENGAD-Bayonne, N.J.
EXHIBIT
AEPCO-6
ADMITTED

DIRECT TESTIMONY OF
WILLIAM K. EDWARDS
BEFORE THE
ARIZONA CORPORATION COMMISSION
ON BEHALF OF
ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Q. What is your name and business address?

A. My name is William K. Edwards. My business address is 2201 Cooperative Way, Herndon, Virginia, 20171.

Q. By whom are you employed, and in what capacity?

A. I am employed by the National Rural Utilities Cooperative Finance Corporation ("CFC") as an economist and Vice President of Regulatory Affairs. In that capacity I am responsible for testifying about and advising on regulatory issues of cooperatives before the FERC and many state commissions.

Q. What is your educational background and experience?

A. I received my B.S. Degree in Business with a concentration in economics from Christopher Newport College of the College of William & Mary in 1977, and

an M.A. degree in Economics from Old Dominion University in 1979. My major fields of study included mathematical economics, econometrics and microeconomics. I have completed a number of courses toward a Ph.D. in Economics from the Virginia Polytechnic Institute & State University. I have worked for the firm of Ernst & Ernst as a consultant principally in the electric utility industry. From 1982 to 1985, I was employed by Mississippi Power & Light Company (Entergy - Mississippi) as a supervisor responsible for rate research. From January 1986 until early 1995, I was employed by Central Louisiana Electric Company, Inc. as Manager of Rate Research and subsequently as Director of Rates. In that capacity I was responsible for regulatory affairs, regulatory accounting, rate design, cost of service studies, rate administration and the attendant litigation associated with regulatory issues before both the Louisiana Public Service Commission and the Federal Energy Regulatory Commission. Since 1996, I have been employed by CFC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support AEPCO's request for a Debt Service Coverage Ratio ("DSCR") of 1.05 and a Times Interest Earned Ratio ("TIER") of 1.29.

THE ROLE OF CFC

Q. What is CFC?

A. CFC was incorporated as a private, not-for-profit cooperative association under the laws of the District of Columbia in April 1969. The principal purpose of CFC is to provide its members with a dependable source of low-cost capital and state-of-the-art financial products and services. CFC provides its members with a source of financing to supplement the loan programs of the Rural Utilities Service ("RUS") of the United States Department of Agriculture, which is the successor agency of the Rural Electrification Administration. CFC is owned by and makes loans primarily to its rural utility system members to enable them to acquire, construct and operate electric distribution, generation, transmission, and related facilities. CFC also provides guarantees on debt to its members for tax-exempt financings of pollution control facilities and other properties constructed or acquired by its members, debt in connection with certain leases and various other transactions.

CFC had 1,546 members as of February 29, 2004, including 898 electric utility members, virtually all of whom are consumer-owned cooperatives. The utility members included 827 distribution systems and 71 generation and transmission ("power supply") systems operating in 49 states and four U.S. territories.

Q. How does CFC obtain the funds it lends to cooperative utilities?

A. CFC functions as both a borrower and a lender. As a lender, CFC makes short-, medium- and long-term loans to its member systems. As security for its long-term loans, CFC receives a first mortgage on its borrowers' facilities. These mortgages and related mortgage notes are in turn used as security for CFC collateral trust bonds issued in the public capital market. Through the sale of such bonds, as well as commercial paper and other debt instruments, CFC obtains capital on behalf of its member borrowers. In this role, CFC acts as a borrower.

CFC issues long-, medium- and short-term debt in both the domestic and foreign capital markets. CFC issues long-term secured collateral trust bonds, unsecured medium-term notes, unsecured quarterly income capital securities and unsecured commercial paper. CFC's collateral trust bonds, medium-term notes, quarterly income capital securities and commercial paper all carry investment grade ratings from three rating agencies (Standard & Poors, Moodys and Fitch).

CFC also sells unsecured commercial paper and medium-term notes to its members. In addition, members may invest in the daily liquidity program, which can be withdrawn by the members on demand.

Consequently, CFC has a great interest in rate of return issues, including but not limited to, the appropriate DSCR and TIER ratio, equity management and the associated issue of return on equity.

Q. Is AEPCO a member of CFC?

A. Yes. AEPCO is a member of CFC and has long-term loans with CFC totaling $40,963,908 concurrent with the RUS.

Q. In what ways does AEPCO differ from an investor-owned utility?

A. The main difference between an investor-owned utility and an electric cooperative is the form of ownership. In the investor-owned utility, stockholders own the equity of the utility and ratepayers (the customers) are not entitled to the benefits of equity holders. Investor-owned utilities typically have a Board of Directors separate from the customers of the utility. Therefore, there is an implicit conflict associated with investor-owned utilities; the interests of the equity owners are different from the interests of the customers. In the past, vertically integrated electric utilities were regarded as a monopoly whose goal was to maximize profits to the stockholders at the expense of its customers. As such, both State and Federal governments instituted rate regulation to control such behavior.

In a cooperative, the customers own the equity. Hence, the benefits of being an equity holder belong to the customer. There are a number of benefits that accrue to customers of cooperative organizations including a return of excess margins and, all things being equal, lower cost electricity. In a cooperative, the Board of

Directors is comprised of customers that are democratically elected. As such, the conflict present with investor-owned utilities is not present with cooperative structures because the customers, the decision-makers and equity owners are the same people. As Mr. Minson has discussed in his testimony, this rate increase request has already faced the scrutiny of AEPCO's Board of Directors who are themselves customers and who represent the interests of other equity owners. Although aware of the differences, sometimes regulators forget that, as a result of the cooperative structure, there is no incentive to maximize prices or otherwise charge a profit on sales to its members. Additionally, should customers of cooperatives become convinced that a specific rate increase or other action is unnecessary or unwise, they have their remedy of representational rights before the Board of Directors.

Q. What are some of the specific criteria that creditors like CFC use to evaluate the credit worthiness of cooperative utilities like AEPCO?

A. With the onset of electric deregulation in the mid-1990s as well as other more subtle changes to the utility industry, CFC has reevaluated its lending policies in an attempt to better manage its portfolio. The revisiting of lending policies is a continuing process to challenge CFC in its efforts to provide low cost capital to its members. Although the credit decisions relating to specific

applicants are "fact specific" decisions, there are company specific criteria that are considered by CFC prior to it issuing credit.

In evaluating the credit quality of cooperative utilities like AEPCO, CFC continues to focus on several key factors: management, rates, generation and distribution facilities, regulation, demographics, financial performance and legal provisions.

With respect to financial evaluations, CFC has devised a list of key financial ratios that are used to supplement its credit decisions. The "G&T Trend Analysis" provides a generalized and quick method for credit analysts to preliminarily evaluate a G&T cooperative. The G&T Trend Analysis is based on: (1) reviews of audit reports, (2) evaluations of prospective financial models and their underlying assumptions and (3) discussions with management regarding financial performance which form the basis of CFC's evaluation.

Table 1 below illustrates several of the more key parameters for AEPCO over the past several years.

Table 1
Key Ratios

Year	TIER	MDSC	Equity Ratio[1]
1997	1.69	NA	-5.78%
1998	1.64	1.13	-2.37%
1999	1.26	0.93	-1.12%
2000	1.66	1.19	2.11%
2001	1.65	1.25	5.40%
2002	1.30	0.98	6.67%
2003	0.42	0.62	4.13%

Exhibit WKE-1 contrasts AEPCO's results to a pool of 55 G&Ts. Table 1 and the Exhibit illustrate that AEPCO's financial posture has been improving in recent years, but that progress was halted in the 2003 test year. Its proposed TIER and DSCR ratios are roughly comparable to pool results, but its equity is considerably below the pool average.

Q. Please explain the importance to a rural electric cooperative of developing and maintaining an adequate equity level.

A. Congress established the Rural Electric Administration in 1936 to provide funding for electric cooperatives to extend their lines and make central station power available in rural areas. Under the original Act, the government provided 100% financing and the need for equity capital was not required.

In 1973, Congress amended the Rural Electrification Act. It established the rural electric revolving fund and required rural electrics to borrow a portion of

[1] Total Equity/Total Assets.

their long-term capital needs from supplemental sources. Because private capital (like CFC) was now required, it was necessary to establish financial standards in order to access affordable funding from the competitive capital markets.

Q. Is equity an important consideration in securing private source capital?

A. Yes. CFC works closely with all its borrowers to assist them in building an appropriate equity level in order to achieve a capital structure that will allow them to attract private capital. CFC makes recommendations designed to manage equity in order to continue to have access to reasonably priced private capital.

Q. Does CFC have an interest in the amount of equity that AEPCO maintains?

A. Yes. CFC is vitally interested in AEPCO's capitalization as well as every other cooperative that seeks financing from CFC. This interest is on an individual as well as a collective basis since the overall position of the borrowers like AEPCO as a group is what CFC proffers to the market. The industry's equity ratios affect the attitudes of investors in CFC securities. Should the overall equity position of electric cooperative utilities change, investors can be expected to react toward CFC securities, as they would towards the securities of an investor-owned utility. If the overall equity ratio

of electric cooperatives declines, the investors would perceive an increase in risk and would demand a higher risk premium associated with the cost of debt.

Q. How Does AEPCO's equity ratio compare to other cooperatives?

A. At the end of the 2003 test year, the equity ratio of total capitalization was approximately 4.13%. At December 31, 2002, the equity ratio was 6.67%. By contrast, G&T cooperatives had a median equity ratio at the end of 2002 of 13.22%.

Q. Why is it important for AEPCO to develop a stronger equity base?

A. The lower the equity ratio, the higher the annual charges for interest expense, and the greater the margin requirements to maintain an adequate DSCR and TIER. As the blended cost of long-term debt rises, the requirements to achieve adequate operating ratios will become more difficult unless the equity ratio is increased.

For this reason, I support both AEPCO and this Commission's efforts to establish long-range goals for AEPCO equity (Decision Nos. 64227 and 65210). Over the past five years, AEPCO has been improving its financial health. Prompt and adequate action on this rate request will return AEPCO to that course.

Q. What is your recommendation for appropriate DSCR and TIER ratios at this time for AEPCO?

A. AEPCO is requesting a TIER and DSCR ratio of 1.29 and 1.05, respectively. In my opinion, these are minimum ratios to provide some financial stability and allow for equity improvement.

Q. Will the requested DSCR and TIER in this case provide AEPCO with comparable security required by creditors?

A. Both will allow AEPCO to again make progress toward improved financial strength, although it has a long way to go. For example, Table 2 illustrates Standard & Poor's ("S&P's") median equity ratios and operating TIER requirements for utilities by financial rating of senior debt.

Table 2
S&P Median Values of
Utility Financial Ratings

Rating	Equity Ratio	Operating TIER
AA	50.3%	4.2
A	43.5%	3.0
BBB	37.4%	2.1
BB	34.6%	1.2

S&P rates senior debt beginning with the rating "AAA." An AAA rated utility has the highest rating assigned by S&P. The obligor's capacity to meet its financial commitment on its debt is extremely strong. In contrast, ratings of "BB" and below are regarded as having significant speculative characteristics.

1 Presently, the proposed operating TIER of 1.29 places AEPCO below
2 investment grade, while the present equity ratio, of course, is far below any of
3 the ratings.
4
5 Q. Would the proposed 1.29 TIER and 1.05 DSCR ratios allow AEPCO to
6 borrow money from CFC and RUS?
7 A. I believe it would qualify for lending by both organizations. Furthermore, it
8 will return AEPCO to its more recent course of gradual, but steady, financial
9 improvement. AEPCO, its members and the retail members they serve will all
10 benefit from that improvement.
11
12 Q. Does this conclude your testimony?
13 A. Yes, it does.
14

Exhibit WKE-1
AEPCO's Historical Parameters

	1997	1998	1999	2000	2001	2002
1 TIER						
ARIZONA ELECTRIC POWER COOPERATIVE	1.69	1.64	1.26	1.66	1.65	1.30
ALL G&TS	1.02	1.58	1.22	1.28	1.26	1.29
2 DSC						
ARIZONA ELECTRIC POWER COOPERATIVE	1.14	1.13	0.97	1.20	1.27	0.99
ALL G&TS	1.13	1.45	1.16	1.20	1.04	0.97
3 MDSC						
ARIZONA ELECTRIC POWER COOPERATIVE	N/A	1.13	0.93	1.19	1.25	0.98
ALL G&TS	N/A	1.24	1.10	1.12	1.00	0.95
4 EQUITY						
ARIZONA ELECTRIC POWER COOPERATIVE	-5.78%	-2.37%	-1.12%	2.11%	5.40%	6.67%
ALL G&TS	-2.78%	-0.25%	11.33%	11.52%	13.05%	13.22%

1204178/10421-36

EXHIBIT
AEPCO-7
ADMITTED
PENGAD-Bayonne, N.J.

Exhibit GEP-11

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

REVENUE REQUIREMENT - COMPANY REJOINDER POSITION

LINE NO.	DESCRIPTION	[A] COMPANY REBUTTAL POSITION	[B] STAFF SURREBUTTAL POSITION	[C] COMPANY REJOINDER POSITION Phase 1	[D] COMPANY REJOINDER POSITION Phase 2	[E] COMPANY REJOINDER POSITION Phase 3
1	Adjusted Operating Income (Loss)	$ 10,457,408	$ 10,425,443	$ 10,425,443	$ 10,425,443	$ 10,425,443
2	Depreciation and Amortization	$ 7,539,289	$ 7,539,289	$ 7,539,289	$ 7,539,289	$ 7,539,289
3	Income Tax Expense	-	-	-	-	-
4	Long-term Interest Expense	$ 13,313,164	$ 13,313,164	$ 13,313,164	$ 13,313,164	$ 13,313,164
5	Principal Repayment	$ 14,360,494	$ 14,360,494	$ 14,360,494	$ 14,360,494	$ 14,360,494
6a	Recommended Increase in Operating Revenue	$ 9,446,032	$ 9,477,998	$ 10,756,447	$ 1,300,817	$ 1,300,827
6b	Percent Increase (Line 6a / Line 7b) - Per Staff	6.80%	6.82%	7.74%	0.94%	0.94%
6c	Percent Increase (Line 6a / Line 7a) - Per Coop	10.92%	10.96%	12.44%	1.50%	1.50%
7a	Adjusted Class A Member Revenue	$ 86,473,931	$ 86,441,965	$ 86,441,965	$ 86,441,965	$ 86,441,965
7b	Adjusted Test Year Operating Revenue	$ 138,951,691	$ 138,919,725	$ 138,919,725	$ 138,919,725	$ 138,919,725
8	Recommended Annual Operating Revenue	$ 148,397,723	$ 148,397,723	$ 149,676,172	$ 150,976,989	$ 152,277,816
9a	Recommended Operating Margin Before Interest	$ 19,903,440	$ 19,903,441	$ 21,181,890	$ 22,482,707	$ 23,783,534
9b	Recommended Margins(Loss) After Interest	$ 6,247,886	$ 6,247,887	$ 7,526,336	$ 8,827,153	$ 10,127,980
10a	Operating TIER (L3+L9a)/L4	1.50	1.50	1.59	1.69	1.79
11a	Operating DSC (L2+L3+L9b)/(L4+L5)	0.99	0.99	1.04	1.08	1.13
12	Adjusted Rate Base	$ 189,637,810	$ 189,637,810	$ 189,637,810	$ 189,637,810	$ 189,637,810
13	Rate of Return (L9a / L12)	10.50%	10.50%	11.17%	11.86%	12.54%

References:
Column [A]: Rebuttal Exhibits GEP-3, GEP-5
Column [B]: Surrebuttal Schedules CSB-1, CSB-3
Column [C]: Gary Pierson Rejoinder Exhibits and Workpapers
Column [D]: Gary Pierson Rejoinder Exhibits and Workpapers
Column [E]: Gary Pierson Rejoinder Exhibits and Workpapers

Arizona Electric Power Cooperative, Inc.

Exhibit GEP-12

Docket No. E-01773A-04-0528

Test Year Ended December 31, 2003

SUMMARY OF PROPOSED RATES - COMPANY REJOINDER POSITION

Line No.	Description	[A] Company Rebuttal Position	[B] Staff Surrebuttal Position	[C] Company Rejoinder Position Phase 1	[D] Company Rejoinder Position Phase 2	[E] Company Rejoinder Position Phase 3
	Proposed Effective Dates (1)			July 1, 2005	July 1, 2006	July 1, 2007
1	All Requirements Members:					
2	Demand Rate - $/kW Month	$ 13.98	$ 13.99	$ 14.31	$ 14.64	$ 14.98
3	Energy Rate - $/kWh	$ 0.02073	$ 0.02073	$ 0.02073	$ 0.02073	$ 0.02073
4	Power Cost Adjustor Base - $/kWh	$ 0.01777	$ 0.01687	$ 0.01687	$ 0.01687	$ 0.01687
5	Partial Requirements Members:					
6	Fixed Charge - $/Month	$ 761,245	$ 758,466	$ 791,099	$ 822,728	$ 855,112
7	O&M Rate - $/kW Month	$ 7.07	$ 7.09	$ 7.15	$ 7.21	$ 7.26
8	Energy Rate - $/kWh	$ 0.02073	$ 0.02073	$ 0.02073	$ 0.02073	$ 0.02073
9	Power Cost Adjustor Base - $/kWh	$ 0.01694	$ 0.01603	$ 0.01603	$ 0.01603	$ 0.01603
10	Proposed Revenue Increase - ($000's):					
11	Anza	$ 167.5	$ 168.1	$ 195.3	$ 28.0	$ 28.1
12	Duncan Valley	101.2	101.1	117.6	16.9	16.9
13	Graham County	527.0	529.7	616.3	89.2	89.6
14	Mohave	4,432.9	4,424.3	4,898.4	455.8	452.1
15	Sulphur Springs	2,415.0	2,426.3	2,816.5	401.0	402.8
16	Trico	1,802.4	1,811.5	2,112.4	309.9	311.3
17	Total Class A	$ 9,446.0	$ 9,461.0	$ 10,756.5	$ 1,300.8	$ 1,300.8
18	Proposed Revenue Increase - Percent:					
19	Anza	8.60%	8.64%	10.04%	1.44%	1.44%
20	Duncan Valley	8.64%	8.67%	10.09%	1.45%	1.45%
21	Graham County	8.69%	8.74%	10.17%	1.47%	1.48%
22	Mohave	15.53%	15.50%	17.16%	1.60%	1.58%
23	Sulphur Springs	8.52%	8.57%	9.95%	1.42%	1.42%
24	Trico	8.83%	8.87%	10.35%	1.52%	1.53%
25	Total Class A	10.92%	10.94%	12.44%	1.50%	1.50%

(1) Proposed effective dates are based upon the assumption that the Commission will act upon the proposed Order in this proceeding at the June 2005 Open Meeting.

References:

Column [A] - Gary Pierson Rebuttal Exhibit GEP-4

Column [B] - Staff Witnesses Keene Surrebuttal Testimony and Workpapers

Column [C] - Gary Pierson Rejoinder Exhibits and Workpapers

Column [D] - Gary Pierson Rejoinder Exhibits and Workpapers

Column [E] - Gary Pierson Rejoinder Exhibits and Workpapers

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-04-0528

DIRECT TESTIMONY OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

ALL-STATE LEGAL®
EXHIBIT
S-1
ADMITTED

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EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

Arizona Electric Power Cooperative, Inc.

Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Cooperative") is a certificated electric generation cooperative that supplied power to six Class A, two Class B, and one Class C member during 2003. The rates requested in this case pertain only to the Class A members.

On July 23, 2004, AEPCO filed an application for a permanent rate increase. The Cooperative states that it incurred an adjusted test year operating loss of $4.5 million resulting in a times interest earned ratio ("TIER") lower than that required by its mortgage covenant agreements.

AEPCO proposed an $8,450,016, or 9.86 percent, revenue increase from $137,611,450 to $146,061,466. The proposed revenue increase would produce an operating margin of $16,422,692 for a 7.39 percent rate of return on an original cost rate base of $222,147,011. The $8,450,016 proposed revenue increase includes $1,887,958 of margin revenue and $6,562,058[1] of base cost of power revenue. Only the $1,887,958 margin increase is comparable to Staff's recommended revenue increase. AEPCO requests a 1.29 TIER.

Staff recommends a revenue requirement no less than the $146,061,466 proposed by AEPCO. This proposed revenue provides a $6,773,320, or 4.86 percent, revenue increase over Staff adjusted Test Year revenues of $139,288,146. Operating revenue of $146,061,466 would produce an operating margin of $17,755,094 for a 9.36 percent rate of return on a Staff adjusted original cost rate base of $189,637,810 and produce a 1.33 TIER.

[1] As shown on Schedule CSB-16, line 4.

INTRODUCTION

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

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

Since joining the Commission, I have participated in numerous rate cases and other regulatory proceedings involving large electric, gas, telecommunications, and water utilities. I have testified on matters involving regulatory accounting and auditing. During the past six years, I have attended utility-related seminars on regulation, accounting, finance and income taxes designed to provide continuing and updated education in these areas. Various professional and industry organizations sponsored these seminars.

I have been employed by the Commission as a regulatory auditor and a rate analyst since August 1996. Prior to joining the Commission, I was employed by the Department of Revenue as a Senior Internal Auditor and by the Office of the Auditor General as a Financial Auditor. I was a Cost Center Review Specialist for Blue Cross Blue Shield of Arizona prior to my employment in state government.

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

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating income, and revenue requirement regarding Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Cooperative") application for a permanent rate increase. Staff witness Alejandro Ramirez is presenting Staff's times interest earned ratio ("TIER") and debt service coverage ("DSC") ratio analysis and recommendations. Staff witness Barbara Keene is presenting Staff's recommendations regarding the base cost of power, fuel adjustor, and rate design. Staff witness Jerry Smith is presenting Staff's engineering analysis and recommendations.

Q. What is the basis of your recommendations?

A. I performed a regulatory audit of AEPCO's application to determine whether sufficient, relevant, and reliable evidence exists to support the Company's requested rate increase. The regulatory audit consisted of examining and testing the financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted National Rural Utilities Service ("RUS") Uniform System of Accounts ("USOA").

BACKGROUND

Q. Please review the background of this application.

A. Prior to August 2001, AEPCO provided both generation and transmission services to its customers. Pursuant to Decision No. 59943, dated December 26, 1996, the Commission approved a phased-in transition to electric competition. In 2001, AEPCO received Commission approval to restructure into three separate affiliated cooperatives: AEPCO, Southwest Transmission Cooperative ("Southwest Transmission"), and Sierra Southwest Cooperative ("Sierra Southwest").

AEPCO became a generation cooperative. Southwest Transmission became a transmission cooperative. Sierra Southwest became a cooperative that provides wholesale marketing and support services, including staffing of non-core positions to AEPCO and Southwest Transmission.

Decision No. 63868 required that the Cooperatives provide the Director of the Utilities Division with "an informational submission" that was required within "35 months of the date of closing"[2] for the restructuring. Decision No. 65367, dated November 5, 2002, modified this requirement to include full Arizona Administrative Code R14-2-103 information and set the rate filing date at July 1, 2004. On July 23, 2004, AEPCO filed an application for a permanent rate increase. On August 27, 2004, Staff filed a Letter of Sufficiency.

AEPCO is a certificated Arizona-based generation cooperative that provided service to six Class A, two Class B, and one Class C member during the test year. The rates requested in this case pertain only to the Class A members.

[2] Decision No. 63868, Page 14, Finding of Fact No. 74

AEPCO's current rates for Class A members were authorized in Decision No. 58405, dated September 3, 1993 and Decision No. 62758, dated July 27, 2000. Decision No. 58405 authorized a TIER of 1.05 and a DSC of 1.0 to provide a 12.96 percent rate of return on a $259,066,000 rate base. Decision No. 62758 authorized the Cooperative's Competitive Transition charge[3].

Q. What are the primary reasons for the Cooperative's requested permanent rate increase?

A. The Cooperative's application discusses three primary reasons for the rate increase: higher coal and gas costs, increased overhaul and maintenance costs, and costs related to plant placed into service after the Test Year. Additionally, it states that it has incurred a Test Year operating loss of $4.5 million resulting in a TIER lower than that required by its mortgage covenant agreements.

CONSUMER SERVICE

Q. Please provide a brief history of customer complaints received by the Commission regarding AEPCO.

A. Staff reviewed the Commission's records and found no formal complaints from its members from 2001 to 2004. Five opinions opposing the rate increase have been received from retail customers of the distribution member cooperative in Mohave County as of February 7, 2005.

[3] In Decision No. 62758, dated July 27, 2000, the Commission approved the transfer of the regulatory asset charge from AEPCO to Southwest Transmission.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Company's filing.

A. The Cooperative proposes total annual operating revenue for Class A members of $94,135,640. This represents an increase of $8,450,016, or 9.86 percent, over Test Year Class A revenue of $85,685,624.

Q. Please summarize Staff's recommended revenue.

A. Staff recommends a revenue requirement no less than the $146,061,466 proposed by AEPCO. This proposed revenue provides a $6,773,320, or 4.86 percent, revenue increase over Staff adjusted Test Year revenues of $139,288,146. Operating revenue of $146,061,466 would produce an operating margin of $17,755,094 for a 9.36 percent rate of return on a Staff adjusted original cost rate base of $189,637,810 and produce a 1.33 TIER.

Q. What Test Year did AEPCO use in this filing?

A. AEPCO's rate filing is based on the twelve months ended December 31, 2003 ("Test Year").

Q. Please summarize the rate base and operating income recommendations and adjustments addressed in your testimony for AEPCO.

A. My testimony addresses the following issues:

<u>Post-Test Year Plant</u>– This adjustment decreases Plant In Service by $9,952,618 to remove plant that was not used and useful during the Test Year.

Plant Acquisition – This adjustment decreases Plant In Service by $13,238 to properly reflect the original cost rate base and to be consistent with Decision No. 65367.

Accumulated Depreciation – This adjustment decreases Accumulated Depreciation by $253,883 to remove retirement work in progress and accumulated depreciation directly related to the Post-Test Year plant.

Member Advances – This adjustment decreases rate base by $11,982,081. This adjustment recognizes that the interest paid to the Members is recovered through operating expense, and consequently, the advances which are directly related to the interest expense should be removed from rate base to prevent double recovery.

Working Capital – This adjustment to reflect Staff's different calculation of certain Working Capital components and to eliminate the Cooperative's selective recognition of components decreases working capital by $6,897,144.

Deferred Debit – This adjustment to remove items that are not generally included in rate base decreases it by $1,955,373.

Asset Retirement Obligation ("ARO") – This adjustment to remove amounts recorded for financial accounting purposes related to future retirement obligations decreases plant in service by $1,962,630.

Post-Test Year Revenue and Expense – This adjustment to remove expenses is directly related to the Post-Test Year ("PTY") plant and increases operating margin by $143,951.

Revenue and Expense Annualizations – This adjustment to reflect the revenues and expenses at the Test-Year end customer level increases operating margin by $1,007,531.

Asset Retirement Obligation – This adjustment to remove costs recorded for financial accounting purposes related to future retirement obligations increases operating margin and net margins by $69,446 and 642,044, respectively.

Base Cost of Power – This adjustment increases operating margin by $250,000 to reflect annualization of savings from a new power contract. Staff also made an adjustment to segregate the revenue associated with the power costs included in the energy charge for Class A members from other revenues. The latter adjustment has no affect on operating margin.

Overhaul Accrual Expense – This adjustment increases operating margin by $657,788 to reflect a normalized level of expense using historical costs.

Transportation Expense Annualization – This adjustment increases operating margin by $19,560 to reflect the Staff recommended Point to Point rate recommended for Southwest Transmission Cooperative.

Normalized Legal Expense – This adjustment decreases operating margin by $539,989 to reflect legal expenses at a normalized level.

Fuel Expense – This adjustment increases operating margin by $1,053,073 to remove legal costs and interest on long-term debt from fuel expense.

Advertising Expense – This adjustment to remove expenses that are not needed for safe and reliable service increases operating margin by $46,241.

Contributions and Other Expense – This adjustment to remove expenses that are not needed for safe and reliable service increases operating margin by $159,891.

ACC Assessment – This adjustment to remove revenues and expenses that should be treated as pass-through items increases operating margin by $141,606.

Interest Expense on Long-term Debt – This non-operating adjustment to reflect Staff's calculation of interest expense on long-term debt increases net margin by $234,585.

RATE BASE

Fair Value Rate Base

Q. Did the Company prepare a Schedule showing the elements of Reconstruction Cost New Rate Base ("RCND")?

A. No, the Company did not. Therefore, Staff evaluated the original cost rate base as the fair value rate base ("FVRB").

Rate Base Summary

Q. Please summarize Staff's adjustments to AEPCO's rate base shown on Schedules CSB-2 and CSB-3.

A. Staff's adjustments to AEPCO's rate base resulted in a net decrease of $32,509,201, from $222,147,011 to $189,637,810. This decrease was primarily due to (1) Staff removing

plant that was not completed and serving customers during the Test Year; (2) recognizing Member Advances as a reduction; and (3) reducing the working capital allowance.

Rate Base Adjustment 1 – Utility Plant In Service, Post-Test Year Plant

Q. What is AEPCO proposing for Utility Plant In Service and Post-Test Year Plant?

A. AEPCO is proposing $389,603,749 for Utility Plant In Service. The amount is composed of $379,651,131 in actual plant that was used and useful during the Test Year and $9,952,618 in Post-Test Year ("PTY") plant as shown on Schedule CSB-4.

Q. Please describe the Post-Test Year Plant.

A. The $9,952,618 in PTY plant is a coal blending facility that was under construction at the end of the Test Year.

Q. What is Staff's recommended treatment for the Post-Test Year Plant?

A. Staff recommends excluding the PTY plant and related operating expenses (i.e., depreciation expense, administration and general, and property taxes) from rates.

Q. What is the effect of AEPCO's proposal to include Post-Test Year plant in rate base?

A. AEPCO's proposal to include the $9.9 million of PTY plant in rate base over-states the revenue requirement, and ultimately, the rates paid by the Class A Member cooperatives' 120,000 customers. The over-stated revenue requirement occurs because the PTY plant creates a mismatch between the revenues, expenses incurred and the plant used to provide service in the Test Year and amounts requested for recovery in rates.

In the absence of extraordinary circumstances, the costs of the historical test year should be used in the development of the revenue requirement. These costs are consistent with

the matching principal and result in plant in service measured at the same date as other rate base components and with revenues and expenses of the same accounting period.

Q. When is recognition of PTY plant in rate base appropriate?

A. By definition PTY plant is mismatched with the revenues, expenses and rate base components of the test year. Matching is one of the most fundamental principles of accounting and rate-making. The absence of matching distorts the meaning of and reduces the usefulness of operating income and rate of return for measuring the fairness and reasonableness of rates. Accordingly, recognizing PTY plant in rate base should be granted only in special and unusual cases where failure to do so would create an inequity.

Staff recognizes two such cases:

1. When the magnitude of the investment relative to the utility's total investment is such that not including the PTY plant in the cost of service would jeopardize the utility's financial health; and

2. When all of the following conditions exist:

a. the cost of the PTY plant is significant and substantial,

b. the net impact on revenue and expenses for the PTY plant is known and insignificant,

c. the PTY plant is prudent and necessary for the provision of service and reflects appropriate, efficient, effective, and timely decision-making,

d. the funding source(s) and amounts for the PTY plant are known and recognized in the rate application,

e. the PTY plant is in service at the time of the rate filing,

f. the PTY plant is recorded in a completed plant account(s) in the general ledger and auditable records are available at the time of the rate filing, and

g. all related retirements are recorded in the general ledger and recognized in the rate filing.

Q. Would excluding the PTY plant jeopardize the Cooperative's financial health?

A. No. Staff's revenue requirement is primarily based on the Cooperative's cash flow requirements.

Q. Does the PTY plant meet all of the conditions of the second case necessary for inclusion in rate base?

A. No. The impact on revenues and expenses for the PTY plant cannot be measured with sufficient accuracy to determine that it is insignificant.

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $9,952,618 to remove all PTY plant from rate base as shown on Schedules CSB-3 and CSB-4.

Rate Base Adjustment 2 – Plant Acquisition Adjustment

Q. What is AEPCO proposing for its Plant Acquisition Adjustment?

A. AEPCO is proposing $13,238 for the Plant Acquisition Adjustment as shown on Schedule CSB-5.

Q. The $13,238 Plant Acquisition Adjustment is not material to Rate Base. Why is Staff proposing that it be removed from Rate Base for rate making purposes?

A. In Decision No. 65367, dated November 5, 2002, Staff recommended and the Commission agreed that Southwest Transmission's acquisition adjustment be removed from rate base

(Page 4 at line 23). Southwest's acquisition adjustment is directly related to AEPCO's acquisition adjustment.[4]

Q. Did Staff audit the plant acquisition adjustment in this rate proceeding?

A. Yes, Staff audited the plant acquisition adjustment and found that the Cooperative did not have sufficient documentation to support the adjustment.

Q. Should the plant acquisition adjustment be included in rate base?

A. No, it should not. Original cost rate base is calculated using the original cost of plant assets. An acquisition adjustment, by definition, is not the original cost of an asset because it is the difference between the original cost of an asset and the purchase price. Staff found no sufficient evidence to support the adjustment. Therefore, non-recognition of the acquisition adjustment in rate base is the normal rate-making treatment.

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $13,238 as shown on Schedule CSB-3 and CSB-5.

Rate Base Adjustment 3 –Accumulated Depreciation

Q. What is AEPCO proposing for Accumulated Depreciation?

A. AEPCO is proposing $185,972,877 for Accumulated Depreciation. The amount is composed of $185,718,994 in accumulated depreciation on plant in service, $54,648 in a reduction of accumulated depreciation for a retirement work in progress, and $308,531 in accumulated depreciation for the PTY plant as shown on Schedule CSB-6.

[4] Per response to data request CSB 3-4.

Q. Is retirement work in progress normally a component of rate base?

A. No. Retirement work in progress should reflect a coordinated treatment of the plant to be retired, accumulated depreciation, salvage value and disposal cost. The recordkeeping for the retirement should be completed before rate base is adjusted. A similar adjustment to remove retirement work in progress was made for Southwest Transmission in Decision No. 65367[5], dated November 5, 2002.

In Decision No. 65367[6], dated November 5, 2002, Staff recommended that a retirement work in progress be removed because the amount was questionable and unaudited.[7] The Commission adopted Staff's recommendation. In the instant case, Staff audited the retirement work in progress and determined that it should be removed.

Q. Did Staff remove the $308,531 of Accumulated Depreciation directly related to the Post-Test Year plant?

A. Yes. Consistent with Staff's recommendation to remove PTY Plant, Staff recommends removing the Accumulated Depreciation directly related to the PTY plant.

Q. What is Staff recommending?

A. Staff recommends decreasing Accumulated Depreciation by $253,883, from $185,972,877 to $185,718,994 as shown on Schedules CSB-3 and CSB-6.

[5] Page 24 at line 23
[6] Page 24 at line 23
[7] Decision No. 65367, page 4, lines 6 through 9

Rate Base Adjustment 4 – Member Advances

Q. What programs does AEPCO have that result in Member Advances

A. The two types of programs are member investments and member prepaid power bills. The member investment program allows members to invest funds with the Cooperative and the Cooperative pays interest on those funds. The prepaid power program allows members to make prepayments on their monthly power bills and the Cooperative pays interest on those prepaid bills.

Q. How does the Cooperative treat the balance of Member Advances and the interest paid on those funds in its filing?

A. The Cooperative did not deduct the $11,982,081[8] million in Member Advances in its rate base calculation, but it included the $166,385[9] of interest paid to members for use of their funds as an operating expense. An inequity is created by the Cooperative's proposal because its provides for recovery of AEPCO's Member Advances costs by treating the related interest as an operating expense without also recognizing that AEPCO has use of the funds advanced by members.

Q. What is the effect of the Cooperative's proposed treatment?

A. The effect of the Cooperative's proposed treatment is to provide double recovery. The Cooperative pays interest to the members that provide the advances and recovers that interest cost by including it in operating expenses. Failure to deduct Member Advances overstates rate base by not recognizing the Cooperative's use of the advanced funds and has the effect, theoretically, of providing a return on the advanced funds.

[8] Per data request response CSB 1-21
[9] Per data request response CSB 3-19

Q. Did the Commission deduct Member Advances in the rate base calculation of the Cooperative's prior rate case?

A. Yes. The Commission, in Decision No. 58405, deducted Member Advances in the rate base calculation.

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends that $11,982,081 in Member Advances be deducted from rate base as shown on Schedules CSB-3 and CSB-7.

Rate Base Adjustment 5 – Working Capital

Q. What is AEPCO proposing for Working Capital?

A. AEPCO is proposing $16,778,408 for Working Capital. The amount is composed of $5,581,933 for fuel stock, $5,265,561 for materials and supplies, $908,046 for prepayments, and $5,022,869 for CFC Certificates and Bonds as shown on Schedule CSB-8.

Q. Did Staff make any adjustments to the Cooperative's Working Capital?

A. Yes. Staff discusses its adjustments to fuel stock, materials and supplies, prepayments, CFC Certificates and Bonds separately.

<u>Working Capital - Fuel Stock, Coal</u>

Q. Why, in general, is it necessary for generation cooperatives to maintain fuel inventories?

A. Fuel inventories are necessary to help ensure the availability of power to customers on a continuous basis. Coal deliveries can be interrupted for many reasons and are not conducive to deliveries made within short time frames.

Q. What amount in fuel stock is AEPCO proposing?

A. AEPCO is proposing $5,581,933 for fuel stock which consists primarily of coal.

Q. How did AEPCO calculate its fuel stock inventory levels during the Test Year?

A. AEPCO's methodology was based on the number of average burn days.[10] Burn days represent the number of days a generating unit could continue to meet customer demands by burning coal already on hand assuming no additional deliveries of coal and an average consumption rate.

Q. AEPCO changed the Number of Burn Days calculation in April[11] of the Test Year which resulted in lower levels of coal inventory. Did AEPCO reflect this lower level of coal inventory in rate base?

A. No, the Cooperative changed its inventory level from 5,300 tons to 4,100[12] tons in April of the Test Year and did not reflect the lower level in rate base.

Q. AEPCO's proposed inventory level is based upon a 13-Month average of fuel stock. Does this calculation over-state the inventory balance included in rate base?

A. Yes it does. This methodology overstates the balance because it includes four months of inventory levels that were calculated using the higher number of burn days.

Q. What methodology to calculate the fuel stock balance does Staff recommend using?

A. Staff recommends basing the inventory balance on the number of burn days rather than on 13-Month average. Staff's recommended inventory balance is calculated by multiplying the number of burn days by the average daily tons per burn day and the average cost per

[10] Per data request response CSB 3-15
[11] Per data request response CSB 1-4, April 2003 AEPCO Monthly Financial Board Report, page 7.1
[12] Per data request response CSB 3-15

ton to obtain the average cost of coal inventory. The calculation is as follows: 42.5[13] burn days x 4,100 tons per burn day x $27.7/ton[14] or $4,826,725.

Q. Did Staff remove fuel related legal expenses from the fuel stock balance?

A. Yes, Staff removed $191,545[15] in fuel related legal costs as shown on Schedule CSB-8.1. Staff discusses this issue in greater detail in Operating Income Adjustment No. 8, Fuel Expense.

Q. What is Staff recommending for the fuel stock balance?

A. Staff recommends $4,635,180 for fuel stock as shown on Schedules CSB-8 and CSB-8.1.

Working Capital - Materials and Supplies

Q. What amount in Materials and Supplies is AEPCO proposing in the Working Capital calculation?

A. AEPCO is proposing $5,265,561 for Materials and Supplies inventory.

Q. How did AEPCO calculate the Materials and Supplies balance proposed in rate base?

A. AEPCO calculated the Materials and Supplies balance using a 13-month average. This method adds together the December 31, 2002, ending Materials and Supplies balance with the Test Year month-end balances and divides by 13.

[13] Per response to data request CSB 3-15, 42.5 days is the average of the 40 to 45 burn days range
[14] Per response to data request CSB 6-9
[15] Per response to data request CSB 15-3

Q. Does use of the 13-month average calculation proposed by AEPCO measure the average monthly balance for each month of the Test Year?

A. No. Therefore, the Cooperative's proposed method could over- or under- state the materials and supplies balance.

Q. What method provides a more accurate measurement of the average balance each month?

A. Staff recommends using a 12-month average based on the average inventory balance for each month of the Test Year. To illustrate, the average monthly balance for January is calculated by adding the beginning balance on January 1st (i.e., the ending balance on December 31st of prior year) to the ending balance on January 31st, and dividing the total by two. The 12 monthly averages are totaled and divided by 12 to obtain an average balance.

Q. What does Staff recommend for the Materials and Supplies balance in the Working Capital calculation?

A. Staff recommends $5,246,085 for Materials and Supplies as shown on Schedule CSB-8.2.

Working Capital - Prepayments, CFC Certificates and Bonds

Q. Is AEPCO proposing to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation?

A. Yes. AEPCO is proposing $908,046 for prepayments, and $5,581,933[16] in CFC Certificates and Bonds.

[16] In response to data request CSB 3-3, the Cooperative indicated that the $5,581,933 balance was the 2002 ending balance rather than the 2003 ending balance. The 2003 ending balance is composed of $2,774,582 of Equity Term Certificates, $1,276,250 of Subscription Term Certificates and $795,000 of Subscription Term Certificates purchased for the Series 1994A Solid Waste Disposal Revenue Bonds.

Q. Does AEPCO's proposal to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation represent an inequitable, selective adjustment to increase rate base?

A. Yes. The Cooperative has ignored a large component of Working Capital (i.e., cash working capital) represented by revenues received and expenses paid. The impact on Working Capital of revenues and expenses can be calculated using a lead-lag study. A lead-lag study is recognized as the most accurate method to calculate cash working capital.

The Cooperative chose not to conduct a lead-lag study, and accordingly, omitted a major component of Working Capital. It is inequitable to ignore a major component of the Working Capital analysis and selectively recognize other components. Had a lead-lag study been conducted, it might have shown that Working Capital is a negative component of rate base.

Q. What factors imply that a lead-lag study could result in Working Capital being a negative component of rate base?

A. Interest and property tax expenses are components of a lead-lag study. The Cooperative has approximately $12 million in interest expense and $4 million in property taxes. The Cooperative collects cash used to make interest and property tax expense payments prior to the dates payment is due. For the period that AEPCO holds these funds before payment, they are a source of cost-free capital. If a lead-lag study were performed, this source of cost-free cash would be a significant negative factor in calculation of the net working capital.

Q. Does the Cooperative receive interest on the CFC Certificates and Bonds?

A. Yes. In response to CSB 3-3, the Cooperative received approximately $272,405 in interest income for these investments during the Test Year[17]. Therefore, including the CFC certificates and bonds in rate base would provide a second return on these investments.

Q. Did the Commission remove Prepayments and CFC Certificates and Bonds from rate base in AEPCO's prior rate case?

A. Yes, it did. The Commission removed prepayments in Decision No. 58405[18]. The Cooperative had not included CFC Certificates and Bonds in the rate base of that proceeding, therefore, it was not addressed in Decision No. 58405.

Q. What is Staff recommending for Prepayments and CFC Certificates and Bonds?

A. Consistent with Decision No. 58405, Staff recommends removal of Prepayments. Staff also recommends removal of CFC Certificates and Bonds from Working Capital as shown on Schedules CSB-3 and CSB-8.

Q. What is Staff's recommended adjustment to Working Capital?

A. Staff recommends decreasing Working Capital by $6,897,144 from $16,778,409 to $9,881,264 as shown on Schedules CSB-3 and CSB-8.

[17] Per response to CSB 3-3, the $2.8 million Equity Term Certificates accrues interest at 5.00 % annually; the $1.3 million Series 1997C Subscription Term Certificates accrues interest at 7.57% annually; and the $795,000 Series 1994A Subscription Term Certificates accrues interest at 5.92% annually.

[18] Page 6, at line

Rate Base Adjustment 6 – Deferred Debit

Q. What amount in Deferred Debits is AEPCO proposing to include in Rate Base?

A. AEPCO is proposing $1,955,373 for Deferred Debits as shown on Schedule CSB-9. The amount is composed of $957,472 for preliminary survey and investigation charges, $731,780 for Job Tickets, and $266,121 for unamortized losses on reacquired debt.[19]

Q. Should these Deferred Debits be included in rate base?

A. No, they should not. The Deferred Debits balance consists of items that are not generally included in rate base. Preliminary survey and investigation charges and job tickets are a type of construction work in progress. Construction work in progress by definition is not used and useful.

Unamortized losses on reacquired debt present no future cash requirements for the Cooperative. Since Staff recommends a revenue requirement dependent on cash flow needs, there is no revenue requirement directly related to the carrying balance.

Including the unamortized loss on reacquired debt in rate base would be inequitable and serve only as a selective adjustment to augment rate base in the same manner as prepayments, CFC Bonds and Certificates.

Q. Did the Commission remove the deferred debit from rate base in AEPCO's prior rate case?

A. Yes, the Commission, in Decision No. 58405, removed the Deferred Debit from rate base.

[19] Per response to CSB 3-1

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends removal of the Deferred Debit from Rate Base as shown on Schedules CSB-3 and CSB-9.

Rate Base Adjustment 7 –Asset Retirement Obligation ("ARO")

Q. What amount did AEPCO include in plant as an ARO?

A. AEPCO included a $1,962,630 ARO in its proposed plant. The Cooperative recorded the amount to "recognize the present value of its projected retirement cost"[20] associated with the retirement of an ash pond.

Q. What is an ARO?

A. In 2003, AEPCO adopted Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligation* for purposes of financial statement presentation. Adoption of SFAS No. 143 represented a change in accounting principle for retirement of long-lived tangible assets with a legal obligation for disposal.

An asset retirement obligation is a liability recognized on the balance sheet for a legal obligation associated with the retirement of a long-lived tangible asset used in operations. Normally upon recognition of an ARO, an ARO asset and an ARO liability are recorded at the present value of the expected cost of disposal. The ARO liability grows as a cost of money factor (accretion expense) is applied to the ARO liability balance each period until the asset is retired. If the initial estimates were correct, the ARO liability will equal the cost at the time of disposal. The ARO asset is depreciated over the life of the asset. It is the ARO asset that AEPCO has included in plant.

[20] Note 19 of AEPCO's 2003 audited financial statements

Q. Does AEPCO have any investment in the ARO asset it included in plant?

A. No. The ARO asset is merely an accounting entry to accommodate financial reporting requirements. AEPCO has no investment in the ARO asset it included in plant, and accordingly, has no basis for inclusion in rate base.

Q. For what asset did AEPCO recognize an ARO?

A. AEPCO recognized an ARO pertaining to a coal ash pond. The Cooperative plans to retire the ash pond in 2006, and estimates the disposal cost to be about $4 million. The Cooperative plans to obtain a loan to finance the disposal cost.

Q. Is the Commission committed to using financial accounting to rate-making purposes?

A. No. The Commission is not compelled to follow financial statement accounting for rate-making purposes. In this instance, following financial accounting is inappropriate because it recognized plant that is simply an accounting entry with no investment by AEPCO.

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $1,962,630 as shown on Schedules CSB-3 and CSB-10. Staff also recommends no change in the rate-making treatment of retirements with legal obligations.

OPERATING INCOME – AEPCO

Operating Income Summary – AEPCO

Q. What are the results of Staff's analysis of Test Year revenues, expenses and operating income?

A. As shown on Schedules CSB-11 and CSB-12 Staff's analysis resulted in Test Year revenues of $139,288,146, expenses of $128,306,372 and operating margin of $10,981,774.

Operating Income Adjustment No. 1 – Post-Test Year Revenue and Expenses

Q. What post-Test Year revenue and expense adjustments is AEPCO proposing?

A. AEPCO is proposing the following post-Test Year revenue and expense adjustments.

Post-Test Year Revenue and Expense Adjustments For Coal Blending Facility					
	AEPCO Adj. No. 5 Fuel Expense	AEPCO Adj. No. 6 SO2 Allowance	AEPCO Adj. No. 7 Ash Sales Credit	AEPCO Adj. No. 8 Coal Blender (Depreciation & Prop Taxes)	Total
Revenues	($ 551,934)	$ 0	$ 0	$ 0	($551,934)
Expenses	($1,534,274)	($167,069)	$820,611	$472,749	($407,983)
Operating Margin	$ 982,340	$167,069	($820,611)	($472,749)	($143,951)
Interest on L-T Debt	$ 0	$ 0	$ 0	$532,465	($532,465)
Total	$ 982,340	$167,069	($820,611)	($1,005,214)	($676,416)

Q. Why did the Cooperative propose a pro forma adjustment for PTY expenses?

A. The Cooperative proposed an adjustment to reflect its projection of operating expenses related to PTY plant additions.

Q. When would recognition of expenses related to PTY be appropriate?

A. The operating expenses related to PTY plant should be recognized only when the PTY plant is recognized and the affect on expenses is known and measurable. This means that all of the criteria for recognizing PTY plant must first be met before any related expense

adjustment is recognized. This is essential to preserve the matching principle as previously discussed in Staff's testimony regard the adjustment to PTY plant.

Q. What treatment does Staff recommend for the Cooperative's pro forma adjustment for PTY expenses?

A. Since Staff recommends disallowance of the PTY plant, Staff also recommends disallowance of the Cooperative's pro forma post-test year adjustment to expenses.

Q. What is Staff recommending?

A. Staff recommends increasing operating revenue and expenses by $551,934 and $407,983, respectively, for a $143,951 net increase to operating margin as shown on Schedules CSB-12 and CSB-13.

Operating Income Adjustment No. 2 – Revenue and Expense Annualizations

Q. What is the purpose of a revenue and expense annualizations?

A. Revenue and expense annualizations are made to achieve matching with the year end rate base measurement date. The adjustments reflect the known and measurable changes to Class A members' customer counts during the Test Year. Revenues are annualized to reflect sales that would have occurred if customers on the system at the end of the Test Year had taken service for the entire year. Likewise, variable expenses are annualized to reflect the increased costs to provide the level of sales related to year end customers.

Q. Has Staff analyzed growth in the number of customers served by AEPCO's Class A Members?

A. Yes. Staff's analysis found that the number of customers grew at a rate of 3.29 percent from 2002 to 2003.

Q. Staff calculated a 3.29 percent growth rate. How was the growth rate used to annualize the revenues and expenses to end of year level?

A. Assuming the growth rate of 3.29 percent takes place evenly over the course of the year, then a 1.65 percent adjustment is needed to annualize sales growth to the end of the Test Year.

To illustrate: At the beginning of the year, Class A Members had a total of 116,074 customers as shown on Schedule CSB-14 line 14. At the end of the year, the actual number of customers was 119,895 as shown on Schedule CSB-14, line 15. To annualize the sales based on year-end customers, an adjustment of 1.65 percent [((119,895-116,074)/ 116,074) / 2] is necessary.

Q. What is Staff recommending?

A. Staff recommends increasing revenues by $1,271,908 and expenses by $264,376 as shown on Schedules CSB-12 and CSB-14.

Operating Income Adjustment No. 3 – Asset Retirement Obligation

Q. What effects of adopting SFAS No. 143 is AEPCO proposing as expenses?

A. AEPCO proposes $69,446 for operating expenses which represents depreciation of the ARO asset, and $191,564 for interest expense which represents accretion expense on the ARO liability, and $381,034 for interest expense which represents a ten-year amortization of a $3,810,335 write-off to record the cumulative effect of a change in accounting principle upon adoption of SFAS No. 143.

Q. Does AEPCO have any investment is the ARO asset upon which it recorded $69,446 of depreciation expense?

A. No. As previously discussed, the ARO asset is merely an accounting entry to accommodate financial reporting requirements. AEPCO has no investment in the ARO asset it included in plant, and accordingly, there is no asset cost to be recovered through depreciation.

Q. How did AEPCO record the adoption of SFAS No. 143 on its books?

A. According to Note 19 of AEPCO's 2003 audited financial statements, AEPCO "recorded the cumulative effect of the accounting change, totaling $3,810,335 in the consolidated statements of revenues and expenses and unallocated accumulated margins. The Cooperative also recognized the present value of its projected asset retirement costs, totaling $1,962,630, as a component of its capitalized utility plant on the consolidated balance sheets. Subsequently, the Cooperative recognized accretion[21] of the liability, totaling $185,802, as a component of interest expense and depreciation of the asset retirement costs, totaling $69,445, as depreciation expense[22] . . ."

As previously mentioned, AEPCO recognized the cumulative effect of implementing SFAS No. 143 on its financial statements in accordance to GAAP. The cumulative effect appears as a $3.8 million below-the-line extraordinary item on the 2003 income statement. The purpose of the $3.8 million below-the-line write-off is to adjust the financial statements so that they appear as if the requirements of SFAS No. 143 had always been followed. The write-off is a one-time, non-cash, nonrecurring expense that relates to past accounting periods.

[21] Accretion expense is a type of interest expense that is added to the ARO liability annually to account for the time value of money.
[22] The ARO asset is depreciated over the life of the associated tangible asset.

Q. What rate-making treatment does AEPCO propose for the $3.8 million write-off?

A. AEPCO proposes to recover the $3.8 million write-off by including one-tenth, or $381,034, in operating expenses over a ten-year period.

Q. Is AEPCO's proposed treatment of the $3.8 million write-off consistent with rate-making principles?

A. No. The $3.8 million write-off pertains to past accounting periods. Recovery of expenses from prior periods is retro-active rate-making.

Q. Did AEPCO experience any cash outlay related to the $3.8 million write-off during the Test Year?

A. No. The write-off is simply an accounting entry used to implement a change in account principle to adopt SFAS No. 143.

Q. If implementation of SFAS No. 143 is not recognized how would AEPCO recover the ash pond disposal cost?

A. AEPCO could either have requested authorization to recover the disposal cost through depreciation expense or it can recognize an adjustment to rate base for the disposal cost upon retirement of the pond.

Q. Could AEPCO's proposed treatment result in excess recovery of the $3.8 million write-off?

A. Yes. Since AEPCO intends to finance the ash pond disposal cost with debt financing, the principle and interest costs will be reflected in the revenue requirements in future rate proceedings. If the $381,034 is simultaneously being recovered as an operating expense in the ten-year amortization period, an over-recovery would occur.

Q. Is there a relationship between the proposed amortization of the ARO write-off and the ARO plant that AEPCO included in rate base?

A. Yes. The ARO plant and the write-off are both associated with the implementation of SFAS No. 143. Staff's recommendation against recognition of the write-off is consistent with its recommendation not to recognize the ARO plant.

Q. Please summarize why the $381,034 ARO write-off should not be included in calculation of the revenue requirement.

A. The ARO write-off is no more than an accounting entry for implementing a change in accounting principle for financial statement purposes. It is a one-time, non-cash charge pertaining to prior periods. Recognition of the proposed ten-year amortization of the write-off would be retro-active rate-making and lead to potential over-recovery.

Q. What is Staff recommending?

A. Staff recommends removing all effects of the ARO on the income statement including $69,446 from operating expenses and $572,598 from Interest and Other Deductions as shown on Schedules CSB-12 and CSB-15.

Operating Income Adjustment No. 4 – Tracker Mechanism (Base Power Cost)

Q. Explain the purpose of the break-out of the Total Class A Member Revenue into two components as shown is Schedules CSB-11 and -12.

A. The purpose is to show separately the portion of revenue that represents costs that flow through the tracker mechanism as proposed by Staff.

Q. What revenue would AEPCO recover through its proposed adjustor rate of $0.02038 per kWh?

A. The Cooperative would collect $41,276,155 (2,025,326,533[23] kWhs x $0.02038[24] per kWh) for generated and purchased power cost as shown on Schedule CSB-16, line 7. This is equal to the Cooperative's proposed base cost of power as shown on Schedule CSB-16, line 53.

Q. Is Staff recommending a different level of base power costs?

A. Yes. The Staff adjusted base power cost is $33,560,400 as shown on Schedule CSB-16, line 53.

Q. What adjustment did Staff make to revenue to recognize the $7,716,227 difference between Staff and AEPCO's base power costs?

A. Staff reclassified $7,716,227 from Base Cost of Power Revenue to Non-Base Cost of Power Revenue. This adjustment has no impact on the revenue requirement. The adjustment simply shows separately the amount of Test Year revenue reflected by Staff's proposed level for base power costs.

Q. Did Staff disallow any costs from the accounts included in the base cost of power expense?

A. Yes, Staff annualized the savings from a new contract that was in effect for only half of the Test Year. Staff decreased base cost of power expense by $250,000 as shown on Schedules CSB-16, line 27 and CSB-12, line 13.

[23] Cooperative Schedule H 2A, Line 36
[24] Cooperative Schedule H 2A, Line 38

Operating Income Adjustment No. 5 – Overhaul Accrual Expense

Q. Why are generation unit overhauls needed?

A. A generation unit consists of thousands of separate components that deteriorate at different rates based on operating conditions. The overhaul of one of these complex units encompasses a wide range of preventative maintenance, repair, and replacement activities that are needed to help ensure safe and reliable operation.

Q. What is AEPCO proposing for overhaul accrual expense?

A. AEPCO is proposing $4,787,507 for overhaul accrual expense[25].

Q. What was AEPCO's actual overhaul expense during the Test Year?

A. AEPCO's actual overhaul expense was $3,148,905[26].

Q. Why are the actual and accrual expenses different?

A. The actual overhaul expense is not representative of the overhaul expense from year to year because the nature and scope of overhauls vary from year to year based on operating conditions. Consequently, the Cooperative estimates and accrues an amount for the annual overhaul expense. In 2003, AEPCO began using a revised methodology to calculate its overhaul accruals.

Q. Does Staff agree that the overhaul accrual expense included in rates should be based upon the AEPCO's revised methodology?

A. No. AEPCO's revision to the method by which it has previously calculated overhaul accrual expense significantly increased the accrual from the prior year. The Cooperative's

[25] Per response to data request CSB 1-38
[26] Per response to data request CSB 1-38

overhaul accrual expense increased by approximately $2 million, from $2.79 million in 2002 to $4.79 million in 2003 (CSB 1-37). The accruals are estimates based on complex projections for which AEPCO has no actual experience.

Q. What method does Staff recommend for calculating the accrual amount?

A. Staff recommends calculating the accrual expense as the eight year average[27] of the actual overhaul expense as shown on Schedule CSB-17. Eight years is representative of the typical overhaul period.

Q. What is Staff recommending?

A. Staff recommends decreasing overhaul accrual expense by $657,788, from $4,787,508 to $4,129,720 as shown on Schedules CSB-12 and CSB-17.

Operating Income Adjustment No. 6 – Transmission Expense Annualization

Q. What is the Cooperative proposing for transmission expense?

A. AEPCO is proposing $8,036,486 for transmission expense. This amount is composed of $6,692,293 of actual Test Year transmission expense; a ($245,438) pro forma adjustment to reflect termination of the City of Mesa contract and; a $1,589,631 pro forma adjustment to reflect the annualization of transmission expense for its (a) wheeling expenses associated with a Western Area Power Administration agreement and (b) an El Paso Palo Verde agreement and (c) the proposed increase in point-to-point transmission rates that Southwest Transmission charges AEPCO.

[27] Per response to CSB 1-38, major overhauls occur approximately every 96 months for base load generating units.

Q. Does Staff recommend a different Point-to-Point rate than that recommended by Southwest Transmission?

A. Yes, Staff recommends a different rate as shown on Schedule CSB-18. Staff recommends a $3.022 Point-to-Point rate, a decrease of $0.010 below the Cooperative's $3.032 rate. Staff's recommended Point-to-Point rate for Southwest Transmission will result in a lower transmission expense for AEPCO.

Q. What is Staff recommending?

A. Staff recommends decreasing transmission expense by $19,560 as shown on Schedule CSB-18.

Operating Income Adjustment No. 7 – Normalized Legal Expense

Q. What is AEPCO proposing for Outside Services Legal Expenses?

A. AEPCO is proposing $903,512[28] for Outside Services Legal Expenses as shown on Schedule CSB-19. The Cooperative's 2003 legal expense report shows total legal expenses of $2,695,758 comprised of $903,512 for Outside Services and $1,792,246[29] for related to the railroad transportation tariff.

Q. What approach did Staff take for evaluating legal expenses?

A. Staff recognized that legal expenses can vary significantly from year-to-year. Accordingly, Staff calculated a normalized cost by averaging the allowable costs for the years 2002, 2003 and 2004. This required making adjustments to remove costs determined to be unallowable from each of those years. For convenience, Staff calculated the normalized railroad transportation tariff legal expense separately from other legal expenses.

[28] Per data request response to CSB 13-1.
[29] Per data request response to CSB 13-1.

A. According to the cooperatives' cost allocation manual, "Anything not specifically ascribed to AEPCO or SWTransCo activities" is allocated. AEPCO's composite allocation rate for legal expenses is 80.23 percent.

Q. Did AEPCO receive 80.23 percent of the natural gas-related legal expenses based on the three-entity allocation factor?

A. No. Virtually all of the $354,824 in natural gas-related legal expenses were direct charged to AECPO with no allocation to the two other entities.

Q. Does Staff agree that virtually all natural gas-related legal expenses should be directly charged to AEPCO?

A. No. Direct charging these legal costs to AEPCO is inappropriate because Sierra Southwest, the unregulated cooperative, is a wholesale gas seller/marketer with several wholesale natural gas contracts (including Duncan Rural Service, Corporation; a California town, and the City of Tucson) would potentially benefit from related legal services. Appropriate allocation of natural gas related legal expenses is necessary to ensure that there is no subsidy of Sierra Southwest's unregulated business activities by AEPCO's ratepayers. Control procedures should be adopted to ensure that proper allocations are recognized.

Q. What amount of natural gas-related legal costs has Staff excluded from its calculation of normalized legal expense?

A. Staff allocated the $354,824 cost by the current three-entity allocation factor (80.23 percent) to calculate $284,675 as AEPCO's allocation resulting in a $70,149 ($354,824-$284,675) exclusion from the normalization calculation shown on Schedule CSB-19.2, line 2.

El Paso Electric Company Contract Related Legal Expenses

Q. What is the El Paso Electric Company contract?

A. The El Paso Electric Company ("EPE") contract is a long-term transmission service agreement between AEPCO and El Paso Electric Company. The Cooperative plans to use the EPE contract in conjunction with the Panda Gila Purchase Agreement to reduce its fuel costs for the three-year period 2005 through 2008.

Q. Is it appropriate to charge all of the costs of a contract that will benefit multiple years to the Test Year?

A. No. Costs that result in multi-year benefits should be distributed on the benefit period. Accordingly, Staff amortized the approximate $34,773 in legal expenses related to El Paso Electric Company over three years to recognize $11,591 per year.

Q. What amount of EPE contract-related legal costs has Staff excluded from its calculation of normalized legal expense?

A. Staff excluded $23,182 ($34,773 - $11,591) from the normalization calculation shown on Schedule CSB-19.2, line 3.

Public Utilities Holding Company Act ("PUHCA")

Q. Was a primary purpose of the Public Utilities Holding Company Act to address the subsidization of non-regulated affiliates by regulated utilities?

A. Yes.

Q. Was AEPCO charged for any legal expenses related to the Public Utilities Holding Company Act?

A. Yes. AEPCO was charged for the legal expenses related to the Securities Exchange Commission's inquiry of Sierra Southwest's business activities. When Staff requested to review documents related to this issue, AEPCO objected citing the attorney-client privilege. In response to data request CSB 5-15, the Cooperative indicated that $15,500 in legal expenses related to PUHCA were improperly charged to AEPCO.

Q. How did Staff treat these PUCHA legal costs in its calculation of normalized legal expenses?

A. Staff excluded $15,500 in legal expenses related to PUHCA in its calculation of normalized legal expense as shown on Schedule CSB-19.2, line 4.

Q. Does AEPCO's denial of access to records provide concerns beyond whether these legal costs are related to the provision of utility service and recoverable?

A. Yes. Beyond the issue of whether the legal costs were incurred for utility purposes, the lack of access to records raises a question as to whether other significant issues related to the revenue requirement went undiscovered.

Q. Does Staff have any other recommendations regarding redacted issues?

A. Yes. In this case, Staff was unable to quantify and remove payroll costs of all employees, outside services staff, and members of the Board of Directors who spent time working on the redacted issues. Staff recommends that in future rate proceedings AEPCO be required to quantify all payroll costs of employees, outside services staff, and members of the Board of Directors fees related to time spent on redacted issues.

Capitalized Expenses

Q. Did AEPCO capitalize any of legal expenses in 2003?

A. Yes. AEPCO capitalized $13,605 of legal expenses in 2003.

Q. How did Staff treat these capitalized legal costs in its calculation of normalized legal expenses?

A. Staff excluded the $13,605 capitalized legal cost from its calculation of normalized legal expense as shown on Schedule CSB-19.2, line 5.

Redacted Minutes and Legal Invoices

Q. Did AEPCO fail to support any of its legal expenses?

A. Yes, AEPCO objected to the release of certain portions of the Minutes of the Executive Session of the Board of Directors and legal invoices citing the attorney-client privilege. Therefore, the appropriateness of the costs could not be substantiated.

Q. Did Staff inform AEPCO of the likely consequence of not providing the requested information?

A. Yes, in a letter to the Cooperative dated September 29, 2004, Staff indicated that failure to provide complete legal invoices would result in a disallowance of such costs.

Q. What was the total amount of expenses related to the redacted legal invoices and minutes that Staff excluded from its calculation of normalize legal expense?

A. Staff excluded $68,412[30] from its calculation of normalized legal expense as shown on Schedule CSB-19.2, line 6.

[30] For the Slover and Loftus legal invoices, Staff estimated the expenses related to the redacted issues based upon the number of general groups of issues on an invoice. The total amount billed on the invoice was divided by the number of general groups. For all other redacted invoices, Staff multiplied the total invoice amount by 15 percent.

Q. What is Staff recommending for normalized legal expense?

A. Staff recommends $620,129 and $823,372 for railroad and non-railroad transportation tariff legal expenses, respectively, for a total of $1,443,501. This amount is $539,989 greater than the $903,512 proposed by AEPCO, as shown on Schedules CSB-12 and CSB-19, line 11.

Operating Income Adjustment No. 8 – Fuel Expense

Q. What is AEPCO proposing for fuel expense?

A. AEPCO is proposing $59,803,425 for fuel expense as shown on Schedule CSB-12, line 9. The amount is composed of $44,521,523 for coal and $15,281,902 for gas and other fuel sources.

Q. Does the $44,521,523 in fuel expense for coal include legal expenses?

A. Yes, it does. The $44,521,523 is calculated using a weighted average cost of coal. The weighted average cost of coal includes legal expenses. A summary of the Cooperative's calculation of the $44,521,523 provided in response to data request CSB 3-14 is presented on Schedule CSB-20. Staff segregated the legal expense included in the weighted cost of coal on line 9.

Q. Did the Commission remove legal expense from fuel costs in the Cooperative's prior rate proceeding?

A. Yes, the Commission removed legal expense from fuel costs in the prior rate proceeding. AEPCO had included all fuel expenses including legal in its purchased power fuel adjustor. The Commission removed these costs in the prior rate proceeding indicating that its inclusion was inappropriate.[31]

[31] Decision No. 58405, page 28, lines 22 through 26, and page 29, lines 1 through 6.

Q. Did Staff calculate the amount of legal expense included in fuel expense?

A. Yes. Staff calculated that fuel cost includes $1,030,873 legal expenses as shown on Schedule CSB-20, line 24.

Q. How did Staff treat the legal expenses embedded fuel costs?

A. Staff reclassified these legal expenses and included them in its calculation of normalized legal expenses as shown on Schedule CSB-19, line 2.

Q. Did Staff find any other costs in the Cooperative's proposed fuel expense for which it recommends alternate treatment?

A. Yes. Included in the fixed costs the Cooperative allocated to coal fuel costs is $22,200 of interest on long-term debt. Staff removed this interest expense from fuel costs, as shown on Schedule CSB-20, line 22, because Staff is recognizing recovery of interest expense separately.

Q. What is Staff recommending?

A. Staff recommends decreasing fuel expense by $1,053,073 as shown on Schedules CSB-12 and CSB-20.

Operating Income Adjustment No. 9 – Advertising

Q. What is AEPCO proposing for advertising expense?

A. AEPCO is proposing $46,241 for advertising expense.

Q. Are these advertising costs necessary for safe and reliable service?

A. No, these costs are not necessary to provide safe and reliable service. AEPCO is a regulated electric service provider. Consequently, there is no reason to recover

advertising costs incurred primarily for image building that may otherwise make economic sense for a firm selling services in an open competitive market.

Q. What rate-making treatment does Staff recommend for these advertising costs?

A. Staff recommends that these costs be recognized below-the-line (removed from rates).

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $46,241 as shown on Schedules CSB-12 and CSB-21.

Operating Income Adjustment No. 10 – Charitable Contributions and Other Expenses

Q. What is AEPCO proposing for contributions, sponsorships, food, entertainment and similar expenses?

A. AEPCO is proposing $159,891 for contributions, sponsorships, food, entertainment, and similar expenses as shown on Schedule CSB - 22.

Q. What ratemaking treatment does Staff recommend for these types of expenses?

A. Since these costs are not necessary to provide service, Staff recommends that they be recognized as non-operating expenses and excluded from the revenue requirement.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $159,891 as shown on Schedules CSB-12 and CSB-22.

Operating Income Adjustment No. 11 – Arizona Corporation Commission Gross Revenue Assessment

Q. What is the Cooperative proposing for the ACC assessment?

A. The Cooperative included $147,146 in operating revenue and $288,752 in operating expense for the ACC assessment.

Q. What does Decision No. 58405 state concerning the ACC assessment for AEPCO?

A. On footnote 9 of page 17, the Commission states that "The gross revenue tax will in the future be recovered through a bill add-on." Therefore, the assessment should not be included in the cost of service.

Q. What is Staff recommending?

A. Staff recommends decreasing operating revenue by $147,146 and operating expense by $288,752 to remove the effects of the ACC assessment as shown on Schedules CSB-12 and CSB-23.

Income Adjustment No. 12 (Non-Operating) – Interest Expense on Long-term Debt

Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?

A. AEPCO is proposing $13,547,749 for Interest Expense on Long-term Debt as shown on Schedule CSB-24. The amount is composed of $12,200,997 in actual interest expense and proforma adjustments totaling $1,346,752 (Cooperative adjustment numbers 8, 9, and 13 in the amounts of $532,465, $1,190,178, and ($375,891), respectively).

Q. Did Staff make an independent assessment of the Cooperative's Interest Expense on Long-term Debt?

A. Yes. Staff witness Alejandro Ramirez independently calculated $13,313,164 as the Cooperative's interest expense on long-term debt and prepared testimony to support his calculation.

Q. What adjustment did Staff make to Interest Expense on Long-term Debt?

A. Staff decreased Interest Expense on Long-term Debt by $234,585 as shown on Schedules CSB-12 and CSB-24.

Deferred Fuel-Related Legal and Pension Expense

Q. Staff noted that Decision No. 58405 authorized AEPCO to establish two deferral accounts. Would you please discuss the background of the deferral accounts?

A. Yes. Fuel related legal costs and pension costs were not included in the cost of service in AEPCO's prior rate proceeding (Decision No. 58405, page 29, beginning at line 2). Subsequently, the Commission ordered AEPCO to establish two deferral accounts: one for fuel related legal expenses and a second deferral account for actual pension costs for possible recovery in a future rate proceeding (Decision No. 58405, Page 37, beginning at line 5).

Q. What were the balances for the fuel-related Legal and Pension expenses as of December 31, 2003?

A. AEPCO had not recorded any amounts related to the deferrals as of December 31, 2003, because the recovery of the deferrals were uncertain (CSB 3-2). However, the Cooperative indicated that it had accumulated $5,839,957 in required NRECA pension

fund contributions and $3,722,948 in legal expenses associated with fuel costs, for a total of $9,562,905 (CSB 6-3).

Q. What treatment does Staff recommend for the $9.5 million unrecorded Legal and Pension deferrals?

A. Staff recommends not including the unrecorded deferrals in rates. The revenue requirement for the Cooperative is based primarily on cash flow needs, and there are no cash requirements going forward for these costs from prior periods that were deferred. Since AEPCO did not record the deferrals, there would be no write-down and associated negative effect on the Cooperatives patronage equity due to non-recovery.

Q. Does Staff recommend that the deferrals continue?

A. Since the cost of service in the instant case includes costs for fuel related legal expenses and pension, Staff recommends that the deferrals be discontinued.

Jurisdictional Separation

Q. Did AEPCO maintain separation between Commission jurisdiction and non-jurisdiction revenues and expenses?

A. No, it did not. The Cooperative serves a California member for which separate revenues and expenses were not maintained.

Q. Is the Cooperative required to maintain separation of the revenues and expenses for the California member?

A. Yes, it is. The Arizona Administrative Code R14-2-103 B4 states the following:

> Separation of nonjurisdictional properties, revenues and expenses associated with the rendition of utility service not subject to the jurisdiction of the

Commission must be identified and properly segregated in a recognized manner when appropriate.

Q. Can Staff identify some cooperatives that provided jurisdictionally separated information in their rate filings?

A. Yes. Duncan Valley Electric Cooperative, Inc. and Garkane Power Association, Inc. provide jurisdictionally separated information in compliance with the Administrative Code. These cooperatives generate much smaller revenues than AEPCO. The jurisdictionally separated financial information helps to verify that Arizona ratepayers are not paying more than their fair share of the cost of providing service.

Q. What is Staff recommending?

A. Staff recommends that the Cooperative comply with Arizona Administrative Code R14-2-103 B4 in its next rate filing.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL COST	[B] STAFF ORIGINAL COST
1	Adjusted Operating Income (Loss)	$ 7,972,676	$ 10,981,774
2	Depreciation and Amortization	$ 7,608,735	$ 7,539,289
3	Income Tax Expense	-	-
4	Long-term Interest Expense	$ 13,547,749	$ 13,313,164
5	Principal Repayment	$ 10,344,950	$ 14,360,494
6a	**Recommended Increase in Operating Revenue**	$ 8,450,016	**$ 6,773,320**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**	N/A	**4.86%**
6c	Percent Increase (Line 6a / $85,685,624) - Per Coop	9.86%	N/A
7	Adjusted Test Year Operating Revenue	$ 137,611,450	$ 139,288,146
8	**Recommended Annual Operating Revenue**	$ 146,061,466	**$ 146,061,466**
9a	**Recommended Operating Margin**	$ 16,422,692	**$ 17,755,094**
9b	Recommended Net Margin	$ 3,922,406	$ 4,099,540
10a	**Recommended Operating TIER (L3+L9)/L4 - Per Staff**	N/A	**1.33**
10b	Recommended Net TIER (L4+L9b)/L4 - Per Coop	1.29	N/A
11a	**Recommended DSC (L2+L3+L9)/(L4+L5) - Per Staff**	N/A	**0.91**
11b	Recommended DSC (L2+L4+L9b)/(L4+L5) - Per Coop	1.05	N/A
12	**Adjusted Rate Base**	$ 222,147,011	**$ 189,637,810**
13	Rate of Return (L9a / L12)	7.39%	9.36%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [B]: Staff Schedules CSB-2, CSB-11, Testimony Alejandro Ramirez

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Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Plant in Service	$ 389,603,749	$ (11,928,486)	$ 377,675,263
2	Less: Acc Depreciation & Amortization	(186,190,519)	253,883	(185,936,636)
3	Net Plant in Service	$ 203,413,230	$ (11,674,603)	$ 191,738,627
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -	$ -
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	$ -	$ -	$ -
9	Member Advances	$ -	$ (11,982,081)	$ (11,982,081)
	ADD:			
10	Working Capital	$ 16,778,408	$ (6,897,144)	$ 9,881,264
11	Plant Held for Future Use	$ -	$ -	$ -
12	Deferred Debits	$ 1,955,373	$ (1,955,373)	$ -
13	**Total Rate Base**	$ 222,147,011	$ (32,509,201)	$ 189,637,810

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Schedule CSB-3
Column [C]: Column [A] + Column [B]

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Schedule CSB-3

SUMMARY OF RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] Coal Blending Plant ADJ No.1	[C] Plant Acquisition Adjustment ADJ No. 2	[D] Accumulated Depreciation ADJ No. 3	[E] Member Advances ADJ No. 4	[F] Working Capital ADJ No. 5	[G] Deferred Debits ADJ No. 6	[H] ARO ADJ No. 7	[I] STAFF ADJUSTED
	PLANT IN SERVICE:									
1	Intangible Plant[1]	$ 18,527 [1]	$ -	$ (13,238)	$ -	$ -	$ -	$ -	$ -	$ 5,289
2	Steam Production Plant - Land and Land Rights	3,915,175	-	-	-	-	-	-	-	3,915,175
3	Steam Production Plant - Structures and Improv	34,923,477	-	-	-	-	-	-	-	34,923,477
4	Steam Production Plant - Boiler Equipment	202,166,807	-	-	-	-	-	-	-	202,166,807
5	Steam Production Plant - Turbine Generators	51,884,782	-	-	-	-	-	-	-	51,884,782
6	Steam Production Plant - Misc Electrical Equip[2]	21,531,578 [2]		-	-	-	-	-	-	21,531,578
7	Steam Production Plant - Asset Retirement Oblig	1,962,630	-	-	-	-	-	-	(1,962,630)	-
8	Other Production Plant - Land and Land Rights	1,160	-	-	-	-	-	-	-	1,160
9	Other Production Plant - Structures and Improv	10,591,888	(9,952,618)	-	-	-	-	-	-	639,270
10	Other Production Plant - Fuel Hldrs Prodcrs & Acces	2,805,026	-	-	-	-	-	-	-	2,805,026
11	Other Production Plant - Prime Movers	29,153,230	-	-	-	-	-	-	-	29,153,230
12	Other Production Plant - Generators	3,284,797	-	-	-	-	-	-	-	3,284,797
13	Other Production Plant - Misc Electrical Equip[3]	3,361,517 [3]	-	-	-	-	-	-	-	3,361,517
14	Transmission Plant - Station Equipment	2,524,442	-	-	-	-	-	-	-	2,524,442
15	Transmission Plant - Poles, Fixtures, Conductors[4]	247,329 [4]	-	-	-	-	-	-	-	247,329
16	General Plant[5]	17,278,108 [5]	-	-	-	-	-	-	-	17,278,108
17	Unclassified Completed Construction - General Plant	3,943,249	-	-	-	-	-	-	-	3,943,249
18	Unclassified Completed Constr - Steam, Generation	10,027	-	-	-	-	-	-	-	10,027
19	Total Plant in Service	$ 389,603,749	(9,952,618)	(13,238)	-	-	-	-	(1,962,630)	$ 377,675,263
20	Less: Accumulated Depreciation	$ (185,972,877)	-	-	253,883	-	-	-	-	$ (185,718,994)
21	Less: Accumulated Amortization	(217,642)	-	-	-	-	-	-	-	(217,642)
22	Total Accumulated Depreciation & Amortization	$ (186,190,519)	$ -	$ -	$ 253,883	$ -	$ -	$ -	$ -	$ (185,936,636)
23	Net Plant in Service	$ 203,413,230	$ (9,952,618)	$ (13,238)	$ 253,883	$ -	$ -	$ -	$ (1,962,630)	$ 191,738,627
	LESS:									
24	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Contributions in Aid of Construction (CIAC)	-	-	-	-	-	-	-	-	-
26	Less: Accumulated Amortization	-	-	-	-	-	-	-	-	-
27	Net CIAC	$ -	-	-	-	-	-	-	-	$ -
28	Member Advances	$ -	-	-	-	(11,982,081)	-	-	-	$ (11,982,081)
	ADD:									
29	Working Capital Allowance	$ 16,778,408	-	-	-	-	(6,897,144)	-	-	$ 9,881,264
30	Plant Held For Future Use	-	-	-	-	-	-	-	-	-
31	Deferred Debits	1,955,373	-	-	-	-	-	(1,955,373)	-	-
32	**Total Rate Base**	$ 222,147,011	$ (9,952,618)	$ (13,238)	$ 253,883	$ (11,982,081)	$ (6,897,144)	$ (1,955,373)	$ (1,962,630)	$ 189,637,810

ADJ No.		References:
1	Coal Blending Plant	Schedule CSB-4
2	Plant Acquisition Adjustment	Schedule CSB-5
3	Accumulated Depreciation	Schedule CSB-6
4	Member Advances	Schedule CSB-7
5	Working Capital	Schedule CSB-8
6	Deferred Debits	Schedule CSB-9
7	Asset Retirement Obligation ("ARO")	Schedule CSB-10

ootnote Explanations

[1] Includes account nos. 301,114,302, & 303
[2] Includes account nos. 315 & 316
[3] Includes account nos. 345 & 346
[4] Includes account nos. 355 & 356
[5] Includes account nos. 389 and 390 to 399

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Schedule CSB-4

RATE BASE ADJUSTMENT NO. 1 - POST-TEST YEAR PLANT, COAL BLENDING FACILITY

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (Sch E-5)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	2003 Actual Plant	$ 379,651,131	$ -	$ 379,651,131
2	Coal Blending Facility (Acct. No. 341)	$ 9,952,618	$ (9,952,618)	$ -
		$ 389,603,749	**$ (9,952,618)**	**$ 379,651,131**

3 To remove plant that was not used and useful during the Test Year.

4 References:
5 Column [A]: Cooperative Schedule E-5, Page 1
6 Column [B]: Testimony, CSB
7 Column [C]: Column [A] + Column [B]

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Schedule CSB-5

RATE BASE ADJUSTMENT NO. 2 - ACQUISITION ADJUSTMENT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (Sch E-5)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Intangible Plant (Excluding Acquisition Adj)	$ 5,289	$ -	$ 5,289
2	Intangible Plant, Acquisition Adjustment	$ 13,238	$ (13,238)	$ -
	Total Intangible Plant	**$ 18,527**	**$ (13,238)**	**$ 5,289**

3 To remove unauthorized acquistion adjustment from plant in service.

4 References:
5 Column [A]: Cooperative Schedule E-5, Page 1
6 Column [B]: Testimony, CSB
7 Column [C]: Column [A] + Column [B]

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Schedule CSB-6

RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEPRECIATION

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Accumulated Depreciation	$ (185,718,994)	$ -	$ (185,718,994)
2	Accumulated Depr, Retirement Work In Progress	$ 54,648	$ (54,648)	$ -
3	Accumulated Depreciation, Coal Blending Plant	$ (308,531)	$ 308,531	$ -
4	**Total Accumulated Depreciation**	**$ (185,972,877)**	**$ 253,883**	**$ (185,718,994)**

5 References:
Column A: Cooperative Schedules B-2, Page 1 and E-5, Page 4

6 Column B: Testimony, CSB, Company Data Request Responses CSB 3-18 and CSB 3-19

7 Column C: Column [A] + Column [B]

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Schedule CSB-7

RATE BASE ADJUSTMENT NO. 4 - MEMBER ADVANCES

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Member Advances	$ -	$ (11,982,081)	$ (11,982,081)

		Member Advances Ending Balance (Per CSB 1-21)	Member Advances Average Balance
2			
3			
4			
5			
6			
7	Dec-02	$ (15,278,804.00)	
8	Jan-03	$ (14,437,497.22)	$ (14,858,150.61)
9	Feb-03	$ (16,543,558.64)	$ (15,490,527.93)
10	Mar-03	$ (12,513,460.14)	$ (14,528,509.39)
11	Apr-03	$ (10,947,970.04)	$ (11,730,715.09)
12	May-03	$ (11,848,040.63)	$ (11,398,005.34)
13	Jun-03	$ (10,325,533.24)	$ (11,086,786.94)
14	Jul-03	$ (10,003,125.98)	$ (10,164,329.61)
15	Aug-03	$ (11,283,568.22)	$ (10,643,347.10)
16	Sep-03	$ (11,769,769.82)	$ (11,526,669.02)
17	Oct-03	$ (9,930,963.36)	$ (10,850,366.59)
18	Nov-03	$ (6,373,504.03)	$ (8,152,233.70)
19	Dec-03	$ (2,529,176.16)	$ (4,451,340.10)
20		$(143,784,971.48)	$ (134,880,981.40)
21			/ 12
22			$ (11,982,080.96)

23 References:
24 Column [A]: Cooperative Schedule B-5, Page 1
25 Column [B]: Column C - Column A
26 Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2; CSB 1-21

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Schedule CSB-8

RATE BASE ADJUSTMENT NO. 5 - WORKING CAPITAL

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Cash Working Capital	$ -	$ -	$ -
2	Fuel Stock, Coal	$ 5,581,933	$ (946,753)	$ 4,635,180
3	Materials and Supplies	$ 5,265,561	$ (19,476)	$ 5,246,085
4	Prepayments	$ 908,046	$ (908,046)	$ -
5	CFC Certificates and Bonds	$ 5,022,869	$ (5,022,869)	$ -
6	**Total Working Capital**	**$ 16,778,409**	**$ (6,897,144)**	**$ 9,881,265**

7 References:

8 Column A: Cooperative Schedule B-5, Page 1

9 Column B: Testimony, CSB; Schedules CSB-8.1 and CSB-8.2

10 Column C: Column [A] + Column [B]

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Schedule CSB-8.1

FUEL STOCK CALCULATION

Line No.	Number of Burn Days (CSB 3-15)	[A] Tons of Coal Burned Per Day (CSB 3-15)	[B] Average Cost Per Ton (CSB 6-9)	[C] Average Cost of Coal Inventory
1	42.5	4,100	$ 27.7	$ 4,826,725
2	**Less:** Legal expenses charge to fuel inventory (CSB 15-3)			$ (191,545)
3	Total Fuel Stock			$ 4,635,180

4 References:
5 Column [A]: Cooperative Response to CSB 3-15 & CSB 15-3
6 Column [B]: Cooperative Response to CSB 6-9
7 Column [C]: Column [A] x Column [B]

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Schedule CSB-8.2

MATERIALS AND SUPPLIES BALANCE CALCULATION

LINE NO.	END OF MONTH BALANCE	[A] COMPANY AS FILED 13-Month Avg	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED 12-Month Avg
1	Dec-02	$ 5,199,651	$ (5,199,651)	$ -
2	Jan-03	$ 5,170,130	$ 14,761	$ 5,184,891
3	Feb-03	$ 5,127,900	$ 21,115	$ 5,149,015
4	Mar-03	$ 4,896,182	$ 115,859	$ 5,012,041
5	Apr-03	$ 4,977,902	$ (40,860)	$ 4,937,042
6	May-03	$ 5,158,387	$ (90,243)	$ 5,068,145
7	Jun-03	$ 5,089,094	$ 34,647	$ 5,123,741
8	Jul-03	$ 5,318,376	$ (114,641)	$ 5,203,735
9	Aug-03	$ 5,313,413	$ 2,482	$ 5,315,895
10	Sep-03	$ 5,339,052	$ (12,820)	$ 5,326,233
11	Oct-03	$ 5,377,843	$ (19,396)	$ 5,358,448
12	Nov-03	$ 5,685,470	$ (153,814)	$ 5,531,657
13	Dec-03	$ 5,798,889	$ (56,710)	$ 5,742,180
14		$ 68,452,289	$ (5,499,270)	$ 62,953,019
15	Divided by	13	$ (1)	12
16		$ 5,265,561	$ (19,476)	$ 5,246,085

17 References:
18 Column [A]: Cooperative Schedule B-5, Pages 1 and 5
19 Column [B]: Testimony, CSB; Column C - Column A
20 Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2

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Schedule CSB-9

RATE BASE ADJUSTMENT NO. 6 - DEFERRED DEBITS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (CSB 3-1)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Preliminary Survey & Investigation Charges	$ 957,472	$ (957,472)	$ -
2	Job Tickets	$ 731,780	$ (731,780)	$ -
3	Unamortized Losses on Reacquired Debt	$ 266,121	$ (266,121)	$ -
4	Total Deferred Debits	**$ 1,955,373**	**$ (1,955,373)**	**$ -**

5 References:
6 Column [A]: Cooperative Schedule B-1, Line 8; CSB 3-1
7 Column [B]: Testimony, CSB
8 Column [C]: Column [A] + Column [B]

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Schedule CSB-10

RATE BASE ADJUSTMENT NO. 7 - ASSET RETIREMENT OBLIGATION ("ARO")

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (CSB 3-1)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Steam Production Plant - Asset Retirement Oblig	$ 1,962,630	$ (1,962,630)	$ -

2 References:
3 Column [A]: Cooperative Schedule E-5, Page 1, Line 12; Note 19 of Audited Financial Statements
4 Column [B]: Testimony, CSB
5 Column [C]: Column [A] + Column [B]

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Schedule CSB-11

OPERATING INCOME - TEST YEAR AND STAFF PROPOSED

Line No.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 44,409,469	$ (6,591,465)	$ 37,818,004	$ 6,773,320	$ 44,591,324
2	Class A Members, Base Cost of Power Revenue	$ 41,276,155	$ 7,716,227	$ 48,992,382		$ 48,992,382
3	Total Class A Member Electric Revenue	$ 85,685,624	$ 1,124,762	$ 86,810,386	$ 6,773,320	$ 93,583,706
4	Non-Class A, Non-Firm, & Non-Member	50,444,504	551,934	50,996,438	-	50,996,438
5	Total Electric Revenue	$ 136,130,128	$ 1,676,696	$ 137,806,824	$ 6,773,320	$ 144,580,144
6	Other Operating Revenue	$ 1,481,322	$ -	$ 1,481,322	$ -	$ 1,481,322
7	**Total Revenues**	$ 137,611,450	$ 1,676,696	$ 139,288,146	$ 6,773,320	$ 146,061,466
	EXPENSES:					
8	Operations - Production, Fuel	$ 59,803,425	$ (788,697)	$ 59,014,728	$ -	$ 59,014,728
9	Operations - Production, Steam	$ 8,764,555	$ -	$ 8,764,555	$ -	$ 8,764,555
10	Operations - Production, Other	$ 1,335,333	$ 407,983	$ 1,743,316	$ -	$ 1,743,316
11	Operations - Other Pwr Supply, Demand	$ 5,769,587	$ -	$ 5,769,587	$ -	$ 5,769,587
12	Operations - Other Pwr Supply - Energy	$ 12,420,888	$ (250,000)	$ 12,170,888	$ -	$ 12,170,888
13	Operations - Transmission	$ 8,036,486	$ -	$ 8,036,486	$ -	$ 8,036,486
14	Operations - Administrative and General	$ 9,191,902	$ 333,857	$ 9,525,759	$ -	$ 9,525,759
15	Maintenance - Production, Steam	$ 10,170,045	$ (657,788)	$ 9,512,257	$ -	$ 9,512,257
16	Maintenance - Production, Other	$ 2,809,881	$ -	$ 2,809,881	$ -	$ 2,809,881
17	Maintenance - Transmission	$ 28,388	$ (19,560)	$ 8,828	$ -	$ 8,828
18	Maintenance - General Plant	$ 63,958	$ -	$ 63,958	$ -	$ 63,958
19	Depreciation and Amortization	$ 7,608,735	$ (69,446)	$ 7,539,289	$ -	$ 7,539,289
20	ACC Gross Revenue Taxes	$ 288,752	$ (288,752)	$ -	$ -	$ -
21	Taxes	$ 3,346,839	$ -	$ 3,346,839	$ -	$ 3,346,839
22	**Total Operating Expenses**	$ 129,638,774	$ (1,332,402)	$ 128,306,372	$ -	$ 128,306,372
23	**Operating Margin Before Interest on L.T.- Debt**	$ 7,972,676	$ 3,009,098	$ 10,981,774	$ -	$ 17,755,094
24	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
25	Interest on Long-term Debt	$ 13,547,749	$ (234,585)	$ 13,313,164	$ -	$ 13,313,164
26	Other Interest & Other Dedcutions	$ 914,988	$ (572,598)	$ 342,390	$ -	$ 342,390
27	**Total Interest & Other Deductions**	$ 14,462,737	$ (807,183)	$ 13,655,554	$ -	$ 13,655,554
28	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (6,490,061)	$ 3,816,281	$ (2,673,780)	$ -	$ 4,099,540
29	***NON-OPERATING MARGINS***					
30	Interest Income	$ 582,014	$ -	$ 582,014	$ -	$ 582,014
31	Other Non-operating Income	$ 1,380,437	$ -	$ 1,380,437	$ -	$ 1,380,437
32	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ 1,962,451	$ -	$ 1,962,451
33	***EXTRAORDINARY ITEMS***	$ -	$ -	$ -	$ -	$ -
34	***NET MARGINS (LOSS)***	$ (4,527,610)	$ 3,816,281	$ (711,329)	$ -	$ 6,061,991

35 References:
36 Column (A): Cooperative Schedule C-1, Pages 1 and 2
37 Column (B): Schedule CSB-12
38 Column (C): Column (A) + Column (B)
39 Column (D): Schedules CSB-1
40 Column (E): Column (C) + Column (D)

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Post-Test Year Revenues and Expenses Ref: Sch CSB-13	[C] ADJ #2 Revenue and Expense Annualizations Ref: Sch CSB-14	[D] ADJ #3 Asset Retirement Obligation Ref: Sch CSB-15	[E] ADJ #4 Tracker Mechanism (Base Power Cost) Ref: Sch CSB-16	[F] ADJ #5 Overhaul Accrual Expense Ref: Sch CSB-17	[G] ADJ #6 Transmission Expense Annualization for Contracts Ref: Sch CSB-18	[H] ADJ #7 Normalized Legal Expense Ref: Sch CSB-19
	REVENUES:								
1	Class A Members, Non-Base Cost of Power Revenue	$ 44,409,469	$ -	$ 1,271,908	$ -	$ (7,716,227)	$ -	$ -	$ -
2	Class A Members, Base Cost of Power Revenue	$ 41,276,155	$ -	$ -	$ -	$ 7,716,227	$ -	$ -	$ -
3	Total Class A Member Electric Revenue	$ 85,685,624	$ -	$ 1,271,908	$ -	$ -	$ -	$ -	$ -
4	Non-Class A, Non-Firm, & Non-Member	50,444,504	551,934	-	-	-	-	-	-
5	Total Electric Revenue	$ 136,130,128	$ 551,934	$ 1,271,908	$ -	$ -	$ -	$ -	$ -
6	Other Operating Revenue	$ 1,481,322	-	-	-	-	-	-	-
7	**Total Revenues**	$ 137,611,450	$ 551,934	$ 1,271,908	$ -	$ -	$ -	$ -	$ -
8	***OPERATING EXPENSES:***								
9	Operations - Production, Fuel	$ 59,803,425	$ -	$ 264,376	$ -	$ -	$ -	$ -	$ -
10	Operations - Production, Steam	8,764,555 [1]	-	-	-	-	-	-	-
11	Operations - Production, Other	1,335,333 [2]	407,983		-	-	-	-	-
12	Operations - Other Pwr Supply, Demand	5,769,587	-	-	-	-	-	-	-
13	Operations - Other Pwr Supply - Energy	12,420,888 [3]	-	-	-	(250,000)	-	-	-
14	Operations - Transmission	8,036,486	-	-	-	-	-	-	-
15	Operations - Administrative and General	9,191,902	-	-	-	-	-	-	539,989
16	Maintenance - Production, Steam	10,170,045 [4]	-	-	-	-	(657,788)	-	-
17	Maintenance - Production, Other	2,809,881	-	-	-	-	-	-	-
18	Maintenance - Transmission	28,388	-	-	-	-	-	(19,560)	-
19	Maintenance - General Plant	63,958	-	-	-	-	-	-	-
20	Depreciation and Amortization	7,608,735	-	-	(69,446)	-	-	-	-
21	ACC Gross Revenue Taxes	288,752	-	-	-	-	-	-	-
22	Taxes	3,346,839	-	-	-	-	-	-	-
23	**Total Operating Expenses**	$ 129,638,774	$ 407,983	$ 264,376	$ (69,446)	$ (250,000)	$ (657,788)	$ (19,560)	$ 539,989
24	**Operating Margin Before Interest on L.T.- Debt**	$ 7,972,676	$ 143,951	$ 1,007,531	$ 69,446	$ 250,000	$ 657,788	$ 19,560	$ (539,989)
25	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***								
26	Interest on Long-term Debt	$ 13,547,749	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Other Interest & Other Dedcutions	914,988	-	-	(572,598)	-	-	-	-
28	**Total Interest & Other Deductions**	$ 14,462,737	$ -	$ -	$ (572,598)	$ -	$ -	$ -	$ -
29	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (6,490,061)	$ 143,951	$ 1,007,531	$ 642,044	$ 250,000	$ 657,788	$ 19,560	$ (539,989)
30	***NON-OPERATING MARGINS***								
31	Interest Income	$ 582,014	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	Other Non-operating Income	1,380,437	-	-	-	-	-	-	-
33	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	***EXTRAORDINARY ITEMS***	$ -	-	-	-	-	-	-	-
35	***NET MARGINS (LOSS)***	$ (4,527,610)	$ 143,951	$ 1,007,531	$ 642,044	$ 250,000	$ 657,788	$ 19,560	$ (539,989)

Footnote Explanations

[1] Includes account nos. 500, 502 to 509
[2] Includes account nos. 546, 548 to 550
[3] Includes account nos. 555 to 557
[4] Includes account nos. 510 to 515

LINE NO.	DESCRIPTION	[I] ADJ #8 Fuel Expense Ref: Sch CSB-20	[J] ADJ #9 Advertising Expense Ref: Sch CSB-21	[K] ADJ #10 Contributions & Other Expenses Ref: Sch CSB-22	[L] ADJ #11 ACC Gross Rev Assessment Ref: Sch CSB-23	[M] ADJ #12 Interest on Long Term Debt Ref: Sch CSB-24	[N] STAFF ADJUSTED
	REVENUES:						
1	Class A Members, Non-Base Cost of Power Revenue	$ -	$ -	$ -	$ (147,146)	$ -	$ 37,818,004
2	Class A Members, Base Cost of Power Revenue	$ -	$ -	$ -	$ -	$ -	$ 48,992,382
3	Total Class A Member Electric Revenue	$ -	$ -	$ -	$ (147,146)	$ -	$ 86,810,386
4	Non-Class A, Non-Firm, & Non-Member	-	-	-	-	-	50,996,438
5	Total Electric Revenue	$ -	$ -	$ -	$ (147,146)	$ -	137,806,824
6	Other Operating Revenue		-	-	-	-	1,481,322
7	**Total Revenues**	$ -	$ -	$ -	$ (147,146)	$ -	$ 139,288,146
8	***OPERATING EXPENSES:***						
9	Operations - Production, Fuel	$ (1,053,073)	$ -	$ -	$ -	$ -	$ 59,014,728
10	Operations - Production, Steam	-	-	-	-	-	8,764,555
11	Operations - Production, Other	-	-	-	-	-	1,743,316
12	Operations - Other Pwr Supply, Demand	-	-	-	-	-	5,769,587
13	Operations - Other Pwr Supply - Energy	-	-	-	-	-	12,170,888
14	Operations - Transmission	-	-	-	-	-	8,036,486
15	Operations - Administrative and General	-	(46,241)	(159,891)	-	-	9,525,759
16	Maintenance - Production, Steam	-	-	-	-	-	9,512,257
17	Maintenance - Production, Other	-	-	-	-	-	2,809,881
18	Maintenance - Transmission	-	-	-	-	-	8,828
19	Maintenance - General Plant	-	-	-	-	-	63,958
20	Depreciation and Amortization	-	-	-	-	-	7,539,289
21	ACC Gross Revenue Taxes	-	-	-	(288,752)	-	-
22	Taxes	-	-	-	-	-	3,346,839
23	**Total Operating Expenses**	$ (1,053,073)	$ (46,241)	$ (159,891)	$ (288,752)	$ -	$ 128,306,372
24	**Operating Margin Before Interest on L.T.- Debt**	$ 1,053,073	$ 46,241	$ 159,891	$ 141,606	$ -	**$ 10,981,774**
25	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***						
26	Interest on Long-term Debt	$ -	$ -	$ -	$ -	$ (234,585)	$ 13,313,164
27	Other Interest & Other Dedcutions	-	-	-	-	-	342,390
28	**Total Interest & Other Deductions**	$ -	$ -	$ -	$ -	$ (234,585)	$ 13,655,554
29	***MARGINS (LOSS) AFTER INTERST EXPENSE***	$ 1,053,073	$ 46,241	$ 159,891	$ 141,606	$ 234,585	$ (2,673,780)
30	***NON-OPERATING MARGINS***						
31	Interest Income	$ -	$ -	$ -	$ -	$ -	$ 582,014
32	Other Nonoperating Income	-	-	-	-	-	1,380,437
33	**Total Non-Operating Margins**	$ -	$ -	$ -	$ -	$ -	$ 1,962,451
34	***EXTRAORDINARY ITEMS***	-	-		-	-	-
35	***NET MARGINS (LOSS)***	$ 1,053,073	$ 46,241	$ 159,891	$ 141,606	$ 234,585	$ (711,329)

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-13

OPERATING INCOME ADJUSTMENT NO. 1 - POST-TEST YEAR REVENUE AND EXPENSE FOR COAL BLENDING PLANT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	**Revenues**			
2	AEPCO Adjustment No. 5 - Fuel Expense	$ (551,934)	$ 551,934	$ -
3	**Total Revenues**	$ (551,934)	**$ 551,934**	$ -
4	**Expenses**			
5	AEPCO Adjustment No. 5 - Fuel Expense	$ (1,534,274)	$ 1,534,274	$ -
6	AEPCO Adjustment No. 6 - S02 Allowance	$ (167,069)	$ 167,069	$ -
7	AEPCO Adjustment No. 7 - Ash Credit Sales	$ 820,611	$ (820,611)	$ -
8	AEPCO Adjustment No. 8 - Depr and Prop Tax	$ 472,749	$ (472,749)	$ -
9	**Total Operating Expenses**	$ (407,983)	**$ 407,983**	$ -
10	**Operating Margin Before Interest on L.T. Debt**	$ (143,951)	**$ 143,951**	$ -
11	AEPCO Adjustment No. 8 - Interest on L.T.-Debt (see Note)	$ 532,465	$ -	$ 532,465
12	**Operating Margin After Interest on L.T. Debt**	**$ (676,416)**	**$ 143,951**	**$ (532,465)**

13 Note: The $532,465 is included in the Cooperative filed amount for Interest on L.T. Debt.

14 References:

15 Column A: Cooperative Schedule C-2, Pages 5 and 6.
16 Column B: Testimony, CSB
17 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-14

OPERATING INCOME ADJUSTMENT NO. 2 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Class A Member Demand Revenues	$ 36,990,731	$ -	$ 36,990,731
2	Class A Member Energy Revenues	$ 40,285,075	$ -	$ 40,285,075
3	Class A Member ACC Assessment Rev	$ 147,146	$ (147,146)	$ -
4	Class A Member Fixed Charge Revenues	$ 8,262,672	$ (8,262,672)	$ -
5	Total Class A Member Base Rate Revenues	$ 85,685,624	$ (8,409,818)	$ 77,275,806
6	Factor to Annualize Revenues to End of Test Year	0.00%		1.65%
7	**Revenue Annualization Adjustment**	$ -	**$ 1,271,908**	$ 1,271,908
8	Variable Expenses Not Recovered Through Fuel Adj	$ -		$ 16,062,410
9	Factor to Annualize Revenues to End of Test Year	0.00%		1.65%
10	**Adjustment to Expenses**	$ -	**$ 264,376**	$ 264,376

	Calculation of Annualization Factor						
	Number of Customers						
	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
2002	3,702	2,446	7,481	31,701	43,113	27,631	116,074
2003	3,824	2,484	7,623	32,804	44,431	28,729	119,895
Increase	122	38	142	1,103	1,318	1,098	3,821
% Increase	3.30%	1.55%	1.90%	3.48%	3.06%	3.97%	3.29%

2003 Growth Rate 3.29%

Annualization Factor - 2003 Growth Rate divided by 2 1.6459%

Caculation of Variable Expenses Not Recovered Through Fuel Adjustor			
Account No.	**Description**	**Amount**	
500	*Operation Supervision and Engineering*	$ 1,999,908	
501&547	Fuel - Steam Power & Other	$ 59,803,425	
502	Steam Expenses	$ 2,710,803	
505	Electric Expenses	$ 1,437,524	
510	Maintenance Supervision & Engineering	$ 840,774	
512	Maintenance of Boiler Plant	$ 6,433,681	
513	Maintenance of Electric Plant	$ 264,759	
514	Maintenance of Miscellaneous Steam Plant	$ 2,374,961	
555	Purchased Power - Demand	$ 5,769,587	
555	Purchased Power - Energy	$ 10,085,538	
	Total Variable Expenses	$ 91,720,960	
501&547	Fuel - Steam Power & Other	$ (59,803,425)	Recovered through Fuel Adj
555	Purchased Power - Demand	$ (5,769,587)	Recovered through Fuel Adj
555	Purchased Power - Energy	$ (10,085,538)	Recovered through Fuel Adj
		$ 16,062,410	
	2003 Growth Rate	1.65%	
	Adjustment to Expenses	$ 264,376	

References:
Column A: Cooperative Data Request Response CSB 6-1
Column B: Testimony, CSB

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-15

OPERATING INCOME ADJUSTMENT NO. 3 - ASSET RETIREMENT OBLIGATION

		Effects on Net Margin				
		[A]	[B]	[C]	[D]	[E]
LINE NO.	DESCRIPTION	AEPCO ACTUAL TEST YEAR Sch C-1, Page 1	AEPCO ADJUSTMENTS TO ACTUAL Sch C-1, Page 4	AEPCO ADJUSTED TEST YEAR Sch C-1, Page 4	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Revenue	$ -	$ -	$ -	$ -	$ -
2	Expense - Depreciation	$ 69,446	$ -	$ 69,446	$ (69,446)	$ -
3	Operating Margin Before Interest	$ (69,446)	$ -	$ (69,446)	**$ 69,446**	$ -
4	Interest and Other Deductions, ARO	$ -	$ 381,034	$ 381,034	$ (381,034)	$ -
5	Interest and Other Deductions, Accretion	$ 191,564	$ -	$ 191,564	$ (191,564)	$ -
6	Total Interest	$ 191,564	$ 381,034	$ 572,598	**$ (572,598)**	$ -
7	Extraordinary Items	$ 3,810,335	$ (3,810,335)	$ -	$ -	$ -
8	Net Margin	$ (4,071,345)	$ 3,429,301	$ (642,044)	**$ 642,044**	$ -

9 References:

10 Column A: Cooperative Data Request Response CSB 1-1 and CSB 1-2; Note 19 of 2003 Audited Financial Statements

11 Column B: Direct Testimony; Cooperative Witness, Gary Pierson

12 Column C: Column [A] + Column [B]

13 Column D: Testimony, CSB

14 Column E: Column [C] + Column [D]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-16

OPERATING INCOME ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	**Base Cost of Power Revenue**			
2	Test Year Sales (In kWhs)	2,025,326,533	-	2,025,326,533
3	Base Cost of Power (Col A, per Dec 58405)	$ 0.017140	$ 0.003240	$ 0.020380
4	**Adjustment to match Coop proposed power expense to revenue**	$ 34,714,097	$ 6,562,058	$ 41,276,155
5	Test Year Sales (In kWhs)	2,025,326,533		2,025,326,533
6	Base Cost of Power (Col C, Line 53/Line 5)	$ 0.020380	$ (0.003810)	$ 0.016570
7	**Adjustment to reflect Staff's adjustments to power costs**	$ 41,276,627	$ (7,716,227)	$ 33,560,400
8	**Total**	$ 34,714,097	$ (1,153,697)	$ 33,560,400
9	**Base Cost of Power Expense**			
10	*Coal Fired Steam Plant Costs:*			
11	Fuel, Coal ($1,534,274 Coop Adj No. 5 - $1,030,873 legal exp)	$ 42,029,531	$ 503,401	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-
14	**Less:** Fixed Fuel Costs	(549,137)	253,272	(295,865)
15	Subtotal	$ 43,789,748	$ 756,673	$ 44,546,421
16	Internal Combustion Plant Costs:			
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809
19	Less: Fixed Fuel Costs	(1,435,208)	1,435,208	-
20	Subtotal	$ 14,029,332	$ 1,435,208	$ 15,464,540
21	**Total Fuel Costs**	**$ 57,819,080**	**$ 2,191,881**	**$ 60,010,961**
22	Purchased Power Energy Costs			
23	Firm Purchases			
24	CRSP	$ 309,547	$ -	$ 309,547
25	Pacificorp	-	-	-
26	Parker Davis	217,629	-	217,629
27	Public Service Company of New Mexico	1,963,061	(250,000)	1,713,061
28	Panda Gila River	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-
30	Subtotal Firm Purchases	$ 3,624,810	$ (250,000)	$ 3,374,810
31	Nonfirm Purchases, Demand	$ -	5,769,587	$ 5,769,587
32	Nonfirm Purchases, Energy	6,460,728	-	6,460,728
33	**Total Purchased Energy Costs**	**$ 10,085,538**	**$ 5,519,587**	**$ 15,605,125**
34	**Firm Wheeling Expenses**	$ -	7,939,635	$ 7,939,635
35	**Non-firm Wheeling Expenses**	77,291	-	77,291
36	**Total Firm and Non-Firm Wheeling Expenses**	**$ 77,291**	**$ 7,939,635**	**$ 8,016,926**
37	**TOTAL FUEL COSTS & PURCHASED ENERGY**	**$ 67,981,909**	**$ 15,651,103**	**$ 83,633,012**
38	**Less:**			
39	Non-tariff Sales Fuel Recovery			
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-
42	City of Mesa (PSA)	2,657,351	(90,879)	2,566,472
43	ED-2 Power Supply	1,376,189	(20,185)	1,356,004
44	SRP	13,039,105	(260,828)	12,778,277
45	Safford	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921
47	Subtotal	$ 18,311,016	$ (371,892)	$ 17,939,124
48	Other Sales Fuel Recovery:			
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,705,282	$ (371,892)	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ -	$ 23,739,222	$ 23,739,222
52	**Total Non-Tariff Sales Fuel Recovery, Energy and Demand**	**$ 26,705,282**	**$ 23,367,330**	**$ 50,072,612**
53	**Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)**	**$ 41,276,627**	**$ (7,716,227)**	**$ 33,560,400**

54 References:
55 Column A: Decision No. 58405, page 29, line 25; Cooperative Application Schedule H-2A
56 Column B: Testimony, CSB
57 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-17

OPERATING INCOME ADJUSTMENT NO. 5 - OVERHAUL ACCRUAL EXPENSE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Overhaul Accrual Expense	$4,787,508	$ (657,788)	$ 4,129,720

2		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 57,354	$ 3,206,259
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 57,354	$ 33,037,763
12								Divided by	8
13									$ 4,129,720

14 * Per response to CSB 1-38, there has been no actual overhaul expense
15 for generating GT2 for the period 1990 to 2004.

16 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.

17 References:

18 Column A: Cooperative Data Request Response CSB 1-37 and 1-38
19 Column B: Testimony, CSB
20 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-18

OPERATING INCOME ADJUSTMENT NO. 6 - TRANSMISSION EXPENSE ANNUALIZATION FOR CONTRACTS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Contract Billing Units (in kW's)	1,956,000	-	1,956,000
2	Transmission rate per kW (see note below)	$ 3.032	$ (0.010)	$ 3.022
3	AEPCO Firm Transmission Expense	$ 5,930,592	**$ (19,560)**	$ 5,911,032

		Contract Billing Units (in kW's)		
4				
5		Per Cooperative	Adjustments	Per Staff
6	SRP	1,200,000	-	1,200,000
7	City of Mesa	180,000	-	180,000
8	Electric District 2	96,000	-	96,000
9	Apache Mead	480,000	-	480,000
10	Total	1,956,000	-	1,956,000

11 Note
12 The transmission rate is the Southwest Transmission proposed rate.

13 <u>References:</u>

14 Column A: Cooperative work paper "Computation of Adjustment to Annualize Wheeling Contracts"
15 Column B: Testimony, CSB
16 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-19

OPERATING INCOME ADJUSTMENT NO. 7 - NORMALIZED LEGAL EXPENSE

LINE NO.	DESCRIPTION		Normalized Legal Expense Calculation
1	**2003 Legal Expenses excl Rail Transportation Tariff Exp - Per Coop (Data Requ Response CSB 13-5)**	**$**	**903,512**
2	Transferred Rail Trans Tariff legal exp from Fuel Exp (from Operating Income Adj No. 8, Sch CSB-20)	$	1,030,873
3	Subtotal	$	1,934,385
4	Additional Expenses from 2003 Legal Exp Report; Data Requ Resp CSB 1-33 (Line 5-Line1-Line2)	$	761,373
5	Total Legal Expenses Per Cooperative's 2003 Legal Expense Report	$	2,695,758
6	To reflect Staff's normalized Rail Transportation Tariff Exp from Sch CSB-7.1 ($1,792,246-$620,129)	$	(1,172,117)
7	Subtotal	$	1,523,641
8	To reflect Staff's normalized Legal Expense Excluding Rail Transp Tariff Exp from Sch CSB-19.2	$	(80,140)
9	**Normalized Legal Expense - Per Staff**	**$**	**1,443,501**
10	Legal Expense - Per Cooperative (Line 1)	$	903,512
11	**Staff's Adjustment (Line 9 - Line 10)**		**539,989**

12 References:
13 Data Request Responses CSB 13-5 and CSB 1-33; Schedules CSB-19.1 and CSB-19.2

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-19.1

NORMALIZED RAILROAD LEGAL EXPENSES

LINE NO.	DESCRIPTION		NORMALIZED RAILROAD TRANSPORTATION TARIFF LEGAL EXPENSE
1	2002 Railroad Transportation Tariff Legal Expenses	$	209,924
2	2003 Railroad Transportation Tariff Legal Expenses		1,792,246
3	2004 Railroad Transportation Tariff Legal Expenses		1,098,477
4	Total Railroad Transportation Tariff Legal Expenses	$	3,100,647
5	Divided by 5 years (Contract Term)		5
6	Normalized Railroad Transportaion Legal Expense - Per Staff	$	620,129
7	2003 Railroad Transportation Tariff Legal Expenses - Per Coop		1,792,246
8	**Staff's Adjustment**	**$**	**(1,172,117)**

9 References:

10 Cooperative Data Request Response CSB 1-33, CSB 13-1, CSB 14-1, CSB 14-2, and Testimony, CSB

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-19.2

NORMALIZED LEGAL EXPENSE
Excluding Railroad Transportation Tariff Legal Expense

LINE NO.	DESCRIPTION		Normalized Legal Expense Calculation (Excl Rail Transp)
1	**2003 Legal Expenses excl Rail Transportation Tariff Expense - Per Cooperative (CSB 13-5)**	**$**	**903,512**
2	To properly reflect AEPCO's allocation for natural gas related legal expenses [$354,824 x (1-0.8023)]	$	(70,149)
3	To properly reflect legal expenses re: El Paso Electric contract that will be effective 2005-2008	$	(23,182)
4	To properly remove PUHCA related legal expenses (CSB 15-5 b)	$	(15,500)
5	To remove capitalized legal exp (CSB 1-33 & 13-5; Office Prop, Coal Blending Plant)	$	(13,605)
6	To remove costs related to redacted legal invoices	$	(68,412)
7	**Adjusted 2003 Legal Expenses**	**$**	**712,664**
8	**2002 Total Legal Expenses - Per Cooperative**	**$**	**1,101,927**
9	To properly reflect AEPCO's allocation for natural gas related legal expenses [$220,906 x (1-0.8023)]	$	(43,673)
10	To remove Restructuring legal costs	$	(48,834)
11	To remove Rail Transportation Tariff legal costs	$	(209,924)
12	**Adjusted 2002 Legal Expenses**	**$**	**799,496**
13	**2004 Total Legal Expenses - Per Cooperative**	**$**	**2,112,189**
14	To properly reflect AEPCO's allocation for natural gas related legal expenses [$282,030 x (1-0.8023)]	$	(55,757)
15	To remove Rail Transportation Tariff legal costs	$	(1,098,477)
16	**Adjusted 2004 Legal Expenses**	**$**	**957,955**
17	**Total Adjusted 2002, 2003 and 2004 Legal Expenses (Line 7 + Line 12 + Line 16)**	**$**	**2,470,115**
18	**Normalized Legal Expense (Line 17 divided by 3) - Per Staff**	**$**	**823,372**
19	Legal Expense - Per Cooperative (Line 1)	$	903,512
20	**Staff's Adjustment (Line 18 - Line 19)**		**(80,140)**
21	References:		
22	Data Request Responses CSB 13-5 and CSB 1-33; Schedules CSB-19.1 and CSB-19.2		

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-20

OPERATING INCOME ADJUSTMENT NO. 8 - FUEL EXPENSE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
	Summary of Variable Coal Fuel Costs			
1	Before the Burn	$ 64,024,628.18	$ -	$ 64,024,628.18
2	Purchase Dollars	$ 17,677,372.66	$ -	$ 17,677,372.66
2	Sales Tax	$ 1,098,611.58	$ -	$ 1,098,611.58
4	Quality	$ 248,731.33	$ -	$ 248,731.33
5	Transportation	$ 11,995,936.28	$ -	$ 11,995,936.28
6	Est. 151 Accrual	$ -	$ -	$ -
7	Subtotal	$ 95,045,280.03	$ -	$ 95,045,280.03
8	Rail Invoices/Demurrge	$ 634,323.21	$ -	$ 634,323.21
9	**Rail Invoices/Demurrge (Legal)**	**$ 2,346,719.65**	$ (2,346,719.65)	**$ -**
10	Subtotal	$ 2,981,042.86	$ (2,346,719.65)	$ 634,323.21
11	Total $ Available Before the Burn (Line 7 + Line 10)	$ 98,026,322.89	$ (2,346,719.65)	$ 95,679,603.24
12	Tons Before Burn	3,425,374.41	-	3,425,374.41
13	Variable Weighted Average (Line 11 / Line 12)	$ 28.62	$ (0.69)	$ 27.93
14	Steam 2 Tons Burned	719,472.15	-	719,472.15
15	**Steam 2 Dollars Burned (Line 13 x Line 14)**	**$ 20,589,635.13**	$ (492,909.45)	**$ 20,096,725.68**
16	Adjustment to reconcile to actual Steam 2 Dollars Burned	$ (213,586.55)	$ 1,369.95	$ (212,216.60)
17	**Actual Steam 2 Dollars Burned**	**$ 20,376,048.58**	$ (491,539.50)	**$ 19,884,509.08**
18	Steam 3 Tons Burned	786,745.15	-	786,745.15
19	**Steam 3 Dollars Burned (Line 13 x Line 18)**	**$ 22,514,833.38**	$ (538,998.10)	**$ 21,975,835.28**
20	Adjustment to reconcile to actual Steam 3 Dollars Burned	$ (152,978.79)	$ (335.59)	$ (153,314.38)
21	**Actual Steam 3 Dollars Burned**	**$ 22,361,854.59**	$ (539,333.69)	**$ 21,822,520.90**
22	**Total Steam Dollars Burned (Line 17 + Line21)**	**$ 42,737,903.17**	**$ (1,030,873.19)**	**$ 41,707,029.98**
23	**Procurement Costs**	**$ 1,487,755.23**	**$ -**	**$ 1,487,755.23**
24	**Fixed Costs - Interest on L.T. Debt (CSB 3-14)**	**$ 295,864.69**	**$ (22,199.90)**	**$ 273,664.79**
25	**Total Coal Fuel Costs**	**$ 44,521,523.09**	**$ (1,053,073.09)**	**$ 43,468,450.00**

Reference: Data Request Response CSB 3-14

Arizona Electric Power Cooperative, Inc.
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Test Year Ended December 31, 2003

Schedule CSB-21

OPERATING INCOME ADJUSTMENT NO. 9 - ADVERTISING EXPENSE

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Advertising Expense	$ 46,241	$ (46,241)	$ -

2 References:

3 Column A: Cooperative Data Request Response CSB 1-35
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-22

OPERATING INCOME ADJUSTMENT NO. 10 - CHARITABLE CONTRIBUTIONS & OTHER EXPENSES

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	CSB 1-41	AEPCO Sponsorships	$ 56,296	$ (56,296)	$ -
2	CSB 1-41	AEPCO Food, Luncheons, Dinners	$ 12,706	$ (12,706)	$ -
3	CSB 1-41	AEPCO - Meals & Entertainment	$ 12,470	$ (12,470)	$ -
4	CSB 3-22	Billings from Affiliates - Charitable Contributions	$ 16,108	$ (16,108)	$ -
5	CSB 3-22	Billings from Affiliates - Sponsorships	$ 1,074	$ (1,074)	$ -
6	CSB 3-22	Billings from Affiliates - Food	$ 15,663	$ (15,663)	$ -
7	CSB 3-22	Billings from Affiliates - Awards	$ 468	$ (468)	$ -
8	CSB 3-22	Billings from Affiliates - Party	$ 5,250	$ (5,250)	$ -
9	CSB 3-22	Billings from Affiliates - Meals & Entertainment	$ 11,769	$ (11,769)	$ -
10	CSB 6-4	Lobbying Costs Included in Memberships	$ 28,087	$ (28,087)	$ -
11		TOTAL	$ 159,891	**$ (159,891)**	$ -

12 References:

13 Column A: Cooperative Data Request Response CSB 1-41, 3-22, and 6-4
14 Column B: Testimony, CSB
15 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-23

OPERATING INCOME ADJUSTMENT NO. 11 - ACC GROSS REVENUE ASSESSMENT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Revenue - ACC Assessment	$ 147,146	$ (147,146)	$ -
2	Expense - ACC Assessment	$ 288,752	$ (288,752)	$ -
3	Operating Margin Before Interest	$ (141,606)	$ 141,606	$ -

4 References:

5 Column A: Cooperative Schedule C-1, Page 4, Line 41
6 Column B: Testimony, CSB
7 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Schedule CSB-24

OPERATING INCOME ADJUSTMENT NO. 12 - INTEREST EXP ON LONG-TERM DEBT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Interest Expense on L.T.- Debt	$ 13,547,749	$ (234,585)	$ 13,313,164

2 References:

3 Column A: Cooperative Schedule C-1
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-04100A-04-0527

DIRECT TESTIMONY OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

ALL-STATE LEGAL®
EXHIBIT
S-2
ADMITTED

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EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

The direct testimony of Staff witness Crystal S. Brown addresses the following issues:

Background - Southwest Transmission Cooperative, Inc. ("Southwest Transmission" or "Cooperative") is a certificated electric transmission cooperative that supplied transmission service to six Class A members during 2003.

On July 23, 2004, Southwest Transmission filed an application for a permanent rate increase. The primary reason stated by the Cooperative for the rate increase is the anticipated loss of approximately $2.8 million in revenues due to Morenci Water and Electric's ("MW&E) planned bypass of Southwest Transmission's system.

Southwest Transmission's application, as filed, proposes a $3,666,668, or 13.16 percent, revenue increase from $27,855,318 to $31,521,986 [including the temporary Regulatory Asset Charge ("RAC") authorized in Decision No. 62758]. The proposed revenue increase would produce an operating margin of $5,891,477 for a 7.42 percent rate of return on an original cost rate base of $79,392,886. Southwest Transmission requests a 1.15 times interest earned ratio ("TIER").

Revenue Requirement – Staff recommends operating revenues of no less than that proposed by the Cooperative. Staff's recommended revenue would produce a $3,666,668, or 14.58 percent, revenue increase from Staff adjusted Test Year revenues of $25,148,196 to $28,814,864. Staff's recommended revenue (excluding normalized annual RAC collections of $2,559,926) would produce an operating margin of $3,439,610 for a 4.51 percent rate of return on a Staff adjusted original cost rate base of $76,345,655. Staff's recommended revenue provides a 0.65 times interest earned ratio ("TIER") and a 0.81 debt service coverage ratio ("DSC"). Including the RAC, the TIER and DSC improve to 1.13 and 1.02, respectively.

Test Year Operating Margin – Staff made five (5) adjustments that reduced the operating margin by $2,451,867 from $2,224,809 to ($227,058). Staff's adjustments included reclassification and normalization of a Regulatory Asset Charge, normalization of legal and employee expenses and removal of costs unrelated to the provision of utility service.

Rate Base – Staff made six (6) adjustments that reduced rate base by $3,047,230 from $79,392,885 to $76,345,655. Staff's adjustments included removal of working capital, plant held for future use, member advances, deferred debits, acquisition costs and retirement work in progress.

INTRODUCTION

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

A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. I am responsible for the examination and verification of financial and statistical information included in utility rate applications. In addition, I develop revenue requirements, prepare written reports, testimonies, and schedules that include Staff recommendations to the Commission. I am also responsible for testifying at formal hearings on these matters.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Business Administration from the University of Arizona and a Bachelor of Science Degree in Accounting from Arizona State University.

Since joining the Commission, I have participated in numerous rate cases and other regulatory proceedings involving large electric, gas, telecommunications, and water utilities. I have testified on matters involving regulatory accounting and auditing. During the past six years, I have attended utility-related seminars on regulation, accounting, finance and income taxes designed to provide continuing and updated education in these areas. Various professional and industry organizations sponsored these seminars.

I have been employed by the Commission as a regulatory auditor and a rate analyst since August 1996. Prior to joining the Commission, I was employed by the Department of Revenue as a Senior Internal Auditor and by the Office of the Auditor General as a Financial Auditor. I was a Cost Center Review Specialist for Blue Cross Blue Shield of Arizona prior to my employment in state government.

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

A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating income, and revenue requirement regarding Southwest Transmission Cooperative, Inc.'s ("Southwest Transmission" or "Cooperative") application for a permanent rate increase. Staff witness Alejandro Ramirez is presenting Staff's times interest earned ratio ("TIER") and debt service coverage ("DSC") ratio analysis and recommendations. Staff witness Erin Casper is presenting Staff's recommendations regarding the rate design. Staff witness Jerry Smith is presenting Staff's engineering analysis and recommendations.

Q. What is the basis of your recommendations?

A. I performed a regulatory audit of Southwest Transmission's application to determine whether sufficient, relevant, and reliable evidence exists to support the Company's requested rate increase. The regulatory audit consisted of examining and testing the financial information, accounting records, and other supporting documentation and verifying that the accounting principles applied were in accordance with the Commission adopted National Rural Utilities Service ("RUS") Uniform System of Accounts ("USOA").

BACKGROUND

Q. Please review the background of this application.

A. Southwest Transmission was formed as a result of the restructuring of Arizona Electric Cooperative, Inc. ("AEPCO"). Prior to August 2001, AEPCO provided both generation and transmission services to its customers. Pursuant to Decision No. 59943, dated December 26, 1996, the Commission approved a phased-in transition to electric competition. In 2001, AEPCO received Commission approval to restructure into three separate affiliated cooperatives: AEPCO, Southwest Transmission, and Sierra Southwest Cooperative ("Sierra Southwest").

AEPCO became a generation cooperative. Southwest Transmission became a transmission cooperative. Sierra Southwest became a cooperative that provides wholesale marketing and support services, including staffing of non-core positions to AEPCO and Southwest Transmission.

Decision No. 63868 required that the Cooperatives provide the Director of the Utilities Division with "an informational submission" that was required within "35 months of the date of closing"[1] for the restructuring. Decision No. 65367, dated November 5, 2002, modified this requirement to include full Arizona Administrative Code R14-2-103 information and set the rate filing date at July 1, 2004. On July 23, 2004, Southwest Transmission filed an application for a permanent rate increase. On August 27, 2004, Staff filed a Letter of Sufficiency.

Southwest Transmission is a certificated Arizona-based transmission cooperative that provided electric transmission service to six Class A members as well as certain other

[1] Decision No. 63868, Page 14, Finding of Fact No. 74

customers during the Test Year. Southwest's current rates were authorized in Decision No. 65367, dated November 5, 2002 and Decision No. 62758, dated July 27, 2000. Decision No. 65367 authorized total revenues of $29,129,952 to provide a 7.99 percent rate of return on a $65,856,223 original cost rate base. Decision No. 62758 authorized the transfer of the Regulatory Asset Charge ("RAC") from AEPCO to Southwest Transmission.

Q. What is the primary reason for the Cooperative's requested permanent rate increase?

A. The primary reason indicated by the Cooperative for the rate increase is the anticipated loss of approximately $2.8 million in revenues due to Morenci Water and Electric's ("MW&E") planned bypass of Southwest Transmission's system.

CONSUMER SERVICE

Q. Please provide a brief history of customer complaints received by the Commission regarding Southwest Transmission.

A. Staff reviewed the Commission's records and found no formal complaints from its members from 2001 to 2004. Five opinions against the rate increase have been received from retail customers of the distribution member cooperative in Mohave County as of February 8, 2005.

SUMMARY OF PROPOSED REVENUES

Q. Please summarize the Company's filing.

A. The Cooperative's application, as filed, proposes total annual operating revenue of $31,521,986, an increase of $3,666,668, or 13.16[2] percent, over claimed Test Year

[2] The Cooperative's Schedule A-1, line 10 reports a 13.70 percent increase; however, mathematically, $3,666,668 divided by $27,855,318 is 13.16 percent.

revenue of $27,855,318. Southwest Transmission's operating revenues include $2,707,122 of RAC revenues.

Q. Please summarize Staff's recommended revenue.

Staff recommends total annual operating revenue of $28,814,864, an increase of $3,666,668, or 14.58 percent, over Staff adjusted Test Year revenues of $25,148,196. Staff recognizes $2,559,926 of non-operating RAC cash flow.

Staff recommends operating revenue no less than that proposed by the Cooperative which (excluding normalized RAC collections of $2,559,926) would produce an operating margin of $3,439,610 for a 4.51 percent rate of return rate return on a Staff adjusted original cost rate base of $76,345,655 to provide a 0.65 times interest earned ratio ("TIER") and a 0.81 debt service coverage ratio ("DSC"). Including the RAC, the TIER and DSC improve to 1.13 and 1.02, respectively.

Q. What Test Year did Southwest Transmission use in this filing?

A. Southwest Transmission's rate filing is based on the twelve months ended December 31, 2003 ("Test Year").

Q. Please summarize the rate base and operating income recommendations and adjustments addressed in your testimony for Southwest Transmission.

A. My testimony addresses the following issues:

<u>Plant Acquisition Adjustment</u> – This adjustment decreases Plant in Service by $4,413 to properly reflect the original cost rate base and to be consistent with Decision No. 65367.

Accumulated Depreciation – This adjustment increases Accumulated Depreciation by $25,756 to remove retirement work in progress.

Member Advances – This adjustment decreases rate base by $228,188. This adjustment recognizes that the interest paid to the Members is recovered through operating expense, and consequently, the advances which are directly related to the interest expense should be removed from rate base to prevent double recovery.

Working Capital – This adjustment decreases Working Capital by $2,265,954 to reflect Staff's different calculation of certain Working Capital components and to eliminate the Cooperative's selective recognition of components.

Plant Held for Future Use – This adjustment decreases rate base by $377,214 to reflect land that will be liquidated.

Deferred Debit – This adjustment decreases rate base by $145,705 to remove items that are not generally included in rate base.

Regulatory Asset Charge ("RAC") Revenue – This adjustment decreases operating margin by $2,707,122 and increases non-operating revenue by $2,559,926. This adjustment recognizes that RAC collections will cease once the deferred asset has been fully amortized. This adjustment also normalizes the revenues expected from the RAC.

Normalized Legal Expense – This adjustment decreases operating expenses by $83,799 to remove legal expenses that provided no benefit to Members.

Employee Vacancy Level Normalization Adjustment – This adjustment decreases operating expenses by $113,684 to normalize the level of employee vacancies.

Food and Other Expense – This adjustment decreases operating expenses by $57,773 to remove expenses that were not needed to provide safe and reliable service.

Interest Expense on Long-term Debt – This adjustment decreases net margin by $133,675 to reflect Staff's recommended interest on long-term debt.

RATE BASE

Fair Value Rate Base

Q. Did the Company prepare a Schedule showing the elements of Reconstruction Cost New Rate Base ("RCND")?

A. No, the Company did not. Therefore, Staff evaluated the original cost rate base as the fair value rate base ("FVRB").

Rate Base Summary

Q. Please summarize Staff's adjustments to Southwest Transmission's rate base shown on Schedules CSB-2.

A. Staff's adjustments to Southwest Transmission's rate base resulted in a net decrease of $3,047,230, from $79,392,885 to $76,345,655. This decrease was primarily due to reducing the working capital requirement.

Rate Base Adjustment 1 – Plant Acquisition Adjustment

Q. What is Southwest Transmission proposing for its Plant Acquisition Adjustment?

A. Southwest Transmission is proposing $4,413 for the Plant Acquisition Adjustment as shown on Schedule CSB-4.

Q. The $4,413 Plant Acquisition Adjustment is not material to rate base. Why is Staff proposing that it be removed from rate base for rate making purposes?

A. In Decision No. 65367, dated November 5, 2002, Staff recommended that the plant acquisition adjustment be removed because the adjustment was questionable and Staff had not audited the adjustment.[3] The Commission adopted Staff's recommendation to remove Southwest Transmission's acquisition adjustment from rate base (Page 4 at line 23).

Q. Did Staff audit the plant acquisition adjustment in this rate proceeding?

A. Yes, Staff audited the plant acquisition adjustment and found that the Cooperative did not have sufficient documentation to support the adjustment.

Q. Should the plant acquisition adjustment be included in rate base?

A. No, it should not. Original cost rate base is calculated using the original cost of plant assets. An acquisition adjustment, by definition, is not the original cost of an asset because it is the difference between the original cost of an asset and the purchase price. Staff found no sufficient evidence to support the adjustment. Therefore, non-recognition of the acquisition adjustment in rate base is the normal rate-making treatment.

[3] Decision No. 65367, page 4, lines 6 through 9

Q. What is Staff recommending?

A. Staff recommends decreasing plant in service by $4,413 as shown on Schedules CSB-3 and CSB-4.

Rate Base Adjustment 2 – Accumulated Depreciation

Q. What is Southwest Transmission proposing for Accumulated Depreciation?

A. Southwest Transmission is proposing $54,763,401 for Accumulated Depreciation. That amount is composed of $54,789,157 in accumulated depreciation of plant in service and a $25,756 reduction of accumulated depreciation for a retirement work in progress as shown on Schedule CSB-5.

Q. Is retirement work in progress normally a component of rate base?

A. No. Retirement work in progress should reflect a coordinated treatment of the plant to be retired, accumulated depreciation, salvage value and disposal cost. The retirement should be completed before rate base is adjusted.

In Decision No. 65367[4], dated November 5, 2002, Staff recommended that a retirement work in progress be removed because the amount was questionable and unaudited.[5] The Commission adopted Staff's recommendation. In the instant case, Staff audited the retirement work in progress and determined that it should be removed.

Q. What is Staff recommending?

A. Staff recommends increasing Accumulated Depreciation by $25,756, from $54,763,401 to $54,789,157 to remove retirement work in progress from rate base as shown on Schedules CSB-3 and CSB-5.

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[4] Page 24 at line 23
[5] Decision No. 65367, page 4, lines 6 through 9

Rate Base Adjustment 3 – Member Advances

Q. What programs does Southwest Transmission have that result in Member Advances?

A. Southwest Transmission has two types of programs that result in member advances: member investments and member prepaid transmission bills. The member investment program allows members to invest funds with the Cooperative and the Cooperative pays interest on those funds. The prepaid transmission program allows members to make prepayments on their monthly transmission bills and the Cooperative pays interest on those prepaid bills.

Q. How does the Cooperative treat the balance of Member Advances and the interest paid on those funds in its filing?

A. The Cooperative did not deduct Member Advances of $228,188[6] in its rate base calculation but it included the $3,281[7] of interest paid to members for use of their funds as an operating expense. An inequity is created by the Cooperative's proposal because it provides for recovery of Southwest Transmission's Member Advances costs by treating the related interest as an operating expense without also recognizing that AEPCO has use of the fund advanced by members.

Q. What is the effect of the Cooperative's proposed treatment?

A. The effect of the Cooperative's proposed treatment is to provide double recovery. The Cooperative pays interest to the members that provide the advances and recovers that interest cost by including it in operating expenses. Failure to deduct Member Advances overstates rate base by not recognizing the Cooperative's use of the advanced funds and has the effect, theoretically, of providing a return on the advanced funds.

[6] Per data request response CSB 2-28
[7] Per data request response CSB 6-1

Q. Did the Commission deduct Member Advances in the rate base calculation of the prior rate proceeding in which Southwest Transmission and AEPCO were one cooperative?

A. Yes. The Commission, in Decision No. 58405[8], deducted Member Advances in the rate base calculation.

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends that $228,188 in Member Advances be deducted from rate base as shown on Schedules CSB-3 and CSB-6.

Rate Base Adjustment 4 – Working Capital

Q. What is Southwest Transmission proposing for Working Capital?

A. Southwest Transmission is proposing $3,122,117 for Working Capital. That amount is composed of $858,420 for materials and supplies, $908,046 for prepayments, and $1,355,651 for CFC Certificates and Bonds as shown on Schedule CSB-7.

Q. Did Staff make any adjustments to the Cooperative's Working Capital?

A. Yes. Staff discusses its adjustments to materials and supplies, prepayments, CFC Certificates and Bonds separately.

<u>Working Capital - Materials and Supplies</u>

Q. What amount did Southwest Transmission include for Materials and Supplies in its proposed Working Capital calculation?

A. Southwest Transmission included $858,420 for Materials and Supplies inventory in its working capital calculation.

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[8] Page 6, at line 9

Q. How did Southwest Transmission calculate the Materials and Supplies balance proposed in rate base?

A. Southwest Transmission calculated the Materials and Supplies balance using a 13-month average. This method adds together the December 31, 2002, ending Materials and Supplies balance with the Test Year month-end balances and divides by 13.

Q. Does use of the 13-month average calculation proposed by Southwest Transmission measure the average monthly balance for each month of the Test Year?

A. No. Therefore, the Cooperative's proposed method could over- or under- state the materials and supplies balance.

Q. What method provides a more accurate measurement of the average balance each month?

A. A 12-month average based on the average inventory balance for each month of the Test Year. To illustrate, the average monthly balance for January is calculated by adding the beginning balance on January 1st (i.e., the ending balance on December 31st of prior year) to the ending balance on January 31st, and dividing the total by two. The 12 monthly averages are totaled and divided by 12 to obtain an average balance.

Q. What does Staff recommend for the Materials and Supplies balance in the Working Capital calculation?

A. Staff recommends $856,163 for Materials and Supplies as shown on Schedule CSB-7.

Working Capital - Prepayments, CFC Certificates and Bonds

Q. Is Southwest Transmission proposing to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation?

A. Yes. Southwest Transmission is proposing $908,046 for prepayments and $1,355,651 in CFC Certificates and Bonds.

Q. Does Southwest Transmission's proposal to include Prepayments, CFC Certificates and Bonds in the Working Capital calculation represent an inequitable, selective adjustment to increase rate base?

A. Yes. The Cooperative has ignored the large component of Working Capital (i.e., cash working capital) represented by revenues received and expenses paid. The impact on Working Capital of revenues and expenses can be calculated using a lead-lag study. A lead-lag study is recognized as the most accurate method to calculate cash working capital.

The Cooperative chose not to conduct a lead-lag study, and accordingly, omitted a major component of Working Capital. It is inequitable to ignore a major component of the Working Capital analysis and selectively recognize other components. Had a lead-lag study been conducted, it might have shown that Working Capital is a negative component of rate base.

Q. What factors imply that a lead-lag study could result in Working Capital being a negative component of rate base?

A. Interest and property tax expenses are components of a lead-lag study. The Cooperative has approximately $5 million in interest expense and $2 million in property taxes. The Cooperative collects cash used to make interest and property tax expense payments prior

to the dates payment is due. For the period that Southwest Transmission holds these funds before payment, they are a source of cost-free capital. If a lead-lag study were performed, this source of cost-free cash would be a significant negative factor in calculation of the net working capital.

Q. Does the Cooperative receive interest on the CFC Certificates and Bonds?

A. Yes. In response to CSB 2-23, the Cooperative stated that it received approximately $67,782[9]. Therefore, including the CFC certificates and bonds in rate base would provide a second return on these investments.

Q. Did the Commission remove Prepayments and CFC Certificates and Bonds from rate base of the prior rate proceeding in which Southwest Transmission and AEPCO were one cooperative?

A. The Commission removed prepayments in Decision No. 58405[10]. The Cooperative had not included CFC Certificates and Bonds in the rate base of that proceeding, therefore, it was not addressed in Decision No. 58405.

Q. What is Staff recommending for Prepayments and CFC Certificates and Bonds?

A. Consistent with Decision No. 58405, Staff recommends removal of Prepayments. Staff also recommends removal of CFC Certificates and Bonds from Working Capital as shown on Schedules CSB-3 and CSB-7.

Q. What is Staff's recommended adjustment to Working Capital?

A. Staff recommends decreasing Working Capital by $2,265,954 from $3,122,117 to $856,163 as shown on Schedules CSB-3 and CSB-7.

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[9] Per response to CSB 2-23, the $1.355 million Equity Term Certificates accrues interest at 5.00 % annually.
[10] Page 6, at line

Rate Base Adjustment 5 – Plant Held for Future Use

Q. What amount in Plant Held for Future Use is Southwest Transmission proposing to include in rate base?

A. Southwest Transmission is proposing to include $377,214 of land classified as Plant Held for Future Use in rate base.

Q. Does Southwest Transmission have a plan for future use of the land?

A. No, it does not. In response to CSB 2-29, the Cooperative indicated that the land was purchased for a substation site's right-of-ways. The location of the substation changed, the land was no longer needed and will likely be liquidated.

Q. What is Staff recommending?

A. Staff recommends removal of the $377,214 in Plant Held for Future Use from Rate Base as shown on Schedules CSB-3 and CSB-8.

Rate Base Adjustment 6 – Deferred Debit

Q. What amount in Deferred Debits is Southwest Transmission proposing to include in Rate Base?

A. Southwest Transmission is proposing $145,705 for Deferred Debits as shown on Schedule CSB-9. The amount is composed of $193 for preliminary survey and investigation charges, $57,657 for Job Tickets, and $87,855 for unamortized losses on reacquired debt.[11]

[11] Per response to CSB 2-22

Q. Should these Deferred Debits be included in rate base?

A. No, they should not. The Deferred Debits balance consists of items that are not generally included in rate base. Preliminary survey and investigation charges and job tickets are a type of construction work in progress. Construction work in progress by definition is not used and useful.

Unamortized losses on reacquired debt present no future cash requirements for the Cooperative. Since Staff recommends a revenue requirement dependent on cash flow needs, there is no revenue requirement directly related to the carrying balance. Moreover, to the extent that losses on reacquired debt were refinanced with new debt, Staff is recommending recovery of these costs via operating and RAC revenue that provides TIER and DSC ratios exceeding 1.0. Including the unamortized loss on reacquired debt in rate base would be inequitable and serve only as a selective adjustment to augment rate base in the same manner as prepayments, CFC Bonds and Certificates.

Q. Did the Commission remove the deferred debit from the rate base of the prior rate proceeding in which Southwest Transmission and AEPCO were one cooperative?

A. Yes, the Commission, in Decision No. 58405[12], removed the Deferred Debit from rate base.

Q. What is Staff recommending?

A. Consistent with Decision No. 58405, Staff recommends removal of the Deferred Debit from Rate Base as shown on Schedules CSB-3 and CSB-9.

[12] Page 6, at line 8 ½

OPERATING INCOME

Operating Income Summary

Q. What are the results of Staff's analysis of Test Year revenues, expenses, and operating income?

A. As shown on Schedules CSB-10 and CSB-11, Staff's analysis resulted in Test Year revenues of $25,148,196, expenses of $25,375,254, and operating income before interest expense on long-term debt of ($227,058).

Operating Income Adjustment No. 1 – Regulatory Asset Charge

Q. What is the source and purpose of the regulatory asset charge?

A. In Decision No. 62758, the Commission transferred the regulatory asset charge ("RAC") from AEPCO to Southwest Transmission. The initial purpose of the RAC was to recover deferred debt refinancing costs and costs associated with the buy-out of the Carbon Coal all-requirements contract. The RAC, as authorized by the Commission, is scheduled to decrease each year over the amortization term until the deferred cost is fully recovered.

Q. Did Staff make an adjustment to the revenue generated by regulatory asset charge in the Test Year?

A. Yes, Staff reclassified the RAC collections from operating revenue and recognized it as a separate source of cash flow since it will cease when the regulatory asset is fully recovered. Staff also reduced the amount of RAC revenue from the actual Test Year amount of $2,707,122 to $2,559,926. Staff's lower amount represents a three-year normalization to recognize the known, scheduled decreasing RAC level as shown on Schedule CSB-12.

Q. What is Staff recommending?

A. Staff recommends reducing operating revenue by $2,707,122 and recognizing $2,559,926 of RAC cash flow as shown on Schedules CSB-11 (lines 6 and 32) and CSB-12 (lines 5 and 9).

Operating Income Adjustment No. 2 – Normalized Legal Expense

Q. What is Southwest Transmission proposing for Outside Services, Legal expenses?

A. Southwest Transmission is proposing $316,875[13] for Outside Services, Legal expenses as shown on Schedule CSB-13, line 4. Staff discusses the components of its legal expense normalization adjustment separately.

ACC Jurisdiction Related Legal Expense

Q Does the Cooperative propose to include legal expenses that provide no benefit to ratepayers in its revenue requirement?

A. Yes. Southwest Transmission incurred and requests recovery of legal expenses related to its filing that requested that the Cooperative not be subject to ACC regulation (Decision No. 66835, dated March 12, 2004).

Q. What is Staff recommending?

A. Staff recommends reducing Outside Services, Legal Expense by $77,936 as shown on Schedule CSB-13, line 2 to eliminate the legal expenses related to the ACC jurisdictional filing.

[13] Per data request response to CSB 2-40.

Redacted Minutes and Legal Invoices

Q. Did Southwest Transmission fail to support any of its legal expenses?

A. Yes. Southwest Transmission objected to the release of certain portions of the Minutes of the Executive Session of the Board of Directors and legal invoices citing the attorney-client privilege. Therefore, the appropriateness of the certain legal costs could not be substantiated.

Q. Did Staff inform Southwest Transmission of the likely consequence of not providing the requested information?

A. Yes, in a letter dated September 29, 2004, addressed to both Southwest Transmission and AEPCO, Staff indicated that failure to provide complete legal invoices will result in a disallowance of such costs.

Q. What was the total amount of expenses related to the redacted legal invoices and minutes that Staff recommends to be disallowed?

A. The total amount was $5,863[14] as shown on Schedule CSB-13 line 3.

Q. Did the Commission find it appropriate to disallow legal expenses from AEPCO prior to Southwest Transmission's spinoff?

A. Yes. In AEPCO's prior rate proceeding before Southwest Transmission was spunoff, Staff recommended that $464,000[15] in legal expenses paid to a law firm should be disallowed because it was imprudent for Southwest Transmission to have entered into the fee arrangements with the law firm. The Commission adopted Staff's recommendation.

[14] Staff estimated the majority of expenses related to the redacted issues based upon the number of general groups of issues on an invoice. The total amount billed on the invoice was divided by the number of general groups.
[15] Decision No. 58405, page 12, lines 5-12 and lines 21-23.

Q. Does Southwest Transmission's denial of access to records provide concerns beyond whether these legal costs are related to the provision of utility service and recoverable?

A. Yes. Beyond the issue of whether the legal costs were incurred for utility purposes, the lack of access to records raises a question as to whether other significant issues related to the revenue requirement went undiscovered.

Q. Does Staff have any other recommendations regarding redacted issues?

A. Yes. In this case Staff was unable to quantify and remove payroll costs of all employees, outside services staff, and members of the Board of Directors who spent time working on the redacted issues. Staff recommends that in future rate proceedings Southwest Transmission be required to quantify all payroll costs of employees, outside services staff, and members of the Board of Directors fees related to time spent on redacted issues.

Operating Income Adjustment No. 3 – Employee Vacancy Level

Q. What is an employee vacancy level?

A. An employee vacancy level reflects the number of employee positions that are not occupied.

Q. What were the Cooperative's vacancy levels for the years 2001, 2002, and 2003?

A. The Cooperative's vacancy levels for the years 2001, 2002, and 2003 were 5, 3, and 1[16], respectively, as shown on Schedule CSB-14.

[16] Per data request response to CSB 2-37

Q. What is an appropriate way to recognize the year-to-year variances in the employee vacancy rate and associated costs to provide an average level of costs?

A. The employee vacancy rate can be normalized by recognizing the average vacancy rate. Staff averaged the employee vacancy rates for the years 2001, 2002 and 2003 to calculate a normalized vacancy rate. Then, Staff calculated the difference between the Test Year rate and the normalized rate and multiplied that difference by the average salary level for those years to determine an adjustment to reflect salaries at the normalized levels. This calculation is shown on Schedule CSB-14.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $113,684 as shown on Schedules CSB-11 and CSB-14.

Operating Income Adjustment No. 4 – Food and Other Expenses

Q. What is Southwest Transmission proposing for food, entertainment, and similar expenses?

A. Southwest Transmission is proposing $57,773 for food, entertainment, and similar expenses as shown on Schedule CSB-15.

Q. Are these expenses necessary for the provision of safe and reliable service?

A. No, these costs are not necessary for the provision of safe and reliable service.

Q. What ratemaking treatment does Staff recommend for these types of expenses?

A. Since these costs are not necessary to provide service, Staff recommends that they be recognized as non-operating expenses and excluded from the revenue requirement.

Q. What is Staff recommending?

A. Staff recommends decreasing operating expense by $57,773 as shown on Schedules CSB-11 and CSB-15.

Non-Operating Income Adjustment No. 5 – Interest Expense on Long-term Debt

Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?

A. Southwest Transmission is proposing $5,168,413 for Interest Expense on Long-term Debt as shown on Schedule CSB-16.

Q. Did Staff accept the proposed Interest Expense on Long-term Debt amount?

A. No, Staff did not. As discussed in the testimony of Staff Witness, Alejandro Ramirez, Staff determined that the appropriate amount of interest expense on long-term debt is $5,302,088.

Q. What is Staff recommending?

A. Staff recommends increasing the Interest Expense on Long-term Debt by $133,675 as shown on Schedules CSB-11 and CSB-16.

Arizona Corporation Commission Gross Revenue Assessment

Q. What came to Staff's attention during the course of the audit concerning the ACC assessment?

A. Southwest Transmission's application did not report collecting any amount for an ACC assessment. This is consistent with the Cooperative's annual report filed with the Commission for the year 2003. The Commission did not assess the Cooperative because the Cooperative reported $0 for intra-state revenues in its 2003 utilities annual report. In a letter addressed to the Utilities Division Compliance section, dated December 10, 2004,

Southwest Transmission stated, "SWTransco did not pay any annual assessment amounts in 2003 pursuant to A.R.S. §40-401 because it did not have any "gross operating revenues derived from intrastate operations during the preceding calendar year.".

Q. Is Staff currently investigating this matter?

A. Yes.

Q. What does Staff recommend pending the outcome of this investigation?

A. If the Commission determines that Southwest Transmission should be assessed, Staff recommends that the assessment be flowed through similar to sales taxes. This flow-through was authorized by the Commission in Decision No. 58405, prior to the restructuring of Southwest Transmission and AEPCO. On footnote 9, page 17, of that decision, the Commission states that "The gross revenue tax will in the future be recovered through a bill add-on." Therefore, the assessment should not be included in the cost of service.

Jurisdictional Separation

Q. Did Southwest Transmission maintain separation between Commission jurisdiction and non-jurisdiction revenues and expenses ?

A. No, it did not. The Cooperative serves a California member for which separate revenues and expenses were not maintained.

Q. Is the Cooperative required to maintain separation of the revenues and expenses for the California member?

A. Yes. The Arizona Administrative Code R14-2-103 B4 states the following:

> Separation of nonjurisdictional properties, revenues and expenses associated with the rendition of utility service not subject to the jurisdiction of the Commission must be identified and properly segregated in a recognized manner when appropriate.

Q. Can Staff identify some cooperatives that provided jurisdictionally separated information in their rate filings?

A. Yes. Duncan Valley Electric Cooperative, Inc. and Garkane Power Association, Inc. provide jurisdictionally separated information in compliance with the Administrative Code. These cooperatives generate much smaller revenues than Southwest Transmission. The jurisdictionally separated financial information helps to verify that Arizona ratepayers are not paying more than their fair share of the cost of providing service.

Q. What is Staff recommending?

A. Staff recommends that the Cooperative comply with Arizona Administrative Code R14-2-103(B)(4) in its next rate filing.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY ORIGINAL COST With RAC	[B] COMPANY ORIGINAL COST Without RAC	[C] STAFF ORIGINAL COST With RAC	[D] STAFF ORIGINAL COST Without RAC
1	Adjusted Operating Income (Loss)	$ 2,224,809	$ (482,313)	$ (227,058)	$ (227,058)
2	Depreciation and Amortization	$ 6,852,107	$ 6,852,107	$ 6,852,107	$ 6,852,107
3	Income Tax Expense	-	-	-	-
4	Interest Expense on Long-term Debt	$ 5,168,413	$ 5,168,413	$ 5,302,088	$ 5,302,088
5	Principal Repayment	$ 6,349,686	$ 6,349,686	$ 7,358,610	$ 7,358,610
6	**Recommended Increase in Operating Revenue**	$ 3,666,668	$ 3,666,668	$ 3,666,668	**$ 3,666,668**
7	Percent Increase (Line 6 / Line 10)	13.16%	14.58%	14.58%	**14.58%**
8	Network Service and Other Revenue	$ 25,148,196	$ 25,148,196	$ 25,148,196	$ 25,148,196
9	Regulatory Asset Charge ("RAC")[1]	$ 2,707,122	$ -	$ -	$ -
10	Adjusted Test Year Operating Revenue	$ 27,855,318	$ 25,148,196	$ 25,148,196	$ 25,148,196
11	**Total Annual Operating Revenue**	$ 31,521,986	$ 28,814,864	$ 28,814,864	**$ 28,814,864**
12	**Operating Margin**	$ 5,891,477	$ 3,184,355	$ 3,439,610	**$ 3,439,610**
13	Net Margin	$ 771,906	$ (1,935,216)	$ 746,290	$ 746,290
14	Normalized RAC Revenue, Non-operating	N/A	N/A	$ 2,559,926	$ -
15	Total Operating Revenue and RAC Revenue			$ 5,999,536	$ 3,439,610
16	Cooperative Net TIER (L4+L13) / L4	1.15	0.63	N/A	N/A
17	**Staff Operating TIER (L3+L12+L14) / L4**	N/A	N/A	1.13	**0.65**
18	Cooperative DSC (L2+L4+L13)/(L4+L5)	1.11	0.88	N/A	N/A
19	**Staff DSC (L2+L3+L12+L14)/(L4+L5)**	N/A	N/A	1.02	**0.81**
20	**Adjusted Rate Base**	$ 79,392,885	$ 79,392,885	$ 76,345,655	**$ 76,345,655**
21	Rate of Return (L12 / L20)	7.42%	4.01%	4.51%	4.51%

References:
Column [A]: Company Schedules A-1, C-1, C-3
Column [D]: Staff Schedules CSB-2, CSB-10, Testimony Alejandro Ramirez

(1) Southwest Transmission classified Regulatory Asset Charge as Operating Revenue. Accordingly, Staff's recommended Operating Revenue is not comparable to the SWT's.

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Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		(A) COMPANY AS FILED	(B) STAFF ADJUSTMENTS	REF	(C) STAFF AS ADJUSTED
1	Plant in Service	$131,520,683	$ (4,413)		$ 131,516,270
2	Less: Accumulated Depreciation	(55,772,833)	(25,756)		(55,798,589)
3	Net Plant in Service	$ 75,747,850	$ (30,169)		$ 75,717,681
	LESS:				
4	Advances in Aid of Construction (AIAC)	$ -	$ -		$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -		$ -
6	Less: Accumulated Amortization	-	-		-
7	Net CIAC	-	-		-
8	Total Advances and Contributions	$ -	$ -		$ -
9	Member Advances	$ -	$ (228,188)		$ (228,188)
	ADD:				
10	Working Capital	$ 3,122,116	$ (2,265,954)		$ 856,162
11	Plant Held for Future Use	$ 377,214	$ (377,214)		$ -
12	Deferred Debits	$ 145,705	$ (145,705)		$ -
13	**Total Rate Base**	$ 79,392,885	$ (3,047,230)		$ 76,345,655

References:
Column [A], Company Schedule B-1, Page 1;
Column [B]: Schedule CSB-4
Column [C]: Column [A] + Column [B]

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Schedule CSB-3

SUMMARY OF RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	[A] COOPERATIVE AS FILED	[B] Plant Acquisition Adjustment ADJ No. 1	[C] Accumulated Depreciation ADJ No. 2	[D] Member Advances ADJ No. 3	[E] Working Capital ADJ No. 4	[F] Plant Held For Future Use ADJ No. 5	[G] Deferred Debits ADJ No. 6	[H] STAFF ADJUSTED
	PLANT IN SERVICE:								
1	Intangible Plant	$ 2,160,171	$ (4,413)	$ -	$ -	$ -	$ -	$ -	$ 2,155,758
2	Transmission Plant - Structures & Improvements	4,139,476	-	-	-	-	-	-	4,139,476
3	Transmission Plant - Station Equipment	44,271,948	-	-	-	-	-	-	44,271,948
4	Transmission Plant - Towers & Fixtures	8,220,075	-	-	-	-	-	-	8,220,075
5	Transmission Plant - Poles & Fixtures	23,837,071	-	-	-	-	-	-	23,837,071
6	Transmission Plant - Overhead Conductors	15,874,087	-	-	-	-	-	-	15,874,087
7	Transmission Plant - All Other Plant	1,783,828 [1]	-	-	-	-	-	-	1,783,828
8	General Plant - Transportation Equipment	1,253,412	-	-	-	-	-	-	1,253,412
9	General Plant - Power Operated Equipment	2,207,359	-	-	-	-	-	-	2,207,359
10	General Plant - Communication Equipment	12,219,399	-	-	-	-	-	-	12,219,399
11	General Plant - All Other Plant	899,545 [2]	-	-	-	-	-	-	899,545
12	Completed Construction - Unclassified	604,312	-	-	-	-	-	-	604,312
13	Total Plant in Service - Actual	117,470,683	(4,413)	-	-	-	-	-	$ 117,466,270
14	Pro-forma Adjustment, Trans Plant - Station Equip	5,084,058	-	-	-	-	-	-	$ 5,084,058
15	Pro-forma Adjustment, Trans Plant - Towers & Fix	8,457,902	-	-	-	-	-	-	8,457,902
16	Pro-forma Adjustment, Communication Equipment	508,040	-	-	-	-	-	-	508,040
17	Total Plant in Service - Pro-forma	14,050,000	-	-	-	-	-	-	$ 14,050,000
18	Total Plant in Service - Actual and Proforma	$ 131,520,683	$ (4,413)	$ -	$ -	$ -	$ -	$ -	$ 131,516,270
19	Less: Accumulated Depreciation - Actual	$ (54,763,401)	$ -	$ (25,756)	$ -	$ -	$ -	$ -	$ (54,789,157)
20	Less: Accumulated Amortization - Actual	(1,009,432)	-	-	-	-	-	-	(1,009,432)
21	Total Accumulated Depreciation & Amortization	$ (55,772,833)	$ -	$ (25,756)	$ -	$ -	$ -	$ -	$ (55,798,589)
22	Net Plant in Service	$ 75,747,850	$ (4,413)	$ (25,756)	$ -	$ -	$ -	$ -	$ 75,717,681
	LESS:								
23	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Contributions in Aid of Construction (CIAC)	$ -	-	-	-	-	-	-	$ -
25	Less: Accumulated Amortization	-	-	-	-	-	-	-	-
26	Net CIAC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	Total Advances and Contributions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Member Advances	$ -	$ -	$ -	$ (228,188)	$ -	$ -	$ -	$ (228,188)
	ADD:								
29	Working Capital Allowance	$ 3,122,116	$ -	$ -	$ -	$ (2,265,954)	$ -	$ -	$ 856,162
30	Plant Held For Future Use	377,214	-	-	-	-	(377,214)	-	-
31	Deferred Debits	145,705	-	-	-	-	-	(145,705)	-
32	**Total Rate Base**	$ 79,392,885	$ (4,413)	$ (25,756)	$ (228,188)	$ (2,265,954)	$ (377,214)	$ (145,705)	$ 76,345,655

Footnote Explanations
[1] Includes account nos. 350 and 359
[2] Includes account nos. 389,390,393,394,395,398, & 399

ADJ No.		References:
1	Plant Acquisition Adj	Schedule CSB-4
2	Accumulated Deprec	Schedule CSB-5
3	Member Advances	Schedule CSB-6
4	Working Capital	Schedule CSB-7
5	Plant Held for Future Use	Schedule CSB-8
6	Deferred Debits	Schedule CSB-9

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Schedule CSB-4

RATE BASE ADJUSTMENT NO. 1 - ACQUISITION ADJUSTMENT

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (Sch E-5)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Intangible Plant (Excluding Acquisition Adj)	$ 2,155,758	$ -	$ 2,155,758
2	Intangible Plant, Acquisition Adjustment	$ 4,413	$ (4,413)	$ -
	Total Intangible Plant	**$ 2,160,171**	**$ (4,413)**	**$ 2,155,758**

3 To remove unauthorized acquistion adjustment from plant in service.

4 References:
5 Column [A]: Cooperative Schedule E-5, Page 1
6 Column [B]: Testimony, CSB
7 Column [C]: Column [A] + Column [B]

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Schedule CSB-5

RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEPRECIATION

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Accumulated Depreciation	$ (54,789,157)	$ -	$ (54,789,157)
2	Accumulated Depr, Retirement Work In Progress	$ 25,756	$ (25,756)	$ -
3	**Total Accumulated Depreciation** (Line 1+Line 2)	**$ (54,763,401)**	**$ (25,756)**	**$ (54,789,157)**

References:

Column A: Cooperative Schedules B-2, Page 1

Column B: Testimony, CSB, Company Data Request Responses CSB 3-18 and CSB 3-19

Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-6

RATE BASE ADJUSTMENT NO. 3 - MEMBER ADVANCES

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Member Advances	$ -	$ (228,188)	$ (228,188)
2				
3				
4				
5		Ending Balance		
6		(Per CSB 2-28)		Average Balance
7	Dec-02	$ 56,105.00		
8	Jan-03	$ (56,105.00)		$ -
9	Feb-03	$ (470,000.00)		$ (263,052.50)
10	Mar-03	$ (578,615.00)		$ (524,307.50)
11	Apr-03	$ (146,720.00)		$ (362,667.50)
12	May-03	$ (115,079.00)		$ (130,899.50)
13	Jun-03	$ (82,308.00)		$ (98,693.50)
14	Jul-03	$ (199,185.00)		$ (140,746.50)
15	Aug-03	$ (225,000.00)		$ (212,092.50)
16	Sep-03	$ (277,487.00)		$ (251,243.50)
17	Oct-03	$ (245,312.00)		$ (261,399.50)
18	Nov-03	$ (214,362.00)		$ (229,837.00)
19	Dec-03	$ (184,193.00)		$ (199,277.50)
20		$ (2,738,261.00)		$ (2,674,217.00)
21				/ 12
22				$ (228,188.42)

References:

Column [A]: Cooperative Schedule B-5, Page 1 and 3
Column [B]: Column C - Column A
Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2; CSB 1-21

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-7

RATE BASE ADJUSTMENT NO. 4 - WORKING CAPITAL

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	*Cash Working Capital*	$ -	$ -	$ -
2	Materials and Supplies	$ 858,420	$ (2,257)	$ 856,163
3	Prepayments	$ 908,046	$ (908,046)	$ -
4	CFC Certificates and Bonds	$ 1,355,651	$ (1,355,651)	$ -
5	**Total Working Capital**	**$ 3,122,117**	**$ (2,265,954)**	**$ 856,163**

6 References:

7 Column A: Cooperative Schedule E-5, Page 1

8 Column B: Testimony, CSB, Company Data Request Responses CSB 2-9

9 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-7.1

MATERIALS AND SUPPLIES BALANCE CALCULATION

LINE NO.	END OF MONTH BALANCE	[A] COMPANY AS FILED 13-Month Avg	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED 12-Month Avg
1	Dec-02	$ 839,883	$ (839,883)	$ -
2	Jan-03	$ 845,237	$ (2,677)	$ 842,560
3	Feb-03	$ 845,435	$ (99)	$ 845,336
4	Mar-03	$ 860,498	$ (7,532)	$ 852,967
5	Apr-03	$ 849,761	$ 5,369	$ 855,130
6	May-03	$ 844,738	$ 2,512	$ 847,250
7	Jun-03	$ 845,081	$ (172)	$ 844,910
8	Jul-03	$ 861,774	$ (8,347)	$ 853,428
9	Aug-03	$ 866,317	$ (2,272)	$ 864,046
10	Sep-03	$ 864,534	$ 892	$ 865,426
11	Oct-03	$ 852,361	$ 6,087	$ 858,448
12	Nov-03	$ 852,730	$ (185)	$ 852,546
13	Dec-03	$ 931,106	$ (39,188)	$ 891,918
14		$ 11,159,455	$ (885,495)	$ 10,273,961
15	Divided by	13		12
16		$ 858,420	$ (2,257)	$ 856,163

17 References:
18 Column [A]: Cooperative Schedule B-5, Pages 1 and 3
19 Column [B]: Testimony, CSB; Column C - Column A
20 Column [C]: Example calculation: Jan-03 = (Dec-02 + Jan-03) / 2

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-8

RATE BASE ADJUSTMENT NO. 5 - PLANT HELD FOR FUTURE USE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	**Plant Held For Future Use**	**$ 377,214**	**$ (377,214)**	**$ -**

2 References:

3 Column A: Cooperative Data Request Response CSB 2-29
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-9

RATE BASE ADJUSTMENT NO. 6 - DEFERRED DEBITS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED (CSB 3-1)	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Preliminary Survey & Investigation Charges	$ 193	$ (193)	$ -
2	Job Tickets	$ 57,657	$ (57,657)	$ -
3	Unamortized Losses on Reacquired Debt	$ 87,855	$ (87,855)	$ -
4	Total Deferred Debits	**$ 145,705**	**$ (145,705)**	**$ -**

5 References:
6 Column [A]: Cooperative Schedule B-1, CSB 2-22
7 Column [B]: Testimony, CSB
8 Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-10

OPERATING INCOME - TEST YEAR AND STAFF PROPOSED

LINE NO.	DESCRIPTION	[A] COMPANY TEST YEAR AS FILED	[B] STAFF TEST YEAR ADJUSTMENTS	[C] STAFF TEST YEAR AS ADJUSTED	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
1	*REVENUES:*					
2	Network Transmission Serv & Other Revenue	$ 25,148,196	$ -	$ 25,148,196	$ 3,666,668	$ 28,814,864
3	Regulatory Asset Charge	2,707,122	(2,707,122)	-	-	-
4	Total Electric Transmission Revenue	$ 27,855,318	$ (2,707,122)	$ 25,148,196	$ 3,666,668	$ 28,814,864
5	*EXPENSES:*					
6	Energy	$ 2,541,334	$ -	$ 2,541,334	$ -	$ 2,541,334
7	Transmission	$ 7,649,597	$ (113,684)	$ 7,535,913	-	7,535,913
8	Administrative and General	$ 3,872,157	$ (141,571)	$ 3,730,586	-	3,730,586
9	Maintenance	$ 2,429,390	$ -	$ 2,429,390	-	2,429,390
10	Maintenance - General Plant	$ 79	$ -	$ 79	-	79
11	Depreciation and Amortization	$ 6,852,107	$ -	$ 6,852,107	-	6,852,107
12	ACC Gross Revenue Taxes	$ -	$ -	$ -	-	-
13	Property Taxes	$ 2,285,845	$ -	$ 2,285,845	-	2,285,845
14	Income Taxes	$ -	$ -	$ -	-	-
15	**Total Operating Expenses**	$ 25,630,509	$ (255,255)	$ 25,375,254	$ -	$ 25,375,254
16	**Operating Margin Before Interest on L.T.- Debt**	$ 2,224,809	$ (2,451,867)	$ (227,058)	$ 3,666,668	$ 3,439,610
17	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
18	Interest on Long-term Debt	$ 5,168,413	$ 133,675	$ 5,302,088	$ -	$ 5,302,088
19	Other Interest & Other Dedcutions	232,030	-	232,030	-	232,030
20	**Total Interest & Other Deductions**	$ 5,400,443	$ 133,675	$ 5,534,118	$ -	$ 5,534,118
21	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (3,175,634)	$ (2,585,542)	$ (5,761,176)	$ 3,666,668	$ (2,094,508)
22	***NON-OPERATING MARGINS***					
23	Interest Income	$ 172,901	$ -	$ 172,901	$ -	$ 172,901
24	Other Non-operating Income	107,971	-	$ 107,971	$ -	$ 107,971
25	**Total Non-Operating Margins**	$ 280,872	$ -	$ 280,872	$ -	$ 280,872
26	***REGULATORY ASSET CHARGE***	$ -	$ 2,559,926	$ 2,559,926	$ -	$ 2,559,926
27	***NET MARGINS (LOSS)***	$ (2,894,762)	$ (25,616)	$ (2,920,378)	$ 3,666,668	$ 746,290

25 References:
26 Column (A): Company Schedule C-1, Page 2
27 Column (B): Schedule CSB-9
28 Column (C): Column (A) + Column (B)
29 Column (D): Schedules CSB-1 and CSB-2
30 Column (E): Column (C) + Column (D)

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-11

SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1 Regulatory Asset Charge Revenue	[C] ADJ #2 Normalized Legal Expense	[D] ADJ #3 Employee Vacancy Level Normalization	[E] ADJ #4 Food & Other Expenses	[F] ADJ #5 Interest on Long Term Debt	[G] STAFF ADJUSTED
			Ref: Sch CSB-12	Ref: Sch CSB-13	Ref: Sch CSB-14	Ref: Sch CSB-15	Ref: Sch CSB-16	
	REVENUES:							
1	Network Transmission Service	$ 13,104,192	$ -	$ -	$ -	$ -	$ -	$ 13,104,192
2	Point to Point	7,617,540	-	-	-	-	-	7,617,540
3	Total Electric Revenue	$ 20,721,732	$ -	$ -	$ -	$ -	$ -	$ 20,721,732
4	Load Dispatch and System Control	$ 2,824,224	$ -	$ -	$ -	$ -	$ -	$ 2,824,224
5	Direct Access Facilities	515,580	-	-	-	-	-	515,580
6	Regulatory Asset Charge	2,707,122	(2,707,122)	-	-	-	-	-
7	Other Operating Revenue	413,318	-	-	-	-	-	413,318
8	Ancilliary Services From AEPCO	-	-	-	-	-	-	-
9	Special Contracts	673,342	-	-	-	-	-	673,342
10	**Total Revenues**	$ 27,855,318	$ (2,707,122)	$ -	$ -	$ -	$ -	$ 25,148,196
	OPERATING EXPENSES:							
11	Energy	$ 2,541,334	$ -	$ -	$ -	$ -	$ -	$ 2,541,334
12	Transmission	7,649,597	-	-	(113,684)	-	-	7,535,913
13	Administrative and General	3,872,157	-	(83,799)	-	(57,773)	-	3,730,586
14	Maintenance	2,429,390	-	-	-	-	-	2,429,390
15	Maintenance - General Plant	79	-	-	-	-	-	79
16	Depreciation and Amortization	6,852,107	-	-	-	-	-	6,852,107
17	ACC Gross Revenue Taxes	-	-	-	-	-	-	-
18	Other Taxes	2,285,845	-	-	-	-	-	2,285,845
19	Income Taxes	-	-	-	-	-	-	-
20	**Total Operating Expenses**	$ 25,630,509	$ -	$ (83,799)	$ (113,684)	$ (57,773)	$ -	$ 25,375,254
21	**Operating Margin Before Interest on L.T.- Debt**	$ 2,224,809	$ (2,707,122)	$ 83,799	$ 113,684	$ 57,773	$ -	$ (227,058)
23	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***							
24	Interest on Long-term Debt	$ 5,168,413	$ -	$ -	$ -	$ -	$ 133,675	$ 5,302,088
25	Other Interest & Other Dedcutions	232,030	-	-	-	-	-	232,030
26	**Total Interest & Other Deductions**	$ 5,400,443	$ -	$ -	$ -	$ -	$ 133,675	$ 5,534,118
27	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (3,175,634)	$ (2,707,122)	$ 83,799	$ 113,684	$ 57,773	$ (133,675)	$ (5,761,176)
28	***NON-OPERATING MARGINS***							
29	Interest Income	$ 172,901	$ -	$ -	$ -	$ -	$ -	$ 172,901
30	Other Non-operating Income	107,971	-	-	-	-	-	107,971
31	**Total Non-Operating Margins**	$ 280,872	$ -	$ -	$ -	$ -	$ -	$ 280,872
32	***REGULATORY ASSET CHARGE***	$ -	$ 2,559,926	$ -	$ -	$ -	$ -	$ 2,559,926
33	***NET MARGINS (LOSS)***	$ (2,894,762)	$ (147,196)	$ 83,799	$ 113,684	$ 57,773	$ (133,675)	$ (2,920,378)

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-12

OPERATING INCOME ADJUSTMENT NO. 1 - REGULATORY ASSET CHARGE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Revenue	$ 25,148,196	$ -	$ 25,148,196
2	Regulatory Asset Charge	$ 2,707,122	$ (2,707,122)	$ -
3	Total Revenue	$ 27,855,318	$ (2,707,122)	$ 25,148,196
4	Expense	$ 25,630,509	$ -	$ 25,630,509
5	Operating Margin Before Interest	$ 2,224,809	$ (2,707,122)	$ (482,313)
6	Total Interest	$ 5,400,423	$ -	$ 5,400,423
7	Margins After Interest Expense	$ (3,175,614)	$ (2,707,122)	$ (5,882,736)
8	Non-Operating Margins	$ 280,872		$ 280,872
9	Normalized Regulatory Asset Charge Rev	$ -	$ 2,559,926	$ 2,559,926
10	Net Margin	$ (2,894,742)	$ (147,196)	$ (3,041,938)

CALCULATION OF NORMALIZED REGULATORY ASSET CHARGE

	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
11		Total kWhs		Total kWhs
12	Anza	44,660,813	-	44,660,813
13	Duncan	26,782,590	-	26,782,590
14	Graham	136,552,300	-	136,552,300
15	Mohave 1	611,433,890	-	611,433,890
16	Sulphur	662,992,990	-	662,992,990
17	TRICO (See Note Below)	437,521,797	-	437,521,797
18		1,919,944,380		1,919,944,380
19	Regulatory Asset Charge	$ 0.00141	$ (0.00008)	$ 0.00133
20	**Regulatory Asset Charge (L8 x L9)**	$ 2,707,122	(147,196)	$ 2,559,926

21			RAC
22			Decision No.62758
23		2004 RAC	$ 0.00137
24		2005 RAC	$ 0.00133
25	**Note:**	2006 RAC	$ 0.00130
26	The Cooperative filed 437,520,942 kWhs.		$ 0.00400
27	Staff used the Cooperative's actual kWhs	Divided by	3
28	of 437,521,797 to reconcile to the $2,707,122		$ 0.00133
29	in RAC revenue shown on Schedule C1, Page 3, Line 6		

30 References:
31 Column A: Cooperative Schedule C1, Page 3, Line 6
32 Column B: Testimony, CSB
33 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-13

OPERATING INCOME ADJUSTMENT NO. 2 - NORMALIZED LEGAL EXPENSE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	2003 Legal Expenses	$ 233,076	$ -	$ 233,076
2	ACC Jurisdiction Adjudication Related Legal Exp	77,936	**(77,936)**	-
3	Redacted Legal Invoices Expense	5,863	**(5,863)**	-
4	Total	$ 316,875	**$ (83,799)**	$ 233,076

	ACC Jurisdiction Adjudication Related Legal Expenses			
5				
6	Firm Name	Date	Invoice No.	Amount
7	Intentionally Left Blank	1/14/2003	227857	$ 10,685.38
8	Intentionally Left Blank	2/18/2003	230060	$ 9,094.48
9	Intentionally Left Blank	3/13/2003	231756	$ 1,196.12
10	Intentionally Left Blank	4/14/2003	233950	$ 2,381.67
11	Intentionally Left Blank	5/13/2003	236060	$ 7,048.99
12	Intentionally Left Blank	6/12/2003	238034	$ 2,784.83
13	Intentionally Left Blank	7/11/2003	240029	$ 2,085.00
14	Intentionally Left Blank	8/7/2003	241860	$ 6,330.52
15	Intentionally Left Blank	9/12/2003	243996	$ 11,122.36
16	Intentionally Left Blank	10/9/2003	245988	$ 15,816.34
17	Intentionally Left Blank	11/11/2003	248029	$ 9,390.04
18			Total	$ 77,935.73

	Redacted Legal Invoices			
19				
20	Firm Name	Date	Invoice No.	Amount
21	Intentionally Left Blank	10/7/2003	250-0903C	$ 2,918.75
22	Intentionally Left Blank	2/14/2003	250-0103C	$ 1,706.92
23	Intentionally Left Blank	1/16/2003	250-1202C	$ 1,237.50
24			Total	$ 5,863.17

25 References:
26 Column A: Company Data Request Response CSB 2-40
27 Column B: Testimony, CSB
28 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-14

OPERATING INCOME ADJUSTMENT NO. 3 - EMPLOYEE VACANCY LEVEL NORMALIZATION

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	Employee Vacancy Level Normalization	$ -	$ (113,684)	$ (113,684)

2		
3	2001 Employee Vacancy Level	(5)
4	2002 Employee Vacancy Level	(3)
5	2003 Employee Vacancy Level	(1)
6	Total	(9)
7	Division Factor	3
8	Normalized Vacancy Level	(3)
9	Less: Test Year Vacancy Level	(1)
10	Amount to Adjust Test Year Vacancy Level	(2)
11	Multiplied by:	$ 56,842
12	**Adjustment to Normalize Employee Vacancy Level**	**$ (113,684)**

13 References:

14 Column A: Company Data Request Response CSB 2-37
15 Column B: Testimony, CSB
16 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-15

OPERATING INCOME ADJUSTMENT NO. 4 - FOOD & OTHER EXPENSES

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	CSB 2-44	Southwest Trans - Food, Luncheons, Dinners	$ 23,387	$ (23,387)	$ -
2	CSB 6-6	Billings from Affiliates - Charitable Contributions	$ 2,751	$ (2,751)	$ -
3	CSB 6-6	Billings from Affiliates - Sponsorships	$ 187	$ (187)	$ -
4	CSB 6-6	Billings from Affiliates - Food	$ 6,537	$ (6,537)	$ -
5	CSB 6-6	Billings from Affiliates - Awards	$ 201	$ (201)	$ -
6	CSB 6-6	Billings from Affiliates - Party	$ 2,211	$ (2,211)	$ -
7	CSB 6-6	Billings from Affiliates - Meals & Entertainment	$ 4,814	$ (4,814)	$ -
8	CSB 6-8	Lobbying Costs Included in Memberships	$ 17,685	$ (17,685)	$ -
9		TOTAL	$ 57,773	$ (57,773)	$ -

10 References:

11 Column A: Cooperative Data Request Response CSB 2-44, 6-6, and 6-8
12 Column B: Testimony, CSB
13 Column C: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Schedule CSB-16

OPERATING INCOME ADJUSTMENT NO. 5 - INTEREST EXPENSE ON LONG-TERM DEBT

		[A]	[B]	[C]
LINE NO.	DESCRIPTION	COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Interest Expense on Long-term Debt	$ 5,168,413	$ 133,675	$ 5,302,088

2 References:

3 Column A: Cooperative Schedule C-1
4 Column B: Testimony, CSB
5 Column C: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-04-0528

SURREBUTTAL TESTIMONY OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

ALL-STATE LEGAL®
EXHIBIT
S-3
ADMITTED

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SCHEDULES

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EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

Ms. Brown's surrebuttal testimony presents Staff's response to Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Cooperative") rebuttal testimony regarding the revenue and expense annualization adjustment, the Tracker Mechanism (Base Cost of Power) adjustment, and the overhaul accrual expense adjustment. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, jurisdictional separation, the Sulphur Springs Partial Requirements Capacity and Energy Agreement, and the revised depreciations rates.

INTRODUCTION

Q. Please state your name.

A. My name is Crystal S. Brown.

Q. Are you the same Crystal S. Brown who previously submitted pre-filed testimony in this docket?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond, on behalf of the Utilities Division ("Staff"), to the rebuttal testimony of Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Cooperative") rebuttal testimony regarding Staff's Revenue and Expense Annualization adjustment, Overhaul Accrual Expense adjustment, and the Tracker Mechanism (Base Power Cost) adjustment. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, jurisdictional separation, the Sulphur Springs Partial Requirements Capacity and Energy Agreement, and the depreciation rates.

SUMMARY OF COOPERATIVE'S REBUTTAL TESTIMONY

Q. Please summarize AEPCO's rebuttal testimony.

A. AEPCO's rebuttal testimony raises concerns about:

1. Staff's inclusion of Mohave Electric Cooperative, Inc.'s ("Mohave") customer growth in the revenue and expense annualization calculations;
2. Staff's use of historical overhaul expense that does not reflect the $1.6 million in overhaul expense expected to be incurred when a new gas turbine is overhauled;

3. Staff's classification of the $250,000 pro forma adjustment as a reduction in the purchased power energy costs of the Public Service Company of New Mexico; Staff's inclusion of $2,215,834 in margins associated with economy energy sales, and; Staff's inclusion of certain purchased capacity charges and associated wheeling expenses for the Panda Gila River purchased power agreement for which Mohave elected not to participate.
4. The Cooperative also comments on the redacted legal invoices, food and similar expenses, jurisdictional separation, Sulphur Springs Partial Requirements Capacity and Energy Agreement, and the revised depreciation rates.

REVENUE AND EXPENSE ANNUALIZATIONS

Q. What is AEPCO's rebuttal response to Staff's Operating Income Adjustment No. 2, "Revenue and Expense Annualizations"?

A. AEPCO agrees with Staff's annualization calculation except for the inclusion of customer growth for Mohave. The Cooperative indicated that since Mohave is a partial requirements customer, Mohave's customer growth does not result in increased revenues and expenses. AEPCO removed the customer growth for Mohave and calculated a 1.61 percent annualization factor.

Q. Does Staff agree that Mohave should be removed from the calculation of the annualization factor and AEPCO's 1.61 percent growth factor?

A. Yes.

Q. Does Staff agree that its annualization adjustment to operating revenue was overstated by $336,455 as proposed by the Cooperative?

A. No. The Cooperative's $336,455 adjustment to revenue is calculated by multiplying $56,092,646 times 1.67 percent rather than its 1.61 percent growth factor. Using a 1.61 percent growth factor, Staff calculated that its annualization adjustment to operating revenue was overstated by $368,421, a difference of $31,966.

Q. Does Staff agree that its annualization adjustment to operating expense was overstated by $5,658 as stated by the Cooperative?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends decreasing Test Year operating revenues by $368,421 and operating expenses by $5,658 as shown on Surrebuttal Schedules CSB-4 and CSB-5.

TRACKER MECHANISM (BASE POWER COST)

Q. What is AEPCO's rebuttal response to Staff's Operating Income Adjustment No. 4, "Tracker Mechanism (Base Power Cost)"?

A. AEPCO accepts Staff's adjustment with the exception of (1) Staff's classification of the $250,000 pro forma adjustment as a reduction in the purchased power energy costs of the Public Service Company of New Mexico ("PNM") (2) Staff's inclusion of $2,215,834 in margins associated with economy energy sales, and (3) Staff's inclusion of certain purchased capacity charges and associated wheeling expenses for the Panda Gila River purchased power agreement for which Mohave elected not to participate.

Q. Please discuss AEPCO's rebuttal response to the $250,000 adjustment.

A. The Cooperative stated that Staff's classification of the $250,000 pro forma adjustment as a reduction in the purchased power energy costs of the Public Service Company of New Mexico contract is incorrect. The $250,000 pertains to the payment for a 2MW contract demand reduction in the AEPCO/PNM contract. Therefore, the $250,000 should have been deducted from purchased power demand costs rather than purchased power energy costs.

Q. Does Staff agree that the $250,000 should have been deducted from purchased power demand costs rather than purchased power energy costs?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends reclassifying the $250,000 reduction from purchased power energy costs to purchased power demand costs as shown on Surrebuttal Schedules CSB-4 and CSB-6.

Q. Please discuss AEPCO's rebuttal response to Staff's inclusion of $2,215,834 in margins associated with economy energy sales.

A. The Cooperative removed the $2,215,834 in margins associated with economy energy sales primarily because it claims the credit would result in a double recovery of those margins.

Q. Does Staff agree that the $2,215,834 in margins associated with economy energy sales should be removed?

A. As discussed in the testimony of Ms. Barbara Keene, Staff does not agree that they should be removed.

Q. What is Staff recommending?

A. Staff continues to recommend inclusion of the $2,215,834 in margins associated with economy energy sales.

Q. Please discuss AEPCO's rebuttal response to the Staff's inclusion of certain purchased capacity charges and associated wheeling expenses related to Mohave.

A. Mohave did not participate in the Panda Gila River purchased power agreement and avoided certain purchased capacity charges and associated wheeling expenses. The Cooperative removed the costs from Mohave's fixed charge and operations and maintenance rate and made a corresponding adjustment to remove the costs from Mohave's base cost of power.

Q. Does the Cooperative's rebuttal proposal affect Staff's Operating Income Adjustment No. 4, "Tracker Mechanism (Base Power Cost)" ?

A. No, it does not. Staff's adjustment pertains to Test Year revenues and expenses which includes Mohave as well as full requirements customers. Staff calculations were not developed to determine the base power cost, only the total cost. Consequently, the breakout of Mohave from the full requirements customers for the purposes of developing separate base rates has no effect on Staff's adjustment.

Q. What is Staff recommending?

A. Staff continues to recommend the Tracker Mechanism (Base Power Cost) adjustments shown on Surrebuttal Schedule CSB-6.

OPERATING INCOME ADJUSTMENT NO. 5 – OVERHAUL ACCRUAL EXPENSE

Q. What is AEPCO's rebuttal response to Staff's Operating Income Adjustment No. 5, "Overhaul Accrual Expense"?

A. The Cooperative accepted Staff's adjustment with the exception of Staff's use of historical data for a new gas turbine that went into service in 2002. Staff's overhaul accrual expense calculation does not reflect the $1.6 million in overhaul expense expected to be incurred when the new gas turbine is overhauled.

Q. Does Staff agree that the overhaul accrual expense calculation should include an estimated overhaul expense for gas turbine no. 4 in the absence of historical data?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends increasing overhaul accrual expense as shown on Surrebuttal Schedules CSB-4 and CSB-7.

REDACTED LEGAL INVOICES AND MINUTES OF THE BOARD OF DIRECTORS

Q. What is AEPCO's rebuttal response to Staff's adjustment to disallow costs related to certain legal invoices and minutes of the board of directors?

A. AEPCO accepted Staff's adjustment. Although Staff does agree with the Cooperative's other statements on this matter, there is no further need to comment on the matter beyond what Staff stated in its direct testimony.

FOOD AND OTHER EXPENSE

Q. What is AEPCO's rebuttal response to Staff's adjustment to disallow costs related to food and other similar expenses?

A. AEPCO accepted Staff's adjustment. However, the Cooperative claims that many of the expenses, such as food for the Member Meetings, training, and recruitment were necessary for safe, reliable, and adequate service.

Q. Are food, entertainment, and similar expenses needed in the provision of safe, reliable service?

A. No, they are non-essential costs for the provision of service.

Q. How are customers affected when non-essential costs are included in rates?

A. Customers are unnecessarily charged higher rates when non-essential costs are built into rates. If this occurs, a portion of each customer's bill would pay for the non-essential costs. These non-essential costs could be reduced or eliminated and the customers' service would not be affected.

JURISDICTIONAL SEPARATION

Q. What is AEPCO's rebuttal response to Staff's recommendation that it "separate nonjurisdictional properties, revenues and expenses" in compliance with the Arizona Administrative Code?

A. AEPCO did not accept Staff's recommendation because (1) the Commission had never required the Cooperative to jurisdictionally separate the rate base and expenses for its California customer (i.e., Anza) and (2) the benefit derived from such compliance would not justify the cost.

Q. Is the Cooperative's argument that it has never been required to perform a cost of service study for Anza since 1979 justification for not jurisdictionally separating rate base and expenses?

A. No. Previous non-filing of jurisdictionally separated data is not justification for continued non-filing of jurisdictionally separated data. The Cooperative's response indicates that the Cooperative does not know nor has ever known (based upon a study) what the rate base and expense elements are for Anza.

Q. Has the Cooperative supported its assertion that the benefits of the jurisdictional separations requirements would exceed the costs?

A. No. The Cooperative does not know the benefits. The benefits cannot be determined until the jurisdictional separation is performed.

Q. Can Staff provide an example of the potential inequity that is presented by absence of jurisdictional separations.

A. Hypothetically, the cost to serve a customer that represents 2 percent of revenues could be 10 percent of costs. The result in such a case is a substantive subsidization for this

customer. Staff cannot know if this situation is occurring unless the Cooperative provides jurisdictionally separated data.

Q. Does Staff believe that it would be cost prohibitive to jurisdictionally separate the data?

A. No, because smaller cooperatives have provided jurisdictionally separated data. In addition, other smaller cooperatives have also provided cost of service studies that allocate rate base, revenue, and expenses by customer class. Further, once the framework/methodology has been established, the process to update the studies should be relatively straightforward.

Q. What is the benefit of requiring jurisdictionally separated data?

A. The information would assist in the pricing out of contracts and development of cost-based rates.

Q. What is Staff recommending?

A. Staff continues to recommend that the Cooperative jurisdictionally separate the data in all subsequent rate filings.

SULPHUR SPRINGS PARTIAL REQUIREMENTS CAPACITY AND ENERGY AGREEMENT

Q. Please discuss the Sulphur Springs Partial Requirements Capacity and Energy Agreement.

A. The Cooperative is currently in negotiations with Sulphur Springs pertaining to a Partial Requirements Capacity and Energy Agreement.

Q. Is the agreement finalized?

A. No, it is not.

Q. What is Staff recommending?

A. Since the impact of the agreement cannot be determined and it is not known and measurable, it should not be considered in this proceeding. As with any other utility activity, AEPCO can assess its regulatory alternatives once the agreement is finalized.

DEPRECIATION RATES

Q. Does Staff recommend adoption of the rates for two of AEPCO's generating units discussed in the direct testimony of Mr. Dirk Minson[1]?

A. Yes. Staff witness, Jerry Smith, has reviewed the depreciation rates and recommends adoption.

SUMMARY OF STAFF'S SURREBUTTAL REVENUE POSITION

Q. Please summarize Staff's recommended revenue.

A. Staff recommends total annual operating revenue of no less than that proposed by AEPCO, which is $148,397,723, an increase of $9,477,998, or 6.82 percent, over Staff adjusted Test Year revenues of $138,919,725. The recommended revenue would produce an operating margin of $19,903,441 for a 10.50 percent rate of return on the original cost and fair value rate base of $189,637,810 to provide a 1.50 times interest earned ratio ("TIER") and a 0.99 debt service coverage ratio ("DSC").

Q. Does this conclude your surrebutal testimony?

A. Yes, it does.

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[1] Page 10, beginning at line 24

Arizona Electric Power Cooperative, Inc.
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Surrebuttal Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] STAFF DIRECT ORIGINAL COST	[B] COOPERATIVE REBUTTAL ORIGINAL COST	[C] STAFF SURREBUTTAL ORIGINAL COST
1	Adjusted Operating Income (Loss)	$ 10,981,774	$ 10,457,408	$ 10,425,443
2	Depreciation and Amortization	$ 7,539,289	$ 7,539,289	$ 7,539,289
3	Income Tax Expense	-	-	-
4	Long-term Interest Expense	$ 13,313,164	$ 13,313,164	$ 13,313,164
5	Principal Repayment	$ 14,360,494	$ 14,360,494	$ 14,360,494
6a	**Recommended Increase in Operating Revenue**	**$ 6,773,320**	**$ 9,446,032**	**$ 9,477,998**
6b	**Percent Increase (Line 6a / Line 7) - Per Staff**	**4.86%**	**6.80%**	**6.82%**
6c	Percent Increase (Line 6a / $85,685,624) - Per Coop	N/A	11.02%	N/A
7	Adjusted Test Year Operating Revenue	$ 139,288,146	$ 138,951,691	$ 138,919,725
8	**Recommended Annual Operating Revenue**	$ 146,061,466	**$ 148,397,723**	**$ 148,397,723**
9a	**Recommended Operating Margin Before Interest**	$ 17,755,094	**$ 19,903,440**	**$ 19,903,441**
9b	Recommended Net Margins(Loss) After Interest	$ 4,099,540	$ 6,247,886	$ 6,247,887
9c	Recommended Net Margins	$ 6,061,991	$ 8,210,337	$ 8,210,338
10a	**Recommended Operating TIER (L3+L9)/L4 - Per Staff**	**1.33**	**1.50**	**1.50**
10b	Recommended Net TIER (L4+L9c)/L4 - Per Coop	N/A	1.62	N/A
11a	**Recommended DSC (L2+L3+L9)/(L4+L5) - Per Staff**	**0.91**	**0.99**	**0.99**
11b	Recommended DSC (L2+L4+L9c)/(L4+L5) - Per Coop	N/A	1.05	N/A
12	**Adjusted Rate Base**	$ 189,637,810	**$ 189,637,810**	**$ 189,637,810**
13	Rate of Return (L9a / L12)	9.36%	10.50%	10.50%

References:
Column [A]: Brown, Direct Testimony, Schedule CSB-1
Column [B]: Pierson, Rebuttal Testimony, Exhibit GEP-2
Column [C]: Surrebuttal Testimony

Arizona Electric Power Cooperative, Inc.
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Surrebuttal Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Plant in Service	$ 377,675,263	$ -	$ 377,675,263
2	Less: Acc Depreciation & Amortization	(185,936,636)	-	(185,936,636)
3	Net Plant in Service	$ 191,738,627	$ -	$ 191,738,627
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -	$ -
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	$ -	$ -	$ -
9	Member Advances	$ (11,982,081)	$ -	$ (11,982,081)
	ADD:			
10	Working Capital	$ 9,881,264	$ -	$ 9,881,264
11	Plant Held for Future Use	$ -	$ -	$ -
12	Deferred Debits	$ -	$ -	$ -
13	**Total Rate Base**	$ 189,637,810	$ -	$ 189,637,810

References:
Column [A], Company Schedule B-1, Page 1
Column [B]: Schedule CSB-3
Column [C]: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
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Schedule CSB-3

OPERATING INCOME - TEST YEAR AND STAFF RECOMMENDED

Line No.	DESCRIPTION	[A] STAFF DIRECT TEST YEAR	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL TEST YEAR	[D] STAFF PROPOSED CHANGES	[E] STAFF SURREBUTTAL RECOMMENDED
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 37,818,004	$ (368,421)	$ 37,449,583	$ 9,477,998	$ 46,927,581
2	Class A Members, Base Cost of Power Revenue	$ 48,992,382	$ -	$ 48,992,382		$ 48,992,382
3	Total Class A Member Electric Revenue	$ 86,810,386	$ (368,421)	$ 86,441,965	$ 9,477,998	$ 95,919,963
4	Non-Class A, Non-Firm, & Non-Member	50,996,438	-	50,996,438	-	50,996,438
5	Total Electric Revenue	$ 137,806,824	$ (368,421)	$ 137,438,403	$ 9,477,998	$ 146,916,401
6	Other Operating Revenue	$ 1,481,322	$ -	$ 1,481,322	$ -	$ 1,481,322
7	**Total Revenues**	$ 139,288,146	$ (368,421)	$ 138,919,725	$ 9,477,998	$ 148,397,723
	EXPENSES:					
8	Operations - Production, Fuel	$ 59,014,728	$ (5,658)	$ 59,009,070	$ -	$ 59,009,070
9	Operations - Production, Steam	$ 8,764,555	$ -	$ 8,764,555	$ -	$ 8,764,555
10	Operations - Production, Other	$ 1,743,316	$ -	$ 1,743,316	$ -	$ 1,743,316
11	Operations - Other Pwr Supply, Demand	$ 5,769,587	$ (250,000)	$ 5,519,587	$ -	$ 5,519,587
12	Operations - Other Pwr Supply - Energy	$ 12,170,888	$ 250,000	$ 12,420,888	$ -	$ 12,420,888
13	Operations - Transmission	$ 8,036,486	$ -	$ 8,036,486	$ -	$ 8,036,486
14	Operations - Administrative and General	$ 9,525,760	$ -	$ 9,525,760	$ -	$ 9,525,760
15	Maintenance - Production, Steam	$ 9,512,257	$ 193,569	$ 9,705,826	$ -	$ 9,705,826
16	Maintenance - Production, Other	$ 2,809,881	$ -	$ 2,809,881	$ -	$ 2,809,881
17	Maintenance - Transmission	$ 8,828	$ -	$ 8,828	$ -	$ 8,828
18	Maintenance - General Plant	$ 63,958	$ -	$ 63,958	$ -	$ 63,958
19	Depreciation and Amortization	$ 7,539,289	$ -	$ 7,539,289	$ -	$ 7,539,289
20	ACC Gross Revenue Taxes	$ -	$ -	$ -	$ -	$ -
21	Taxes	$ 3,346,839	$ -	$ 3,346,839	$ -	$ 3,346,839
22	**Total Operating Expenses**	$ 128,306,372	$ 187,910	$ 128,494,282	$ -	$ 128,494,282
23	**Operating Margin Before Interest on L.T.- Debt**	$ 10,981,774	$ (556,331)	$ 10,425,443	$ -	$ 19,903,441
24	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
25	Interest on Long-term Debt	$ 13,313,164	$ -	$ 13,313,164	$ -	$ 13,313,164
26	Other Interest & Other Dedcutions	$ 342,390	$ -	$ 342,390	$ -	$ 342,390
27	**Total Interest & Other Deductions**	$ 13,655,554	$ -	$ 13,655,554	$ -	$ 13,655,554
28	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (2,673,780)	$ (556,331)	$ (3,230,111)	$ -	$ 6,247,887
29	***NON-OPERATING MARGINS***					
30	Interest Income	$ 582,014	$ -	$ 582,014	$ -	$ 582,014
31	Other Non-operating Income	$ 1,380,437	$ -	$ 1,380,437	$ -	$ 1,380,437
32	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ 1,962,451	$ -	$ 1,962,451
33	***EXTRAORDINARY ITEMS***	$ -	$ -	$ -	$ -	$ -
34	***NET MARGINS (LOSS)***	$ (711,329)	$ (556,331)	$ (1,267,660)	$ -	$ 8,210,338

35 References:
36 Column (A): Cooperative Schedule C-1, Pages 1 and 2
37 Column (B): Schedule CSB-12
38 Column (C): Column (A) + Column (B)
39 Column (D): Schedules CSB-1
40 Column (E): Column (C) + Column (D)

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Surrebuttal Schedule CSB-4

TEST YEAR OPERATING INCOME - STAFF DIRECT AND SURREBUTTAL

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJ #2 Revenue and Expense Annualizations Ref: Sch CSB-14	[C] ADJ #4 Tracker Mechanism (Base Power Cost) Ref: Sch CSB-16	[D] ADJ #5 Overhaul Accrual Expense Ref: Sch CSB-17	[E] STAFF SURREBUTTAL
	REVENUES:					
1	Class A Members, Non-Base Cost of Power Revenue	$ 37,818,004	$ (368,421)	$ -	$ -	$ 37,449,583
2	Class A Members, Base Cost of Power Revenue	$ 48,992,382	$ -	$ -	$ -	$ 48,992,382
3	Total Class A Member Electric Revenue	$ 86,810,386	$ (368,421)	$ -	$ -	$ 86,441,965
4	Non-Class A, Non-Firm, & Non-Member	50,996,438	-	-	-	50,996,438
5	Total Electric Revenue	$ 137,806,824	$ (368,421)	$ -	$ -	137,438,403
6	Other Operating Revenue	$ 1,481,322	-	-	-	1,481,322
7	**Total Revenues**	$ 139,288,146	$ (368,421)	$ -	$ -	$ 138,919,725
8	***OPERATING EXPENSES:***					
9	Operations - Production, Fuel	$ 59,014,728	$ (5,658)	$ -	$ -	$ 59,009,070
10	Operations - Production, Steam	8,764,555 [1]	-	-	-	8,764,555
11	Operations - Production, Other	1,743,316 [2]		-	-	1,743,316
12	Operations - Other Pwr Supply, Demand	5,769,587	-	(250,000)	-	5,519,587
13	Operations - Other Pwr Supply - Energy	12,170,888 [3]	-	250,000	-	12,420,888
14	Operations - Transmission	8,036,486	-		-	8,036,486
15	Operations - Administrative and General	9,525,760	-	-	-	9,525,760
16	Maintenance - Production, Steam	9,512,257 [4]	-	-	193,569	9,705,826
17	Maintenance - Production, Other	2,809,881	-	-	-	2,809,881
18	Maintenance - Transmission	8,828	-	-	-	8,828
19	Maintenance - General Plant	63,958	-	-	-	63,958
20	Depreciation and Amortization	7,539,289	-	-	-	7,539,289
21	ACC Gross Revenue Taxes	-	-	-	-	-
22	Taxes	3,346,839	-	-	-	3,346,839
23	**Total Operating Expenses**	$ 128,306,372	$ (5,658)	$ -	$ 193,569	$ 128,494,282
24	**Operating Margin Before Interest on L.T.- Debt**	**$ 10,981,774**	$ (362,762)	$ -	$ (193,569)	**$ 10,425,443**
25	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
26	Interest on Long-term Debt	$ 13,313,164	$ -	$ -	$ -	$ 13,313,164
27	Other Interest & Other Dedcutions	342,390	-	-	-	342,390
28	**Total Interest & Other Deductions**	$ 13,655,554	$ -	$ -	$ -	$ 13,655,554
29	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (2,673,780)	$ (362,762)	$ -	$ (193,569)	$ (3,230,111)
30	***NON-OPERATING MARGINS***					
31	Interest Income	$ 582,014	$ -	$ -	$ -	$ 582,014
32	Other Non-operating Income	1,380,437	-	-	-	1,380,437
33	**Total Non-Operating Margins**	$ 1,962,451	$ -	$ -	$ -	$ 1,962,451
34	***EXTRAORDINARY ITEMS***	$ -	-	-	-	-
35	***NET MARGINS (LOSS)***	$ (711,329)	$ (362,762)	$ -	$ (193,569)	$ (1,267,660)

Footnote Explanations

[1] Includes account nos. 500, 502 to 509
[2] Includes account nos. 546, 548 to 550
[3] Includes account nos. 555 to 557
[4] Includes account nos. 510 to 515

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Surrebuttal Schedule CSB-5

OPERATING INCOME ADJUSTMENT NO. 2 - REVENUE AND EXPENSE ANNUALIZATIONS

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] STAFF ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Class A Member Demand Revenues	$ 36,990,731	$ (6,922,455)	$ 30,068,276
2	Class A Member Energy Revenues	$ 40,285,075	$ (14,260,705)	$ 26,024,370
3	Class A Member ACC Assessment Rev	$ -	$ -	$ -
4	Class A Member Fixed Charge Revenues	$ -	$ -	$ -
5	Total Class A Member Base Rate Revenues	$ 77,275,806	$ (21,183,160)	$ 56,092,646
6	Factor to Annualize Revenues to End of Test Year	1.65%		1.61%
7	**Revenue Annualization Adjustment**	$ 1,271,908	**$ (368,421)**	$ 903,487
8	Variable Expenses Not Recovered Through Fuel Adj	$ 16,062,410		$ 16,062,410
9	Factor to Annualize Revenues to End of Test Year	1.65%		1.61%
10	**Adjustment to Expenses**	$ 264,376	**$ (5,658)**	$ 258,718

	Calculation of Annualization Factor						
	Number of Customers						
	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
2002	3,702	2,446	7,481	-	43,113	27,631	84,373
2003	3,824	2,484	7,623	-	44,431	28,729	87,091
Increase	122	38	142	-	1,318	1,098	2,718
% Increase	3.30%	1.55%	1.90%	0.00%	3.06%	3.97%	3.22%

2003 Growth Rate 3.22%

Annualization Factor - 2003 Growth Rate divided by 2 1.6107%

Calculation of Variable Expenses Not Recovered Through Fuel Adjustor			
Account No.	**Description**	**Amount**	
500	Operation Supervision and Engineering	$ 1,999,908	
501&547	Fuel - Steam Power & Other	$ 59,803,425	
502	Steam Expenses	$ 2,710,803	
505	Electric Expenses	$ 1,437,524	
510	Maintenance Supervision & Engineering	$ 840,774	
512	Maintenance of Boiler Plant	$ 6,433,681	
513	Maintenance of Electric Plant	$ 264,759	
514	Maintenance of Miscellaneous Steam Plant	$ 2,374,961	
555	Purchased Power - Demand	$ 5,769,587	
555	Purchased Power - Energy	$ 10,085,538	
	Total Variable Expenses	$ 91,720,960	
501&547	Fuel - Steam Power & Other	$ (59,803,425)	Recovered through Fuel Adj
555	Purchased Power - Demand	$ (5,769,587)	Recovered through Fuel Adj
555	Purchased Power - Energy	$ (10,085,538)	Recovered through Fuel Adj
		$ 16,062,410	
	2003 Growth Rate	1.61%	
	Adjustment to Expenses	$ 258,718	

References:
Column A: Direct Testimony, CSB
Column B: Surrebuttal Testimony, CSB
Column C: Column [A] + Column [B]

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Surrebuttal Schedule CSB-6

OPERATING INCOME ADJUSTMENT NO. 4 - TRACKER MECHANISM (BASE POWER COST)

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	**Base Cost of Power Revenue**			
2	Test Year Sales (In kWhs)	2,025,326,533	-	2,025,326,533
3	Base Cost of Power (Col A, per Dec 58405)	$ 0.020380	$ -	$ 0.020380
4	**Adjustment to match Coop proposed power expense to revenue**	$ 41,276,155	$ -	$ 41,276,155
5	Test Year Sales (In kWhs)	2,025,326,533		2,025,326,533
6	Base Cost of Power (Col C, Line 53/Line 5)	$ 0.016570	$ -	$ 0.016570
7	**Adjustment to reflect Staff's adjustments to power costs**	$ 33,560,400	$ -	$ 33,560,400
8	**Total**	$ 33,560,400	$ -	$ 33,560,400
9	**Base Cost of Power Expense**			
10	Coal Fired Steam Plant Costs:			
11	Fuel, Coal ($1,534,274 Coop Adj No. 5 - $1,030,873 legal exp)	$ 42,532,932	$ -	$ 42,532,932
12	Fuel, Gas	2,309,354	-	2,309,354
13	Fuel, Oil	-	-	-
14	**Less:** Fixed Fuel Costs	(295,865)	-	(295,865)
15	Subtotal	$ 44,546,421	$ -	$ 44,546,421
16	Internal Combustion Plant Costs:			
17	Fuel, Gas	$ 15,454,731	$ -	$ 15,454,731
18	Fuel, Oil	9,809	-	9,809
19	Less: Fixed Fuel Costs	-	-	-
20	Subtotal	$ 15,464,540	$ -	$ 15,464,540
21	**Total Fuel Costs**	**$ 60,010,961**	**$ -**	**$ 60,010,961**
22	Purchased Power Energy Costs			
23	Firm Purchases			
24	CRSP	$ 309,547	$ -	$ 309,547
25	Pacificorp	-	-	-
26	Parker Davis	217,629	-	217,629
27	Public Service Company of New Mexico	1,713,061	250,000	1,963,061
28	Panda Gila River	1,134,573	-	1,134,573
29	Spinning Reserves	-	-	-
30	Subtotal Firm Purchases	$ 3,374,810	$ 250,000	$ 3,624,810
31	Nonfirm Purchases, Demand	$ 5,769,587	(250,000)	$ 5,519,587
32	Nonfirm Purchases, Energy	6,460,728	-	6,460,728
33	**Total Purchased Energy Costs**	**$ 15,605,125**	**$ -**	**$ 15,605,125**
34	**Firm Wheeling Expenses**	$ 7,939,635	-	$ 7,939,635
35	**Non-firm Wheeling Expenses**	77,291	-	77,291
36	**Total Firm and Non-Firm Wheeling Expenses**	**$ 8,016,926**	**$ -**	**$ 8,016,926**
37	**TOTAL FUEL COSTS & PURCHASED ENERGY**	**$ 83,633,012**	**$ -**	**$ 83,633,012**
38	**Less:**			
39	Non-tariff Sales Fuel Recovery			
40	TRICO PD Sierrita	$ 862,555	$ -	$ 862,555
41	City of Mesa	-	-	-
42	City of Mesa (PSA)	2,566,472	-	2,566,472
43	ED-2 Power Supply	1,356,004	-	1,356,004
44	SRP	12,778,277	-	12,778,277
45	Safford	232,895	-	232,895
46	Mohave Schedule B Sales	142,921	-	142,921
47	Subtotal	$ 17,939,124	$ -	$ 17,939,124
48	Other Sales Fuel Recovery:			
49	Non-Firm Sales	$ 8,394,266	$ -	$ 8,394,266
50	Total Non-Tariff Sales Fuel Recovery, Energy	$ 26,333,390	$ -	$ 26,333,390
51	Total Non-Tariff Sales Fuel Recovery, Demand	$ 23,739,222	$ -	$ 23,739,222
52	**Total Non-Tariff Sales Fuel Recovery, Energy and Demand**	**$ 50,072,612**	**$ -**	**$ 50,072,612**
53	**Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)**	**$ 33,560,400**	**$ -**	**$ 33,560,400**

54 References:
55 Column A: Decision No. 58405, page 29, line 25; Cooperative Application Schedule H-2A
56 Column B: Testimony, CSB
57 Column C: Column [A] + Column [B]

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-7

OPERATING INCOME ADJUSTMENT NO. 5 - OVERHAUL ACCRUAL EXPENSE

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Overhaul Accrual Expense	$4,129,720	**$ 193,569**	$ 4,323,289

2		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 1,605,900	$ 4,754,805
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 1,605,900	$ 34,586,309
12								Divided by	8
13									$ 4,323,289

14 * Per response to CSB 1-38, there has been no actual overhaul expense
15 for generating GT2 for the period 1990 to 2004.

16 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.
The Cooperative estimates that the cost of the overhaul, anticipated to occur
in eight years, will be $1,605,900.

17 References:

18 Column A: Cooperative Data Request Response CSB 1-37 and 1-38
19 Column B: Testimony, CSB
20 Column C: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-04100A-04-0527

SURREBUTTAL TESTIMONY

OF

CRYSTAL S. BROWN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

ALL-STATE LEGAL®
EXHIBIT
S-4
ADMITTED

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EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

Ms. Brown's surrebuttal testimony presents Staff's response to Southwest Transmission Cooperative, Inc.'s ("Southwest Transmission" or "Cooperative") rebuttal testimony regarding the regulatory asset charge and a $2.3 million contract termination effective January 1, 2006. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, and jurisdictional separation.

INTRODUCTION

Q. Please state your name.

A. My name is Crystal S. Brown.

Q. Are you the same Crystal S. Brown who previously submitted pre-filed testimony in this docket?

A. Yes, I am.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond, on behalf of the Utilities Division ("Staff"), to the rebuttal testimony of Southwest Transmission Cooperative Inc.'s ("Southwest Transmission" or the "Cooperative") rebuttal testimony regarding the regulatory asset charge and a $2.3 million contract termination effective January 1, 2006. Also, Staff responds to the Cooperative's comments on the redacted legal invoices, food and similar expenses, and jurisdictional separation.

SUMMARY OF COOPERATIVE'S REBUTTAL TESTIMONY

Q. Please summarize Southwest Transmission's rebuttal testimony.

A. Southwest Transmission's rebuttal testimony suggests that Staff's reclassification of the regulatory asset charge revenue should be matched with a reclassification of the related regulatory asset charge amortization expense. Additionally, the Cooperative proposed a second set of rates to become effective January 1, 2006, to recover $2,294,640 of revenue it will lose on that date due to the termination by Morenci Water and Electric of a 60 MW firm point-to-point contract. The Cooperative also comments, by way of reference to the rebuttal testimony of Arizona Electric Power Cooperative, Inc. (Docket No. E-01773A-

040528),[1] on the redacted legal invoices, food and similar expenses, and jurisdictional separation.

REGULATORY ASSET CHARGE ("RAC")

Q. What is Southwest Transmission's rebuttal response to Staff's Operating Income Adjustment No. 1, "Regulatory Asset Charge" that reclassified RAC revenue from operating to non-operating revenue and reduced the amount from $2,707,122 to $2,559,926?

A. Southwest Transmission accepted Staff's adjustment, and suggested that a corresponding adjustment to reclassify the associated amortization of the RAC asset from operating to non-operating expense is appropriate.

Q. Does Staff agree with Southwest Transmission's position that the amortization of the RAC asset from operating to non-operating expense is appropriate?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends removing the $2,707,122 RAC amortization expense recorded in the Test Year from operating expense and recognizing $2,559,926 of non-operating amortization expense as shown on Surrebuttal Schedules CSB-4 and CSB-5.

[1] Minson Rebuttal testimony, pages 5 through 7

MW&E 60MW FIRM POINT-TO-POINT CONTRACT TERMINATION

Q. What amount of revenue did the Cooperative collect under the MW&E 60MW Firm Point-to-Point contract during the Test Year?

A. Southwest Transmission collected $2,294,640 under the MW&E 60MW Firm Point-to-Point contract during the Test Year.

Q. When will the MW&E firm point-to-point contract terminate?

A. The contract will terminate January 1, 2006.

Q. How does Southwest Transmission propose to address the $2.3 million revenue loss?

A. The Cooperative requests that the Commission authorize a second set of rates to become effective January 1, 2006, to recover the $2,294,640 revenue loss due to termination of the MW&E 60 MW point-to-point contract from other customers.

Q. Does Staff support Southwest Transmission's proposal for authorization of a second set of rates to recover the anticipated loss of the MW&E revenue?

A. Yes.

Q. What is Staff recommending?

A. Staff recommends authorization of a second set of rates to become effective January 1, 2006, to recover the revenue that will be lost due to termination of the MW&E contract. Staff's proposed rates for the second phase are presented in the surrebuttal testimony of Staff witness Ms. Erin Casper.

REDACTED LEGAL INVOICES AND MINUTES OF THE BOARD OF DIRECTORS

Q. What is Southwest Transmission's rebuttal response to Staff's adjustment to disallow costs related to certain legal invoices and minutes of the board of directors?

A. Southwest Transmission accepted Staff's adjustment. Although Staff does agree with the Cooperative's other statements on this matter, there is no further need to comment on the matter beyond what Staff stated in its direct testimony.

FOOD AND OTHER EXPENSE

Q. What is Southwest Transmission's rebuttal response to Staff's adjustment to disallow costs related to food and other similar expenses?

A. Southwest Transmission accepted Staff's adjustment. However, the Cooperative claims that many of the expenses, such as food for the Member Meetings, training, and recruitment were necessary for safe, reliable, and adequate service.

Q. Are food, entertainment, and similar expenses needed in the provision of safe, reliable service?

A. No, they are non-essential costs for the provision of service.

Q. How are customers affected when non-essential costs are included in rates?

A. Customers are unnecessarily charged higher rates when non-essential costs are built into rates. If this occurs, a portion of each customer's bill would pay for the non-essential costs. These non-essential costs could be reduced or eliminated and the customers' transmission service would not be affected.

JURISDICTIONAL SEPARATION

Q. What is Southwest Transmission's rebuttal response to Staff's recommendation that it "separate nonjurisdictional properties, revenues and expenses" in compliance with the Arizona Administrative Code?

A. Southwest Transmission did not accept Staff's recommendation because (1) the Commission had never required the Cooperative to jurisdictionally separate the rate base and expenses for its California customer (i.e., Anza) and (2) the benefit derived from such compliance would not justify the cost.

Q. Is the Cooperative's argument that it has never been required to perform a cost of service study for Anza since 1979 justification for not jurisdictionally separating rate base and expenses?

A. No. Previous non-filing of jurisdictionally separated data is not justification for continued non-filing of jurisdictionally separated data. The Cooperative's response indicates that the Cooperative does not know nor has ever known (based upon a study) what the rate base and expense elements are for Anza.

Q. Has the Cooperative supported its assertion that the benefits of the jurisdictional separations requirements would exceed the costs?

A. No. The Cooperative does not know the benefits. The benefits cannot be determined until the jurisdictional separation is performed.

Q. Can Staff provide an example of the potential inequity that is presented by absence of jurisdictional separations.

A. Hypothetically, the cost to serve a customer that represents 2 percent of revenues could be 10 percent of costs. The result in such a case is a substantive subsidization for this

customer. Staff cannot know if this situation is occurring unless the Cooperative provides jurisdictionally separated data.

Q. Does Staff believe that it would be cost prohibitive to jurisdictionally separate the data?

A. No, because smaller cooperatives have provided jurisdictionally separated data. In addition, other smaller cooperatives have also provided cost of service studies that allocate rate base, revenue, and expenses by customer class. Further, once the framework/methodology has been established, the process to update the studies should be relatively straightforward.

Q. What is the benefit of requiring jurisdictionally separated data?

A. The information would assist in the pricing out of contracts and development of cost-based rates.

Q. What is Staff recommending?

A. Staff continues to recommend that the Cooperative jurisdictionally separate the data in all subsequent rate filings.

SUMMARY OF STAFF'S SURREBUTTAL REVENUE POSITION

Q. Please summarize Staff's recommended revenue.

A. Staff recommends total annual operating revenue of no less than that proposed by Southwest Transmission, which is $28,814,864, an increase of 3,666,668, or 14.58 percent, over Staff adjusted Test Year revenues of $25,148,196. In addition, Staff and the Cooperative recognize $2,559,926 of non-operating RAC cash flow. The recommended revenue (including RAC) would produce an operating margin of $6,146,732 for an 8.05

percent rate of return on the original cost and fair value rate base of $76,235,655 to provide a 1.16 times interest earned ratio ("TIER") and a 1.02 debt service coverage ratio ("DSC").

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-1

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] STAFF DIRECT ORIGINAL COST With RAC	[B] COOPERATIVE REBUTTAL ORIGINAL COST With RAC	[C] STAFF SURREBUTTAL ORIGINAL COST With RAC
1	Adjusted Operating Income (Loss)	$ (227,058)	$ 2,480,064	$ 2,480,064
2	Depreciation and Amortization	$ 6,852,107	$ 4,144,985	$ 4,144,985
3	Income Tax Expense	-	-	-
4	Interest Expense on Long-term Debt	$ 5,302,088	$ 5,302,088	$ 5,302,088
5	Principal Repayment	$ 7,358,610	$ 7,358,610	$ 7,358,610
6	**Recommended Increase in Operating Revenue**	**$ 3,666,668**	**$ 3,666,668**	**$ 3,666,668**
7	Percent Increase (Line 6 / Line 8)	**14.58%**	**14.58%**	**14.58%**
8	Network Service and Other Revenue	$ 25,148,196	$ 25,148,196	$ 25,148,196
9	Regulatory Asset Charge ("RAC")	$ -	$ -	$ -
10	Adjusted Test Year Operating Revenue	$ 25,148,196	$ 25,148,196	$ 25,148,196
11	**Total Annual Operating Revenue**	**$ 28,814,864**	**$ 28,814,864**	**$ 28,814,864**
12	**Operating Margin**	**$ 3,439,610**	**$ 6,146,732**	**$ 6,146,732**
13	Net Margin	$ 746,290	$ 893,486	$ 893,486
14a	Normalized RAC Revenue, Non-operating			
14b	Normalized RAC Revenue	$ 2,559,926	$ 2,559,926	$ 2,559,926
14c	Normalized RAC Expense	$ -	$ 2,559,926	$ 2,559,926
14d	Net Normalized RAC Margin	$ 2,559,926	$ -	$ -
15	Total Operating Revenue and RAC Revenue (L12 + L14b)	$ 5,999,536	$ 8,706,658	$ 8,706,658
16	Cooperative Net TIER (L4+L13) / L4	N/A	1.17	N/A
17	**Staff Operating TIER (L3+L12+L14) / L4**	**1.13**	**1.16**	**1.16**
18	Cooperative DSC (L2+L4+L13+L14b)/(L4+L5)	N/A	1.02	N/A
19	**Staff DSC (L2+L3+L12+L14)/(L4+L5)**	**1.02**	**1.02**	**1.02**
20	**Adjusted Rate Base**	**$ 76,345,655**	**$ 76,345,655**	**$ 76,345,655**
21	Rate of Return (L12 / L20)	4.51%	8.05%	8.05%

References:
Column [A]: Brown, Direct Testimony, Schedule CSB-1
Column [B]: Pierson, Rebuttal Testimony, Exhibit GEP-2
Column [C]: Surrebuttal Testimony

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-2

RATE BASE - ORIGINAL COST

LINE NO.		[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Plant in Service	$ 131,516,270	$ -	$ 131,516,270
2	Less: Accumulated Depreciation	(55,798,589)	-	(55,798,589)
3	Net Plant in Service	$ 75,717,681	$ -	$ 75,717,681
	LESS:			
4	Advances in Aid of Construction (AIAC)	$ -	$ -	$ -
5	Contributions in Aid of Construction (CIAC)	$ -	$ -	$ -
6	Less: Accumulated Amortization	-	-	-
7	Net CIAC	-	-	-
8	Total Advances and Contributions	$ -	$ -	$ -
9	Member Advances	$ (228,188)	$ -	$ (228,188)
	ADD:			
10	Working Capital	$ 856,162	$ -	$ 856,162
11	Plant Held for Future Use	$ -	$ -	$ -
12	Deferred Debits	$ -	$ -	$ -
13	**Total Rate Base**	$ 76,345,655	$ -	$ 76,345,655

References:
Column [A], Brown, Direct Testimony Schedule CSB-4
Column [B], Brown, Direct Testimony Schedule CSB-4
Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-3

OPERATING INCOME - TEST YEAR AND STAFF RECOMMENDED

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL	[D] STAFF PROPOSED CHANGES	[E] STAFF RECOMMENDED
1	*REVENUES:*					
2	Network Transmission Serv & Other Revenue	$ 17,530,656	$ -	$ 17,530,656	$ 3,666,668	$ 21,197,324
	Point-to-Point Revenues	7,617,540	-	7,617,540		$ 7,617,540
3	Regulatory Asset Charge	-	-	-	-	-
4	Total Electric Transmission Revenue	$ 25,148,196	$ -	$ 25,148,196	$ 3,666,668	$ 28,814,864
5	*EXPENSES:*					
6	Energy	$ 2,541,334	$ -	$ 2,541,334	$ -	$ 2,541,334
7	Transmission	7,535,913	-	7,535,913	-	7,535,913
8	Administrative and General	3,730,586	-	3,730,586	-	3,730,586
9	Maintenance	2,429,390	-	2,429,390	-	2,429,390
10	Maintenance - General Plant	79	-	79	-	79
11	Depreciation and Amortization	6,852,107	(2,707,122)	4,144,985	-	4,144,985
12	ACC Gross Revenue Taxes	-	-	-	-	-
13	Property Taxes	2,285,845	-	2,285,845	-	2,285,845
14	Income Taxes	-	-	-	-	-
15	**Total Operating Expenses**	$ 25,375,254	$ (2,707,122)	$ 22,668,132	$ -	$ 22,668,132
16	**Operating Margin Before Interest on L.T.- Debt**	$ (227,058)	$ 2,707,122	$ 2,480,064	$ 3,666,668	$ 6,146,732
17	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***					
18	Interest on Long-term Debt	$ 5,302,088	$ -	$ 5,302,088	$ -	$ 5,302,088
19	Other Interest & Other Dedcutions	232,030	-	232,030	-	232,030
20	**Total Interest & Other Deductions**	$ 5,534,118	$ -	$ 5,534,118	$ -	$ 5,534,118
21	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (5,761,176)	$ 2,707,122	$ (3,054,054)	$ 3,666,668	$ 612,614
22	***NON-OPERATING MARGINS***					
23	Interest Income	$ 172,901	$ -	$ 172,901	$ -	$ 172,901
24	Other Non-operating Income	107,971	-	$ 107,971	$ -	$ 107,971
25	**Total Non-Operating Margins**	$ 280,872	$ -	$ 280,872	$ -	$ 280,872
26	***REGULATORY ASSET CHARGE***					
27	**Regulatory Asset Charge Revenue**	$ 2,559,926	$ -	$ 2,559,926	$ -	$ 2,559,926
28	**Regulatory Asset Amortization Expense**	$ -	$ 2,559,926	$ 2,559,926	$ -	$ 2,559,926
29	**Total Regulatory Asset Charge**	$ 2,559,926	$ (2,559,926)	$ 0	$ -	$ 0
30	***NET MARGINS (LOSS)***	$ (2,920,378)	$ 147,196	$ (2,773,182)	$ 3,666,668	$ 893,486

31 References:
32 Column (A): Brown Direct Testimony, Schedule CSB-9
33 Column (B): Surrebuttal Schedule CSB-4
34 Column (C): Column (A) + Column (B)
35 Column (D): Surrebuttal Schedules CSB-1
36 Column (E): Column (C) + Column (D)

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-4

TEST YEAR OPERATING INCOME - STAFF DIRECT AND SURREBUTTAL

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJ #1 Regulatory Asset Charge Revenue	[C] STAFF SURREBUTTAL
	REVENUES:		Ref: Surrebuttal Sch CSB-5	
1	Network Transmission Service	$ 13,104,192	$ -	$ 13,104,192
2	Point to Point	7,617,540	-	7,617,540
3	Total Electric Revenue	$ 20,721,732	$ -	$ 20,721,732
4	Load Dispatch and System Control	$ 2,824,224	$ -	$ 2,824,224
5	Direct Access Facilities	515,580	-	515,580
6	Regulatory Asset Charge	-	-	-
7	Other Operating Revenue	413,318	-	413,318
8	Ancilliary Services From AEPCO	-	-	-
9	Special Contracts	673,342	-	673,342
10	**Total Revenues**	$ 25,148,196	$ -	$ 25,148,196
	OPERATING EXPENSES:			
11	Energy	$ 2,541,334	$ -	$ 2,541,334
12	Transmission	7,535,913	-	7,535,913
13	Administrative and General	3,730,586	-	3,730,586
14	Maintenance	2,429,390	-	2,429,390
15	Maintenance - General Plant	79	-	79
16	Depreciation and Amortization	6,852,107	(2,707,122)	4,144,985
17	ACC Gross Revenue Taxes	-	-	-
18	Other Taxes	2,285,845	-	2,285,845
19	Income Taxes	-	-	-
20	**Total Operating Expenses**	$ 25,375,254	$ (2,707,122)	$ 22,668,132
21	**Operating Margin Before Interest on L.T.- Debt**	$ (227,058)	$ 2,707,122	$ 2,480,064
23	***INTEREST ON LONG-TERM DEBT & OTHER DEDUCTIONS***			
24	Interest on Long-term Debt	$ 5,302,088	$ -	$ 5,302,088
25	Other Interest & Other Dedcutions	232,030	-	232,030
26	**Total Interest & Other Deductions**	$ 5,534,118	$ -	$ 5,534,118
27	***MARGINS (LOSS) AFTER INTEREST EXPENSE***	$ (5,761,176)	$ 2,707,122	$ (3,054,054)
28	***NON-OPERATING MARGINS***			
29	Interest Income	$ 172,901	$ -	$ 172,901
30	Other Non-operating Income	107,971	-	107,971
31	**Total Non-Operating Margins**	$ 280,872	$ -	$ 280,872
32	***REGULATORY ASSET CHARGE***			
33	Regulatory Asset Charge Revenue	$ 2,559,926	$ -	$ 2,559,926
34	Regulatory Asset Amortization Expense	$ -	$ 2,559,926	$ 2,559,926
	Total Regulatory Asset Charge	$ 2,559,926	$ (2,559,926)	$ 0
33	***NET MARGINS (LOSS)***	$ (2,920,378)	$ 147,196	$ (2,773,182)

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule CSB-5

OPERATING INCOME ADJUSTMENT NO. 1 - REGULATORY ASSET CHARGE

LINE NO.	DESCRIPTION	[A] STAFF DIRECT	[B] ADJUSTMENTS	[C] STAFF SURREBUTTAL
1	Revenue	$ 25,148,196	$ -	$ 25,148,196
2	Regulatory Asset Charge	$ -	$ -	$ -
3	Total Revenue	$ 25,148,196	$ -	$ 25,148,196
4	Expense	$ 22,668,132	$ -	$ 22,668,132
5	Regulatory Asset Charge Amortization Exp	$ 2,707,122	$ (2,707,122)	$ -
6	Total Expenses	$ 25,375,254	$ (2,707,122)	$ 22,668,132
7	Operating Margin Before Interest	$ (227,058)	$ 2,707,122	$ 2,480,064
8	Total Interest	$ 5,534,118	$ -	$ 5,534,118
9	Margins After Interest Expense	$ (5,761,176)	$ 2,707,122	$ (3,054,054)
10	Non-Operating Margins	$ 280,872	$ -	$ 280,872
11	Normalized Regulatory Asset Charge Rev	$ 2,559,926	$ -	$ 2,559,926
12	Normalized Regulatory Asset Charge Amort Exp	$ -	$ 2,559,926	$ 2,559,926
13	Net Margin	$ (2,920,378)	$ 147,196	$ (2,773,182)

CALCULATION OF NORMALIZED REGULATORY ASSET CHARGE

	DESCRIPTION	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
13		Total kWhs		Total kWhs
14	Anza	44,660,813	-	44,660,813
15	Duncan	26,782,590	-	26,782,590
16	Graham	136,552,300	-	136,552,300
17	Mohave 1	611,433,890	-	611,433,890
18	Sulphur	662,992,990	-	662,992,990
19	TRICO (See Note Below)	437,521,797	-	437,521,797
20		1,919,944,380		1,919,944,380
21	Regulatory Asset Charge	$ 0.00141	$ (0.00008)	$ 0.00133
22	**Regulatory Asset Charge (L8 x L9)**	$ 2,707,122	(147,196)	$ 2,559,926

23			RAC
24			Decision No.62758
25		2004 RAC	$ 0.00137
26		2005 RAC	$ 0.00133
27	**Note:**	2006 RAC	$ 0.00130
28	The Cooperative filed 437,520,942 kWhs.		$ 0.00400
29	Staff used the Cooperative's actual kWhs	Divided by	3
30	of 437,521,797 to reconcile to the $2,707,122		$ 0.00133
31	in RAC revenue shown on Schedule C1, Page 3, Line 6		

32 References:
33 Column A: Direct Testimony, CSB
34 Column B: Surrebuttal Testimony, CSB
35 Column C: Column [A] + Column [B]

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A RATE INCREASE	DOCKET NO. E-01773A-04-0528

DIRECT

TESTIMONY

OF

JERRY D SMITH

ELECTRIC UTILITY ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

ALL-STATE LEGAL®
EXHIBIT
S-5
ADMITTED

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Engineering Report, Docket No. E-01773A-02-0112 ..... JDS-2

December 9, 2004 AEPCO Site Visit Report JDS-3

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE
DOCKET NO. E-01773A-04-0528

Arizona Electric Power Cooperative ("AEPCO") filed a rate application with the Arizona Corporation Commission ("ACC or Commission") on July 23, 2004. The 2003 calendar year was selected by AEPCO as its test-year for all rate making revenues, rate based utility plant, and operating expenses. This testimony solely concerns the rate based utility plant. AEPCO adjusted its 2003 rate based utility plant to include a coal blending facility constructed following the test-year but preceding its July 2004 rate application.

The justification of need for all AEPCO rate based utility plant constructed since October 2002 is addressed in this testimony. Commission witness, Jerry D. Smith, reaffirms the justification of need for such facilities established in prior Commission proceedings. His testimony concludes that all utility plant contained in AEPCO's rate application is used and useful.

WITNESS BACKGROUND AND QUALIFICATION

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

A. My name is Jerry D. Smith. I am an Electric Utility Engineer employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Briefly describe your responsibilities as an Electric Utility Engineer.

A. I joined the Commission's Utilities Division Staff as an electric engineer in 1999. In my capacity as an Electric Utility Engineer, I have investigated the quality of service provided by electric utilities in Arizona and been responsible for three biennial transmission assessments regarding the reliability of existing and planned Arizona transmission facilities. During my employment at the Commission, I have investigated numerous system disturbances on behalf of the Commission. A 1999 blackout of Southern Arizona, a 2001 blackout of Gila Bend, and several extra high voltage ("EHV") disturbances occurring in 2003 and 2004 are among the system disturbances I have investigated. My most recent investigations were of the Westwing and Deer Valley Substation fires.

I chaired a series of Commission Distributed Generation workshops in 1999 and have participated in the revision and application of electric retail competition rules throughout Arizona. I have also inspected physical electric utility plant consisting of generation, transmission and distribution facilities. Such facility inspections were necessary to make a "used and useful" determination for rate case applications and to ascertain the level of security, safety, operational integrity, and maintenance exhibited by such facilities.

Q. Please describe other pertinent work experience.

A. I have over 27 years of experience as an engineer and manager in the electric utility industry. I was employed by the Salt River Project from 1968 through 1995. During that time I: 1) analyzed and planned transmission and distribution system improvements; 2) managed the design and consultation services required for retail customer projects; and 3) served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities. I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation, modification and administration of new contribution in aid of construction charges and tariffs.

Q. Have you previously testified before this Commission?

A. Yes. I have extensive experience testifying before the Commission. I have testified on numerous occasions regarding quality of service to electric customers in the City of Nogales and Santa Cruz County. I was a Staff witness regarding the 2003 competitive wholesale power solicitations required by the Commission. I have provided testimony for over 35 power plant and transmission line applications for a Certificate of Environmental Compatibility. My experience filing engineering reports and providing testimony for the

Commission in rates cases is most applicable to this case. I have provided engineering reports and rate case testimony for Duncan Valley Electric Cooperative, Navapache Electric Cooperative, and the Arizona Public Service Company and an Open Access Transmission Tariff ("OATT") case for Southwest Transmission Cooperative.

PURPOSE AND PREPARATION OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I am providing testimony concerning the security, safety, operational integrity, and maintenance status of AEPCO's Apache Station power plant. My testimony considers both test-year facilities and *post* test-year facilities filed by the applicant for inclusion in this rate case. This testimony documents the justification of need previously considered by this Commission for all new *post* test-year capital improvements proposed for inclusion in the rate base by AEPCO. Finally my testimony determines to what degree the test-year and post test-year AEPCO facilities are "used and useful."

Q. How have you prepared for your testimony?

A. I have reviewed information on file, issued data requests to AEPCO, inspected AEPCO's Apache Station generating plant and talked with AEPCO, Southwest Transmission Cooperative ("SWTC") and Sierra Southwest Cooperative Services ("Sierra Southwest") personnel.

Q. When did you inspect AEPCO's facilities?

A. I inspected AEPCO's Apache Station and all on-site facilities appurtenant to the power plant during a December 9, 2004 site visit. A summary report of my findings is attached as Exhibit JS-3.

Q. What AEPCO, SWTC and Sierra Southwest personnel have you talked with concerning this docket?

A. I have talked with Mr. Dirk Minson, Chief Financial Officer; Mr. Gary Pierson, Financial Services Manager; Mr. Larry Huff, General Manager; Mr. Gary Grim, Transmission Engineering Manager; Mr. Mark Schwirtz, Plant Manager; and Mr. Charles Walling, Generation Engineering Manager.

Q. What documentation have you reviewed in preparing your testimony?

A. I have reviewed all rate application material filed by the applicant and numerous responses to Staff data requests. I also reviewed testimony and ACC engineering reports filed for two prior AEPCO power plant financing applications[1]. ACC engineering reports for the two respective financing cases are attached as Exhibit JS-1 and Exhibit JS-2.

Q. Is your testimony herein based upon the aforementioned facility site observations, conclusions drawn from review of available documentation, information gathered by talking with applicant personnel and your educational background and work experience as a utility professional?

A. Yes it is.

FACILITIES CONSIDERED IN TESTIMONY

Q. Have you reviewed AEPCO's application and testimony regarding facilities it proposes to include in rate base for this case?

A. Yes. I reviewed AEPCO's Schedule E-5 that provides a detailed account of utility plant. AEPCO witness, Mr. Dirk Minson's testimony indicates that the addition of a new

[1] Docket No. E-01773A-01-0701 and Docket No. E-01773A-02-0112.

Combustion Turbine Unit 4 ("CT4") in October 2002 and the addition of a coal blending facility are among the primary reasons for requesting a rate increase.

Q. What other facilities are considered in your testimony?

A. AEPCO's Schedule E-5 also includes other recent capital improvements contained in AEPCO's 2001-2004 Construction Work Plan. ACC Engineering Staff reviewed AEPCO's construction plans at the time of its 2001 and 2002 financing applications with this Commission. Those facilities include four key capital improvements:

1. Consolidation and upgrade of controls in a common control room for Apache Steam Turbine Units 1, 2 and 3,
2. A deluge fire protection system for Steam Turbine Units 2 and 3 cooling towers,
3. A new coal blending system, and
4. A deep well system upgrade to replace the well displaced by the new coal blending system.

The Combustion Turbine Unit 4 construction was completed in October of 2002. All of other capital improvements, with the exception of the coal blending system, were constructed in 2002 and 2003. The coal blending facility was completed in April of 2004.

JUSTIFICATION OF NEED FOR RECENT IMPROVEMENTS

Q. Briefly describe how AEPCO established with the Commission a justification of need for Combustion Turbine Unit 4.

A. AEPCO filed a financing application with the Commission in 2001 for funds to construct Combustion Turbine Unit 4.[2] Exhibit JS-1 is a copy of the Engineering Report filed by Staff in that case. That report offers numerous citations that document the need for the

[2] Docket No. E-01773A-01-0701.

new 38 Megawatt ("MW") generator. AEPCO's inability to meet its generating reserve requirements beginning in 2001 were first exposed to the Commission at an Energy Workshop held on February 16, 2001. The generator did not become operational until October 2002. This means APCO was deficient in generating reserves for a period of two years.

AEPCO provided further justification of need for the CT4 generator via Sections 8, 17, 18 and 19 of Rural Utility Service ("RUS") and Capital Financing Corporation ("CFC") financing materials. AEPCO filed those materials in support of its financing application with the Commission. ACC Staff concluded in an Engineering Report[3] that "AEPCO was pursuing the only option available to meet its short-term generation reserve requirements." The report also noted the $30 million estimated cost of the proposed project was consistent with costs of similar facilities constructed by others. The Commission approved the requested financing for this project.

Q. Briefly describe how AEPCO established with the Commission a justification of need for other recent major capital improvements.

A. AEPCO filed a financing application with the Commission in 2002 for funds to construct its other recent capital improvements.[4] Exhibit JS-2 is a copy of the Engineering Report filed by Staff in that case. The report determined that the proposed improvements would favorably impact the reliability, plant efficiency and operational economics of Apache Station. Upgrades of Apache Station controls would improve combustion efficiencies, reduce spare parts and increase unit reliability. Installing a fire deluge protection system for Steam Turbine Unit 2 and 3 cooling towers would reduce the risk of fires. The coal blending system would provide the capability to blend coal from three sources to achieve

[3] Exhibit JS-1.
[4] Docket No. E-01773A-02-0112.

an optimal fuel blend from both an economic performance and an emissions standpoint. The deep well system improvements were necessary to replace a well displaced by the coal blending project and gain access to the aquifer at a greater depth. ACC Engineering Staff found the proposed Apache Station improvements to be appropriate and necessary given the age and operational status of the existing facilities. Nevertheless, Staff deferred a "used and useful" determination until such time that AEPCO filed for a rate adjustment[5]. The Commission approved the requested financing authority for these capital improvement projects.

USED AND USEFUL DETERMINATION

Q. Please describe how you determined if all of the capital improvements addressed by your testimony were used and useful.

A. On December 9, 2004, I toured the Apache Station power plant. I observed all of the AEPCO capital improvements for which justification of need had been previously established with the Commission and for which the Commission had approved financing authority. Photos were taken to document my observations and are attached to the Engineering Report of the site visit. This report is attached as Exhibit JS-3.

Q. Please summarize your observations of the Apache Station facilities.

A. I observed each of the 7 generating units, the natural gas and coal fuel supply facilities, the power plant water facilities and the emergency equipment and supplies. The power plant complies with National Electric Safety Code ("NESC") security and safety requirements. All of the generating units were operational. All natural gas and coal facilities were observed to be operational and well maintained. The associated fuel was secure and safely managed. The new coal blending facilities appeared well designed and effectively

[5] Exhibit JS-2.

integrated into the pre-existing infrastructure. With the exception of an inactive ash pond, all plant water facilities were observed to be operational, in use and adequately maintained. The inactive ash pond is to be retired at some future date once financing is authorized.

During my tour of the plant, I observed that personnel seemed well trained to respond to both operational and emergency events. The improved control room SCADA equipment, operational controls, informational displays, computers, and communication equipment enabled operating personnel to quickly respond to a boiler feed pump problem while I toured the control room. The plant has appropriate and sufficient emergency medical and fire fighting equipment and sufficient supplies to effectively manage emergency events as well. Furthermore, the site is being managed with a primary focus on personnel safety and operational safety.

Q. Has Staff determined if the capital improvements made by AEPCO are "used and useful?"

A. Yes. All facilities observed during my December 9, 2004 tour of Apache Station were operational and well maintained. The inactive ash pond is planned for retirement. The new CT4 generator, new control room and controls for Steam Turbine Units 1, 2 and 3, the new coal blending facilities, the fire protection upgrades, and deep well system for plant water needs all appear well designed and constructed to comply with current industry standards. Therefore, the subject AEPCO power plant facilities are found to be used and useful.

SUMMARY OF TESTIMONY CONCLUSIONS

Q. Please summarize the conclusions of your testimony.

A. Utility plant improvements constructed by AEPCO between October 2002 and July 2004 were appropriate and necessary to maintain reliable, efficient and cost effective service to its members and the wholesale market. The justifications of need for such facilities were established before the Commission in prior proceedings. All utility plant contained in AEPCO's rate application is "used and useful" in supplying the energy needs of existing retail customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Memorandum

To: Jim Johnson, Auditor III, Utilities Division
From: Jerry D. Smith, Electric Utilities Engineer, Utilities Division
Thru: Del Smith, Engineering Supervisor, Utilities Division
Subject: AEPCO Financing Application, Docket No. E-01773A-01-0701
Date: October 2, 2001

Arizona Electric Power Cooperative ("AEPCO") filed an application on September 4, 2001, for authority to incur debt and secure liens on its property for the financing of a new Combustion Turbine Unit 4. AEPCO proposes to borrow an amount not to exceed $30 million from either the National Rural Utilities Cooperative Finance Cooperative and/or the Rural Utilities Service. Engineering Staff (Engineering) has reviewed the most recent AEPCO financing application and AEPCO's response to Commission Staff data requests. Engineering offers the following assessment.

AEPCO first documented its inability to meet it generating reserve requirements beginning in 2001 at the ACC Energy Workshop 2001-2002 held on February 16, 2001. The generating reserves deficiency is further substantiated by Section 8 of AEPCO's Fast Track A Materials for RUS/CFC. AEPCO has documented the need for the proposed 38 MW combustion turbine generator very effectively in Section 3 of the same RUS/CFC material. In fact, AEPCO documents that it was unable to arrange cost-effective purchase power alternatives from the new Calpine South Point Power plant or the new Griffith Power Plant because of their intent to sell only at the commodity price (spot market).

AEPCO also provided excellent documentation in Sections 17 and 18 of its RUS/CFC material of its fuel supply / delivery arrangements and its commitment to appropriate emission control technology. In Section 19, AEPCO documents the various transmission line constraints that impede its ability to purchase or deliver to others. Engineering concludes AEPCO is pursuing the only option available to meet its short-term generation reserve requirements. AEPCO's documentation serves as a good model of what Engineering would appreciate seeing in large power plant Certificate of Environmental Compatibility applications regarding project need, adequate and reliable transmission capacity and fuel supply / delivery capability.

Engineering finds no technical flaws in AEPCO's application for financing of a 38 MW combustion turbine generator. The cost estimate of the proposed project is consistent with cost of similar facilities constructed by others.

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JDS

CC: Steve Olea, Acting Director, Utilities Division
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Memorandum

To: Jim Johnson, Auditor III, Utilities Division
From: Jerry D. Smith, Electric Utilities Engineer, Utilities Division
Thru: Del Smith, Engineering Supervisor, Utilities Division
Subject: AEPCO Financing Application, Docket No. E-01773A-02-0112
Date: August 2, 2002

Arizona Electric Power Cooperative ("AEPCO") filed an application on February 11, 2002, for authority to incur debt and secure liens on its property for the financing of necessary improvements at the Apache Generating Station. AEPCO proposes to borrow interim funds not to exceed $30,588,576 from the National Rural Utilities Cooperative Finance Corporation ("CFC") and $26,764,000 to repay the interim CFC loan when permanent loan funds are available from the Rural Utilities Service ("RUS") guaranteed Federal Financing Bank ("FFB"). Engineering Staff ("Engineering") has reviewed the most recent AEPCO financing application and offers the following technical assessment.

Engineering has reviewed AEPCO's revised 2001-2004 Construction Work Plan filed with its financing application. The work plan contains all power plant related improvements for which the loan is requested. The bulk of the loan is for four key improvements as depicted in the table below:

Table 1: Summary of Work Plan

RUS 740c Code	Project Name	Amount
1200.4	Apache Controls Upgrades	6,896,380.
1200.7	ST2&3 CT Fire Protection Upgrade	1,064,330.
1200.11	Coal Blending System	9,952,618.
1200.27	Deep Well System Upgrades and Land Purchase	3,687,836.
	Other Miscellaneous Items	5,163,157.
	TOTAL	$26,764,321.

The improvements address reliability, plant efficiency and operational economics of the existing Apache Station. The Apache Controls Upgrades will improve combustion efficiency, reduce spare parts inventory and increase reliability. The Fire Protection Upgrade for ST2&3 cooling towers will reduce the risk of cooling tower fires by installing a deluge fire protection system to replace the existing inoperative fire protection system. The Coal Blending System will provide the capability to blend coal from three sources to achieve a fuel blend that is optimal from both a performance and an emission standpoint. The Deep Well System Upgrade establishes a new well to replace the deep well that will be displaced by the Coal Blending Facility and gives access to the aquifer at a greater depth.

The remaining $5 million of improvements result in fuel diversity and delivery capability, improved emissions performance, unit efficiency improvements, and safety improvements. Oil

burning capability for Combustion Turbine 2 is being re-established and a second fuel pipeline is being installed at the site to deliver fuel, backing up the gas obtained via El Paso Natural Gas under a full requirements contract. Coupling these improvements with the Coal Blending Facility assures AEPCO greater flexibility in negotiating fuel and delivery contracts to assure a reliable supply of fuel. This added flexibility is particularly of value in the existing economic climate where gas has been curtailed and is being reallocated on the El Paso pipeline. Many of the efficiency and emission improvements are likely to be viewed favorably during the air permitting process for the new Combustion Turbine 4 project which is not included in this loan package.

The Apache Station site has been experiencing uniform subsidence accompanied by some fissures at the periphery of the site. Similarly, the local aquifer is being depleted and the water table has been dropping at a rate of approximately 4-5 feet annually for the last five years. AEPCO indicates that neither of these conditions is unusual or problematic for the plant. Nevertheless, water and subsidence monitoring systems are in place.

Conclusion

Engineering finds the power plant improvements proposed for Apache Station in AEPCO's financing application to be appropriate and necessary given the age and operational status of the facilities. The cost estimates of the proposed projects are reasonable and are consistent with cost of similar facility improvements made by others in the power plant industry. However, Engineering defers judgement of all proposed improvements as "used and useful" until such time that AEPCO applies for a rate adjustment. A more thorough review of facilities will be undertaken at that time.

~~~

JDS

CC: Steve Olea, Assistant Director, Utilities Division
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Memorandum

Date: February 11, 2005
To: File
From: Jerry D. Smith, Electric Utility Engineer
Subject: AEPCO Site Visit – December 9, 2004
Docket No. E-01773A-04-0528

I visited with Arizona Electric Power Cooperative ("AEPCO") and Southwest Transmission Cooperative ("SWTC") personnel on December 9, 2004. The purpose of the visit was to tour the Apache Power Plant, the Apache Substation, the new Winchester Substation, and a new Apache to Winchester 230 kV line to ascertain the operational status of new capital improvements contained in financing and rate application cases pending before the Arizona Corporation Commission ("ACC" or "Commission"). Gary Grim served as my host throughout the entire visit. We were joined by Mark Schwirtz and Charles Walling for the Apache Power Plant segment of the tour.

The following documents my observations of AEPCO's generation facilities during the site visit. It documents safety, security, and operation of the Apache Power Plant, new control room, coal blending facilities, new combustion turbine unit 4, ash ponds and fire protection equipment. Photos taken during this visit are attached as exhibits to document what was observed in the field regarding the subject power plant facilities.

Apache Station

The Apache Station power plant is located on highway 191 approximately 10 miles south of its intersection with the I-10 interstate highway. The entrance to the power plant is depicted in Figure 1 of Exhibit 1. The same figure depicts the three steam turbine units. Steam Turbine Unit 1, Combustion Turbine Unit 3 and the new Combustion Turbine Unit 4 are depicted respectively in Figures 3 through 6. Security personnel maintain security and access to the plant site on a twenty four hours per day basis. Figure 2 depicts the location of security personnel at the entrance gate. The entire site has perimeter chain link fencing topped with barbed wiring. The chain-link fence is 8 feet in height, the plant entrance gate is properly secured, and proper signage is displayed in both English and Spanish as observed in Figure 2. These power plant security features comply with National Electric Safety Code ("NESC") requirements.

Fuel Supply Facilities

Exhibit 2 contains photos depicting facilities that supply fuel for the various Apache Station generators. Figures 7 and 8 provide views of the natural gas facilities. The natural gas substation depicted in Figure 7 is properly enclosed by a chain link fence and the substation site is secured with a locked gate. The natural gas pipeline, owned and operated by El Paso Gas, is located to the south of the plant site and gas substation and runs in both an easterly and westerly direction. The pipeline corridor east of the plant is depicted in Figure 8.

Figures 9 through 12 depict the on-site coal facilities. The plant's coal stockpile is depicted in Figure 9 while the railcar coal dump conveyors and fuel blending facilities are depicted in Figure 10. The conveyors

for moving the blended coal to the respective generating units are depicted in Figure 11. The new coal blending addition is depicted in Figure 12.
All natural gas and coal facilities were observed to be operational and well maintained. The associated fuel was secure and safely managed. The new coal blending facilities were well designed, were effectively integrated into the pre-existing infrastructure and are operational, and well maintained.

Plant Water Facilities

Exhibit 3 depicts all of the major water facilities appurtenant to operation of a power plant. Figure 13 depicts a combustion waste disposal facility ("CWDF") or cooling water evaporation pond constructed north of the plant site in 1995. Meanwhile, Figure 14 shows the location of the old inactive CWDF or ash pond east of the plant site. Cooling towers in operation and use for the plant are depicted in Figures 15 through 17. A water supply tank and tower is also depicted in Figure 15. With the exception of the inactive ash pond, all water facilities were observed to be operational, in use and adequately maintained.

Emergency Readiness

Apache Station has a trained and certified emergency response team that can attend to medical emergencies, chemical spills or fires. The photos contained in Exhibit 4 depict facilities that enable effective on-site emergency and operational responses. The fire station depicted in Figure 17 stores all emergency vehicles and supplies. Emergency vehicles depicted in Figure 18 include a fire truck, a hazardous response truck, and a medical evacuation van. Figure 19 documents an ample supply of F-500 fire retardant stored in the fire house for use with electric fires. Fire fighting water is available from three sources: the water tower depicted in Figure 15, the well house containing a water feed pump depicted in Figure 20 or the Fire Truck storage tank.

Personnel operating and maintaining the power plant also exhibited an attention to details that is also indicative of their emergency readiness. The new control room for steam turbine units 1, 2 and 3 is depicted in Figure 21. While touring the control room I observed operating personnel respond to a boiler feed pump problem that tripped unit 3. The personnel appeared properly trained in responding to the event. Necessary Supervisory Control And Data Acquisition ("SCADA"), controls, informational displays, computers and communication equipment were available to enable other units to be timely ramped up in response to loss of unit 3.

It was evident that the lessons learned by the Westwing transformer fires of July 4, 2004 were being applied at this plant site. Figures 22 and 23 depict the step-up transformers that connect steam turbine units 1 and 2 to the Apache Substation. These transformers have foundations setting in a cement oil spill cache basin. The basins were clean and maintenance personnel were replacing soil containing combustible coal dust with new soil and gravel around the transformer foundations.

During tour of the plant facilities I observed that personnel are properly trained to respond to operational or emergency events. They have appropriate and sufficient equipment and supplies to effectively manage such events. Furthermore, the site is being maintained with a focus on personnel and operational safety as a priority.

Conclusions

Personnel were well trained and demonstrated operational safety and personnel safety were a priority. With the exception of the inactive ash pond, all facilities observed during the December 9, 2004 tour of AEPCO's Apache Station were operational and well maintained. The inactive ash pond is planned for retirement. The new Combustion Turbine Unit 3, new control room and controls for Steam Turbine Units 1, 2 and 3, the new coal blending facilities, the Fire Protection upgrades, and deep wells for power plant water needs all appear to be designed and constructed to comply with industry standards. Therefore, I conclude the subject AEPCO power plant facilities are "used and useful."

JDS/rdp

Attachment: Exhibits 1-4
cc: Ernest Johnson, Utilities Director
Steve Olea, Assistant Utilities Director
Del Smith, Engineering Supervisor

EXHIBIT 1
Apache Station Power Plant

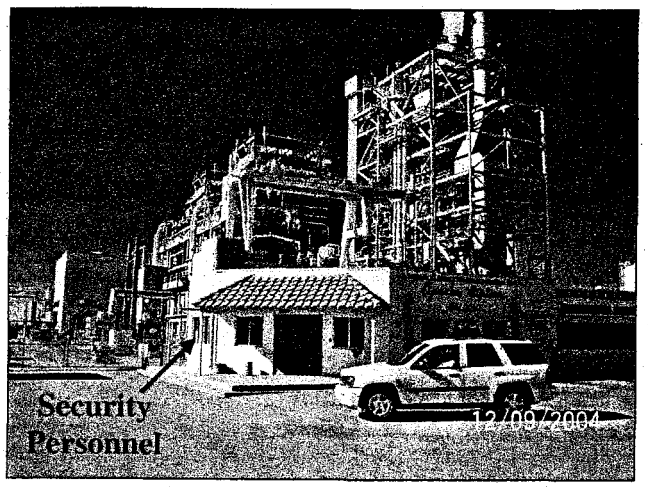

Figure 1. Site Entrance

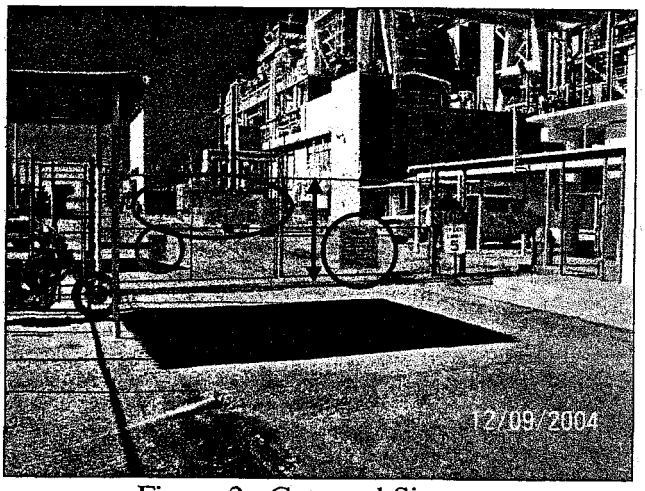

Figure 2. Gate and Signage

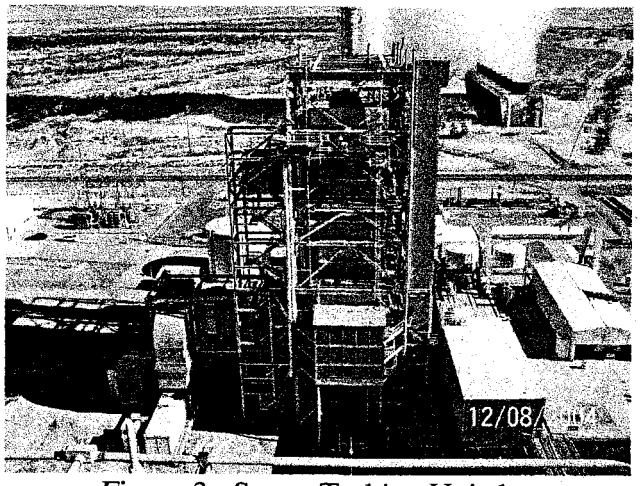
Figure 3. Steam Turbine Unit 1

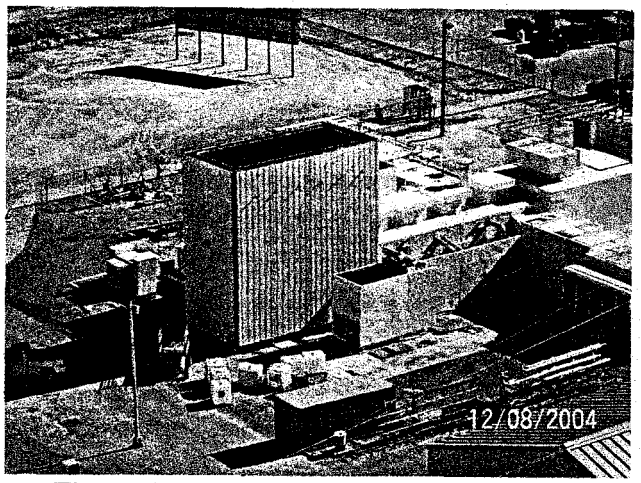

Figure 4. Combustion Turbine Unit 3

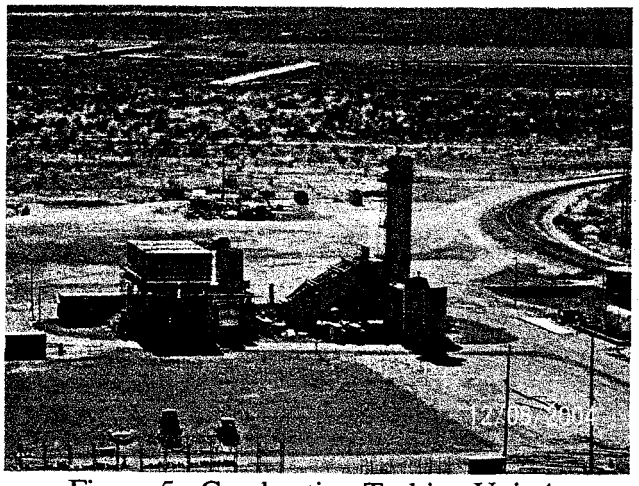
Figure 5. Combustion Turbine Unit 4

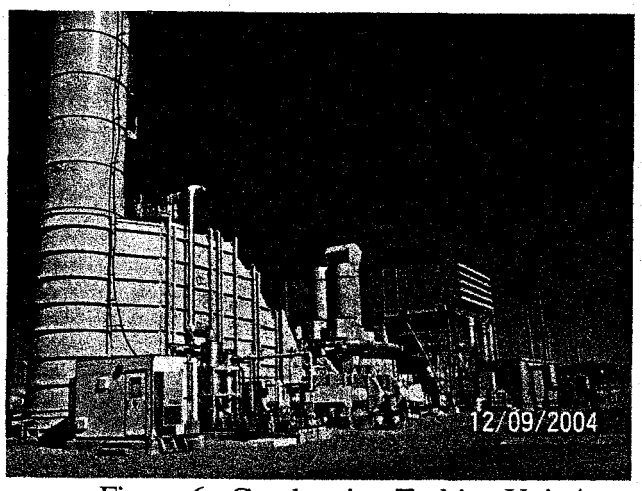

Figure 6. Combustion Turbine Unit 4

EXHIBIT 2
Fuel Supply Facilities

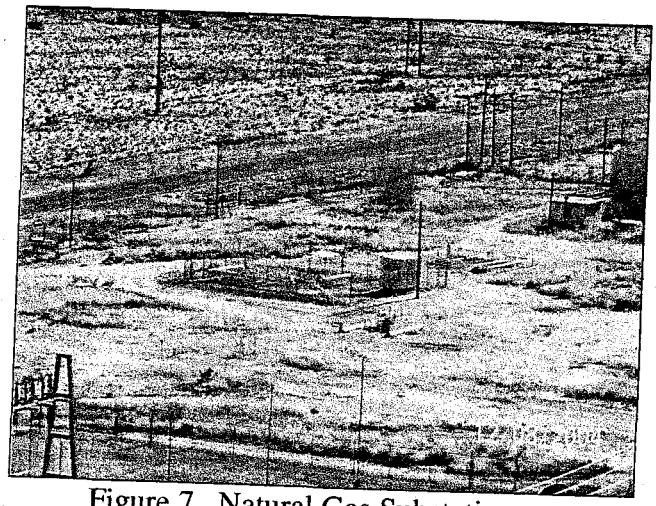

Figure 7. Natural Gas Substation

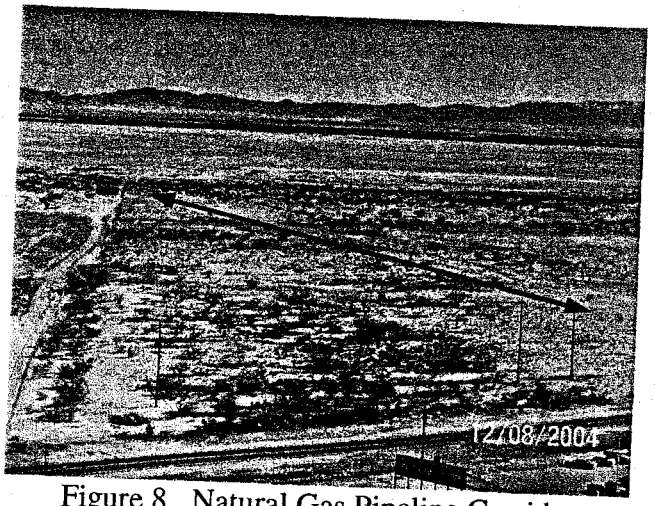

Figure 8. Natural Gas Pipeline Corridor

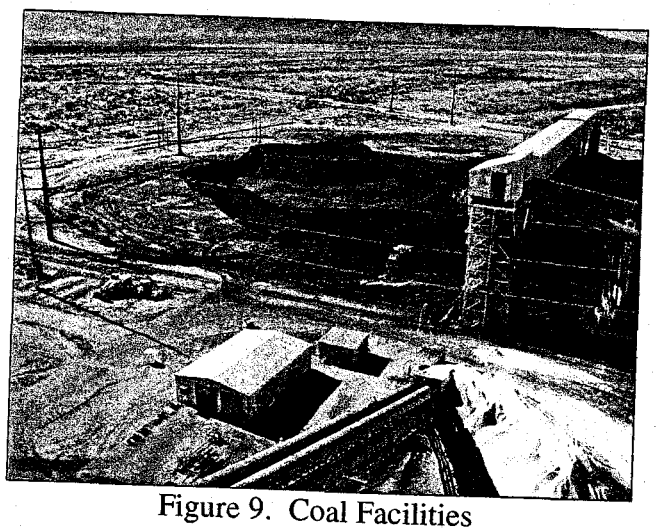

Figure 9. Coal Facilities

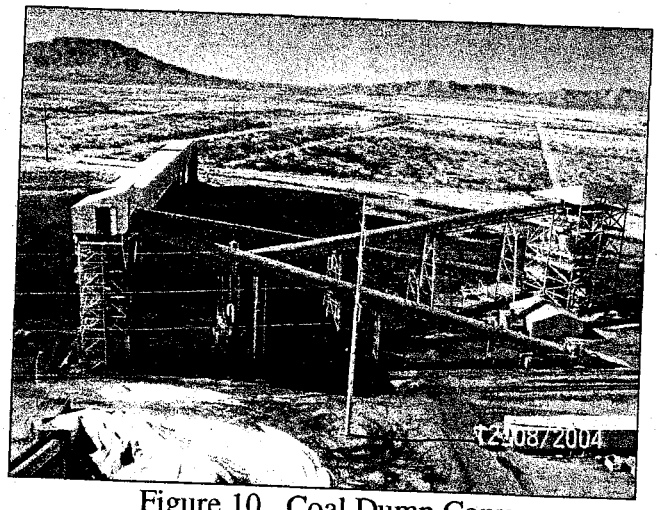

Figure 10. Coal Dump Conveyors

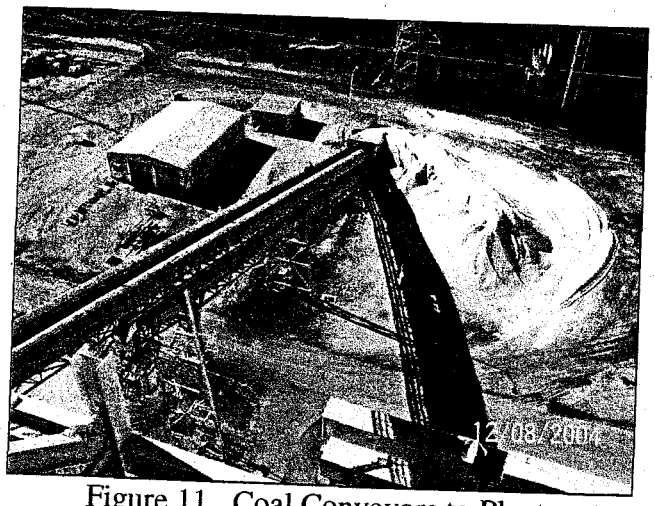

Figure 11. Coal Conveyors to Plant

Figure 12. Coal Blending Facilities

EXHIBIT 3
Water Facilities

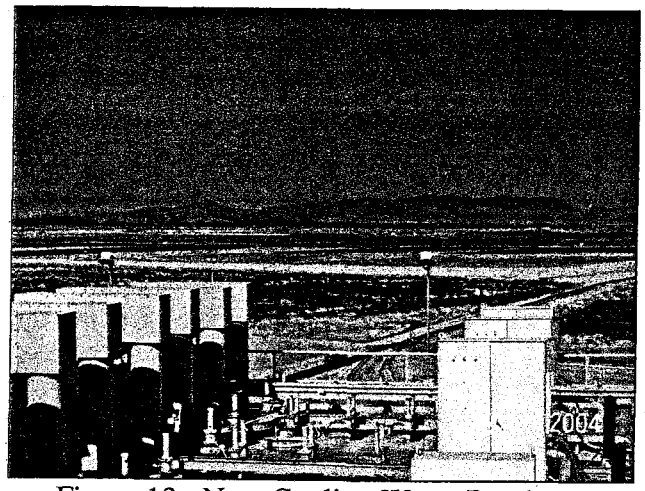

Figure 13. New Cooling Water Ponds

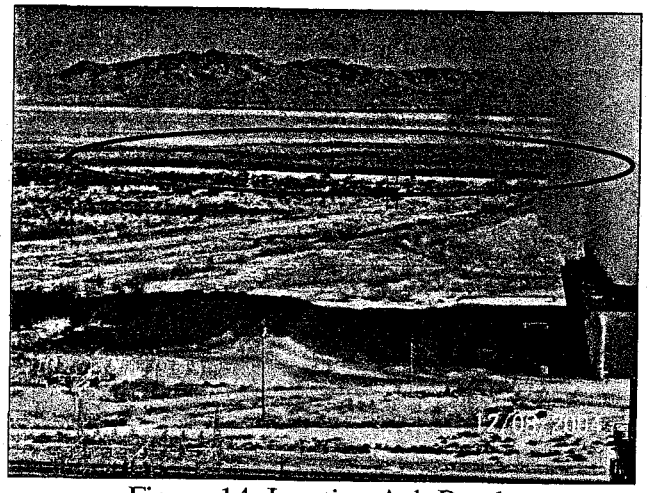

Figure 14. Inactive Ash Pond

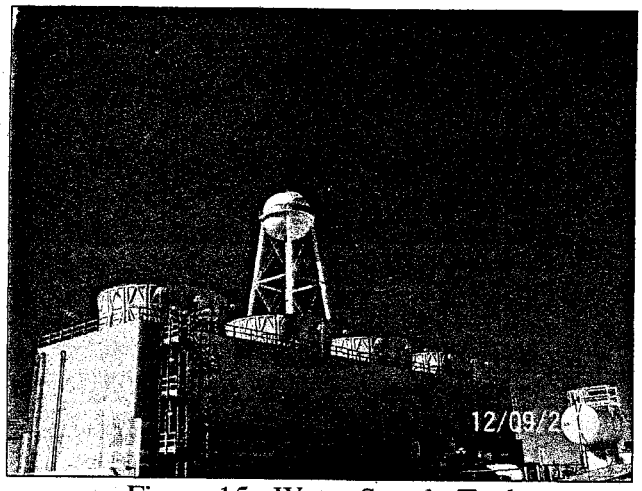

Figure 15. Water Supply Tank

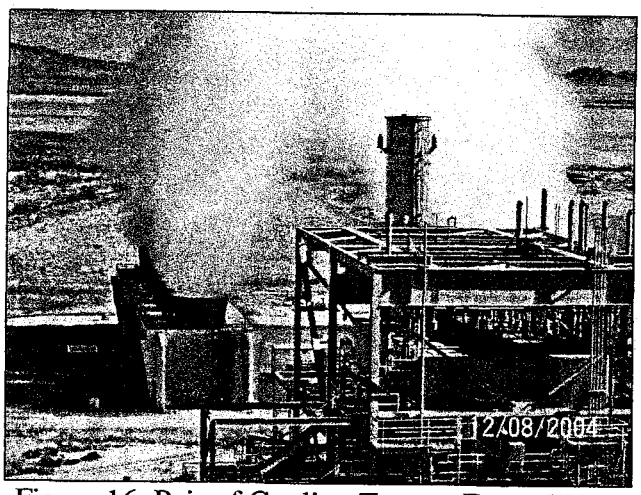

Figure 16. Pair of Cooling Towers East of Plant

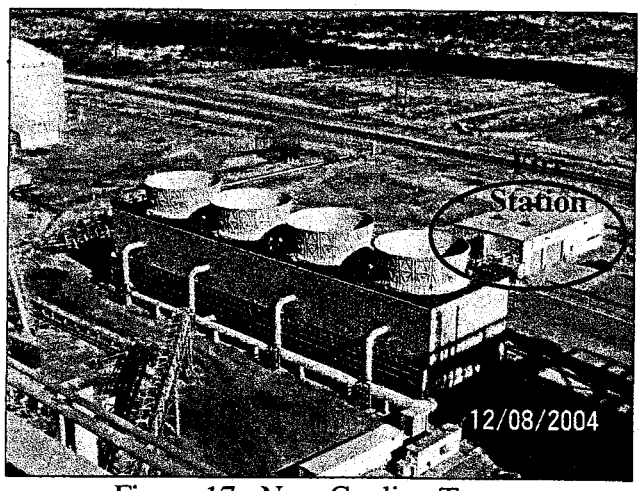

Figure 17. New Cooling Tower

EXHIBIT 4
Emergency and Fire Fighting Facilities

Figure 18. Fire Truck / Emergency Vehicles

Figure 19. F-500 Fire Retardant

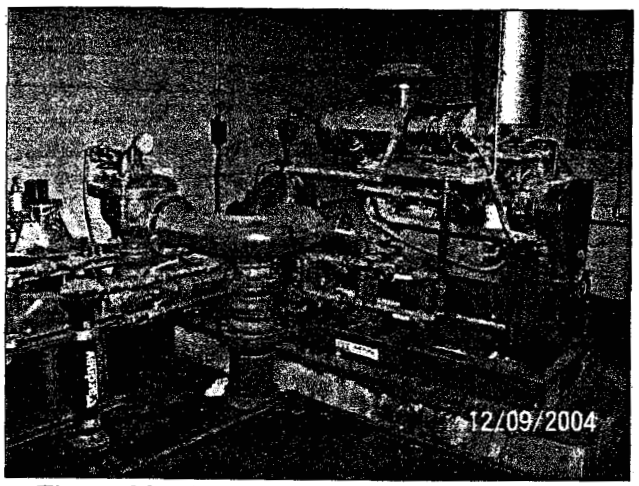

Figure 20. Fire Fighting Water Feed Pumps

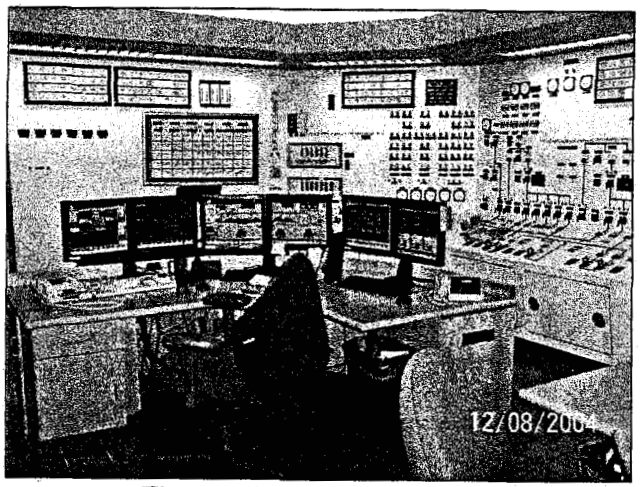

Figure 21. Control Room

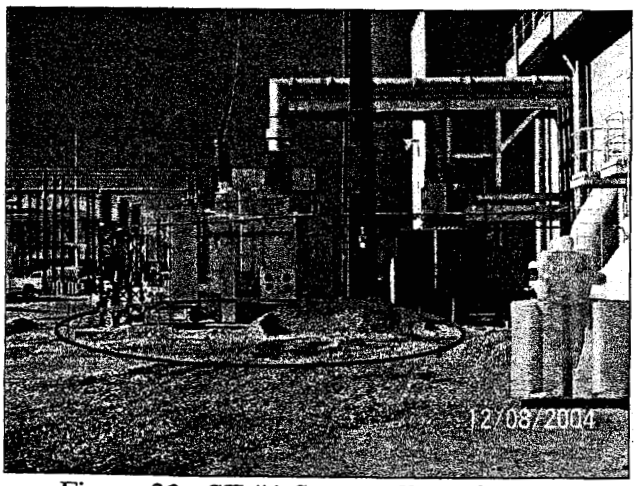

Figure 22. ST #1 Step-up Transformer

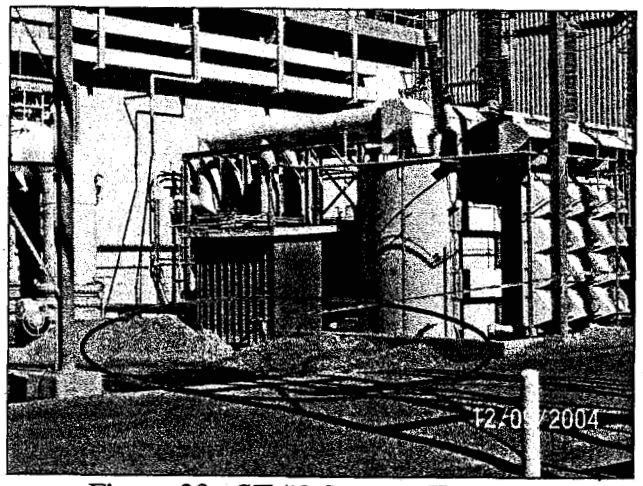

Figure 23. ST #2 Step-up Transformer

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE	))))	DOCKET NO. E-01773A-04-0527

DIRECT

TESTIMONY

OF

JERRY D SMITH

ELECTRIC UTILITY ENGINEER

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

ALL-STATE LEGAL®
EXHIBIT
S-6
ADMITTED

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December 9, 2004 SWTC Site Visit Report JDS-2

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE
DOCKET NO. E-01773A-04-0528

Southwest Transmission Cooperative ("SWTC") filed a rate application with the Arizona Corporation Commission ("ACC or Commission") on July 23, 2004. The 2003 calendar year was selected by SWTC as its test-year for all rate making revenues, rate based utility plant, and operating expenses. This testimony solely concerns the rate based utility plant. SWTC adjusted its 2003 rate based utility plant to include a Winchester Transmission Project constructed following the test-year but preceding its July 2004 rate application.

The justification of need for all SWTC rate based utility plant constructed since October 2002 is addressed in this testimony. Commission witness, Jerry D. Smith, reaffirms the justification of need for such facilities established in prior Commission proceedings. His testimony concludes that all utility plant contained in SWTC's rate application is used and useful.

WITNESS BACKGROUND AND QUALIFICATIONS

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

A. My name is Jerry D. Smith. I am an Electric Utility Engineer employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Please describe your educational background.

A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science degree in Electrical Engineering. I received a Masters of Science degree in Electrical Engineering from New Mexico State University in 1977 majoring in power systems and electric utility management.

Q. Do you hold any special licenses or certificates?

A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

Q. Briefly describe your responsibilities as an Electric Utility Engineer.

A. I joined the Commission's Utilities Division Staff as an electric engineer in 1999. In my capacity as an Electric Utility Engineer, I have investigated the quality of service provided by electric utilities in Arizona and been responsible for three biennial transmission assessments regarding the reliability of existing and planned Arizona transmission facilities. During my employment at the Commission, I have investigated numerous system disturbances on behalf of the Commission. A 1999 blackout of Southern Arizona, a 2001 blackout of Gila Bend, and several extra high voltage ("EHV") disturbances occurring in 2003 and 2004 are among the system disturbances I have investigated. My most recent investigations were of the Westwing and Deer Valley Substation fires.

I chaired a series of Commission Distributed Generation workshops in 1999 and have participated in the revision and application of electric retail competition rules throughout Arizona. I have also inspected physical electric utility plant consisting of generation, transmission and distribution facilities. Such facility inspections were necessary to make a "used and useful" determination for rate case applications and to ascertain the level of security, safety, operational integrity, and maintenance exhibited by such facilities.

Q. Please describe other pertinent work experience.

A. I have over 27 years of experience as an engineer and manager in the electric utility industry. I was employed by the Salt River Project from 1968 through 1995. During that time I: 1) analyzed and planned transmission and distribution system improvements; 2) managed the design and consultation services required for retail customer projects; and 3) served as primary contact for local municipalities regarding siting of facilities and utilizing funds for aesthetic treatment of water and power facilities. I also performed ancillary functions such as development and management of capital improvement budgets; formation and modification of system planning, operational and maintenance policies, procedures and practices; and creation, modification and administration of new contribution in aid of construction charges and tariffs.

Q. Have you previously testified before this Commission?

A. Yes. I have extensive experience testifying before the Commission. I have testified on numerous occasions regarding quality of service to electric customers in the City of Nogales and Santa Cruz County. I was a Staff witness regarding the 2003 competitive wholesale power solicitations required by the Commission. I have provided testimony for over 35 power plant and transmission line applications for a Certificate of Environmental Compatibility. My experience filing engineering reports and providing testimony for the

Commission in rates cases is most applicable to this case. I have provided engineering reports and rate case testimony for Duncan Valley Electric Cooperative, Navapache Electric Cooperative, and the Arizona Public Service Company and an Open Access Transmission Tariff ("OATT") case for Southwest Transmission Cooperative ("SWTC").

PURPOSE AND PREPARATION OF TESTIMONY

Q. What is the purpose of your testimony in this case?

A. I am providing Staff's testimony concerning the security, safety, operational integrity, and maintenance status of SWTC's transmission facilities. My testimony considers both test-year facilities and *post* test-year facilities filed by the applicant for inclusion in this rate case. This testimony documents the justification of need previously considered by this Commission for all new *post* test-year capital improvements proposed for inclusion in the rate base by SWTC. Finally my testimony determines to what degree the test-year and post test-year SWTC facilities are "used and useful."

Q. How have you prepared for your testimony?

A. I have reviewed information on file, issued data requests to SWTC, inspected SWTC's Winchester Transmission Project facilities and talked with SWTC, Arizona Electric Power Cooperative ("AEPCO") and Sierra Southwest Cooperative Services ("Sierra Southwest") personnel.

Q. When did you inspect AEPCO's facilities?

A. I inspected SWTC's utility plant during a December 9, 2004 site visit of the Apache Substation, Winchester Substation and the new 230 kV line between the two substations. A summary report of my findings is attached as Exhibit JS-2.

Q. What AEPCO, SWTC and Sierra Southwest personnel have you talked with concerning this docket?

A. I have talked with Mr. Dirk Minson, Chief Financial Officer; Mr. Gary Pierson, Financial Services Manager; Mr. Larry Huff, General Manager; and Mr. Gary Grim, Transmission Engineering Manager.

Q. What documentation have you reviewed in preparing your testimony?

A. I have reviewed all rate application material filed by the applicant and numerous responses to Staff data requests. I also reviewed testimony and ACC engineering reports filed for a 2002 SWTC financing application,[1] the Winchester Transmission Project line siting case[2], and the Commission's three Biennial Transmission Assessments. The ACC engineering report for the financing case is attached as Exhibit JS-1 and the report for my tour of the Winchester Transmission Project is attached as Exhibit JS-2.

Q. Is your testimony herein based upon the aforementioned facility site observations, conclusions drawn from review of available documentation, information gathered by talking with applicant personnel and your educational background and work experience as a utility professional?

A. Yes it is.

FACILITIES CONSIDERED IN TESTIMONY

Q. Have you reviewed AEPCO's application and testimony regarding facilities it proposes to include in rate base for this case?

A. Yes. I reviewed SWTC's Schedule E-5 that provides a detailed account of its utility plant. SWTC witness, Mr. Dirk Minson's testimony indicates that the addition of a new

[1] Docket No. E-01773A-02-0261.
[2] Docket No. L-00000C-03-0121.

Winchester Transmission Project completed in May of 2004 is chief among the transmission system maintenance and upgrades necessitating a rate increase.

Q. What other facilities are considered in your testimony?

A. SWTC's Schedule E-5 also includes other capital improvements contained in SWTC's 2001-2004 Construction Work Plan. These construction plans were reviewed by ACC Engineering Staff at the time of SWTC's 2002 financing application with this Commission. Those facilities fell into three key capital improvements categories:

1. New substations and substation transformer additions for member distribution cooperatives, accompanied by appurtenant communication and Supervisory Control and Data Acquisition ("SCADA") equipment and transmission line improvements,
2. Routine line and transmission substation changes, and
3. The Winchester 230 kV Transmission Project.

The Winchester Transmission Project was completed in May of 2004. SWTC made a *post* test-year adjustment to include the Winchester Project in its rate base. All other capital improvements were constructed in 2002 and 2003.

JUSTIFICATION OF NEED FOR RECENT IMPROVEMENTS

Q. Briefly describe how SWTC established with the Commission a justification of need for the recent improvements.

A. On June 22, 1999 a SWTC 230 kV transmission line outage, caused by a fire, interrupted service to most communities in Southern Arizona. The outage resulting in tripping the Apache Station power plant and numerous transmission lines interconnected at the Apache Substation. This cascading event occurred because of insufficient area transmission

capacity due to another SWTC line being out of service for planned maintenance and repair when the event occurred. The Commission held a special open meeting on August 19, 1999 to consider the cause and effects of this event.[3] The Commission's Second Biennial Transmission Assessment[4] documented that SWTC planned a Winchester Project to enhance its transmission system reliability, mitigate transmission line overloads for single contingency outages and reduce the need for remedial action schemes during multiple contingency outages.

The need for the Winchester Project was also documented in SWTC's 2001-2004 Construction Work Plan. SWTC filed the work plan in support of their 2002 financing application with the Commission. Exhibit JS-1 is a copy of the Engineering Report filed by Staff in that case. Staff's report reaffirmed the need for SWTC's Winchester Project.[5]

SWTC provided further justification of need for the Winchester Project in its transmission line siting case in 2003.[6] During those proceedings testimony established that the proposed project would help accommodate the Combustion Turbine Unit 4 addition at Apache Station. Testimony also reaffirmed that the project would help mitigate the cause and effects of the 1999 blackout in Southern Arizona, solve local transmission overloads and provide SWTC a 345 kV interconnection for transmission transactions. The ACC approved the Certificate of Environmental Compatibility ("CEC") for the project on May 16, 2003 after balancing the need for the line against its likely environmental impact.

[3] E-00000A-01-0120.
[4] Docket No. E-00000D-02-0065.
[5] Exhibit JS-1
[6] Docket No. L-00000C-03-0121.

USED AND USEFUL DETERMINATION

Q. Please describe how you determined if the Winchester Project was used and useful.

A. On December 9, 2004, I toured the SWTC Winchester Project. I observed all of the associated capital improvements at Apache Substation, the new Winchester Substation, and the new transmission line between the two substations. Photos were taken to document my observations and are attached to the Engineering Report of the site visit. This report is attached as Exhibit JS-2.

Q. Please summarize your observations of the Winchester Project.

A. All transmission facilities observed during the December 9, 2004 tour of SWTC facilities were operational, designed and constructed to comply with National Electric Safety Code ("NESC") requirements. Both the Apache Substation and the Winchester substations were secure regarding public access and displayed proper safety warnings. The pre-existing Apache Substation transmission facilities were well maintained and the new 230 kV and 345 kV lines and associated equipment were designed and constructed in accordance with current NESC and the Institute of Electrical and Electronic Engineers ("IEEE") standards.

Q. Has Staff determined if the capital improvements made by SWTC are "used and useful?"

A. Yes. All the transmission facilities I observed during my December 9, 2004 tour of Apache Substation, Winchester Substation and the new transmission lines between the two substations were operational and well maintained. Therefore, Staff concludes the SWTC transmission facilities are used and useful.

SUMMARY OF TESTIMONY CONCLUSIONS

Q. Please summarize the conclusions of your testimony.

A. Utility plant improvements constructed by SWTC between January 2003 and July 2004 were appropriate and necessary to maintain reliable, efficient and cost effective service to its members and the wholesale market. The justifications of need for such facilities were established before the Commission in prior proceedings. All utility plant contained in SWTC's rate application is "used and useful" in reliably delivering the energy needs of existing retail customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Memorandum

To: Jim Johnson, Auditor III, Utilities Division
From: Jerry D. Smith, Electric Utilities Engineer, Utilities Division
Thru: Del Smith, Engineering Supervisor, Utilities Division
Subject: Southwest Transmission Coop. Financing Application, Docket No. E-01773A-02-0261
Date: August 2, 2002

Southwest Transmission Cooperative ("TRANSCO") filed an application on April 4, 2002, for authority to incur debt and secure liens on its property for the financing of necessary improvements to its transmission system. TRANSCO proposes to borrow funds not to exceed $30,853,000 from the Rural Utilities Service ("RUS") guaranteed Federal Financing Bank ("FFB"). Engineering Staff ("Engineering") has reviewed the TRANSCO financing application and offers the following technical assessment.

Engineering has reviewed TRANSCO's revised 2001-2004 Construction Work Plan filed with its financing application. The work plan contains all capital improvements upon which the loan is based. A summary of the proposed work is provided in Table 1.

Table 1: Summary of Work Plan

RUS 740c Code	Construction Category	Amount
800	Transmission Lines	9,890,000.
900	New Substations, Switching Stations	9,841,683.
1000	Line and Station Changes	7,181,690.
1101	Communication/Supervisory Control And Data Acquisition	2,083,491.
1102	Ordinary Line and Substation Replacement	1,857,060.
	TOTAL	$30,853,924.

One major project, the Winchester Project, represents approximately $21 million in the work plan. This project is an exception to TRANSCO's normal work plan. The project consists of replacing 23 miles of Apache to Hayden 115 kV transmission line with a double circuit 230 kV and 115 kV line. The new 230 kV line connects Apache Substation with a new Winchester 345 kV Substation on TEP's 345 kV Greenlee to Vail transmission line.

The Winchester project is needed to resolve system overloads for single contingency outages. The project will also decrease TRANSCO's need for remedial action schemes ("RAS") for multiple contingency outages. The project provides TRANSCO a third transmission interconnection point to the Arizona Extra High Voltage ("EHV") System. The project is expected to increase TRANSCO's import/export capability by approximately 400 MW. TRANSCO filed with the Commission a copy of a report entitled "Winchester Interconnect Project Report" with it ten-year plans in January 2002.

The project has also been modeled and studied as part of the Central Arizona Study ("CATS").

The remaining approximately $10 million of the work plan consists of routine and customary improvements. New substation and substation transformers for TRANSCO's member Distribution Cooperatives represents approximately $6 million and the remaining $4 million is for Communication and Supervisory Control And Data Acquisition ("SCADA") improvements and Ordinary Replacements. Need for the new substations and transformers for member Distribution Cooperatives was validated this summer when Trico experienced substation transformer overloads that resulted in several consecutive days of customer outages. Several of the proposed transformer additions are slated for Trico's service area.

Conclusions

Engineering finds the capital improvements proposed in TRANSCO's financing application to be appropriate and necessary for reliable operation of its system. TRANSCO has complied with its requirements to file transmission plans for the next ten years with the Commission by the end of January of each year. The most recent filing properly included technical studies supporting the planned transmission improvements. Cost estimates of the proposed projects are reasonable and are typical of cost for similar facility improvements made by other transmission providers. However, Engineering defers judgement of all proposed improvements as "used and useful" until such time that TRANSCO applies for a rate adjustment. A more thorough review of transmission facilities will be undertaken at that time.

~~~

JDS

CC: Steve Olea, Assistant Director, Utilities Division
~~~

Memorandum

Date: February 11, 2005
To: File
From: Jerry D. Smith, Electric Utility Engineer
Subject: SWTC Site Visit – December 9, 2004
Docket No. E-04100A-04-0527

I visited with Arizona Electric Power Cooperative ("AEPCO") and Southwest Transmission Cooperative ("SWTC") personnel on December 9, 2004. The purpose of the visit was to tour the Apache Power Plant, the Apache Substation, the new Winchester Substation, and a new Apache to Winchester 230 kV line to ascertain the operational status of new capital improvements contained in financing and rate application cases pending before the Arizona Corporation Commission ("ACC" or "Commission"). Gary Grim served as my host throughout the entire visit. We were joined by Mark Schwirtz and Charles Walling for the Apache Power Plant segment of the tour.

The following documents my observations of SWTC's transmission facilities during this site visit. It documents safety and security matters related to the Apache Substation and new Winchester Substation. It also documents the new 230 kV transmission line between the two substations. Photos taken during this visit are attached as exhibits to document what was observed in the field regarding the subject transmission facilities. Exhibit 1 identifies the locations where photos were taken and an orientation to the direction of view for the various photos.

Apache Substation

The Apache Substation is located on a site in common with the Apache Power Plant and is enclosed within the perimeter fencing of the power plant. The substation consists of multiple switchyards operated at 230 kV, 115 kV and 69 kV. Exhibit 2 displays photos that depict various views of Apache Substation. The fence enclosing the substation is topped with barbed wiring and is depicted in Figure 2-1. The chain-link fence is 8 feet in height, the substation gate is properly secured with a lock, and proper signage is displayed in both English and Spanish as observed in Figures 2-1 and 2-2. These substation features comply with National Electric Safety Code ("NESC") requirements.

Figures 2-3 through 2-6 provide views of the substation taken from a walkway atop the Apache Power Plant. Figure 2-3 shows the Apache Steam Turbine Unit 3 step-up transformer and ties which terminate in the 230 kV switchyard. This photo further documents the location of the substation gate. Figure 2-4 depicts the 115 kV and 69 kV switchyards. A spare 115/69 kV transformer is located adjacent to the operational 115/69 kV transformer as depicted in Figure 2-5. The separation between these two transformers does not presently meet IEEE standards. However, addition of a second 115/69 kV transformer is needed within the next few years. At that time the spare transformer will be repositioned with the necessary separation from the existing transformer and then placed in service. The two 230/115 kV transformers depicted in Fire 2-6 are both operational and have sufficient space separation to meet the IEEE standards. No oil spill cache basins or firewalls are provided for these substation transformers. These switchyards were observed to be fully operational and equipment well maintained.

Winchester Substation

The Winchester Substation is located in Section 28 of Township 14S and Range 21E where two existing Tucson Electric Power Company's ("TEP") Greenlee to Vail 345 kV lines cross the existing SWTC Apache to Hayden 115 kV line. Construction of the substation was completed in the Spring of 2004. Exhibit 3 displays photos that depict various views of the new Winchester Substation

Winchester Substation consists of two switchyards operated at 345 kV and 230 kV as depicted in Figure 3-1. TEP owns and operates the 345 kV switchyard while SWTC owns and operates the 230 kV switchyard. The fence enclosing the entire substation is topped with barbed wiring and is depicted in Figures 3-1 through 3-3. The chain-link fence is 8 feet in height, the substation gate is properly secured with a lock, and proper signage is displayed in both English and Spanish as observed in Figure 3-2. These substation features comply with National Electric Safety Code ("NESC") requirements.

Figure 3-3 depicts the new 230 kV switchyard and associated 345/230 kV transformer. The nameplate placard attached to the transformer is portrayed in Figure 3-5 and indicates the transformer is rated at 420 Megavolt-amperes ("MVA"). The transformer foundation integrates a cement oil spill cache basin. The switchyard bays are laid out so that addition of a second transformer at some future date can be located such that sufficient space separation will exist between transformers to meet current IEEE standards. The control house depicted in Figure 3-4 was properly secured with a locked door and contained all communication equipment, supervisory control and data acquisition ("SCADA") equipment and protective relays necessary and appropriate for a new substation. The control house facilities, switchyard and all associated equipment were observed to be fully operational, well designed and exhibited a level of maintenance and repair typical of a new substation.

Apache to Winchester 230 kV Transmission Line

Exhibit 4 depicts the new Apache to Winchester 230 kV transmission line. It is approximately 23 miles in length and was constructed utilizing a pre-existing 115 kV transmission line corridor. It is constructed using steel monopole structures designed for two 230 kV circuits. One of the circuits is actually operated at 115 kV and replaces the pre-existing Apache to Hayden 115 kV line. At some future date the second circuit may be converted for operation at 230 kV. Construction of the line was completed in the Spring of 2004.

The route for this line is depicted in Exhibit 1. It egresses from the Apache Substation in a westerly direction for approximately 3miles. Figures 4-1 through 4-4 depict this segment of the line. Then the line route travels approximately 21 miles in a northwesterly direction to Winchester Substation. Figures 4-5 and 4-6 depict the line in a southeasterly direction and northwesterly direct where it crosses I-10. Figure 4-7 depicts the corner structure at the Winchester Substation site. At this location the 230 kV circuit turns east and is terminated at the Winchester Substation. The pre-existing 115 kV circuit continues in a northerly direction as depicted in Figure 4-8. The 115 kV circuit continues to the Hayden Substation. Figures 4-9 and 4-10 depict the Winchester ingress and egress of TEP's two Greenlee to Vail 345 kV lines. The new 345 kV line construction is on double circuit steel monopole structures while the pre-existing 345 kV lines were constructed on lattice towers which are visible in Figure 4-10.

The new 230 kV and 345 kV line construction is complete, operational, and the portions observed are judged to be compliant with NESC design requirements. Furthermore, the construction is in accordance with the Certificate of Compatibility ("CEC") granted by Decision No. 65934 in Docket

No. L-00000C-03-0121 during siting of the new Winchester transmission project.

Conclusions

All transmission facilities observed during the December 9, 2004 tour of SWTC facilities were operational, designed and constructed to comply with NESC requirements. Both substations were secure regarding public access and displayed proper safety warnings. The pre-existing transmission facilities were well maintained and all new lines and equipment were designed and constructed in accordance with current NESC and IEEE standards. Therefore, I conclude the subject SWTC transmission facilities are "used and useful."

JDS/rdp

Attachment: Exhibits 1-4
cc: Ernest Johnson, Utilities Director
Steve Olea, Assistant Utilities Director
Del Smith, Engineering Supervisor

EXHIBIT 1
Location and Orientation of Photos

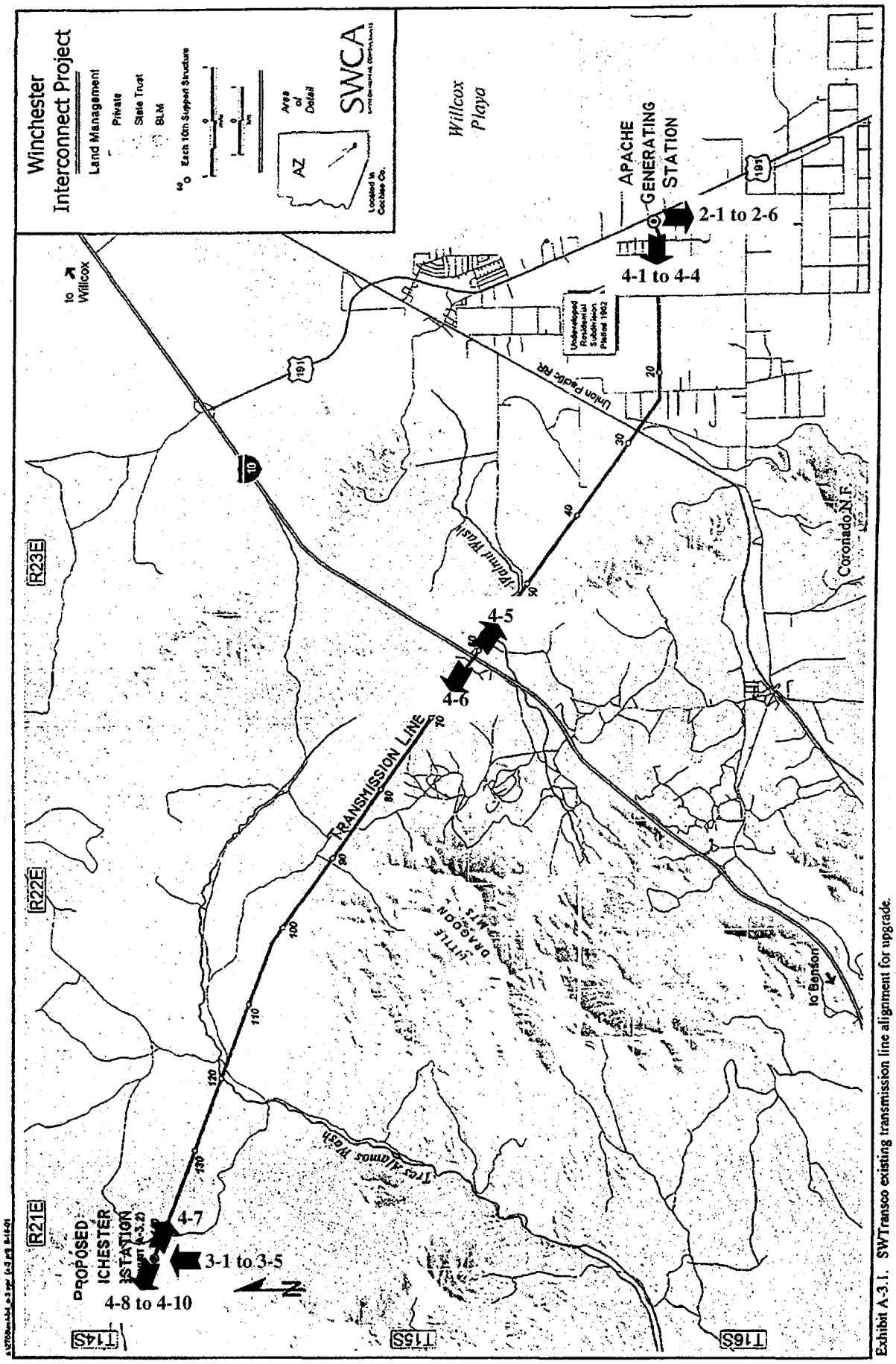

Exhibit A-3.1. SWTransco existing transmission line alignment for upgrade.

EXHIBIT 2
Apache Substation

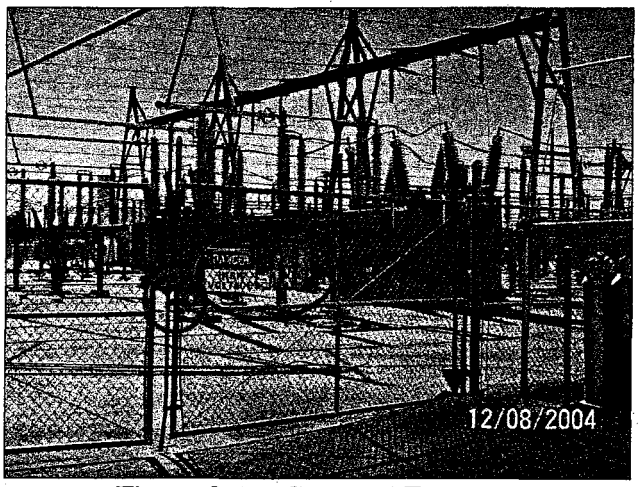

Figure 2-1. Gate and Fence

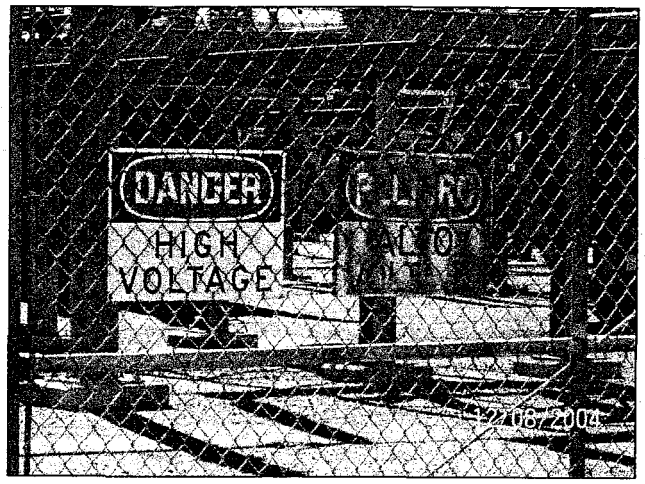

Figure 2-2. Signage

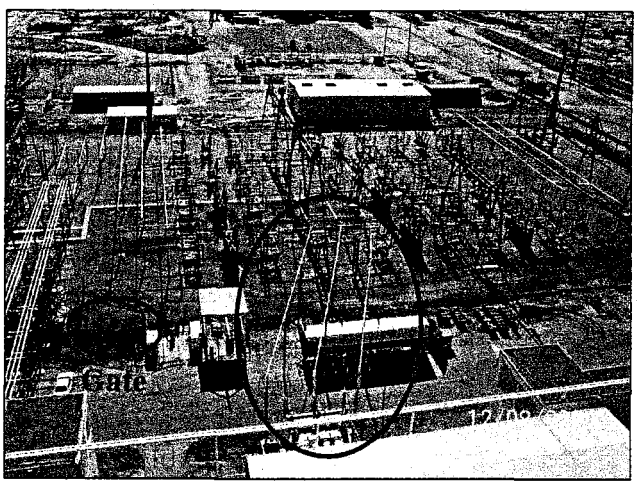

Figure 2-3. 230 kV Switchyard

Figure 2-4. 115 kV & 69 kV Switchyards

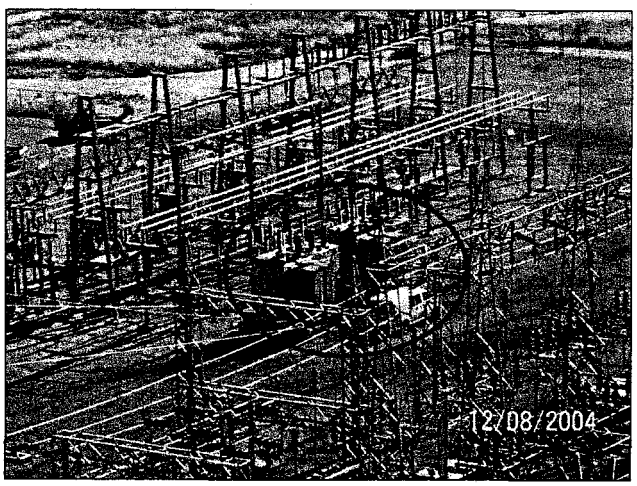

Figure 2-5. 115/69 kV Transformers

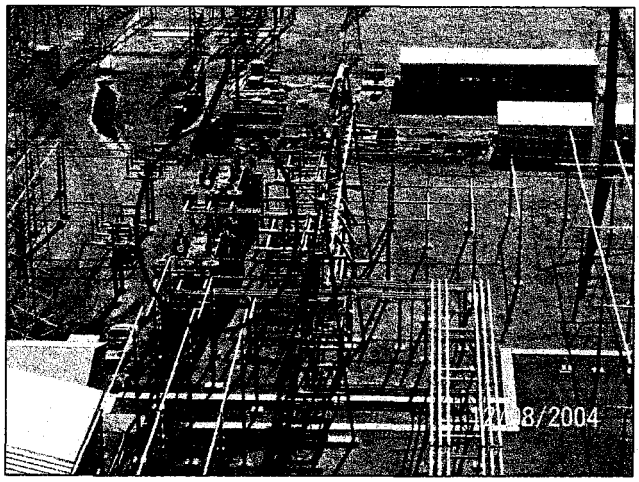

Figure 2-6. 230/115 kV Transformers

EXHIBIT 3
Winchester Substation

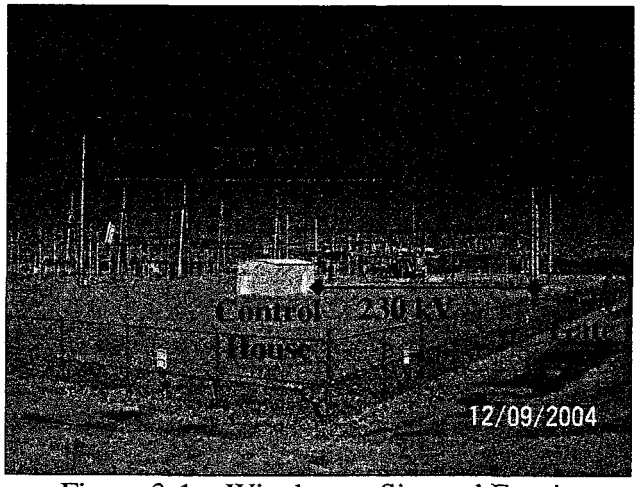

Figure 3-1. Winchester Site and Fencing

Figure 3-2. Gate and Signage

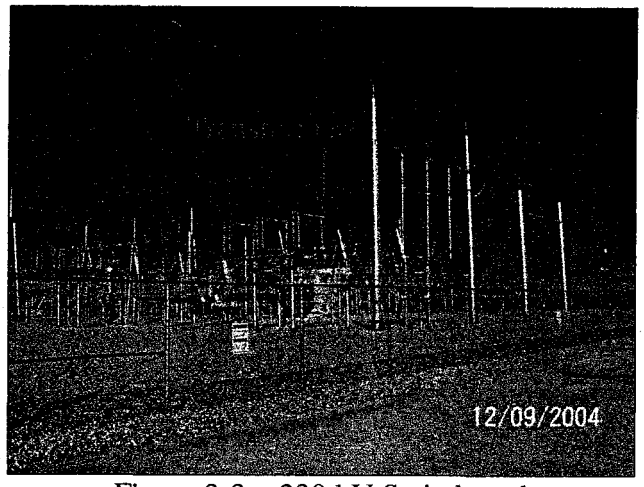

Figure 3-3. 230 kV Switchyard

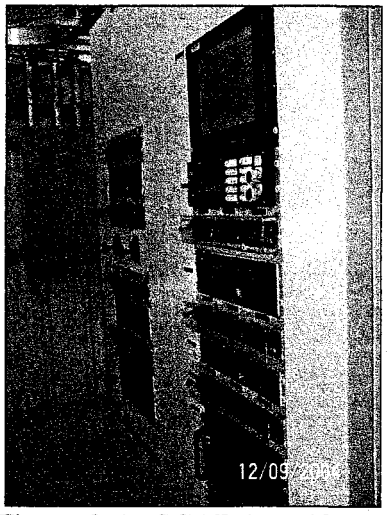

Figure 3-4. SCADA and Relays

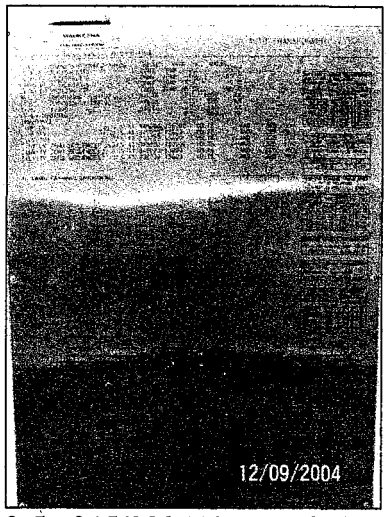

Figure 3-5. 345/230 kV Transformer Nameplate

EXHIBIT 4
Apache to Winchester 230 kV Line

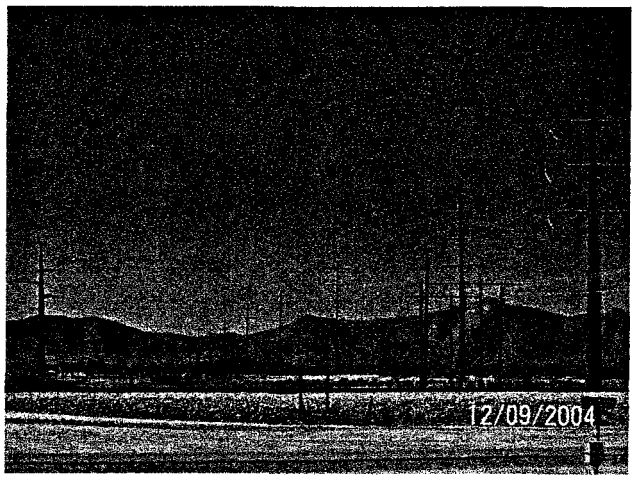

Figure 4-1. Westerly Egress from Apache

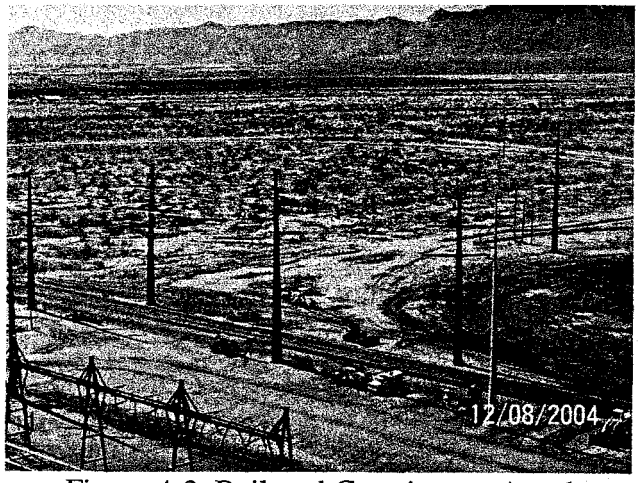

Figure 4-2 Railroad Crossings at Apache

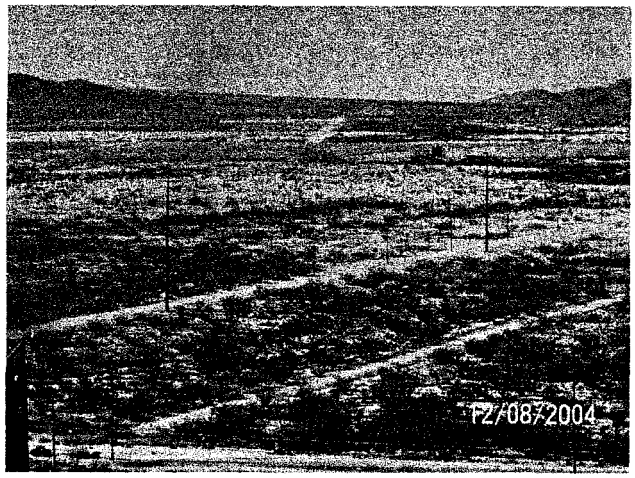

Figure 4-3. Westerly 230 kV Corridor at Apache

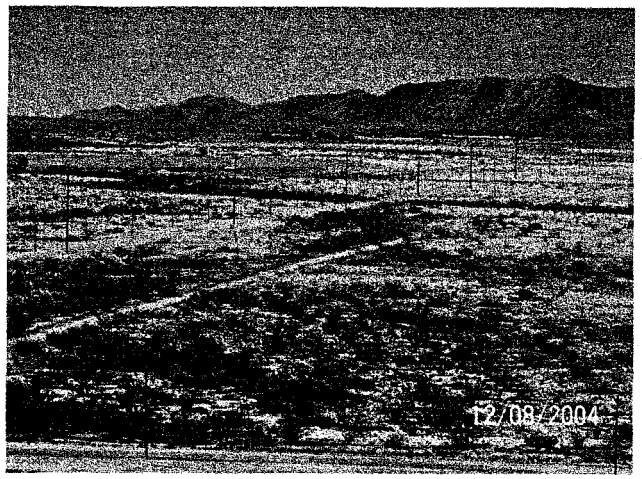

Figure 4-4. 230 kV Corridor West of Apache

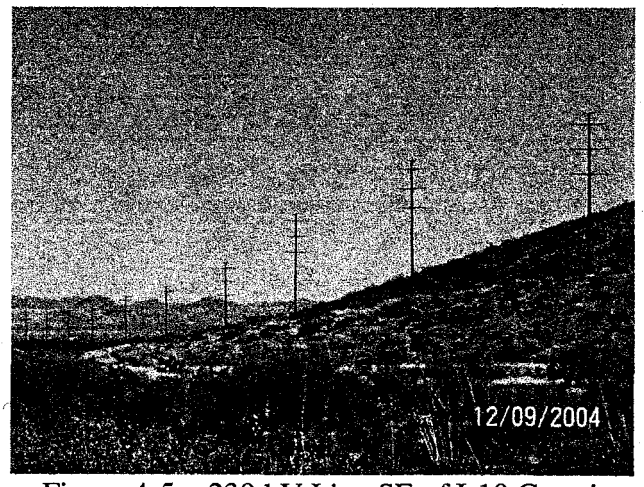

Figure 4-5. 230 kV Line SE of I-10 Crossing

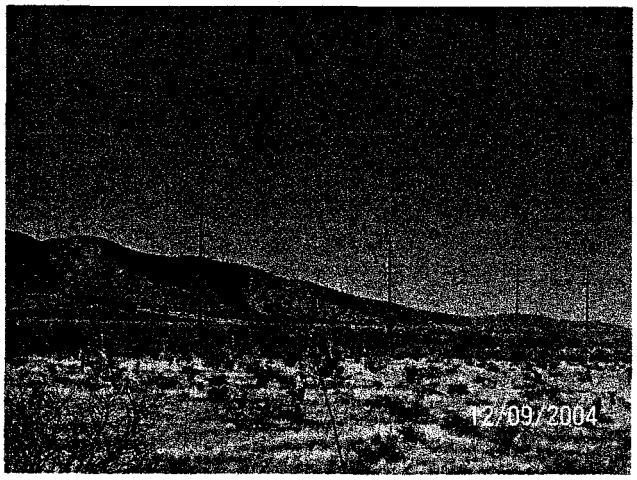

Figure 4-6. 230 kV Line NW of I-10 Crossing

(EXHIBIT 4 continued)

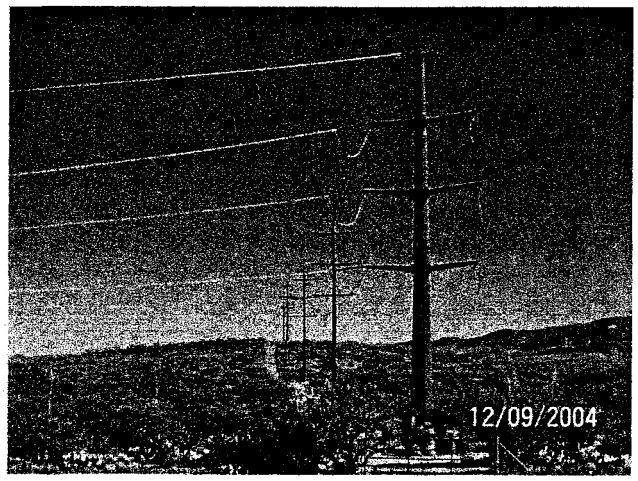

Figure 4-7. Southerly 230 kV Winchester Ingress Egress

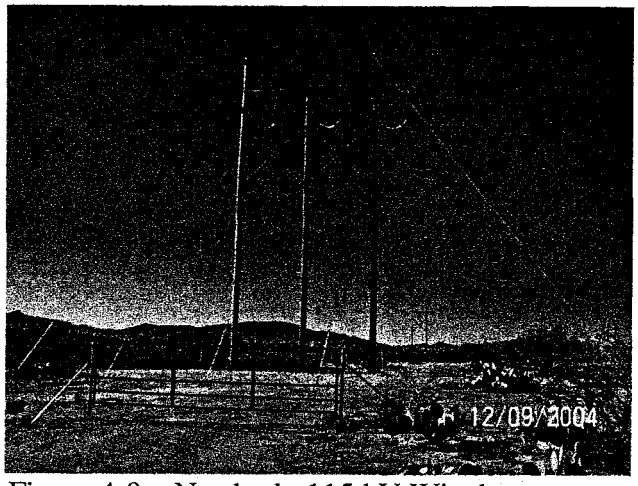

Figure 4-8. Northerly 115 kV Winchester

Figure 4-9. NE 345 kV Winchester Ingress

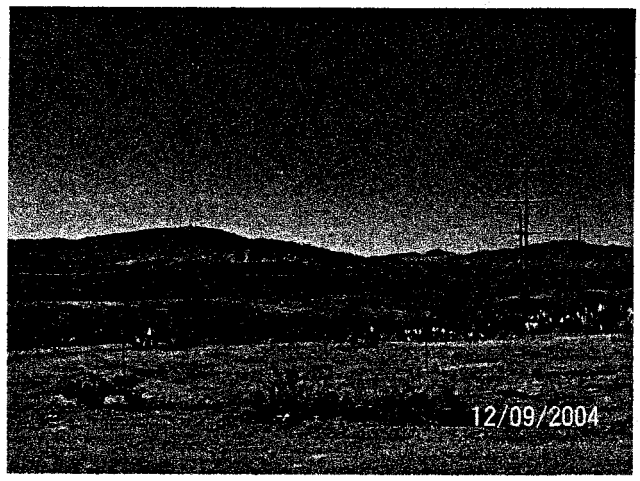

Figure 4-10. NW 345 kV Winchester Egress

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF)	DOCKET NO. E-01773A-04-0528
ARIZONA ELECTRIC POWER COOPERATIVE,)	
INC. FOR A RATE INCREASE)	

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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EXHIBIT
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ADMITTED

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2. Base Cost of Fuel and Purchased Power for AEPCO Adjustor

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE/
DOCKET NO. E-01773A-04-0528

Ms. Keene's testimony recommends that a fuel and purchased power cost adjustor be established for AEPCO but only with certain features and conditions. The base cost of fuel and purchased power be set at $0.01659 per kWh.

Ms. Keene's testimony recommends that AEPCO engage in cost-effective DSM programs. AEPCO should be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism. AEPCO should submit annual and quarterly DSM reports to the Commission.

Ms. Keene's testimony recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 7.8 percent. Mohave Electric's increase would be 15.3 percent, while the increase for the other distribution cooperatives would be 4.1 percent each.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. By whom are you employed and in what capacity?

A. I am employed by the Utilities Division of the Arizona Corporation Commission as a Public Utilities Analyst. My duties include evaluation of electric utility special contracts, review of utility tariff filings, assessment of utility demand-side management programs, and analysis of electric utility production costs and marginal costs. A copy of my résumé is provided in the Appendix.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket Nos. E-04100A-04-0527 and E-01773A-04-0528?

A. Yes.

Q. What is the purpose of your testimony?

A. My testimony is concerned with a fuel and purchased power cost adjustor, a demand-side management ("DSM") adjustor, and rate design for Arizona Electric Power Cooperative ("AEPCO").

FUEL AND PURCHASED POWER COST ADJUSTOR

Q. What has AEPCO requested in regard to an adjustor?

A. AEPCO (witness Gary Pierson's direct testimony, pages 14-15) has requested that the Commission approve an adjustor mechanism that would enable the recovery of increases and decreases in the fuel and purchased energy costs over which AEPCO has little control, without the time and expense of a rate case.

Q. Does AEPCO currently have a fuel and purchased power cost adjustor?

A. Not currently. AEPCO did have a Purchased Power and Fuel Adjustment Clause ("PPFAC") that was eliminated, at AEPCO's request, in Decision No. 64677 (March 27, 2002). The PPFAC, created in 1982, was a very complicated mechanism without clear understanding about its structure, leading to disagreements between AEPCO and Staff over the years. The PPFAC was discontinued as of August 1, 2001. However, at that time AEPCO indicated it would explore a revised adjustor mechanism in the future.

Q. How does AEPCO propose that the new adjustor mechanism work?

A. Mr. Pierson's direst testimony, page 15, suggests that an adjustor base be established in this rate case and that changes from the base would be tracked monthly and recouped as a positive or negative charge in the next quarter's billing to the Class A members. The base cost (AEPCO's Schedule H-2A) would include fuel costs (less fixed costs), purchased power energy costs , and non-firm wheeling costs. The costs would be offset by the fuel cost recovery portion of non-tariff sales. In response to BEK 16-3, Mr. Pierson has changed the request for a quarterly adjustment to a semi-annual adjustment.

Q. What is Staff's position regarding an adjustor mechanism?

A. Staff is not opposed to the establishment of a Fuel and Purchased Power Cost Adjustor ("FPPCA") with certain features and conditions.

Q. Please describe the structure of the adjustor mechanism that Staff would not oppose.

A. The FPPCA would track changes in the cost of fuel for AEPCO's generating units and power purchased from others. The adjustor rate would be calculated by comparing the rolling 12-month average of actual fuel and purchased power costs to the base cost established in this rate case. The rate would be applied to customer bills as a kilowatt-hour (kWh) charge.

Q. What cost components would be included in the adjustor?

A. The cost components would be the costs recorded in RUS Accounts 501 (fuel costs for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 547 (fuel costs for other power generation), 555 (purchased power costs, both demand and energy), and 565 (wheeling costs, both firm and non-firm). The prudent direct costs of contracts used for hedging fuel and purchased power costs may also be included. Power supply costs directly assignable to special contract customers would not be included in the calculation. Non-Class A sales for resale (RUS Account 447), less revenue for legal expenses, would be credited against the cost components.

Q. How does Staff's proposal differ from AEPCO's proposal regarding the components in the adjustor?

A. Staff proposes to include gas reservation charges, demand charges for purchased power, firm wheeling costs, and non-energy charge revenue from non-Class A sales for resale that AEPCO did not propose to be included in the adjustor.

Q. Why is Staff proposing that those items be included?

A. Gas reservation charges should be included because they are a part of the cost of obtaining natural gas for operating power plants.

Demand charges for purchased power should be included so that the method of cost recovery does not influence decision making when negotiating contracts. Some contracts in the marketplace are structured with only a per kWh energy charge that would include capacity costs. Other contracts are structured so that capacity costs are recovered through a per kW demand charge. AEPCO should negotiate these contracts so that they obtain the best deal for ratepayers. If only energy charges went into the adjustor, the method of cost recovery could influence the resulting structure of the contracts.

Firm wheeling costs should be included in the adjustor because they should be considered when negotiating purchased power and wheeling contracts. If only non-firm wheeling costs were included in the adjustor, the method of cost recovery could influence the type of contract that AEPCO would negotiate.

Including all revenue from non-Class A sales for resale as an offset to costs allows the Class A members to benefit from the margins of those sales. Since Class A members pay for the costs of the resources, it only seems fair that they benefit from the non-Class A sales.

Q. How often would the adjustor rate be reset?

A. The adjustor rate, initially set at zero, would be reset semi-annually on October 1, 2006, and April 1, 2007, and thereafter on October 1 and April 1 of each subsequent year. AEPCO would submit a publicly available report, with a revised tariff, that shows the calculation of the new rate on September 1, 2006, and March 1, 2007, and thereafter on September 1 and March 1 of each subsequent year. The adjustor rate would become effective with billings for October and April unless suspended by the Commission.

Q. Are the above dates different from those proposed by AEPCO?

A. Yes. Staff changed the dates to have the new rates go into effect before the winter season and before the summer season, taking into account the probable time for a Commission decision in this case.

Q. Would there be a balancing account?

A. Yes. The dollars associated with the calculation of the adjustor rate would be accumulated in a balancing account.

Q. At what amount should the base cost be set?

A. The base cost of fuel and purchased power would be set at $0.01657 per kWh. Derivation of the base costs is shown in Appendix 2.

Q. Would the structure of the FPPCA have the same problems as the old PPFAC?

A. No. The old PPFAC required that individual supply resources be matched to specific customer classes, without a clear-cut method of how to do it. The new FPPCA would not require the matching because all of the costs of resources are added together, and all of the non-Class A member sales are credited against the costs.

Q. Please describe Staff's recommended conditions.

A. Staff is not opposed to an adjustment mechanism with the following conditions:

1. **The FPPCA would expire in five years unless it is extended by the Commission.** AEPCO would file a report that addresses the FPPCA's operation, its merits, and its shortcomings and that provides recommendations as to whether the FPPCA should remain in effect. In order to allow time for review of the adjustor before the five-year expiration date, the report should be filed in its next rate case application or no later than four years from the effective date of implementation of the FPPCA. The Commission would consider whether to continue the FPPCA after AEPCO has filed its FPPCA report or during AEPCO's next rate case, whichever comes first.

2. **The Commission or its Staff would have the right to review the prudence of fuel and power purchases at any time.** Conducting a prudence review involves reviewing the utility's purchasing activities both as individual transactions and as an overall supply portfolio, generating unit performance, and other related issues. Such a review would consider what the utility knew or should have known at the time actions were taken. Prudence reviews can be time consuming. In light of

these issues, the Commission should not be limited as to when it may conduct a prudence review of AEPCO's purchasing practices.

3. **The Commission or its Staff would have the right to review any calculations associated with the FPPCA at any time.** The Commission needs the flexibility to monitor the calculations on a frequent and regular basis to ensure clarity and the correctness of those calculations for the ratepayers.

4. **Any costs flowed through the FPPCA would be subject to refund if the Commission later determines that the costs were not prudently incurred.** This condition would give AEPCO an incentive to minimize costs.

5. **AEPCO would file monthly reports to Staff's Compliance Section detailing all calculations related to the FPPCA.** The first report would be due 60 days from the effective date of a Commission order in this rate case. Thereafter, these reports would be due on the first day of the third month following the end of the reporting month for which the information applies. The reports would be publicly available and would contain, at a minimum, the following items:

   a. bank balance calculation, including all inputs and outputs;
   b. total power and fuel costs;
   c. Class A member sales in both kWh and dollars by member;
   d. a detailed listing of all items excluded from the FPPCA calculations;
   e. a detailed listing of any adjustments to the reports;
   f. non-class A member sales;
   g. system losses in MW and MWh;
   h. monthly maximum demand in MW; and
   i. identification of a contact person and phone number from AEPCO for questions.

6. **AEPCO would file additional monthly reports with Staff providing information on AEPCO's generating units, power purchases, and fuel purchases.** The first report would be due 60 days from the effective date of a

Commission order in this rate case. Thereafter, these reports would be due on the first day of the third month following the end of the reporting month for which the information applies. The reports may be provided confidentially.

The information for each generating unit would include, at a minimum, the following items:

a. net generation, in MWh per month, and 12 months cumulatively;

b. average heat rate, both monthly and 12-month average;

c. equivalent forced outage rate, both monthly and 12-month average;

d. outage information for each month, including event type, start date and time, end date and time, and description;

e. total fuel costs per month;

f. fuel cost per kWh per month;

At a minimum, the information on power purchases would consist of the following items per seller:

a. quantity purchased in MWh;

b. demand purchased in MW to the extent specified in contract;

c. total cost for demand to the extent specified in contract; and

d. total cost for energy.

Information on economy interchange purchases could be aggregated. These reports would also include an itemization of off-system sales.

At a minimum, the information on fuel purchases would consist of the following information:

a. natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge and incremental cost; and

b. natural gas commodity costs, categorized by short-term purchases (one month or less) and long-term purchases, including price per therm, total cost, supply basin, and volume, by contract.

7. **An AEPCO Officer would certify under oath that all information provided in the required reports is true and accurate to the best of his or her information and belief.** The Officer should be high level, either Chief Executive Officer, Chief Operating Officer, or Chief Financial Officer.

8. **AEPCO should file a plan of administration that describes how the FPPCA would operate.** The plan would be filed for Staff review within 30 days of a decision in this rate case.

DEMAND-SIDE MANAGEMENT

Benefits of DSM

Q. What is DSM?

A. DSM is the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner.

Q. Does AEPCO and the rest of society benefit from having DSM programs?

A. Cost-effective DSM programs 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. In addition, reducing energy needs reduces the operating costs of current generating facilities. Reduced energy production may also lead to reduced air emissions from power plants, reduced consumption of water by generating unit cooling towers, and reduced degradation of land at mining sites.

Q. Why should AEPCO and Staff consider the benefits and costs of DSM to society rather than just to AEPCO?

A. We are seeking the least cost means of meeting the demand for electric energy services. A program that is not least cost wastes society's resources. Because customer costs and new generation costs may not be part of AEPCO's costs, we need to look beyond AEPCO's costs and benefits. The Commission adopted the use of the societal cost test in its resource planning decision (Decision No. 57589).

Q. What are the societal benefits of a DSM program?

A. From a societal perspective, relevant benefits come from avoiding new generating, transmission, and distribution capacity and avoiding burning of fuel and other variable costs. Because existing power plants have already been built and the associated societal costs have already been incurred, the fixed costs of existing power plants are sunk costs which cannot be avoided by a reduction in the demand for kW and kWh. Therefore, the only costs to society that can be avoided by DSM are those associated with the construction of new capacity and the variable costs associated with the generation of additional electricity.

Q. How can the societal costs of a DSM program be calculated?

A. The costs to society to implement a DSM program are the incremental costs of any equipment, including installation and operating costs, and program administrative costs. Incentives offered to customers to participate are not societal costs, but are transfer payments (transfers of income from one person or organization to another without supplying goods or services for these payments).

Q. Does AEPCO currently have any DSM program?

A. No. According to AEPCO's response to BEK 5-6, AEPCO currently does not administer or coordinate member distribution cooperative DSM programs. Following the

Commission's suspension of most of the Resource Planning rules in 1997, the institution of various DSM programs by some of AEPCO's member distribution cooperatives, and the cancellation of its PPFAC (which included a DSM component), AEPCO phased out its involvement in DSM programs.

Q. What DSM programs should AEPCO pursue?

A. AEPCO should evaluate possible DSM programs, considering the costs and kW and kWh savings associated with each program. AEPCO should then select the most beneficial and cost-effective projects to pursue. Ideally, AEPCO should engage in DSM programs as long as the incremental societal benefits (deferred capacity, avoided fuel costs, and avoided environmental impacts) are greater than the incremental cost of those programs to society.

Because AEPCO is a wholesaler, it should work with its member distribution cooperatives to develop and implement programs as was done in the past.

<u>Cost Recovery of DSM Programs</u>

Q. What cost recovery mechanisms could be used to recover AEPCO's DSM costs?

A. Possible mechanisms include using a deferral account with amortization into base rates, simply putting a level of costs in base rates, recovery through any fuel and purchased power adjustor approved for AEPCO, or setting up a separate DSM adjustment mechanism.

Q. Should AEPCO recover its DSM costs through a deferral account with base rate amortization?

A. No. When a deferral account is used, pre-approved DSM costs are placed in the deferral account and earn interest until the utility's next rate case, when the costs are considered for base rate cost recovery. If there are significant DSM activities taking place, the

deferral account balance grows quickly, including the attendant interest, and can become a major cost which has to be dealt with in the utility's next rate case. In addition, a deferral account may not allow for the timely recovery of DSM costs to the same extent as some other cost recovery mechanisms.

Q. Should AEPCO recover its DSM costs directly through base rates with no deferral accounting?

A. No. Placing DSM costs in base rates does not provide the Commission and AEPCO with flexibility to increase or decrease DSM spending, as circumstances dictate. Additionally, a utility could choose to end its DSM activities, and there would be no way to remove the DSM funding from base rates until the next rate case.

Q. Should AEPCO recover its DSM costs through a fuel and purchased power adjustor (if approved for AEPCO)?

A. No. While recovery of DSM costs through a fuel and purchased power adjustor would provide timely and more flexible cost recovery, it would complicate the administration of the fuel and purchased power adjustor.

Q. How should AEPCO recover its costs for DSM programs?

A. Staff recommends that AEPCO be allowed to recover its costs for pre-approved DSM programs through a separate DSM adjustment mechanism. Recovery of pre-approved DSM costs through a DSM adjustment mechanism would provide the flexibility to adjust the level of DSM spending as needed in the future, while also providing timely recovery of pre-approved DSM costs. It would also provide a separate and specific accounting for pre-approved DSM costs.

A DSM adjustment mechanism would allow the costs associated with pre-approved programs to be recovered as the level of expenses associated with those programs

changes. In addition, separating these expenses from other expenses included in base rates provides an incentive to initiate programs at any time rather than in the context of a rate case.

Q. How would customers be billed?

A. The DSM adjustment mechanism, as a charge per kWh, would be included on customer bills as a separate line item.

Q. How would the proposed DSM adjustment mechanism work?

A. The proposed DSM adjustment mechanism would consist of an account where the costs for pre-approved DSM programs would be recorded for each program by AEPCO as the costs were incurred. Revenues received through the DSM adjustor would be credited to the account. The per kWh adjustor rate would initially be set at zero. By February 1 of each year, AEPCO would file a request and supporting documentation with Staff to set a new adjustor rate to be effective on March 1. The new rate would be calculated by dividing the account balance by the number of kWh used by customers in the previous calendar year.

Q. What kinds of costs should AEPCO be able to recover?

A. Staff recommends that AEPCO recover the program costs associated with pre-approved DSM projects. Program costs include administrative expenses, monitoring expenses, any incentives such as rebates, promotional expenses, educational program expenses, and the costs of demonstration facilities.

Implementation of DSM Programs

Q. How should AEPCO implement DSM programs?

A. AEPCO should submit proposed programs to the Commission for approval. After a program is approved, AEPCO may begin entering the costs for that program as they are incurred into the DSM adjustment mechanism account.

Q. What should AEPCO include in a DSM program proposal?

A. The proposal should include a description of the program, objectives and rationale for the program, identification of the market segment at which the program is aimed; expected level of program participation, an estimate of the baseline, estimated societal benefits and savings from the program, estimated societal costs of the program, marketing and delivery strategy, utility costs and budget, an implementation schedule, a monitoring and evaluation plan, and any proposed performance incentives.

Staff would consider whether the benefits of the measures to society exceed the costs to society. In addition, Staff would consider the reasonableness of any customer incentives proposed by AEPCO. Staff would then provide the Commission with a recommendation regarding the DSM proposal. New programs could be added or existing programs terminated anytime during the year subject to Commission approval.

Q. Why should each program proposal include a monitoring and evaluation plan?

A. AEPCO should include a monitoring plan in each program proposal because AEPCO needs to monitor and evaluate all DSM programs to reliably ensure that they are cost-effective. Monitoring and evaluation should:

1. determine participation rates, energy savings, and demand reductions;
2. assess the utility's program implementation process;
3. provide information on whether to continue, modify, or terminate a program; and
4. determine the persistence and reliability of DSM.

Q. What are Staff's recommendations regarding monitoring?

A. If the monitoring activity reveals that the program is not working as well as expected, AEPCO should modify or terminate the program. AEPCO should file an application with the Commission about any plans to terminate a program before such termination occurs. AEPCO should provide its plans for notification to potential participants. If a program is terminated, AEPCO would be expected to give proper notice to potential participants as well as honor existing commitments.

Q. How can Staff and the Commission monitor AEPCO's efforts?

A. Staff recommends that AEPCO submit annual reports to the Commission containing, at a minimum, the following information separately for each program: a brief description of the program; predetermined program goals, objectives, and savings targets; the level of customer participation; costs incurred during the reporting period disaggregated by type of cost (such as administrative costs, rebates, and monitoring costs); a description of evaluation and monitoring activities and results; kW and kWh savings; benefits and net benefits in dollars; any program-specific performance incentive calculations; problems encountered and proposed solutions; and proposed program modifications. Findings from all research projects and other significant information should be included. Each annual report would be due on February 1, reporting for the previous calendar year.

Staff also recommends that AEPCO file quarterly reports that consist of a tabular summary of expenditures compared to the budget. Quarterly reports would be due on May 1 (for January through March), August 1 (for April through June), and November 1 (for July through September). Information on the last quarter of the year would be included in the annual report.

In addition, the Commission may review program costs and performance in future rate cases.

RATE DESIGN

Q. What do you recommend as AEPCO's rates for its Class A members?

A. Based on Staff's recommended revenue requirements, the rates should be set as follows:

	Full Requirements
Demand charge	$12.90 per kW of demand coincident with AEPCO monthly peak
Energy charge	$0.02079 per kWh used during billing period
	Partial Requirements
O&M charge	$7.48 per kW of allocated capacity based on coincident AEPCO demand
Energy charge	$0.02079 per kWh used during billing period
Fixed Charge	$707,392 per month for Mohave

These rates would result in an overall increase for Class A members of 7.8 percent. Mohave Electric's increase would be 15.3 percent, while the increase for the other distribution cooperatives would be 4.1 percent each.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. 1. Staff recommends that a fuel and purchased power cost adjustor be established for AEPCO but only with certain features and conditions.

2. Staff recommends that the base cost of fuel and purchased power be set at $0.01659 per kWh.

3. Staff recommends that AEPCO engage in cost-effective DSM programs.

4. Staff recommends that AEPCO be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism.

5. Staff recommends that AEPCO submit annual and quarterly DSM reports to the Commission.

6. Staff recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 7.8 percent. Mohave Electric's increase would be 15.3 percent, while the increase for the other distribution cooperatives would be 4.1 percent each.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceeding Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Tucson Electric Power Company's Application for Approval of New Partial Requirements Service Tariffs, Modification of Existing Partial Requirements Service Tariff 101, and Elimination of Qualifying Facility Tariffs (Docket No. E-01933A-02-0345) and Application for Approval of its Stranded Cost Recovery (Docket No. E-01933A-98-0471), Arizona Corporation Commission, 2002, testimony on proposals to eliminate, modify, or introduce tariffs and testimony on the modification of the Market Generation Credit.

Arizona Public Service Company's Application for Approval of Adjustment Mechanisms (Docket No. E-01345A-02-0403), Arizona Corporation Commission, 2003, testimony on the proposed Power Supply Adjustment and the proposed Competition Rules Compliance Charge.

Generic Proceeding Concerning Electric Restructuring Issues, et al (Docket No. E-00000A-02-0051, et al), Arizona Corporation Commission, 2003; Staff Report on Code of Conduct.

Arizona Public Service Company Rate Case (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004; testimony on demand-side management, system benefits, renewable energy, the Returning Customer Direct Assignment Charge, and service schedules.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986
"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

"DSM Workshop Progress Report," Arizona Corporation Commission, 2004.

(with Erin Casper) "Staff Report on Demand Side Management Policy," Arizona Corporation Commission, 2005.

Base Cost of Fuel and Purchased Power
for AEPCO Adjustor

RUS Account			
501	fuel costs for steam power generation		$46,830,878
	less MEC Schedule A adjustment		-550,220
	less City of Mesa adjustments		-407,498
	less legal fees		-1,030,873
	less fixed fuel costs (except gas reservation)		-295,865
			$44,546,422
547	fuel costs for other power generation		**$15,464,540**
555	purchased power costs (demand & energy)		$16,270,579
	less MEC Schedule A adjustment		-333,790
	less City of Mesa adjustments		-169,803
	plus Purchase Power adjustment		88,139
	less PNM adjustment		-250,000
			$15,605,125
565	wheeling costs (firm & non-firm)		$8,036,486
	plus wheeling contract adjustment		-19,560
			$8,016,926
		Costs	***$83,633,013***
447	non-Class A sales for resale		$51,757,181
	plus MEC Schedule B reclassification		142,921
	less City of Mesa adjustments		-903,664
	less revenue for legal expenses		-923,826
		Revenues	***$50,072,612***
	Base Cost (Costs-Revenues)		**$33,560,401**
	Class A kWh sales		2,025,326,533
		$/kWh	**$0.01657**

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF) ARIZONA ELECTRIC POWER COOPERATIVE,) INC. FOR A RATE INCREASE)	DOCKET NO. E-01773A-04-0528

SURREBUTTAL

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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1. Base Costs of Fuel and Purchased Power for AEPCO Adjustor

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE/
DOCKET NO. E-01773A-04-0528

Ms. Keene's testimony recommends that a fuel and purchased power cost adjustor include the margins from non-Class A sales as an offset to costs. The base costs of fuel and purchased power be set at $0.01687 per kWh for full requirements customers and $0.01603 per kWh for the partial requirements customer.

Ms. Keene's testimony recommends that AEPCO engage in cost-effective DSM programs. AEPCO should be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism.

Ms. Keene's testimony recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 10.9 percent. Mohave Electric's increase would be 15.5 percent, while the increase for the other distribution cooperatives would range from 8.6 to 8.9 percent each.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony concerning a fuel and purchased power cost adjustor, a demand-side management ("DSM") adjustor, and rate design for Arizona Electric Power Cooperative ("AEPCO").

Q. As part of your employment responsibilities, were you assigned to review AEPCO's rebuttal testimony?

A. Yes. I conducted a review of the testimonies of Mr. Dirk Minson and Mr. Gary Pierson concerning the fuel and purchased power cost adjustor, DSM, and rate design.

FUEL AND PURCHASED POWER COST ADJUSTOR

Q. What did AEPCO's witness Mr. Minson include in his rebuttal testimony regarding Staff's recommendations about a fuel and purchased power adjustor?

A. Mr. Minson, on pages 10 and 11 of his rebuttal testimony, disagrees with Staff's recommendation to credit all revenue from non-Class A sales to the adjustor balance as an offset to costs.

Q. What are Mr. Minson's reasons for excluding the margins received from such sales in the adjustor?

A. Mr. Minson has stated three reasons for the exclusion: 1) the margins have already been credited to reduce members' cost of service in proposed rates, 2) crediting margins from economy sales would distort the true price signal concerning fuel and purchase power

costs sent to members through the adjustor, and 3) margins from non-member economy sales are a way for AEPCO to build equity.

Q. Please respond to Mr. Minson's reasons for excluding the margins of non-Class A sales from the adjustor.

A. Even though the margins have been credited to reduce members' cost of service in the Class A member tariff base rates, the margins should also be included in the adjustor. The adjustor base cost of fuel and purchased power reflects what is in the adjusted test year, and recovered through the Class A member tariff rates, for both costs and revenues. The adjustor base is used for comparison to later fuel and purchased power costs and non-Class A sales revenues. It is the difference between the adjustor base and later fuel and purchased power costs and non-Class A sales revenues that would be recovered through the adjustor rate. Thus, the fact that revenues from non-Class A member sales are accounted for in the base rates does not mean that they should be ignored in the adjustor. Those revenues may be different in any given year than what is reflected in the base rates, and the adjustor should account for the difference.

Mr. Minson also claims that crediting margins from economy sales would distort the true price signal concerning fuel and purchased power costs sent to members through the adjustor. However, leaving out an important component from the adjustor would distort the price signal. Price signals should reflect the true cost the company incurs, and the company's fuel and purchased power costs are offset by non-Class A sales. Including all revenue from non-Class A sales for resale as an offset to costs allows the Class A members to benefit from the margins of those sales. Since Class A members pay for the costs of the resources, it only seems fair that they benefit from the non-Class A sales.

Margins from non-member economy sales could help AEPCO to build equity, but the adjustor is not the proper mechanism to address that issue. Equity is addressed in operating margins.

Q. What did AEPCO witness Mr. Pierson recommend in his rebuttal testimony regarding the adjustor?

A. On page 6 of his rebuttal testimony, Mr. Pierson recommends that there be two bases for fuel and purchased power costs - one for the all (full) requirements customers and one for the partial requirements customer.

Q. Why did Mr. Pierson recommend two bases for fuel and purchased power costs?

A. There are certain demand and wheeling costs that are not applicable to the partial requirements customer because Mohave elected to not participate in the Panda Gila River purchased power agreement.

Q. Does Staff agree with Mr. Pierson?

A. Yes.

Q. At what amounts should the base costs be set?

A. The base cost of fuel and purchased power should be set at $0.01687 per kWh for full requirements customers and $0.01603 per kWh for the partial requirements customer. Derivation of the base costs is shown in Appendix 1.

DEMAND-SIDE MANAGEMENT

Q. What did Mr. Minson include in his rebuttal testimony regarding DSM?

A. Mr. Minson, on pages 11 and 12 of his rebuttal testimony, states that AEPCO disagrees with Staff's proposal to establish a DSM program for AEPCO.

Q. Why does AEPCO take that position?

A. Mr. Minson states that AEPCO supports DSM, but that it is not appropriate for AEPCO, as a wholesale generator, to have a DSM program.

Q. What are AEPCO's reasons for DSM not being appropriate for AEPCO?

A. AEPCO's reasons are: 1) DSM programs are designed to affect end-use energy consumption, 2) there would likely be confusion by the end-use customer and a duplication of administrative costs, and 3) there is wide diversity among the distribution cooperatives served by AEPCO.

Q. Does Staff agree with AEPCO's contentions about DSM?

A. No.

Q. Please respond to AEPCO's reasons for not having a DSM program.

A. Although DSM does affect end-use consumption, the ultimate goal of DSM is often reducing peak demand in order to reduce the costs of generation and purchased power, which are incurred by AEPCO. Cost-effective DSM programs 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. In addition, reducing energy needs reduces the operating costs of current generating facilities. Reduced energy production may also lead to reduced air emissions from power plants, reduced consumption of water by generating unit cooling towers, and reduced degradation of land at coal mining sites.

AEPCO would need to work with the distribution cooperatives to deliver programs to the end-users as they did in the past. It appeared to have been successful in the 1990s when AEPCO engaged in DSM. Some of the distribution cooperatives had there own programs, others only participated in AEPCO's programs. They benefited by AEPCO's

expertise and coordination of efforts. Staff never heard of any end-use customer confusion at the time. There may even be a reduction in administrative costs rather than a duplication of costs if AEPCO develops the programs for the distribution cooperatives. AEPCO has begun developing renewable energy projects on behalf of the member cooperatives and therefore has experience in such coordination.

Staff agrees that there is diversity among the distribution cooperatives. However, there is a great deal that can be standardized while allowing flexibility regarding individual programs. For example, all of the distribution cooperatives might want to participate in a refrigerator program where AEPCO could negotiate with manufacturers or distributors. On the other hand, an air conditioner program might only be appropriate for the warmer weather cooperatives.

Q. What did Staff recommend in its direct testimony regarding AEPCO and DSM?

A. Staff recommended that AEPCO engage in cost-effective DSM programs and that AEPCO be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism. Staff did not recommend a specific DSM goal for AEPCO nor any specific programs.

Q. If a DSM cost recovery mechanism is not approved in this rate case, does that mean that AEPCO would not have to engage in DSM?

A. No. In another docket, Staff has filed a DSM policy that will be transformed into proposed rules. The proposed policy would require applicable utilities to file DSM plans for Commission approval.

Q. Would the proposed DSM rules apply to AEPCO?

A. Yes. The proposed rules are expected to apply to AEPCO. If those rules become effective, AEPCO would have to engage in DSM without any cost recovery mechanism unless the mechanism is approved in this rate case.

RATE DESIGN

Q. What do you recommend as AEPCO's rates for its Class A members?

A. Based on Staff's recommended revenue requirements contained in the Surrebuttal Testimony of Crystal Brown, the rates should be set as follows:

	Full Requirements
Demand charge	$13.99 per kW of demand coincident with AEPCO monthly peak
Energy charge	$0.02073 per kWh used during billing period
	Partial Requirements
O&M charge	$7.09 per kW of allocated capacity based on coincident AEPCO demand
Energy charge	$0.02073 per kWh used during billing period
Fixed Charge	$758,466 per month for Mohave

These rates would result in an overall increase for Class A members of 10.9 percent. Mohave Electric's increase would be 15.5 percent, while the increase for the other distribution cooperatives would range from 8.6 percent to 8.9 percent each. Mohave's percentage is higher than that of the full requirements members because the full requirements members have increasing billing units. As a partial requirements customer, Mohave's rates do not reflect an increase in billing units. However, the relative

contribution of Mohave's revenue to the total Class A member revenue is about the same between existing AEPCO rates and proposed rates.

SUMMARY OF STAFF RECOMMENDATIONS

Q. Please summarize Staff's recommendations.

A. 1. Staff recommends that a fuel and purchased power cost adjustor include the margins from non-Class A sales as an offset to costs.

2. Staff recommends that the base cost of fuel and purchased power be set at $0.01687 per kWh for full requirements customers and $0.01603 per kWh for the partial requirements customer.

3. Staff recommends that AEPCO engage in cost-effective DSM programs.

4. Staff recommends that AEPCO be allowed to recover its program costs for pre-approved DSM projects through a DSM adjustment mechanism.

5. Staff recommends new rates for AEPCO in order for AEPCO to recover Staff's recommended revenue requirements. These rates would result in an overall increase for Class A members of 10.9 percent. Mohave Electric's increase would be 15.5 percent, while the increase for the other distribution cooperatives would range from 8.6 percent to 8.9 percent each.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

Base Cost of Fuel and Purchased Power
for AEPCO Adjustor
Partial Requirements

RUS Account			
501	fuel costs for steam power generation		$46,830,878
	less MEC Schedule A adjustment		-550,220
	less City of Mesa adjustments		-407,498
	less legal fees		-1,030,873
	less fixed fuel costs (except gas reservation)		-295,865
			$44,546,422
547	fuel costs for other power generation		**$15,464,540**
555	purchased power costs (demand & energy)		$16,270,579
	less MEC Schedule A adjustment		-333,790
	less City of Mesa adjustments		-169,803
	plus Purchase Power adjustment		88,139
	less PNM adjustment		-250,000
	less Panda Gila demand*		-1,000,872
			$14,604,253
565	wheeling costs (firm & non-firm)		$8,036,486
	plus wheeling contract adjustment		-19,560
	less El Paso Wheeling*		-102,500
			$7,914,426
		Costs	***$82,529,641***
447	non-Class A sales for resale		$51,757,181
	plus MEC Schedule B reclassification		142,921
	less City of Mesa adjustments		-903,664
	less revenue for legal expenses		-923,826
		Revenues	***$50,072,612***
	Base cost (costs-revenues)		$32,457,029
	Class A kWh sales		2,025,326,533
	Partial Requirements Base Cost Rate	**$/kWh**	**$0.01603**
	Mohave kWh sales		716,978,668
	Mohave base cost		**$11,489,998**

* Mohave elected to not participate in the Panda Gila River purchased power agreement.

Base Cost of Fuel and Purchased Power
for AEPCO Adjustor
Full Requirements

RUS Account			
501	fuel costs for steam power generation		$46,830,878
	less MEC Schedule A adjustment		-550,220
	less City of Mesa adjustments		-407,498
	less legal fees		-1,030,873
	less fixed fuel costs (except gas reservation)		-295,865
			$44,546,422
547	fuel costs for other power generation		**$15,464,540**
555	purchased power costs (demand & energy)		$16,270,579
	less MEC Schedule A adjustment		-333,790
	less City of Mesa adjustments		-169,803
	plus Purchase Power adjustment		88,139
	less PNM adjustment		-250,000
			$15,605,125
565	wheeling costs (firm & non-firm)		$8,036,486
	plus wheeling contract adjustment		-19,560
			$8,016,926
		Costs	***$83,633,013***
447	non-Class A sales for resale		$51,757,181
	plus MEC Schedule B reclassification		142,921
	less City of Mesa adjustments		-903,664
	less revenue for legal expenses		-923,826
		Revenues	***$50,072,612***
	Base cost (costs-revenues)		$33,560,401
	Mohave base cost		-$11,489,998
	Full Requirements Base Cost		**$22,070,403**
	Class A kWh sales (less Mohave)		1,308,347,865
	Full Requirements Base Cost Rate	**$/kWh**	**$0.01687**

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE	))))	DOCKET NO. E-04100A-04-0527

DIRECT

TESTIMONY

OF

ERIN CASPER

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

Southwest Transmission Cooperative, Inc. ("Southwest" or "The Cooperative") provides transmission service to its six Class A Member distribution cooperatives including Anza Electric Cooperative, Inc., Duncan Valley Electric Cooperative, Inc., Graham County Electric Cooperative, Inc., Mohave Electric Cooperative, Inc., Sulphur Springs Valley Electric Cooperative, Inc., and Trico Electric Cooperative, Inc. Southwest also provides transmission service to its Class B Members including AEPCO and Morenci Water & Electric Company. Finally, Southwest provides wholesale transmission service to non-members through its open access transmission tariff ("OATT") and through pre-OATT contracts.

On July 23, 2004, Southwest filed an Application for a Rate Increase. The Cooperative requested an increase in revenue of $3,666,668 resulting in an increase of 13.7 percent to overall revenues. The Cooperative's proposed rates are designed to recover its proposed revenue requirement of $28,814,864 net of revenues collected through the regulatory asset charge.[1] Southwest proposed an increase in the firm and non-firm point-to-point rates of 7.8 percent and an increase in the firm network service revenue requirement of 26.2 percent. The Cooperative requested that it be allowed to pass through an increase in rates charged by AEPCO for generation-related ancillary services provided by AEPCO. Finally, Southwest proposed a decrease to its Schedule 1: System Control and Load Dispatch of 37.9 percent. Southwest has proposed no changes to the structure of its rates or its service offerings.

Staff has recommended a revenue requirement net of revenues collected through the regulatory asset charge equal to $28,814,864. Staff's recommended rates are designed to recover Staff's recommended revenue requirement. Staff recommends an increase in the rates for firm and non-firm point-to-point service of 7.45 percent and an increase in the network service revenue requirement of 26.30 percent. Staff recommends an increase in the cost-based ancillary service rates commensurate with Staff's recommendations for the associated costs and plant balances. Finally, Staff recommends a decrease in the rate for Schedule 1: System Control and Load Dispatch of 37.86 percent. Staff recommends no changes to the structure of Southwest's rates or its service offerings.

Staff's recommended rate design is intended to recover revenues equal to Staff's recommended revenue requirement. Staff has designed rates consistent with standard FERC embedded cost ratemaking methods. Staff proposes no changes to the structure of Southwest's rates or its service offerings.

---

[1] Southwest's proposed revenue includes revenues from the regulatory asset charge and is equal to $28,814,864 + $2,707,122 = $31,521,986.

INTRODUCTION

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

A. My name is Erin Casper. I am a Public Utility Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Avenue, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utility Analyst.

A. In my capacity as a Public Utility Analyst, I provide recommendations to the Commission on energy and telecommunications issues. My current energy-related responsibilities include review and evaluation of demand-side management issues, utility rate-case filings, and rate design.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Wisconsin in 2001, receiving a Bachelor of Science degree in Economics and Music. From May, 2001 to May, 2004, I was a Staff Economist with the economic consulting firm of Laurits R. Christensen Associates in Madison, Wisconsin. As a Staff Economist, I worked on projects in the electric and gas utilities industry and in patent infringement and antitrust litigation cases. Among my duties as a Staff Economist, I prepared rate-case filing schedules and analysis for both electric and gas utilities including revenue requirement, cost of capital, cost of service, and rate design. Since joining the Arizona Corporation Commission in June of 2004, I have attended various seminars and classes on general energy industry and regulatory issues.

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

A. I will address the cost allocation and rate recommendations for Southwest Transmission Cooperative's ("Southwest" or "Southwest Transmission" or "Cooperative") application

for a general rate increase. In particular, I will explain the calculation of the point-to-point and network transmission rates, ancillary service rates, and adjustments to recognize certain grandfathered and discounted point-to-point contracts. I will also describe the process by which ancillary services are offered to customers by Southwest via Arizona Electric Power Cooperative ("AEPCO"). Staff witnesses Crystal Brown, Alejandro Ramirez, and Jerry Smith will provide testimony covering other aspects of Southwest's rate application.

SUMMARY OF RECOMMENDATIONS

Q. Briefly summarize the important concepts in transmission ratemaking.

A. The Federal Energy Regulatory Commission ("FERC") has established that transmission providers must offer transmission service on a non-discriminatory open access basis. FERC Order No. 888 requires that a transmission company file an open access transmission tariff ("OATT") that offers firm and non-firm point-to-point service, firm network service, and six ancillary services. In that order, FERC indicated that it would consider alternative pricing methodologies, but that embedded cost-based rates would remain acceptable. Additionally, FERC indicated that while developing point-to-point rates using the annual system peak ("1 CP") is the standard methodology, it would no longer summarily reject firm point-to-point rates based on different cost allocations such as the average of the twelve monthly peaks ("12 CP"). With respect to network service, FERC concluded that the load ratio allocation method would remain the standard methodology but that it would consider rates based on different cost allocation methods on a case by case basis. FERC Order No. 888 also established that transmission providers must offer six ancillary services including (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve-Spinning; and (6)

Operating Reserve-Supplemental. The pro forma OATT sets forth standard rate design methodologies for point-to-point, network, and ancillary services.

Q. Please explain how Transmission Cooperatives are treated differently than Investor Owned Utilities both at the Federal and State levels.

A. Southwest is financed by the Rural Utility Service ("RUS") Fund and therefore claims status as a non-FERC jurisdictional entity. FERC Order No. 888 established that non-public or non-jurisdictional utilities that own, operate, or control transmission facilities must provide reciprocal transmission service as a condition of receiving open access transmission service from public utilities. One method of satisfying the reciprocity requirement is for the non-public utilities to voluntarily file a "safe harbor" OATT with FERC. The "safe harbor" tariff filings are subject to less regulatory scrutiny on the federal level than the tariffs filed by public utilities. FERC generally finds the OATT appropriate for "safe harbor" status if the tariff is substantially similar to the pro forma OATT set forth in Order No. 888. On May 10, 2004, FERC issued an order clarifying the "safe harbor" status of the OATT filed by Southwest.

The Arizona Corporation Commission has jurisdiction over the rates and charges assessed by Southwest. The Commission also has jurisdiction over Southwest's tariff. The Commission approved the rates and charges contained in Southwest's current OATT in Decision No. 65367.

Q. Please identify the different types of transmission rates included in the rate design.

A. Southwest Transmission offers firm and non-firm point-to-point transmission service, firm network transmission service, and six ancillary services (1) Scheduling, System Control and Dispatch Service ("Schedule 1"); (2) Reactive Supply and Voltage Control ("Schedule

2"); (3) Regulation and Frequency Response Service ("Schedule 3"); (4) Energy Imbalance Service ("Schedule 4"); (5) Operating Reserve-Spinning ("Schedule 5"); and (6) Operating Reserve-Supplemental ("Schedule 6").

Q. In general, how did Staff calculate the recommended rates?

A. Staff calculated rates based on embedded costs for firm and non-firm point-to-point service, firm network service, and the six required ancillary services. The Total Transmission Revenue Requirement ("TTRR") is equal to Staff's recommended Total Revenue Requirement for Southwest Transmission less revenues from Schedule 1: Load Dispatching and System Control, Direct Assignment Facilities, Special Contracts, and Other Revenues. Point-to-point rates are calculated using the TTRR and the annual coincident peak demand. The monthly network transmission service revenue requirement is equal to the TTRR less the point-to-point revenues divided by twelve. Rates for the six ancillary services are cost-based and explained later in my testimony.

Q. What is the Cooperative's proposed rate design?

A. Southwest Transmission has proposed the following changes to its rates:

Transmission Service	Present Rate	Cooperative Proposed Rate	% Change From Present
Firm Point-to-Point ($ / kW)	$2.805	$3.032	7.78%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.032	7.78%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,021,676	26.16%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,418,473	26.16%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.051	-9.35%
Schedule 2 – Network ($ / kW)	$0.065	$0.064	-1.55%
Schedule 3 ($ / kW)	$0.518	$0.411	-23.14%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$20.71	-10.49%
Schedule 5 ($ / kW)	$0.685	$0.621	-9.83%
Schedule 6 ($ / kW)	$0.343	$0.411	18.09%

Q. Did Staff adopt the ratemaking methodology used by Southwest Transmission in its proposed rate design?

A. In general, Staff employed the methods of cost allocation and rate design used by Southwest in its rate calculations. Staff has accepted Southwest's use of the annual system peak demand in the calculation of point-to-point rates. Staff has accepted the Cooperative's method of allocating the network service monthly revenue requirement based on its customers' load ratio shares. Staff has also utilized Southwest's cost allocation methodology for the purpose of determining the ancillary service rates (Schedules 1-6).

Q. What is Staff's recommended rate design?

A. Based on Staff's overall revenue requirement, Staff recommends the following rates for Southwest Transmission Cooperative.

Transmission Service	Present Rate	Staff	% Change From Present	% Change From Cooperative Proposed
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	-0.33%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	-0.33%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,046,503	26.30%	0.15%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,542	26.30%	0.15%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	0.00%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.064	13.35%	22.71%
Schedule 2 – Network ($ / kW)	$0.065	$0.080	20.76%	22.31%
Schedule 3 ($ / kW)	$0.518	$0.428	-19.09%	4.05%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$20.32	-12.39%	-1.90%
Schedule 5 ($ / kW)	$0.685	$0.646	-5.80%	4.11%
Schedule 6 ($ / kW)	$0.343	$0.417	19.54%	1.45%

Q. Explain the differences in Staff's recommended rate design versus the Cooperative's proposed rate design.

A. Staff's recommended revenue requirement net of regulatory asset revenues is equal to Southwest's $28,814,864 proposed revenue requirement net of regulatory asset revenues. Staff's recommended revenue requirement is discussed in detail in the testimony of Staff witness Brown.

As explained in greater detail below, the calculations of point-to-point and network service rates are largely based on the transmission revenue requirement and billing kW. However, where rate base, operating expenses, and/or the operating margin are used

explicitly to calculate rates, Staff's recommendations are used. For example, several point-to-point customers have discounts that are based, in part, on rate base, operating expenses, and operating margin. The cost-based ancillary service rates are also based in part on rate base, operating expenses, and operating margin. To the extent that Staff's recommendations for those items deviate from the Cooperative's proposed adjusted test year numbers, Staff's proposed rates will differ from the rates proposed by Southwest.

Q. Please discuss the billing KW and kWh Staff has used in your rate design.

A. In its original filing, Southwest provided both 2003 test year and forecasted 2004 billing data for network customers. Southwest provided annualized 2003 test year loads for its point-to-point customers. In its rate calculations, the Cooperative utilized the forecasted 2004 demands for its network customers along with the annualized 2003 contracted loads for its point-to-point customers. Staff has accepted the annualization adjustments made by Southwest for its point-to-point loads, and has used these billing units in the rate design. The adjustments recognize the termination of a 17.5 MW contract with the City of Mesa, a change in the contract with the Town of Thatcher. Staff believes these adjustments to contracted point-to-point loads are reasonable because they are known and measurable. However, it is Staff's general practice to use test year billing data. As such, Staff does not accept the 2004 forecasted load data for the Cooperative's network customers. Staff has used the 2003 test year billing data for network loads. Schedule EEC-1 shows the differences in billing data utilized by Southwest and Staff in the rate design.

Q. How does Staff's use of the 2003 test year billing kW for network loads affect the rate calculation?

A. As is discussed below, the calculation of the point-to-point rate is dependent on the annual system coincident peak demand. Using the 2003 test year billing kW rather than the

forecasted 2004 demand increases the annual system coincident peak demand slightly. The slight increase in annual system peak demand results in a slightly lower point-to-point rate.

In addition, the actual 2003 test year billing units yield different load ratio shares and subsequently, a different estimated allocation of the network service revenue requirement among Southwest's network customers than do the forecasted billing units. However, this estimated allocation is for informational purposes only. When new rates take effect, the actual 12-month rolling average load ratio shares will be used to allocate the network service revenue requirement among Southwest's network service customers.

POINT-TO-POINT TRANSMISSION SERVICE

Q. Please explain point-to-point transmission service.

A. Point-to-point transmission service is the reservation and transmission of capacity and energy on either a firm or non-firm basis from designated point(s) of receipt to designated point(s) of delivery. Points of receipt are points of interconnection between the transmission provider and the customer or a 3rd party at which power is received onto the transmission provider's system. Points of delivery are points at which power is delivered by the transmission provider to the receiving party.

Q. Please describe the calculation of the firm point-to-point transmission service rates.

A. Firm point-to-point ("PTP") rates are calculated by dividing the Total Transmission Revenue Requirement ("TTRR") by the Annual Coincident Peak Demand ("1 CP") of Southwest's system. Please see Schedule EEC-2 for the calculation of the PTP rate. The TTRR equals the Total Revenue Requirement less revenues from Schedule 1: Load Dispatching and System Control, Direct Assignment Facilities, Special Contracts, and

Other Revenues. The TTRR represents the amount of revenue that must be collected by point-to-point and network transmission service customers. Based on Staff's recommended overall revenue requirement and the system 1 CP, the recommended point-to-point rate is $3.022/kW. This represents an increase of 7.45 percent over Southwest's present rate.

Q. Please explain why the Annual Coincident Peak Demand is used to calculate the firm point-to-point transmission rate.

A. In Order No. 888, FERC allowed transmission providers more flexibility in setting rates as it did not mandate the use of a particular cost allocation methodology. FERC stated that it would no longer "summarily reject a firm point-to-point transmission rate developed by using the average of the 12 monthly system peaks."[2] However, using the annual system peak remains as a standard methodology. The use of 1 CP yields a lower PTP rate than the use of the twelve monthly system peaks ("12 CP") because the TTRR is divided by a larger denominator using the 1 CP. Southwest explained its rationale for using 1 CP to set point-to-point rates in its response to Staff's Ninth Set of Data Requests. The Cooperative stated that the use of the 1 CP in setting PTP rates reflects its need to remain competitive with neighboring utilities' point-to-point service rates. In addition, Southwest recognized that point-to-point transmission service is a less valuable service than network service and rates should reflect that fact.[3]

Staff acknowledges that point-to-point service is a less valuable transmission service than network service which allows a customer to integrate and economically dispatch its resources. As such, it is appropriate for pricing to reflect the relative value of the services. In addition, Southwest's transmission system was primarily built to serve its network

[2] FERC Order No. 888 page 301.
[3] Response to Staff's ninth set of data requests: 9-1.

customers, and it is the network customers that have priority with respect to the available transmission capacity. Southwest is entitled to recover its entire revenue requirement even if it is only serving network customers. To the extent there is available capacity, it is in the interest of the network customers for Southwest to offer and provide point-to-point service to non-member customers. Revenues from PTP service directly offset the network service revenue requirement that is allocated among the network customers. Staff concludes that it is in the interest of Southwest's members for the point-to-point rate to remain competitive. Using the 1 CP to set the PTP rate yields a lower and more competitive rate than the 12 CP.

Q. Did Staff consider any grandfathered contracts between Southwest and any of its customers in its recommended rate design?

A. Yes. The total transmission revenue requirement must be recovered through point-to-point and network services. To the extent that Southwest is contractually obligated to provide service on a discounted basis to certain point-to-point customers, those discounts must be considered when setting rates that are designed to recover the total transmission revenue requirement. Therefore, the total revenue recovered from point-to-point transmission service reflects revenues collected from the standard point-to-point rates as well as the discounted rates for Morenci Water & Electric and the Town of Thatcher.

Q. Briefly describe the discount applied to the point-to-point rate for Morenci Water & Electric.

A. Under its firm PTP service agreement with Southwest, Morenci Water & Electric ("MW&E") receives a discount based on the revenue requirement associated with the Greenlee 345/230 kV Transformer. The discount reflects MW&E's bypass of the Greenlee transformer. Whereas the standard PTP rate is calculated by dividing the TTRR

by the Annual Coincident Peak Demand ("1 CP"), the MW&E discounted PTP rate is calculated by dividing the TTRR less the revenue requirement associated with the Greenlee Transformer by the 1 CP. See Schedule EEC-3 for the calculation of the discount applied to the PTP rate for MW&E. Staff's recommended point-to-point rate for MW&E is $3.007/kW. This represents a discount of $0.015/kW from the recommended standard point-to-point rate.

Q. Briefly describe the discount applied to the point-to-point rate for the Town of Thatcher.

A. Under its firm PTP service agreement with Southwest, the Town of Thatcher ("Thatcher") receives a discount based on the expenses associated with Southwest's wheeling contract with the Western Area Power Administration ("WAPA"). The discount reflects Thatcher's use of its own WAPA rights that allow it to avoid using Southwest's system from the Westwing Substation to the Apache Substation. Whereas the standard PTP rate is calculated by dividing the TTRR by the Annual Coincident Peak Demand ("1 CP"), the Thatcher discounted PTP rate is calculated by dividing the TTRR less the expenses associated with the WAPA wheeling contract by the 1 CP. See Schedule EEC-4 for the calculation of the discount applied to the PTP rate for Thatcher. Staff's recommended point-to-point rate for the Town of Thatcher is $2.605/kW. This represents a discount of $0.417/kW from the recommended standard point-to-point rate.

Q. Please describe the calculation of the non-firm point-to-point transmission service rates.

A. FERC Order No. 888 established that the non-firm rate for point-to-point service should be capped at the firm rate. FERC concluded that pricing flexibility for non-firm service is acceptable but that any discounts given for non-firm point-to-point service must be offered

to all similarly situated customers. In its current OATT, Southwest sets forth its rate for non-firm PTP transmission service. The current rate for non-firm PTP service is equal to the firm PTP rate. Southwest has indicated that it provides non-firm PTP service on a limited and non-discriminatory basis.[4] The Cooperative's proposed non-firm rate for point-to-point service is set equal to the firm rate. Consistent with current practice, Staff's recommended non-firm point-to-point transmission rate is set equal to the recommended firm rate of $3.022/kW. Please see Schedule EEC-2 for the calculation of the firm and non-firm point-to-point rates.

NETWORK TRANSMISSION SERVICE

Q. Please explain network transmission service.

A. Network transmission service allows a customer to efficiently and economically dispatch and regulate its network resources to serve its network load within the area served by the transmission provider. Essentially, a customer taking service under Southwest's network transmission service tariff may inject power at any point on the system for delivery to any point on the system so long as those delivery points are designated as "network load." Network service allows a transmission customer to use Southwest's transmission system in a comparable manner to the way in which a vertically integrated utility uses its own transmission system.

Q. Please describe the calculation of the firm network transmission service rates.

A. Network transmission service is priced differently than point-to-point in that the average dollar per kW may change from month to month for a given customer. The pro forma OATT established by FERC Order No. 888 allows a transmission utility to set an annual network service transmission revenue requirement ("NSRR") to be allocated among all

[4] Southwest Transmission's Responses to Staff's Ninth Set of Data Requests: STF 9-3.

network transmission customers. The annual network service transmission revenue requirement is equal to the Total Transmission Revenue Requirement less the point-to-point revenues. Please see Schedule EEC-5 for the total revenues from point-to-point customers. The annual NSRR is divided by twelve to obtain the monthly NSRR. Schedule EEC-6 presents the calculation of the network service revenue requirement. Staff's recommended monthly NSRR is $1,420,542. The monthly NSRR is allocated among Southwest's network service customers using each customer's load ratio share. Each customer's load ratio share is equal to that customer's twelve-month rolling average network transmission service demand (measured in kW) divided by the total of all network service customers' twelve-month rolling average demand. Each customer's load ratio share is computed monthly. Each customer pays its monthly load ratio share times the monthly NSRR. Schedule EEC-7 shows the estimated allocation of the network service revenue requirement among Southwest's network service customers. Load Ratios used in revenue allocation shown in Schedule EEC-7 are based on 2002 and 2003 billing kW. When new rates take effect, actual rolling 12-month average Load Ratio Shares will be used to allocate the Network Service Revenue Requirement.

ANCILLARY SERVICES

Q. Please explain the six ancillary services that Southwest is required to offer.

A. Ancillary services are those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission provider's transmission system. FERC requires that transmission providers offer six ancillary services. Scheduling, System Control and Dispatch Service ("Schedule 1") is required to schedule the movement of power through, out of, within, or into a control area. Reactive Supply and Voltage Control ("Schedule 2") is the provision of reactive power needed to maintain transmission voltage on the transmission facilities

within acceptable limits. Regulation and Frequency Response Service ("Schedule 3") provides the continuous balancing of resources and load to maintain scheduled interconnection frequency at sixty cycles per second. Energy Imbalance Service ("Schedule 4") is provided when a difference occurs between scheduled and actual delivery of energy to a load located within a control area over an hour. Operating Reserve-Spinning ("Schedule 5") provides reserve power needed to serve load immediately to maintain reliability in the event of a system contingency. Operating Reserve-Supplemental ("Schedule 6") provides reserve power needed to serve load within fifteen minutes to maintain reliability in the event of a system contingency.

Of these services, FERC determined that the transmission provider is required to provide and the customer must purchase from the provider the first two services (Schedules 1-2). The remaining four services (Schedules 3-6) must be offered by the transmission provider but the customer has the option to acquire the services from the transmission provider, a third party, or self-provide.

Q. Please explain the calculation of the rate for Schedule 1: System Control and Load Dispatch.

A. The rate for Schedule 1 is based on Southwest's costs to schedule the movement of power through, out of, within, or into its control area. The rate is based on the system control and load dispatching expenses incurred by Southwest less the payment from AEPCO for the use of the Energy Management System owned by Southwest divided by the average capacity of the generation dispatched by Southwest. Schedule EEC-8 shows the calculation of the rate for Schedule 1. Staff's recommended rate for Schedule 1 is equal to Southwest's proposed rate of $0.289/kW which represents a decrease of 37.86 percent from the present rate. Southwest explained that the proposed decrease in the rate for

Schedule 1 is a result of the reclassification of revenue credits including the Energy Management System payment from AEPCO and an increase in generating capacity.[5]

Q. Is Southwest capable of providing all of the ancillary services using its own facilities?

A. As a stand-alone transmission provider, Southwest does not have its own source of generation resources with which to provide the generation-related ancillary services including Reactive Supply and Voltage Control, Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-Supplemental ("Schedules 2-6"). In order to fulfill its obligation to offer these five generation-related ancillary services, the Cooperative procures them from AEPCO. The rates charged to Southwest by AEPCO for its ancillary services are based on AEPCO's embedded costs to provide these services. Southwest passes the cost-based rates directly on to its transmission customers.

Q. Do the rates for the generation-related ancillary services reflect Southwest's costs?

A. Indirectly, the rates that Southwest has proposed for Schedules 2-6 reflect its costs to provide those services in that they are the rates they will pay AEPCO to provide those services to its customers. However, the costs included in the "cost-based" rates for Schedules 2-6 are costs that AEPCO incurs to provide those services.

Q. Did Staff use AEPCO's costs to calculate the rates for the generation-related ancillary services?

A. Yes. Although Schedules 2-6 are included in Southwest's open access transmission tariff, the costs to provide these generation-related services are incurred by AEPCO and passed on to Southwest. Therefore, Staff's recommended expenses, plant balances, and revenue

[5] Southwest Transmission's Responses to Staff's Ninth Set of Data Requests: STF 9-12.

requirements for AEPCO were used to calculate the rates for Schedules 2–6. Schedules 9, 10, and 11 show the derivation of the generation-related ancillary services.

Q. Is Southwest earning a rate of return on Schedules 2-6?

A. No. When a customer buys any generation-related ancillary services from Southwest, Southwest purchases those services from AEPCO at cost-based rates and passes AEPCO's cost-based rates on to the customer. The rate the customer pays for generation-related ancillary services is the same cost-based rate that Southwest pays to AEPCO for the provision of the generation-related ancillary services.

REGULATORY ASSET CHARGE

Q. Please explain the Regulatory Asset Charge.

A. Pursuant to Decision No. 62758, Southwest was authorized to collect a Regulatory Asset Charge ("RAC") to be assessed against all kWh sold to Southwest's Class A members according to the schedule set forth in the order. The RAC is to remain in effect until the full amount of regulatory assets assumed by Southwest is recovered. The initial total regulatory assets to be recovered was equal to $21,849,000. The RAC is to be collected over an eleven year period from December, 1999 through December, 2012 and is adjusted downward on an annual basis as set forth in the order. The RAC rate for 2005 is equal to $0.00133 per kWh as specified in Decision No. 62758 and Southwest's current OATT.

Q. What is Staff's recommendation with respect to the Regulatory Asset Charge?

A. Staff recommends that the Commission require Southwest to provide annual status reports that detail how much revenue has been collected through the RAC since December, 1999. The report should detail the billing kWh, RAC rate, and revenues collected through the

RAC by Class A member, by year. Southwest should file the report on February 1 of each year beginning February 1, 2006.

Staff also recommends that the Commission order that Southwest discontinue the assessment of the Regulatory Asset Charge at such time as it has collected the full $21,849,000 regardless of whether that event coincides with the projected schedule set forth in Decision No. 62758.

Q. Does this conclude your testimony?

A. Yes, it does.

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Schedule EEC-1

Comparison of Billing Units

	Actual 2003 Test Year Billing Units			Forecast 2004 Billing Units		
Month	**Network kW**	**PTP kW**	**Total kW**	**Network kW**	**PTP kW**	**Total kW**
Jan	227,326	227,000	454,326	251,454	227,000	478,454
Feb	246,798	227,000	473,798	271,964	227,000	498,964
Mar	233,791	227,000	460,791	232,235	227,000	459,235
Apr	241,243	227,000	468,243	244,410	227,000	471,410
May	377,915	229,000	606,915	381,943	229,000	610,943
Jun	416,091	229,000	645,091	415,103	229,000	644,103
Jul	468,093	229,000	**697,093**	466,214	229,000	**695,214**
Aug	455,578	229,000	684,578	442,545	229,000	671,545
Sep	411,003	229,000	640,003	413,101	229,000	642,101
Oct	363,220	229,000	592,220	329,224	229,000	558,224
Nov	241,090	227,000	468,090	250,291	227,000	477,291
Dec	273,026	227,000	500,026	271,211	227,000	498,211
1 CP	468,093	229,000	697,093	466,214	229,000	695,214
4 CP	437,691	229,000	666,691	434,241	229,000	663,241
12 CP	329,598	228,000	557,598	330,808	228,000	558,808

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Schedule EEC-2

Calculation of the Point-to-Point Rate

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depreciation & Amortization		6,852,107
Taxes		2,285,845
Operating Margin		3,439,610
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / kW**	
Schedule 1 - PtP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,933,749
Total Transmission Revenue Requirement		**25,278,875**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Rate ($/kW)
1 CP Rate - Standard	25,278,875	697,093		$36.26	$3.022

Point-to-Point Service	Standard Ave Montly kW	Standard PTP Rate	Standard PTP Revenute
Jan	163,000	$3.022	$492,586
Feb	163,000	$3.022	$492,586
Mar	163,000	$3.022	$492,586
Apr	163,000	$3.022	$492,586
May	163,000	$3.022	$492,586
Jun	163,000	$3.022	$492,586
Jul	163,000	$3.022	$492,586
Aug	163,000	$3.022	$492,586
Sep	163,000	$3.022	$492,586
Oct	163,000	$3.022	$492,586
Nov	163,000	$3.022	$492,586
Dec	163,000	$3.022	$492,586
Total			**$5,911,032**

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Schedule EEC-3

Calculation of the Discount to the Point-to-Point Rate for Morenci Water & Electric

Total Transmission Revenue Requirement	**25,278,875**
Greenlee Transformer Revenue Credit for MW&E	
(Remove Required Revenue Allocated to Greenlee Transformer from Total Transmission Revenue Requirement)	
Net Investement Greenlee Transformer	571,326
*Carrying Charge on Investment in Plant**	4.505%
Carrying Cost - Greenlee	25,740
O&M Expenses - Greenlee	100,869
Revenue Requirement Allocated to Greenlee Transformer	126,609
MW&E Transmission Revenue Requirement	**25,152,266**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - MW&E Greenlee Discount	25,152,266	697,093		$36.08	$0.015	$3.007

Point-to-Point Service	MW&E Ave Monthly kW	MW&E Discount PTP Rate	MW&E Discount PTP Revenue
Jan	60,000	$3.007	$180,420
Feb	60,000	$3.007	$180,420
Mar	60,000	$3.007	$180,420
Apr	60,000	$3.007	$180,420
May	60,000	$3.007	$180,420
Jun	60,000	$3.007	$180,420
Jul	60,000	$3.007	$180,420
Aug	60,000	$3.007	$180,420
Sep	60,000	$3.007	$180,420
Oct	60,000	$3.007	$180,420
Nov	60,000	$3.007	$180,420
Dec	60,000	$3.007	$180,420
Total			$2,165,040

* The Carrying Cost is equal to Staff's Recommended (Operating Margin / Rate Base)

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Schedule EEC-4

Calculation of the Discount to the Point-to-Point Rate for the Town of Thatcher

Total Transmission Revenue Requirement	**25,278,875**
Discount for Town of Thatcher - WAPA Wheeling Expenses	
(Remove WAPA Wheeling Expenses from Total Transmission Revenue Requirement)	
WAPA Wheeling Costs $3,484,188	3,484,188
Town of Thatcher Transmission Revenue Requirement	**21,794,687**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Thatcher Discount	21,794,687	697,093		$31.27	$0.417	$2.605

Point-to-Point Service	Thatcher Ave Monthly kW	Thatcher Discount PTP Rate	Thatcher Discount PTP Revenue
Jan	4,000	$2.605	$10,420
Feb	4,000	$2.605	$10,420
Mar	4,000	$2.605	$10,420
Apr	4,000	$2.605	$10,420
May	6,000	$2.605	$15,630
Jun	6,000	$2.605	$15,630
Jul	6,000	$2.605	$15,630
Aug	6,000	$2.605	$15,630
Sep	6,000	$2.605	$15,630
Oct	6,000	$2.605	$15,630
Nov	4,000	$2.605	$10,420
Dec	4,000	$2.605	$10,420
Total - Town of Thatcher			**$156,300**

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Schedule EEC-5

Calculation of the Point-to-Point Revenues

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Standard	25,278,875	697,093		$36.26	$0.000	$3.022
1 CP Rate - Thatcher Discount	21,794,687	697,093		$31.27	$0.417	$2.605
1 CP Rate - MW&E Greenlee Discount	25,152,266	697,093		$36.08	$0.015	$3.007

Point-to-Point Service	Standard Ave Monthly kW	Thatcher Ave Monthly kW	MW&E Ave Monthly kW	Standard PTP Rate	Thatcher Discount PTP Rate	MW&E Discount PTP Rate
Jan	163,000	4,000	60,000	$3.022	$2.605	$3.007
Feb	163,000	4,000	60,000	$3.022	$2.605	$3.007
Mar	163,000	4,000	60,000	$3.022	$2.605	$3.007
Apr	163,000	4,000	60,000	$3.022	$2.605	$3.007
May	163,000	6,000	60,000	$3.022	$2.605	$3.007
Jun	163,000	6,000	60,000	$3.022	$2.605	$3.007
Jul	163,000	6,000	60,000	$3.022	$2.605	$3.007
Aug	163,000	6,000	60,000	$3.022	$2.605	$3.007
Sep	163,000	6,000	60,000	$3.022	$2.605	$3.007
Oct	163,000	6,000	60,000	$3.022	$2.605	$3.007
Nov	163,000	4,000	60,000	$3.022	$2.605	$3.007
Dec	163,000	4,000	60,000	$3.022	$2.605	$3.007

Point-to-Point Service	Standard PTP Revenute	Thatcher Discount PTP Revenue	MW&E Discount PTP Revenue	Total PTP Annual Revenues
Jan	$492,586	$10,420	$180,420	$683,426
Feb	$492,586	$10,420	$180,420	$683,426
Mar	$492,586	$10,420	$180,420	$683,426
Apr	$492,586	$10,420	$180,420	$683,426
May	$492,586	$15,630	$180,420	$688,636
Jun	$492,586	$15,630	$180,420	$688,636
Jul	$492,586	$15,630	$180,420	$688,636
Aug	$492,586	$15,630	$180,420	$688,636
Sep	$492,586	$15,630	$180,420	$688,636
Oct	$492,586	$15,630	$180,420	$688,636
Nov	$492,586	$10,420	$180,420	$683,426
Dec	$492,586	$10,420	$180,420	$683,426
Total Revenues	$5,911,032	$156,300	$2,165,040	$8,232,372

Point-to-Point Revenue Total **$8,232,372**

Southwest Transmission Cooperative, Inc.
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Schedule EEC-6

Calculation of the Network Service Revenue Requirement

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depr&Amort		6,852,107
Taxes		2,285,845
Operating Margin		3,439,610
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / KW**	
Schedule 1 - PtP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,933,749
Total Transmission Revenue Requirement		**25,278,875**
Less: Point-to-Point Revenue Total		**8,232,372**
Network Services Annual Revenue Requirement		**17,046,503**
Network Services Monthly Revenue Requirement		**1,420,542**

Network Services Revenue Requirement	2003 TY Billing Demand kW	Recommended Revenue Requirement Network Service	Average Network Service $/kW
Annual		**17,046,503**	**$4.310**
January	227,326	$1,420,542	$6.249
February	246,798	$1,420,542	$5.756
March	233,791	$1,420,542	$6.076
April	241,243	$1,420,542	$5.888
May	377,915	$1,420,542	$3.759
June	416,091	$1,420,542	$3.414
July	468,093	$1,420,542	$3.035
August	455,578	$1,420,542	$3.118
September	411,003	$1,420,542	$3.456
October	363,220	$1,420,542	$3.911
November	241,090	$1,420,542	$5.892
December	273,026	$1,420,542	$5.203

Southwest Transmission Cooperative, Inc.
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Schedule EEC-7

Estimated Allocation of the Network Service Revenue Requirement*

NETWORK CUSTOMERS		January	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total 2003	Average
Anza	2002 kW Demand	6,432	6,084	5,472	5,496	6,660	7,068	8,628	8,400	7,812	5,112	6,324	6,912	80,400	6,700
Anza	Loads 2003	5,436	5,556	6,012	5,496	7,452	7,920	9,516	9,264	7,644	6,708	5,424	6,036	82,464	6,872
Anza	12 Month Rolling Avg	6,617	6,573	6,618	6,618	6,684	6,755	6,829	6,901	6,887	7,020	6,945	6,872	81,319	6,777
Anza	Revenue - 2003 Load	32,077	31,943	32,112	32,327	32,428	32,250	31,794	31,371	30,700	30,552	30,057	29,618	377,228	31,436
Duncan	2002 kW Demand	3,320	2,360	3,440	3,780	5,320	6,040	5,240	5,340	4,840	2,900	3,080	3,460	49,120	4,093
Duncan	Loads 2003	3,000	3,280	3,280	3,420	4,780	5,400	5,180	4,820	5,380	4,600	3,300	3,760	50,200	4,183
Duncan	12 Month Rolling Avg	4,067	4,143	4,130	4,100	4,055	4,002	3,997	3,953	3,998	4,140	4,158	4,183	48,927	4,077
Duncan	Revenue - 2003 Load	19,714	20,135	20,039	20,027	19,673	19,105	18,607	17,971	17,823	18,018	17,997	18,030	227,140	18,928
Graham	2002 kW Demand	14,758	15,023	15,662	20,461	27,751	33,126	33,349	30,972	28,798	16,583	14,149	16,503	267,135	22,261
Graham	Loads 2003	13,710	14,481	15,790	17,075	23,316	31,629	33,111	33,096	29,452	22,775	15,313	14,738	264,486	22,041
Graham	12 Month Rolling Avg	22,174	22,129	22,139	21,857	21,488	21,363	21,343	21,520	21,575	22,091	22,188	22,041	261,906	21,826
Graham	Revenue - 2003 Load	107,493	107,539	107,424	106,767	104,249	101,991	99,367	97,827	96,172	96,141	96,024	94,993	1,215,987	101,332
Mohave 1	2002 kW Demand	71,793	71,893	62,190	94,674	110,200	99,000	116,000	115,000	96,000	79,000	60,296	64,007	1,040,053	86,671
Mohave 1	Loads 2003	60,706	68,839	61,639	64,778	116,000	137,930	130,000	129,000	109,000	112,000	65,082	73,050	1,128,024	94,002
Mohave 1	12 Month Rolling Avg	85,747	85,493	85,447	82,955	83,439	86,683	87,850	89,016	90,100	92,850	93,248	94,002	1,056,829	88,069
Mohave 1	Revenue - 2003 Load	415,678	415,469	414,603	405,215	404,809	413,843	409,002	404,653	401,632	404,092	403,564	405,142	4,897,701	408,142
Sulphur Springs	2002 kW Demand	94,849	93,072	82,413	71,220	103,544	110,561	112,009	107,663	102,241	76,651	75,788	92,659	1,122,670	93,556
Sulphur Springs	Loads 2003	82,360	84,958	82,242	83,467	101,093	112,464	123,813	121,214	108,324	101,850	83,848	96,867	1,182,500	98,542
Sulphur Springs	12 Month Rolling Avg	92,515	91,839	91,825	92,845	92,641	92,800	93,783	94,913	95,419	97,519	98,191	98,542	1,132,832	94,403
Sulphur Springs	Revenue - 2003 Load	448,486	446,310	445,550	453,525	449,455	443,045	436,627	431,456	425,345	424,416	424,955	424,707	5,253,877	437,823
Trico	2002 kW Demand	60,797	59,164	51,292	61,409	79,649	96,441	94,660	92,968	90,421	62,274	45,742	58,683	853,500	71,125
Trico	Loads 2003	48,450	55,671	51,504	52,628	83,909	98,670	109,062	108,124	91,233	84,203	58,199	68,109	909,762	75,814
Trico	12 Month Rolling Avg	70,096	69,805	69,823	69,091	69,446	69,632	70,832	72,095	72,163	73,990	75,028	75,814	857,813	71,484
Trico	Revenue - 2003 Load	339,806	339,232	338,792	337,491	336,922	332,436	329,772	327,731	321,674	322,013	324,709	326,750	3,977,329	331,444
AEPCO Bundled	2002 kW Demand	8,000	7,880	7,880	7,620	7,360	6,920	7,320	6,740	6,700	6,760	6,700	6,740	86,620	7,218
Power Sales using	Loads 2003	6,320	6,220	5,980	6,260	6,780	6,900	6,360	5,920	6,100	5,700	2,780	2,660	67,980	5,665
Network Service	12 Month Rolling Avg	7,078	6,940	6,782	6,668	6,620	6,618	6,538	6,470	6,420	6,332	6,005	5,665	78,137	6,511
Cyprus TB and PD	Revenue - 2003 Load	34,314	33,726	32,906	32,573	32,117	31,597	30,441	29,412	28,618	27,556	25,989	24,416	363,664	30,305
Mohave 2	2002 kW Demand	-	-	-	-	13,579	-	-	-	-	11,570	-	-	25,149	2,096
Mohave 2	Loads 2003	-	-	-	-	21,304	-	35,037	29,166	38,625	15,590	-	-	139,722	11,644
Mohave 2	12 Month Rolling Avg	2,096	2,096	2,096	2,096	2,740	2,740	5,659	8,090	11,309	11,644	11,644	11,644	73,850	6,154
Mohave 2	Revenue - 2003 Load	10,160	10,185	10,169	10,237	13,291	13,079	26,348	36,775	50,409	50,674	50,391	50,183	331,900	27,658
Safford/Gila	2002 kW Demand	-	-	-	-	-	-	-	-	-	9,649	7,038	7,691	24,378	2,032
Safford/Gila	Loads 2003	7,344	7,793	7,344	8,119	13,281	15,178	16,014	14,974	15,245	9,794	7,144	7,806	130,036	10,836
Safford/Gila	12 Month Rolling Avg	2,644	3,293	3,905	4,582	5,688	6,953	8,288	9,535	10,806	10,818	10,827	10,836	88,174	7,348
Safford/Gila	Revenue - 2003 Load	12,815	16,003	18,947	22,379	27,597	33,196	38,585	43,346	48,169	47,081	46,856	46,704	401,677	33,473
Total	2002 kW Demand	259,949	255,476	228,349	264,660	354,063	359,156	377,206	367,083	336,812	270,499	219,117	256,655	3,549,025	295,752
Total	Loads 2003	227,326	246,798	233,791	241,243	377,915	416,091	468,093	455,578	411,003	363,220	241,090	273,026	3,955,174	329,598
Total	12 Month Rolling Avg	293,034	292,310	292,764	290,812	292,800	297,545	305,119	312,493	318,676	326,403	328,234	329,598	3,679,786	306,649
Total	Revenue - 2003 Load	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	1,420,542	17,046,503	1,420,542
Average	Per kW-month	$ 6.249	$ 5.756	$ 6.076	$ 5.888	$ 3.759	$ 3.414	$ 3.035	$ 3.118	$ 3.456	$ 3.911	$ 5.892	$ 5.203	$ 4.310	$ 4.310

* Load Ratios used in revenue allocation are based on 2002 and 2003 billing kW. Actual rolling 12-month average Load Ratio Shares will be used to allocate the Network Service Revenue Requirement.

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Schedule EEC-8

Calculation of Schedule 1: System Control and Load Dispatch

Costs: System Control and Load Dispatch	Southwest Adjusted 2003 TY	Staff Adjustments	Staff Adjusted 2003 TY
556 - Power Prod. Exp. - Maint. Syst Cntl & Load Disp	2,537,388	-	2,537,388
557 - Power Prod. Exp. - Maint. Other Expenses	3,946	-	3,946
561 - Transm Exp – Op. Load Disp	635	(9)	626
EMS payment from AEPCO	(306,624)	-	(306,624)
Total Cost - System Control and Load Dispatch	**2,235,345**	**(9)**	**2,235,336**

Generation Capacity	Net kW Rate
Apache Units (@SRSG)	585,300
Purchased Pwr (PNM & TECO)	29,667
Federal Hydro (CRSP & PD)	29,113
Total Generation Capacity	**644,080**

Annual Rate ($ / kW)	**$ 3.471**
Monthly Rate ($ / kW)	**$ 0.289**

Point-to-Point Schedule 1

Month			Present Rate		Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,000	$	0.4220	$	0.2890	95,794	65,603
Feb	227,000	$	0.4220	$	0.2890	95,794	65,603
Mar	227,000	$	0.4220	$	0.2890	95,794	65,603
Apr	227,000	$	0.4220	$	0.2890	95,794	65,603
May	229,000	$	0.4220	$	0.2890	96,638	66,181
Jun	229,000	$	0.4220	$	0.2890	96,638	66,181
Jul	229,000	$	0.4220	$	0.2890	96,638	66,181
Aug	229,000	$	0.4220	$	0.2890	96,638	66,181
Sep	229,000	$	0.4220	$	0.2890	96,638	66,181
Oct	229,000	$	0.4220	$	0.2890	96,638	66,181
Nov	227,000	$	0.4220	$	0.2890	95,794	65,603
Dec	227,000	$	0.4220	$	0.2890	95,794	65,603
Total Schedule 1 Revenues from Point-to-Point Customers						1,154,592	**790,704**

Network Service Schedule 1

Month			Present Rate		Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,326	$	0.4220	$	0.2890	95,932	65,697
Feb	246,798	$	0.4220	$	0.2890	104,149	71,325
Mar	233,791	$	0.4220	$	0.2890	98,660	67,566
Apr	241,243	$	0.4220	$	0.2890	101,805	69,719
May	377,915	$	0.4220	$	0.2890	159,480	109,217
Jun	416,091	$	0.4220	$	0.2890	175,590	120,250
Jul	468,093	$	0.4220	$	0.2890	197,535	135,279
Aug	455,578	$	0.4220	$	0.2890	192,254	131,662
Sep	411,003	$	0.4220	$	0.2890	173,443	118,780
Oct	363,220	$	0.4220	$	0.2890	153,279	104,971
Nov	241,090	$	0.4220	$	0.2890	101,740	69,675
Dec	273,026	$	0.4220	$	0.2890	115,217	78,905
Total Schedule 1 Revenues from Network Customers						1,669,083	**1,143,045**

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Schedule EEC-9

Calculation of Schedule 2: Cost of Reactive Power (VAR) Production

Line No.	Power Factor	Gross Namplate KW	Power Factor Generator Nameplate	Weighted Power Factor
1	Steam Unit 1	77,400	0.85	10.9%
2	Steam Unit 2	195,000	0.85	27.4%
3	Steam Unit 3	195,000	0.85	27.4%
4	Gas Turbine 1	10,000	0.85	1.4%
5	Gas Turbine 2	20,000	0.90	3.0%
6	Gas Turbine 3	65,000	0.90	9.7%
7	Gas Turbine 4	42,000	0.85	5.9%
	Total Capacity	604,400		85.7%
8	**1 - Power Factor**			14.30%

		Account	Original Cost	Net Plant in Service
	AEPCO System Investment in Power Production Facilities			
9	Total Production Plant in Service		389,590,504	203,345,337
10	Turbogenerator Systems	314 & 344	55,169,579	26,798,200
11	Accessory Electric Equipment	315 & 345	19,941,398	9,686,381
	Separation of Production Plant Allocation to VAR Production			
12	Generator and Exciter Systems	(8) * (10)		3,831,291
13	Accessory Electric Equipment	(8) * (11)		1,384,845
14	Other Power Production Facilities	(9) - (12) - (13) * (0.25%)		495,323
15	Total Plant Allocated to VAR Production			5,711,459
16	TIER & Associated Required Rate of Return (AEPCO)		1.33	9.363%
17	Annualized Required Revenue Allocation to VAR Production			$ 534,743

	Schedule 2: Reactive Power (VAR) Production	Billing Unit	Demand kW		$/KW/year	$/kW/month
18	Network Service Rate	System 12 CP	557,598	$	0.9590	$ 0.0800
19	Point-to-Point Rate	System 1 CP	697,093	$	0.7671	$ 0.0640

Southwest Transmission Cooperative, Inc.
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Schedule EEC-10

Calculation of Schedule 4: Energy Imbalance

Southwest Transmission Proposed Rate

Costs: Energy Imbalance Incremental Energy Costs	**TY 2003** Southwest Per Books	**TY 2003** Southwest Pro Forma Adjustments	**TY 2003** Southwest Adjusted	**TY 2003** Southwest Cost of Service: Energy	**TY 2003** Southwest Schedule 4 Costs
Production Exp - Fuel - 501/547	62,295,417	(2,491,992)	59,803,425	57,819,080	57,819,080
Purchased Power Exp - 555	9,639,192	446,346	10,085,538	10,085,538	10,085,538
Production Exp - Transmission	8,036,486	-	8,036,486	77,291	77,291
Total	79,971,095	(2,045,646)	77,925,449	67,981,909	67,981,909
Total Energy Sales (kWh)					3,281,912,645
Southwest Transmission Proposed - Cost per kWh					$ 0.02071
Southwest Transmission Proposed - Cost per MWH					$ 20.71

Staff Recommended Rate

Costs: Energy Imbalance Incremental Energy Costs	**TY 2003** Southwest Cost of Service: Energy	**TY 2003** Staff Adjustments to Cost of Service: Energy	**TY 2003** Staff Recommended Schedule 4 Costs
Production Exp - Fuel - 501/547	57,819,080	(1,030,873)	56,788,207
Purchased Power Exp - 555	10,085,538	(250,000)	9,835,538
Production Exp - Transmission	77,291	-	77,291
Total	67,981,909	(1,280,873)	66,701,036
Total Energy Sales (kWh)			3,281,912,645
Staff Recommended - Cost per kWh			$ 0.02032
Staff Recommended - Cost per MWH			$ 20.32

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Schedule EEC-11

Calculation of Schedule 3, 5, & 6

Cost of Ancillary Services:

Regulation and Frequency Response, Operating Reserve - Spinning, and Operating Reserve - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Production Plant	O&M Expenses	A&G Expenses	Tax Expenses	Deprectiation Expenses	Required Return on Production Plant	Annual Revenue Requirement	Revenue Requirement per KW
Total to Allocate			25,165,359	9,589,717	3,346,839	7,539,289	19,428,883	65,070,087	
ST1	77,400	21,981,781	1,513,147	576,612	201,239	453,324	1,168,223	3,912,545	$ 50.55
ST2	185,000	154,434,564	10,630,722	4,051,030	1,413,821	3,184,858	8,207,435	27,487,866	$ 148.58
ST3	186,000	147,491,658	10,152,797	3,868,908	1,350,260	3,041,676	7,838,454	26,252,095	$ 141.14
IC1/GT1	10,400	1,843,357	126,890	48,354	16,876	38,015	97,965	328,100	$ 31.55
GT2	17,600	2,898,287	199,508	76,026	26,533	59,771	154,030	515,867	$ 29.31
GT3	66,500	8,359,793	575,458	219,289	76,532	172,401	444,282	1,487,963	$ 22.38
GT4	42,400	28,572,620	1,966,837	749,499	261,577	589,245	1,518,494	5,085,651	$ 119.94
Total	585,300	365,582,060	25,165,359	9,589,717	3,346,839	7,539,289	19,428,883	65,070,087	$ 111.17

Schedule 3
Regulation and Frequency Response

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST1	77,400	$ 50.55	3,912,545
ST2	185,000	$ 148.58	27,487,866
ST3	186,000	$ 141.14	26,252,095
Total	448,400		57,652,506

Annual Generation Capacity Rate	$	128.574
Monthly Generation Capacity Rate	$	10.714
Required Reserve Percentage		3.99%
Schedule 3 Monthly Rate ($/KW)	**$**	**0.4280**

Schedule 5
Operating Reserves - Spinning

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST2	185,000	149	27,487,866
ST3	186,000	141	26,252,095
Total	371,000		53,739,961

Annual Generation Capacity Rate	$	144.852
Monthly Generation Capacity Rate	$	12.071
Required Reserve Percentage		5.35%
Schedule 5 Monthly Rate ($/KW)	**$**	**0.6460**

Schedule 6
Operating Reserves - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
GT2	17,600	$ 29.31	515,867
GT4	42,400	$ 119.94	5,085,651
Total	60,000		5,601,518

Annual Generation Capacity Rate	$	93.359
Monthly Generation Capacity Rate	$	7.780
Required Reserve Percentage		5.36%
Schedule 6 Monthly Rate ($/KW)	**$**	**0.4170**

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE	))))	DOCKET NO. E-04100A-04-0527

SURREBUTTAL

TESTIMONY

OF

ERIN CASPER

PUBLIC UTILITIES ANALYST IV

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

ALL-STATE LEGAL®
EXHIBIT
S-10
ADMITTED

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Calculation of the Network Service Revenue Requirement EEC-6

Estimated Allocation of the Network Service Revenue Requirement EEC-7

Calculation of Schedule 1: System Control and Load Dispatch EEC-8

Calculation of Schedule 2: Cost of Reactive Power (VAR) Production EEC-9

Calculation of Schedule 4: Energy Imbalance EEC-10

Calculation of Schedule 3, 5, & 6 ..... EEC-11

Comparison of Billing Units EEC-12

Calculation of the Point-to-Point Rate EEC-13

Calculation of the Discount to the Point-to-Point Rate for the Town of Thatcher EEC-14

Calculation of the Point-to-Point Revenues EEC-15

Calculation of the Network Service Revenue Requirement EEC-16

Estimated Allocation of the Network Service Revenue Requirement EEC-17

Calculation of Schedule 1: System Control and Load Dispatch EEC-18

Calculation of Schedule 2: Cost of Reactive Power (VAR) Production EEC-19

Calculation of Schedule 4: Energy Imbalance EEC-20

Calculation of Schedule 3, 5, & 6 ..... EEC-21

EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-04100A-04-0527

The following surrebuttal testimony presents Staff's response to Southwest Transmission Cooperative, Inc.'s ("Southwest Transmission" or "Cooperative") rebuttal testimony regarding the rate design and the loss of revenues associated with the termination of Morenci Water & Electric's 60 MW firm point-to-point contract effective January 1, 2006.

Staff provides updated rate recommendations using Staff's revised revenue requirement to be effective through December 31, 2005. Staff also presents a second set of recommended rates consistent with its recommendation that, effective January 1, 2006, Southwest's rates should increase to reflect the loss of revenue resulting from the termination of the Morenci Water & Electric 60 MW firm point-to-point contract.

INTRODUCTION

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

A. My name is Erin Casper. I am a Public Utility Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington, Phoenix, Arizona 85007.

Q. Did you file direct testimony in this matter?

A. Yes. On February 23, 2005, I submitted direct testimony that addressed the cost allocation and rate recommendations for Southwest Transmission Cooperative's ("Southwest" or "Southwest Transmission" or "Cooperative") application for a general rate increase.

Q. What is the purpose of this surrebuttal testimony?

A. I will provide Staff's updated rate recommendations to be effective through December 31, 2005 using Staff's revised revenue requirement described in the surrebuttal testimony of Staff Witness Crystal Brown. Secondly, consistent with Staff Witness Brown's recommendation that, effective January 1, 2006, Southwest's rates should increase to reflect the loss of revenue due to the termination of the Morenci Water & Electric ("MW&E") 60 MW firm point-to-point contract, I will provide Staff's recommended rates to go into effect January 1, 2006.

SUMMARY OF RECOMMENDATIONS

Q. In general, how did Staff calculate the revised recommended rates to be effective through December 31, 2005?

A. Staff calculated revised rates consistent with the methodology described in the direct testimony. While recommending the same overall revenue requirement of $28,814,864 for Southwest Transmission Company, in its surrebuttal testimony, Staff proposed some

changes to depreciation expenses and operating margin that require Staff to make minor modifications to the recommended rates. These changes yield a slightly lower point-to-point rate for Morenci Water & Electric (effective through December 31, 2005) and a slightly higher Network Services Revenue Requirement.

Q. Please describe Staff's recommendation with respect to Southwest's proposal to phase in rates to reflect revenue loss associated with the termination of the MW&E 60 MW firm point-to-point contract on January 1, 2006.

A. Southwest has requested that the Commission authorize initial rates to be effective through December 31, 2005 followed by a second set of rates to reflect the termination of the MW&E 60 MW firm point-to-point contract to be effective beginning January 1, 2006. Staff recommends that the Commission approve a rate phase-in plan as set forth on Schedule EEC-1. Both sets of recommended rates are designed to recover Staff's recommended revenue requirement of $28,814,864.

Q. In general, how did Staff calculate the revised recommended rates to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract?

A. Staff adjusted the values for the system coincident peak demand ("1CP"), system average monthly peak demand ("12CP"), and point-to-point megawatts that reflect the loss of 60 MW of point-to-point load. Staff then calculated recommended rates to be effective beginning January 1, 2006 consistent with the methodology described in the direct testimony and used to calculate recommended rates to be in effect through December 31, 2005.

RATES EFFECTIVE THROUGH DECEMBER 31, 2005

Q. What is the Cooperative's revised proposed rate design to be effective through December 31, 2005?

A. Southwest Transmission has proposed the following revised rates to be effective through December 31, 2005:

Transmission Service	Present Rate	Cooperative Rebuttal Rate	% Change From Present
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,046,503	26.30%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,542	26.30%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.064	13.35%
Schedule 2 – Network ($ / kW)	$0.065	$0.080	20.76%
Schedule 3 ($ / kW)	$0.518	$0.428	-19.09%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0203	-12.39%
Schedule 5 ($ / kW)	$0.685	$0.646	-5.80%
Schedule 6 ($ / kW)	$0.343	$0.417	19.54%

Q. What is Staff's revised recommended rate design to be effective through December 31, 2005?

A. Based on Staff's overall revised revenue requirement, Staff recommends the following rates for Southwest Transmission Cooperative to be effective through December 31, 2005:

Transmission Service	Present Rate	Staff Surrebuttal	% Change From Present	% Change From Cooperative Rebuttal
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	0.0%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	0.0%

Firm Network Service - Annual Rev. Req.	$13,104,193	$17,048,663	26.31%	0.013%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,722	26.31%	0.013%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	0.0%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.072	25.13%	11.8%
Schedule 2 – Network ($ / kW)	$0.065	$0.090	32.54%	11.8%
Schedule 3 ($ / kW)	$0.518	$0.444	-15.42%	3.7%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0204	-12.00%	0.4%
Schedule 5 ($ / kW)	$0.685	$0.671	-2.01%	3.8%
Schedule 6 ($ / kW)	$0.343	$0.433	23.30%	3.8%

Q. Explain the differences in Staff's revised recommended rate design versus Staff's originally filed recommended rate design for rates to be effective through December 31, 2005.

A. Although Staff recommended the same overall revenue requirement of $28,814,864 for Southwest Transmission Company as in its direct testimony, Staff's surrebuttal testimony proposes changes to depreciation expenses and operating margin that yield an increased rate of return on rate base. The rate of return is used in the calculation of the discount to the Morenci Water & Electric point-to-point rate. The larger rate of return produces a slightly larger discount, thus, a lower point-to-point rate for MW&E. The lower rate for MW&E yields slightly lower total point-to-point revenues. Staff's revised recommended point-to-point rate for MW&E is $3.004/kW as compared to Staff's original recommendation of $3.007/kW. Schedule EEC-3 shows the revised calculation of the discounted point-to-point rate for MW&E.

Due to the decreased point-to-point revenues, the Network Services Revenue Requirement, which is equal to the Total Revenue Requirement less Other Revenues less Schedule 1 Revenues less Point-to-Point Revenues, must increase slightly. Staff's revised recommended monthly Network Service Revenue Requirement is $1,420,722 as compared

to its original recommendation of $1,420,542. Schedule EEC-6 shows the revised calculation for the Network Service Revenue Requirement and Schedule EEC-7 shows the revised estimated allocation of the Network Service Revenue Requirement among the Network Service customers.

Finally, Staff's recommended rates for Ancillary Services Schedules 2-6 have been revised as necessary to account for minor revisions to Staff's recommended operating expenses and rate of return for AEPCO. Rates for Ancillary Services Schedules 2-6 increased slightly as a result of a slightly higher rate of return on rate base for AEPCO. Schedules EEC-9, EEC-10, and EEC-11 show Staff's revised recommended rates for Ancillary Services Schedules 2-6.

Q. Explain the differences in Staff's revised recommended rate design versus the Cooperative's revised proposed rate design for rates through December 31, 2005.

A. In its rebuttal testimony, Southwest proposed rates equal to those recommended by Staff in its direct testimony. Thus, Staff's revised recommended rates differ from the Cooperative's revised proposed rates as described above.

RATES EFFECTIVE BEGINNING JANUARY 1, 2006

Q. What is the Cooperative's proposed rate design to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract?

A. Southwest Transmission has proposed the following rates to go into effect following the termination of the MW&E 60 MW firm point-to-point contract:

Transmission Service	Present Rate	Cooperative Rebuttal Rate	% Change From Present
Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%

Non-Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%
Firm Network Service - Annual Rev. Req.	$13,104,193	$18,792,971	36.06%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,566,081	36.06%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.064	13.35%
Schedule 2 – Network ($ / kW)	$0.065	$0.080	20.76%
Schedule 3 ($ / kW)	$0.518	$0.428	-19.09%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0203	-12.39%
Schedule 5 ($ / kW)	$0.685	$0.646	-5.80%
Schedule 6 ($ / kW)	$0.343	$0.417	19.54%

Q. What is Staff's recommended rate design to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract?

A. Based on Staff's overall revised revenue requirement and adjusted values for the system coincident peak demand ("1CP"), system average monthly peak demand ("12CP"), and point-to-point megawatts that reflect the termination of the MW&E 60 MW firm point-to-point contract, Staff recommends the following rates for Southwest Transmission Cooperative to go into effect January 1, 2006:

Transmission Service	Present Rate	Staff Surrebuttal	% Change From Present	% Change From Cooperative Rebuttal
Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%	0.0%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.334	17.28%	0.0%
Firm Network Service - Annual Rev. Req.	$13,104,193	$18,792,971	36.06%	0.0%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,566,081	36.06%	0.0%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	0.0%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.078	33.14%	19.78%
Schedule 2 – Network ($ / kW)	$0.065	$0.100	43.08%	22.31%
Schedule 3 ($ / kW)	$0.518	$0.444	-15.42%	3.7%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$23.25	$0.0204	-12.00%	0.4%

Schedule 5 ($ / kW)	$0.685	$0.671	-2.01%	3.8%
Schedule 6 ($ / kW)	$0.343	$0.433	23.30%	3.8%

Q. Explain the differences in Staff's revised recommended rate design to be effective through December 31, 2005, and Staff's recommended rate design to go into effect January 1, 2006, following the termination of the MW&E 60 MW firm point-to-point contract.

A. Southwest will lose a total of $2,370,960[1] in annual revenues following the termination of the MW&E 60 MW firm point-to-point contract on January 1, 2006. As a result, Staff has recalculated rates that recognize the loss of this revenue to go into effect beginning January 1, 2006. Schedule EEC-1 shows Staff's recommended rates effective through December 31, 2005, compared to rates effective January 1, 2006. Essentially, Staff recalculated the rates using revised values for the system coincident peak demand ("1CP"), system average monthly peak demand ("12CP"), and point-to-point megawatts that reflect the loss of 60 MW of point-to-point load. The revised billing data, shown on Schedule EEC-12, yield the following results.

Schedule 1 point-to-point revenues decrease as a result of the loss of 60 MW of point-to-point load. The reduction in Schedule 1 revenues effectively increases the Total Transmission Revenue Requirement which is equal to the Total Revenue Requirement less Other Revenues less Schedule 1 Revenues.

The increased Total Transmission Revenue Requirement is divided by the lower system coincident peak demand ("1CP") to derive the higher point-to-point rates shown on

[1] The total revenue loss of $2,370,960 is equal to $2,162,880 in annual point-to-point revenues plus $208,080 in annual Schedule 1 revenues.

Schedule EEC-13. The point-to-point rate increases from $3.022[2] to $3.334. The same methodology applies to the calculation of the discounted point-to-point rate for the Town of Thatcher shown on Schedule EEC-14. The discounted point-to-point rate for the Town of Thatcher increases from $2.605[3] to $2.878. As calculated on Schedule EEC-15, the total revenues derived from point-to-point service drop from $8,230,212[4] to $6,693,984 as a result of the loss of 60 MW of point-to-point load.

As a result of the decrease in point-to-point revenues, the monthly Network Service Revenue Requirement increases from $1,420,722[5] to $1,566,081. The Network Service Revenue Requirement, shown on Schedule EEC-16, is equal to the Total Transmission Revenue Requirement less the point-to-point revenues and is allocated among the Network Service customers as shown on Schedule EEC-17.

Finally, Ancillary Service Schedule 2, Cost of Reactive Power (VAR) Production, must be revised to reflect the revised 1CP and 12CP values. The recommended rates for Schedule 2 are shown on Schedule EEC-19.

Q. Explain the differences in Staff's revised recommended rate design versus the Cooperative's revised proposed rate design to go into effect January 1, 2006 following the termination of the MW&E 60 MW firm point-to-point contract.

A. There is only one major difference between Staff's recommended rates and the Cooperative's proposed rates to go into effect beginning January 1, 2006. Southwest did not revise the rate for Ancillary Service Schedule 2, Cost of Reactive Power (VAR) Production, to reflect the changes in the 1CP and the 12CP. Staff finds that it is

[2] Shown on Schedule EEC-2.
[3] Shown on Schedule EEC-4.
[4] Shown on Schedule EEC-5.
[5] Shown on Schedule EEC-6.

appropriate to recalculate the rate for Schedule 2 to reflect the loss of the 60 megawatts associated with the termination of the MW&E firm point-to-point contract and recommends the rates set forth on Schedule EEC-19.

Rates for Ancillary Services Schedules 3-6 do not depend on the billing data for Southwest Transmission Cooperative, and thus, do not need to be revised due to the loss of the MW&E contract. Rates for Ancillary Service Schedules 3-6 effective January 1, 2006 are shown on Schedules EEC-20 and EEC-21.

Q. Does this conclude your testimony?

A. Yes, it does.

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Surrebuttal Schedule EEC-1

Comparison of Recommended Rates

Transmission Service	Present Rate	Staff Recommended Effective Through December 31, 2005	% Change from Present	Staff Recommended Effective Beginning January 1, 2006	% Change from Staff Recommended 2005 Rates	% Change from Present
Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	$3.334	9.83%	17.28%
Non-Firm Point-to-Point ($ / kW)	$2.805	$3.022	7.45%	$3.334	9.83%	17.28%
Firm Network Service - Annual Rev. Req.	$13,104,193	$17,048,663	26.31%	$18,792,971	9.74%	36.06%
Firm Network Service - Monthly Rev. Req.	$1,092,016	$1,420,722	26.31%	$1,566,081	9.74%	36.06%
Schedule 1 ($ / kW)	$0.422	$0.289	-37.86%	$0.289	0.00%	-37.86%
Schedule 2 – Point-to-Point ($ / kW)	$0.056	$0.072	25.13%	$0.078	8.00%	33.14%
Schedule 2 – Network ($ / kW)	$0.065	$0.090	32.54%	$0.100	10.54%	43.08%
Schedule 3 ($ / kW)	$0.518	$0.444	-15.42%	$0.444	0.00%	-15.42%
Schedule 4 - +/- 1.5% Imbalance ($ / MW)	$0.0230	$0.0204	-12.00%	$0.0204	0.00%	-12.00%
Schedule 5 ($ / kW)	$0.685	$0.671	-2.01%	$0.671	0.00%	-2.01%
Schedule 6 ($ / kW)	$0.343	$0.433	23.30%	$0.433	0.00%	23.30%

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Surrebuttal Schedule EEC-2

Calculation of the Point-to-Point Rate
Recommended Rates Through December 31, 2005

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depreciation & Amortization		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / kW**	
Schedule 1 - PtP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,933,749
Total Transmission Revenue Requirement		**25,278,875**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Rate ($/kW)
1 CP Rate - Standard	25,278,875	697,093		$36.26	$3.022

Point-to-Point Service	Standard Ave Montly kW	Standard PTP Rate	Standard PTP Revenute
Jan	163,000	$3.022	$492,586
Feb	163,000	$3.022	$492,586
Mar	163,000	$3.022	$492,586
Apr	163,000	$3.022	$492,586
May	163,000	$3.022	$492,586
Jun	163,000	$3.022	$492,586
Jul	163,000	$3.022	$492,586
Aug	163,000	$3.022	$492,586
Sep	163,000	$3.022	$492,586
Oct	163,000	$3.022	$492,586
Nov	163,000	$3.022	$492,586
Dec	163,000	$3.022	$492,586
Total			**$5,911,032**

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-3

Calculation of the Discount to the Point-to-Point Rate for Morenci Water & Electric Recommended Rates Through December 31, 2005

Total Transmission Revenue Requirement	**25,278,875**
Greenlee Transformer Revenue Credit for MW&E	
(Remove Required Revenue Allocated to Greenlee Transformer from Total Transmission Revenue Requirement)	
Net Investement Greenlee Transformer	571,326
Carrying Charge on Investment in Plant*	8.051%
Carrying Cost - Greenlee	45,999
O&M Expenses - Greenlee	100,869
Revenue Requirement Allocated to Greenlee Transformer	146,868
MW&E Transmission Revenue Requirement	**25,132,007**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - MW&E Greenlee Discount	25,132,007	697,093		$36.05	$0.018	$3.004

Point-to-Point Service	MW&E Ave Monthly kW	MW&E Discount PTP Rate	MW&E Discount PTP Revenue
Jan	60,000	$3.004	$180,240
Feb	60,000	$3.004	$180,240
Mar	60,000	$3.004	$180,240
Apr	60,000	$3.004	$180,240
May	60,000	$3.004	$180,240
Jun	60,000	$3.004	$180,240
Jul	60,000	$3.004	$180,240
Aug	60,000	$3.004	$180,240
Sep	60,000	$3.004	$180,240
Oct	60,000	$3.004	$180,240
Nov	60,000	$3.004	$180,240
Dec	60,000	$3.004	$180,240
Total			$2,162,880

* The Carrying Cost is equal to Staff's Recommended (Operating Margin / Rate Base)

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-4

Calculation of the Discount to the Point-to-Point Rate for the Town of Thatcher Recommended Rates Through December 31, 2005

Total Transmission Revenue Requirement	**25,278,875**
Discount for Town of Thatcher - WAPA Wheeling Expenses	
(Remove WAPA Wheeling Expenses from Total Transmission Revenue Requirement)	
WAPA Wheeling Costs $3,484,188	3,484,188
Town of Thatcher Transmission Revenue Requirement	**21,794,687**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Thatcher Discount	21,794,687	697,093		$31.27	$0.417	$2.605

Point-to-Point Service	Thatcher Ave Monthly kW	Thatcher Discount PTP Rate	Thatcher Discount PTP Revenue
Jan	4,000	$2.605	$10,420
Feb	4,000	$2.605	$10,420
Mar	4,000	$2.605	$10,420
Apr	4,000	$2.605	$10,420
May	6,000	$2.605	$15,630
Jun	6,000	$2.605	$15,630
Jul	6,000	$2.605	$15,630
Aug	6,000	$2.605	$15,630
Sep	6,000	$2.605	$15,630
Oct	6,000	$2.605	$15,630
Nov	4,000	$2.605	$10,420
Dec	4,000	$2.605	$10,420
Total - Town of Thatcher			$156,300

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-5

Calculation of the Point-to-Point Revenues
Recommended Rates Through December 31, 2005

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Standard	25,278,875	697,093	$36.26	$0.000	$3.022
1 CP Rate - Thatcher Discount	21,794,687	697,093	$31.27	$0.417	$2.605
1 CP Rate - MW&E Greenlee Discount	25,132,007	697,093	$36.05	$0.018	$3.004

Point-to-Point Service	Standard Ave Monthly kW	Thatcher Ave Monthly kW	MW&E Ave Monthly kW	Standard PTP Rate	Thatcher Discount PTP Rate	MW&E Discount PTP Rate
Jan	163,000	4,000	60,000	$3.022	$2.605	$3.004
Feb	163,000	4,000	60,000	$3.022	$2.605	$3.004
Mar	163,000	4,000	60,000	$3.022	$2.605	$3.004
Apr	163,000	4,000	60,000	$3.022	$2.605	$3.004
May	163,000	6,000	60,000	$3.022	$2.605	$3.004
Jun	163,000	6,000	60,000	$3.022	$2.605	$3.004
Jul	163,000	6,000	60,000	$3.022	$2.605	$3.004
Aug	163,000	6,000	60,000	$3.022	$2.605	$3.004
Sep	163,000	6,000	60,000	$3.022	$2.605	$3.004
Oct	163,000	6,000	60,000	$3.022	$2.605	$3.004
Nov	163,000	4,000	60,000	$3.022	$2.605	$3.004
Dec	163,000	4,000	60,000	$3.022	$2.605	$3.004

Point-to-Point Service	Standard PTP Revenute	Thatcher Discount PTP Revenue	MW&E Discount PTP Revenue	Total PTP Annual Revenues
Jan	$492,586	$10,420	$180,240	$683,246
Feb	$492,586	$10,420	$180,240	$683,246
Mar	$492,586	$10,420	$180,240	$683,246
Apr	$492,586	$10,420	$180,240	$683,246
May	$492,586	$15,630	$180,240	$688,456
Jun	$492,586	$15,630	$180,240	$688,456
Jul	$492,586	$15,630	$180,240	$688,456
Aug	$492,586	$15,630	$180,240	$688,456
Sep	$492,586	$15,630	$180,240	$688,456
Oct	$492,586	$15,630	$180,240	$688,456
Nov	$492,586	$10,420	$180,240	$683,246
Dec	$492,586	$10,420	$180,240	$683,246
Total Revenues	$5,911,032	$156,300	$2,162,880	$8,230,212

Point-to-Point Revenue Total $8,230,212

Southwest Transmission Cooperative, Inc.
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Test Year Ended December 31, 2003

Surrebuttal Schedule EEC-6

Calculation of the Network Service Revenue Requirement
Recommended Rates Through December 31, 2005

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depr&Amort		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / KW**	
Schedule 1 - PtP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,933,749
Total Transmission Revenue Requirement		**25,278,875**
Less: Point-to-Point Revenue Total		**8,230,212**
Network Services Annual Revenue Requirement		**17,048,663**
Network Services Monthly Revenue Requirement		**1,420,722**

Network Services Revenue Requirement	2003 TY Billing Demand kW	Recommended Revenue Requirement Network Service	Average Network Service $/kW
Annual		**17,048,663**	**$4.310**
January	227,326	$1,420,722	$6.250
February	246,798	$1,420,722	$5.757
March	233,791	$1,420,722	$6.077
April	241,243	$1,420,722	$5.889
May	377,915	$1,420,722	$3.759
June	416,091	$1,420,722	$3.414
July	468,093	$1,420,722	$3.035
August	455,578	$1,420,722	$3.119
September	411,003	$1,420,722	$3.457
October	363,220	$1,420,722	$3.911
November	241,090	$1,420,722	$5.893
December	273,026	$1,420,722	$5.204

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-7

Estimated Allocation of the Network Service Revenue Requirement*
Recommended Rates Through December 31, 2005

NETWORK CUSTOMERS		January	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total 2003	Average
Anza	2002 kW Demand	6,432	6,084	5,472	5,496	6,660	7,068	8,628	8,400	7,812	5,112	6,324	6,912	80,400	6,700
Anza	Loads 2003	5,436	5,556	6,012	5,496	7,452	7,920	9,516	9,264	7,644	6,708	5,424	6,036	82,464	6,872
Anza	12 Month Rolling Avg	6,617	6,573	6,618	6,618	6,684	6,755	6,829	6,901	6,887	7,020	6,945	6,872	81,319	6,777
Anza	Revenue - 2003 Load	32,081	31,947	32,116	32,331	32,432	32,254	31,798	31,375	30,704	30,556	30,061	29,622	377,275	31,440
Duncan	2002 kW Demand	3,320	2,360	3,440	3,780	5,320	6,040	5,240	5,340	4,840	2,900	3,080	3,460	49,120	4,093
Duncan	Loads 2003	3,000	3,280	3,280	3,420	4,780	5,400	5,180	4,820	5,380	4,600	3,300	3,760	50,200	4,183
Duncan	12 Month Rolling Avg	4,067	4,143	4,130	4,100	4,055	4,002	3,997	3,953	3,998	4,140	4,158	4,183	48,927	4,077
Duncan	Revenue - 2003 Load	19,717	20,138	20,042	20,030	19,676	19,107	18,610	17,973	17,825	18,020	17,999	18,032	227,169	18,931
Graham	2002 kW Demand	14,758	15,023	15,662	20,461	27,751	33,126	33,349	30,972	28,798	16,583	14,149	16,503	267,135	22,261
Graham	Loads 2003	13,710	14,481	15,790	17,075	23,316	31,629	33,111	33,096	29,452	22,775	15,313	14,738	264,486	22,041
Graham	12 Month Rolling Avg	22,174	22,129	22,139	21,857	21,488	21,363	21,343	21,520	21,575	22,091	22,188	22,041	261,906	21,826
Graham	Revenue - 2003 Load	107,506	107,553	107,438	106,780	104,262	102,004	99,380	97,839	96,184	96,153	96,036	95,005	1,216,141	101,345
Mohave 1	2002 kW Demand	71,793	71,893	62,190	94,674	110,200	99,000	116,000	115,000	96,000	79,000	60,296	64,007	1,040,053	86,671
Mohave 1	Loads 2003	60,706	68,839	61,639	64,778	116,000	137,930	130,000	129,000	109,000	112,000	65,082	73,050	1,128,024	94,002
Mohave 1	12 Month Rolling Avg	85,747	85,493	85,447	82,955	83,439	86,683	87,850	89,016	90,100	92,850	93,248	94,002	1,056,829	88,069
Mohave 1	Revenue - 2003 Load	415,730	415,522	414,655	405,267	404,861	413,895	409,054	404,704	401,682	404,143	403,615	405,193	4,898,322	408,193
Sulphur Springs	2002 kW Demand	94,849	93,072	82,413	71,220	103,544	110,561	112,009	107,663	102,241	76,651	75,788	92,659	1,122,670	93,556
Sulphur Springs	Loads 2003	82,360	84,958	82,242	83,467	101,093	112,464	123,813	121,214	108,324	101,850	83,848	96,867	1,182,500	98,542
Sulphur Springs	12 Month Rolling Avg	92,515	91,839	91,825	92,845	92,641	92,800	93,783	94,913	95,419	97,519	98,191	98,542	1,132,832	94,403
Sulphur Springs	Revenue - 2003 Load	448,543	446,367	445,606	453,582	449,512	443,101	436,682	431,511	425,399	424,469	425,009	424,761	5,254,543	437,879
Trico	2002 kW Demand	60,797	59,164	51,292	61,409	79,649	96,441	94,660	92,968	90,421	62,274	45,742	58,683	853,500	71,125
Trico	Loads 2003	48,450	55,671	51,504	52,628	83,909	98,670	109,062	108,124	91,233	84,203	58,199	68,109	909,762	75,814
Trico	12 Month Rolling Avg	70,096	69,805	69,823	69,091	69,446	69,632	70,832	72,095	72,163	73,990	75,028	75,814	857,813	71,484
Trico	Revenue - 2003 Load	339,849	339,275	338,835	337,534	336,965	332,479	329,814	327,773	321,715	322,054	324,750	326,792	3,977,833	331,486
AEPCO Bundled	2002 kW Demand	8,000	7,880	7,880	7,620	7,360	6,920	7,320	6,740	6,700	6,760	6,700	6,740	86,620	7,218
Power Sales using	Loads 2003	6,320	6,220	5,980	6,260	6,780	6,900	6,360	5,920	6,100	5,700	2,780	2,660	67,980	5,665
Network Service	12 Month Rolling Avg	7,078	6,940	6,782	6,668	6,620	6,618	6,538	6,470	6,420	6,332	6,005	5,665	78,137	6,511
Cyprus TB and PD	Revenue - 2003 Load	34,318	33,731	32,910	32,577	32,122	31,601	30,444	29,415	28,622	27,560	25,992	24,419	363,711	30,309
Mohave 2	2002 kW Demand	-	-	-	-	13,579	-	-	-	-	11,570	-	-	25,149	2,096
Mohave 2	Loads 2003	-	-	-	-	21,304	-	35,037	29,166	38,625	15,590	-	-	139,722	11,644
Mohave 2	12 Month Rolling Avg	2,096	2,096	2,096	2,096	2,740	2,740	5,659	8,090	11,309	11,644	11,644	11,644	73,850	6,154
Mohave 2	Revenue - 2003 Load	10,161	10,186	10,170	10,238	13,293	13,081	26,351	36,779	50,416	50,680	50,398	50,189	331,942	27,662
Safford/Gila	2002 kW Demand	-	-	-	-	-	-	-	-	-	9,649	7,038	7,691	24,378	2,032
Safford/Gila	Loads 2003	7,344	7,793	7,344	8,119	13,281	15,178	16,014	14,974	15,245	9,794	7,144	7,806	130,036	10,836
Safford/Gila	12 Month Rolling Avg	2,644	3,293	3,905	4,582	5,688	6,953	8,288	9,535	10,806	10,818	10,827	10,836	88,174	7,348
Safford/Gila	Revenue - 2003 Load	12,817	16,005	18,950	22,382	27,600	33,200	38,589	43,352	48,175	47,087	46,862	46,710	401,728	33,477
Total	2002 kW Demand	259,949	255,476	228,349	264,660	354,063	359,156	377,206	367,083	336,812	270,499	219,117	256,655	3,549,025	295,752
Total	Loads 2003	227,326	246,798	233,791	241,243	377,915	416,091	468,093	455,578	411,003	363,220	241,090	273,026	3,955,174	329,598
Total	12 Month Rolling Avg	293,034	292,310	292,764	290,812	292,800	297,545	305,119	312,493	318,676	326,403	328,234	329,598	3,679,786	306,649
Total	Revenue - 2003 Load	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	1,420,722	17,048,663	1,420,722
Average	Per kW-month	$ 6.250	$ 5.757	$ 6.077	$ 5.889	$ 3.759	$ 3.414	$ 3.035	$ 3.119	$ 3.457	$ 3.911	$ 5.893	$ 5.204	$ 4.310	$ 4.310

* Load Ratios used in revenue allocation are based on 2002 and 2003 billing kW. Actual rolling 12-month average Load Ratio Shares will be used to allocate the Network Service Revenue Requirement.

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-8

Calculation of Schedule 1: System Control and Load Dispatch Recommended Rates Through December 31, 2005

Costs: System Control and Load Dispatch	Southwest Adjusted 2003 TY	Staff Adjustments	Staff Adjusted 2003 TY
556 - Power Prod. Exp. - Maint. Syst Cntl & Load Disp	2,537,388	-	2,537,388
557 - Power Prod. Exp. - Maint. Other Expenses	3,946	-	3,946
561 - Transm Exp – Op. Load Disp	635	(9)	626
EMS payment from AEPCO	(306,624)	-	(306,624)
Total Cost - System Control and Load Dispatch	**2,235,345**	**(9)**	**2,235,336**

Generation Capacity	Net kW Rate
Apache Units (@SRSG)	585,300
Purchased Pwr (PNM & TECO)	29,667
Federal Hydro (CRSP & PD)	29,113
Total Generation Capacity	**644,080**

Annual Rate ($ / kW)	**$ 3.471**
Monthly Rate ($ / kW)	**$ 0.289**

Point-to-Point Schedule 1

Month		Present Rate	Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Feb	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Mar	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Apr	227,000	$ 0.4220	$ 0.2890	95,794	65,603
May	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Jun	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Jul	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Aug	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Sep	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Oct	229,000	$ 0.4220	$ 0.2890	96,638	66,181
Nov	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Dec	227,000	$ 0.4220	$ 0.2890	95,794	65,603
Total Schedule 1 Revenues from Point-to-Point Customers				1,154,592	**790,704**

Network Service Schedule 1

Month		Present Rate	Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,326	$ 0.4220	$ 0.2890	95,932	65,697
Feb	246,798	$ 0.4220	$ 0.2890	104,149	71,325
Mar	233,791	$ 0.4220	$ 0.2890	98,660	67,566
Apr	241,243	$ 0.4220	$ 0.2890	101,805	69,719
May	377,915	$ 0.4220	$ 0.2890	159,480	109,217
Jun	416,091	$ 0.4220	$ 0.2890	175,590	120,250
Jul	468,093	$ 0.4220	$ 0.2890	197,535	135,279
Aug	455,578	$ 0.4220	$ 0.2890	192,254	131,662
Sep	411,003	$ 0.4220	$ 0.2890	173,443	118,780
Oct	363,220	$ 0.4220	$ 0.2890	153,279	104,971
Nov	241,090	$ 0.4220	$ 0.2890	101,740	69,675
Dec	273,026	$ 0.4220	$ 0.2890	115,217	78,905
Total Schedule 1 Revenues from Network Customers				1,669,083	**1,143,045**

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-9

Calculation of Schedule 2: Cost of Reactive Power (VAR) Production
Recommended Rates Through December 31, 2005

Line No.	Power Factor	Gross Namplate KW	Power Factor Generator Nameplate	Weighted Power Factor
1	Steam Unit 1	77,400	0.85	10.9%
2	Steam Unit 2	195,000	0.85	27.4%
3	Steam Unit 3	195,000	0.85	27.4%
4	Gas Turbine 1	10,000	0.85	1.4%
5	Gas Turbine 2	20,000	0.90	3.0%
6	Gas Turbine 3	65,000	0.90	9.7%
7	Gas Turbine 4	42,000	0.85	5.9%
	Total Capacity	604,400		85.7%
8	**1 - Power Factor**			14.30%

		Account	Original Cost	Net Plant in Service
	AEPCO System Investment in Power Production Facilities			
9	Total Production Plant in Service		389,590,504	203,345,337
10	Turbogenerator Systems	314 & 344	55,169,579	26,798,200
11	Accessory Electric Equipment	315 & 345	19,941,398	9,686,381
	Separation of Production Plant Allocation to VAR Production			
12	Generator and Exciter Systems	(8) * (10)		3,831,291
13	Accessory Electric Equipment	(8) * (11)		1,384,845
14	Other Power Production Facilities	(9) - (12) - (13) * (0.25%)		495,323
15	Total Plant Allocated to VAR Production			5,711,459
16	TIER & Associated Required Rate of Return (AEPCO)		1.50	10.496%
17	Annualized Required Revenue Allocation to VAR Production			$ 599,446

	Schedule 2: Reactive Power (VAR) Production	Billing Unit	Demand kW	$/KW/year	$/kW/month
18	Network Service Rate	System 12 CP	557,598	$ 1.0751	$ 0.0900
19	Point-to-Point Rate	System 1 CP	697,093	$ 0.8599	$ 0.0720

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-10

Calculation of Schedule 4: Energy Imbalance
Recommended Rates Through December 31, 2005

Southwest Transmission Proposed Rate

Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Per Books	Southwest Pro Forma Adjustments	Southwest Adjusted	Southwest Cost of Service: Energy	Southwest Schedule 4 Costs
Production Exp - Fuel - 501/547	62,295,417	(2,491,992)	59,803,425	57,819,080	57,819,080
Purchased Power Exp - 555	9,639,192	446,346	10,085,538	10,085,538	10,085,538
Production Exp - Transmission	8,036,486	-	8,036,486	77,291	77,291
Total	79,971,095	(2,045,646)	77,925,449	67,981,909	67,981,909
Total Energy Sales (kWh)					3,281,912,645
Southwest Transmission Proposed - Cost per kWh					$ 0.02071
Southwest Transmission Proposed - Cost per MWH					$ 20.71

Staff Recommended Rate

Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Cost of Service: Energy	Staff Adjustments to Cost of Service: Energy	Staff Recommended Schedule 4 Costs
Production Exp - Fuel - 501/547	57,819,080	(1,030,873)	56,788,207
Purchased Power Exp - 555	10,085,538	-	10,085,538
Production Exp - Transmission	77,291	-	77,291
Total	67,981,909	(1,030,873)	66,951,036
Total Energy Sales (kWh)			3,281,912,645
Staff Recommended - Cost per kWh			$ 0.02040
Staff Recommended - Cost per MWH			$ 20.40

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-11

Calculation of Schedule 3, 5, & 6
Recommended Rates Through December 31, 2005

Cost of Ancillary Services:
Regulation and Frequency Response, Operating Reserve - Spinning, and Operating Reserve - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Production Plant	O&M Expenses	A&G Expenses	Tax Expenses	Deprectiation Expenses	Required Return on Production Plant	Annual Revenue Requirement	Revenue Requirement per KW
Total to Allocate			25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	
ST1	77,400	21,981,781	1,524,786	576,612	201,239	453,324	1,309,577	4,065,538	$ 52.53
ST2	185,000	154,434,564	10,712,492	4,051,030	1,413,821	3,184,858	9,200,526	28,562,727	$ 154.39
ST3	186,000	147,491,658	10,230,891	3,868,908	1,350,260	3,041,676	8,786,898	27,278,634	$ 146.66
IC1/GT1	10,400	1,843,357	127,866	48,354	16,876	38,015	109,819	340,930	$ 32.78
GT2	17,600	2,898,287	201,042	76,026	26,533	59,771	172,667	536,039	$ 30.46
GT3	66,500	8,359,793	579,885	219,289	76,532	172,401	498,039	1,546,147	$ 23.25
GT4	42,400	28,572,620	1,981,965	749,499	261,577	589,245	1,702,230	5,284,516	$ 124.63
Total	585,300	365,582,060	25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	$ 115.52

Schedule 3
Regulation and Frequency Response

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST1	77,400	$ 52.53	4,065,538
ST2	185,000	$ 154.39	28,562,727
ST3	186,000	$ 146.66	27,278,634
Total	448,400		59,906,898

Annual Generation Capacity Rate	$ 133.601
Monthly Generation Capacity Rate	$ 11.133
Required Reserve Percentage	3.99%
Schedule 3 Monthly Rate ($/KW)	**$ 0.4440**

Schedule 5
Operating Reserves - Spinning

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST2	185,000	154	28,562,727
ST3	186,000	147	27,278,634
Total	371,000		55,841,360

Annual Generation Capacity Rate	$ 150.516
Monthly Generation Capacity Rate	$ 12.543
Required Reserve Percentage	5.35%
Schedule 5 Monthly Rate ($/KW)	**$ 0.6710**

Schedule 6
Operating Reserves - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
GT2	17,600	$ 30.46	536,039
GT4	42,400	$ 124.63	5,284,516
Total	60,000		5,820,555

Annual Generation Capacity Rate	$ 97.009
Monthly Generation Capacity Rate	$ 8.084
Required Reserve Percentage	5.36%
Schedule 6 Monthly Rate ($/KW)	**$ 0.4330**

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-12

Comparison of Billing Units
Recommended Rates Effective January 1, 2006

	Actual 2003 Test Year Billing Units Including MW&E 60 MW			Adjusted 2003 Test Year Billing Units Excluding MW&E 60 MW		
Month	**Network kW**	**PTP kW**	**Total kW**	**Network kW**	**PTP kW**	**Total kW**
Jan	227,326	227,000	454,326	227,326	167,000	394,326
Feb	246,798	227,000	473,798	246,798	167,000	413,798
Mar	233,791	227,000	460,791	233,791	167,000	400,791
Apr	241,243	227,000	468,243	241,243	167,000	408,243
May	377,915	229,000	606,915	377,915	169,000	546,915
Jun	416,091	229,000	645,091	416,091	169,000	585,091
Jul	468,093	229,000	**697,093**	468,093	169,000	**637,093**
Aug	455,578	229,000	684,578	455,578	169,000	624,578
Sep	411,003	229,000	640,003	411,003	169,000	580,003
Oct	363,220	229,000	592,220	363,220	169,000	532,220
Nov	241,090	227,000	468,090	241,090	167,000	408,090
Dec	273,026	227,000	500,026	273,026	167,000	440,026
1 CP	468,093	229,000	697,093	468,093	169,000	637,093
4 CP	437,691	229,000	666,691	437,691	169,000	606,691
12 CP	329,598	228,000	557,598	329,598	168,000	497,598

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-13

Calculation of the Point-to-Point Rate
Recommended Rates Effective January 1, 2006

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depreciation & Amortization		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / kW**	
Schedule 1 - PtP Revenue	0.289	582,624
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,725,669
Total Transmission Revenue Requirement		**25,486,955**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Rate ($/kW)
1 CP Rate - Standard	25,486,955	637,093		$40.01	$3.334

Point-to-Point Service	Standard Ave Montly kW	Standard PTP Rate	Standard PTP Revenute
Jan	163,000	$3.334	$543,442
Feb	163,000	$3.334	$543,442
Mar	163,000	$3.334	$543,442
Apr	163,000	$3.334	$543,442
May	163,000	$3.334	$543,442
Jun	163,000	$3.334	$543,442
Jul	163,000	$3.334	$543,442
Aug	163,000	$3.334	$543,442
Sep	163,000	$3.334	$543,442
Oct	163,000	$3.334	$543,442
Nov	163,000	$3.334	$543,442
Dec	163,000	$3.334	$543,442
Total			**$6,521,304**

Southwest Transmission Cooperative, Inc.
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Surrebuttal Schedule EEC-14

Calculation of the Discount to the Point-to-Point Rate for the Town of Thatcher
Recommended Rates Effective January 1, 2006

Total Transmission Revenue Requirement	**25,486,955**
Discount for Town of Thatcher - WAPA Wheeling Expenses	
(Remove WAPA Wheeling Expenses from Total Transmission Revenue Requirement)	
WAPA Wheeling Costs $3,484,188	3,484,188
Town of Thatcher Transmission Revenue Requirement	**22,002,767**

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 (kW)	1 CP	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Thatcher Discount	22,002,767	637,093		$34.54	$0.456	$2.878

Point-to-Point Service	Thatcher Ave Monthly kW	Thatcher Discount PTP Rate	Thatcher Discount PTP Revenue
Jan	4,000	$2.878	$11,512
Feb	4,000	$2.878	$11,512
Mar	4,000	$2.878	$11,512
Apr	4,000	$2.878	$11,512
May	6,000	$2.878	$17,268
Jun	6,000	$2.878	$17,268
Jul	6,000	$2.878	$17,268
Aug	6,000	$2.878	$17,268
Sep	6,000	$2.878	$17,268
Oct	6,000	$2.878	$17,268
Nov	4,000	$2.878	$11,512
Dec	4,000	$2.878	$11,512
Total - Town of Thatcher			**$172,680**

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Surrebuttal Schedule EEC-15

Calculation of the Point-to-Point Revenues
Recommended Rates Effective January 1, 2006

Point to Point Transmission Serive (1 CP method)

	Revenue Requirement	TY 2003 1 CP (kW)	Annual Rate ($/kW)	Monthly Discount	Monthly Rate ($/kW)
1 CP Rate - Standard	25,486,955	637,093	$40.01	$0.000	$3.334
1 CP Rate - Thatcher Discount	22,002,767	637,093	$34.54	$0.456	$2.878
1 CP Rate - MW&E Greenlee Discount	-	-	-	-	-

Point-to-Point Service	Standard Ave Monthly kW	Thatcher Ave Monthly kW	MW&E Ave Monthly kW	Standard PTP Rate	Thatcher Discount PTP Rate	MW&E Discount PTP Rate
Jan	163,000	4,000	0	$3.334	$2.878	$0.000
Feb	163,000	4,000	0	$3.334	$2.878	$0.000
Mar	163,000	4,000	0	$3.334	$2.878	$0.000
Apr	163,000	4,000	0	$3.334	$2.878	$0.000
May	163,000	6,000	0	$3.334	$2.878	$0.000
Jun	163,000	6,000	0	$3.334	$2.878	$0.000
Jul	163,000	6,000	0	$3.334	$2.878	$0.000
Aug	163,000	6,000	0	$3.334	$2.878	$0.000
Sep	163,000	6,000	0	$3.334	$2.878	$0.000
Oct	163,000	6,000	0	$3.334	$2.878	$0.000
Nov	163,000	4,000	0	$3.334	$2.878	$0.000
Dec	163,000	4,000	0	$3.334	$2.878	$0.000

Point-to-Point Service	Standard PTP Revenute	Thatcher Discount PTP Revenue	MW&E Discount PTP Revenue	Total PTP Annual Revenues
Jan	$543,442	$11,512	$0	$554,954
Feb	$543,442	$11,512	$0	$554,954
Mar	$543,442	$11,512	$0	$554,954
Apr	$543,442	$11,512	$0	$554,954
May	$543,442	$17,268	$0	$560,710
Jun	$543,442	$17,268	$0	$560,710
Jul	$543,442	$17,268	$0	$560,710
Aug	$543,442	$17,268	$0	$560,710
Sep	$543,442	$17,268	$0	$560,710
Oct	$543,442	$17,268	$0	$560,710
Nov	$543,442	$11,512	$0	$554,954
Dec	$543,442	$11,512	$0	$554,954
Total Revenues	$6,521,304	$172,680	$0	$6,693,984

Point-to-Point Revenue Total $6,693,984

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Surrebuttal Schedule EEC-16

Calculation of the Network Service Revenue Requirement
Recommended Rates Effective January 1, 2006

Total Revenue Requirement = O&M + Depr&Amort + Taxes + Operating Margin		
O&M		16,237,302
Depr&Amort		4,144,985
Taxes		2,285,845
Operating Margin		6,146,732
Total Revenue Requirement		**28,814,864**
Less Other Operating Revenues		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Reveues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
Total Other Operating Revenues		**1,602,240**
Transmission Revenue Requirement (including Schedule 1)		**27,212,624**
Schedule 1 Revenues	**$ / KW**	
Schedule 1 - PtP Revenue	0.289	582,624
Schedule 1 - Network Services Revenue	0.289	1,143,045
Total Schedule 1 Revenues		1,725,669
Total Transmission Revenue Requirement		**25,486,955**
Less: Point-to-Point Revenue Total		**6,693,984**
Network Services Annual Revenue Requirement		**18,792,971**
Network Services Monthly Revenue Requirement		**1,566,081**

Network Services Revenue Requirement	2003 TY Billing Demand kW	Recommended Revenue Requirement Network Service	Average Network Service $/kW
Annual		**18,792,971**	**$4.751**
January	227,326	$1,566,081	$6.889
February	246,798	$1,566,081	$6.346
March	233,791	$1,566,081	$6.699
April	241,243	$1,566,081	$6.492
May	377,915	$1,566,081	$4.144
June	416,091	$1,566,081	$3.764
July	468,093	$1,566,081	$3.346
August	455,578	$1,566,081	$3.438
September	411,003	$1,566,081	$3.810
October	363,220	$1,566,081	$4.312
November	241,090	$1,566,081	$6.496
December	273,026	$1,566,081	$5.736

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Estimated Allocation of the Network Service Revenue Requirement*
Recommended Rates Effective January 1, 2006

NETWORK CUSTOMERS		January	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total 2003	Average
Anza	2002 kW Demand	6,432	6,084	5,472	5,496	6,660	7,068	8,628	8,400	7,812	5,112	6,324	6,912	80,400	6,700
Anza	Loads 2003	5,436	5,556	6,012	5,496	7,452	7,920	9,516	9,264	7,644	6,708	5,424	6,036	82,464	6,872
Anza	12 Month Rolling Avg	6,617	6,573	6,618	6,618	6,684	6,755	6,829	6,901	6,887	7,020	6,945	6,872	81,319	6,777
Anza	Revenue - 2003 Load	35,364	35,215	35,402	35,639	35,750	35,554	35,051	34,585	33,845	33,682	33,136	32,652	415,876	34,656
Duncan	2002 kW Demand	3,320	2,360	3,440	3,780	5,320	6,040	5,240	5,340	4,840	2,900	3,080	3,460	49,120	4,093
Duncan	Loads 2003	3,000	3,280	3,280	3,420	4,780	5,400	5,180	4,820	5,380	4,600	3,300	3,760	50,200	4,183
Duncan	12 Month Rolling Avg	4,067	4,143	4,130	4,100	4,055	4,002	3,997	3,953	3,998	4,140	4,158	4,183	48,927	4,077
Duncan	Revenue - 2003 Load	21,734	22,198	22,093	22,079	21,689	21,062	20,514	19,812	19,649	19,864	19,840	19,877	250,411	20,868
Graham	2002 kW Demand	14,758	15,023	15,662	20,461	27,751	33,126	33,349	30,972	28,798	16,583	14,149	16,503	267,135	22,261
Graham	Loads 2003	13,710	14,481	15,790	17,075	23,316	31,629	33,111	33,096	29,452	22,775	15,313	14,738	264,486	22,041
Graham	12 Month Rolling Avg	22,174	22,129	22,139	21,857	21,488	21,363	21,343	21,520	21,575	22,091	22,188	22,041	261,906	21,826
Graham	Revenue - 2003 Load	118,506	118,557	118,430	117,706	114,930	112,440	109,548	107,849	106,025	105,991	105,862	104,725	1,340,569	111,714
Mohave 1	2002 kW Demand	71,793	71,893	62,190	94,674	110,200	99,000	116,000	115,000	96,000	79,000	60,296	64,007	1,040,053	86,671
Mohave 1	Loads 2003	60,706	68,839	61,639	64,778	116,000	137,930	130,000	129,000	109,000	112,000	65,082	73,050	1,128,024	94,002
Mohave 1	12 Month Rolling Avg	85,747	85,493	85,447	82,955	83,439	86,683	87,850	89,016	90,100	92,850	93,248	94,002	1,056,829	88,069
Mohave 1	Revenue - 2003 Load	458,265	458,035	457,080	446,731	446,283	456,242	450,905	446,111	442,780	445,493	444,910	446,650	5,399,486	449,957
Sulphur Springs	2002 kW Demand	94,849	93,072	82,413	71,220	103,544	110,561	112,009	107,663	102,241	76,651	75,788	92,659	1,122,670	93,556
Sulphur Springs	Loads 2003	82,360	84,958	82,242	83,467	101,093	112,464	123,813	121,214	108,324	101,850	83,848	96,867	1,182,500	98,542
Sulphur Springs	12 Month Rolling Avg	92,515	91,839	91,825	92,845	92,641	92,800	93,783	94,913	95,419	97,519	98,191	98,542	1,132,832	94,403
Sulphur Springs	Revenue - 2003 Load	494,435	492,036	491,197	499,990	495,503	488,436	481,361	475,660	468,923	467,898	468,493	468,220	5,792,153	482,679
Trico	2002 kW Demand	60,797	59,164	51,292	61,409	79,649	96,441	94,660	92,968	90,421	62,274	45,742	58,683	853,500	71,125
Trico	Loads 2003	48,450	55,671	51,504	52,628	83,909	98,670	109,062	108,124	91,233	84,203	58,199	68,109	909,762	75,814
Trico	12 Month Rolling Avg	70,096	69,805	69,823	69,091	69,446	69,632	70,832	72,095	72,163	73,990	75,028	75,814	857,813	71,484
Trico	Revenue - 2003 Load	374,620	373,987	373,502	372,068	371,441	366,496	363,558	361,308	354,631	355,004	357,977	360,227	4,384,819	365,402
AEPCO Bundled	2002 kW Demand	8,000	7,880	7,880	7,620	7,360	6,920	7,320	6,740	6,700	6,760	6,700	6,740	86,620	7,218
Power Sales using	Loads 2003	6,320	6,220	5,980	6,260	6,780	6,900	6,360	5,920	6,100	5,700	2,780	2,660	67,980	5,665
Network Service	12 Month Rolling Avg	7,078	6,940	6,782	6,668	6,620	6,618	6,538	6,470	6,420	6,332	6,005	5,665	78,137	6,511
Cyprus TB and PD	Revenue - 2003 Load	37,829	37,182	36,277	35,910	35,408	34,835	33,559	32,425	31,550	30,379	28,651	26,917	400,923	33,410
Mohave 2	2002 kW Demand	-	-	-	-	13,579	-	-	-	-	11,570	-	-	25,149	2,096
Mohave 2	Loads 2003	-	-	-	-	21,304	-	35,037	29,166	38,625	15,590	-	-	139,722	11,644
Mohave 2	12 Month Rolling Avg	2,096	2,096	2,096	2,096	2,740	2,740	5,659	8,090	11,309	11,644	11,644	11,644	73,850	6,154
Mohave 2	Revenue - 2003 Load	11,200	11,228	11,211	11,286	14,653	14,419	29,047	40,542	55,574	55,866	55,554	55,324	365,904	30,492
Safford/Gila	2002 kW Demand	-	-	-	-	-	-	-	-	-	9,649	7,038	7,691	24,378	2,032
Safford/Gila	Loads 2003	7,344	7,793	7,344	8,119	13,281	15,178	16,014	14,974	15,245	9,794	7,144	7,806	130,036	10,836
Safford/Gila	12 Month Rolling Avg	2,644	3,293	3,905	4,582	5,688	6,953	8,288	9,535	10,806	10,818	10,827	10,836	88,174	7,348
Safford/Gila	Revenue - 2003 Load	14,128	17,642	20,889	24,672	30,424	36,596	42,538	47,787	53,104	51,904	51,657	51,489	442,830	36,903
Total	2002 kW Demand	259,949	255,476	228,349	264,660	354,063	359,156	377,206	367,083	336,812	270,499	219,117	256,655	3,549,025	295,752
Total	Loads 2003	227,326	246,798	233,791	241,243	377,915	416,091	468,093	455,578	411,003	363,220	241,090	273,026	3,955,174	329,598
Total	12 Month Rolling Avg	293,034	292,310	292,764	290,812	292,800	297,545	305,119	312,493	318,676	326,403	328,234	329,598	3,679,786	306,649
Total	Revenue - 2003 Load	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	1,566,081	18,792,971	1,566,081
Average	Per kW-month	$ 6.889	$ 6.346	$ 6.699	$ 6.492	$ 4.144	$ 3.764	$ 3.346	$ 3.438	$ 3.810	$ 4.312	$ 6.496	$ 5.736	$ 4.751	$ 4.751

* Load Ratios used in revenue allocation are based on 2002 and 2003 billing kW. Actual rolling 12-month average Load Ratio Shares will be used to allocate the Network Service Revenue Requirement.

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Surrebuttal Schedule EEC-18

Calculation of Schedule 1: System Control and Load Dispatch
Recommended Rates Effective January 1, 2006

Costs: System Control and Load Dispatch	Southwest Adjusted 2003 TY	Staff Adjustments	Staff Adjusted 2003 TY
556 - Power Prod. Exp. - Maint. Syst Cntl & Load Disp	2,537,388	-	2,537,388
557 - Power Prod. Exp. - Maint. Other Expenses	3,946	-	3,946
561 - Transm Exp – Op. Load Disp	635	(9)	626
EMS payment from AEPCO	(306,624)	-	(306,624)
Total Cost - System Control and Load Dispatch	**2,235,345**	**(9)**	**2,235,336**

Generation Capacity	Net kW Rate
Apache Units (@SRSG)	585,300
Purchased Pwr (PNM & TECO)	29,667
Federal Hydro (CRSP & PD)	29,113
Total Generation Capacity	**644,080**

Annual Rate ($ / kW)	**$ 3.471**
Monthly Rate ($ / kW)	**$ 0.289**

Point-to-Point Schedule 1

Month		Present Rate	Recommended Rate	Present Revenue	Recommended Revenue
Jan	167,000	$ 0.4220	$ 0.2890	70,474	48,263
Feb	167,000	$ 0.4220	$ 0.2890	70,474	48,263
Mar	167,000	$ 0.4220	$ 0.2890	70,474	48,263
Apr	167,000	$ 0.4220	$ 0.2890	70,474	48,263
May	169,000	$ 0.4220	$ 0.2890	71,318	48,841
Jun	169,000	$ 0.4220	$ 0.2890	71,318	48,841
Jul	169,000	$ 0.4220	$ 0.2890	71,318	48,841
Aug	169,000	$ 0.4220	$ 0.2890	71,318	48,841
Sep	169,000	$ 0.4220	$ 0.2890	71,318	48,841
Oct	169,000	$ 0.4220	$ 0.2890	71,318	48,841
Nov	167,000	$ 0.4220	$ 0.2890	70,474	48,263
Dec	167,000	$ 0.4220	$ 0.2890	70,474	48,263
Total Schedule 1 Revenues from Point-to-Point Customers				850,752	**582,624**

Network Service Schedule 1

Month		Present Rate	Recommended Rate	Present Revenue	Recommended Revenue
Jan	227,326	$ 0.4220	$ 0.2890	95,932	65,697
Feb	246,798	$ 0.4220	$ 0.2890	104,149	71,325
Mar	233,791	$ 0.4220	$ 0.2890	98,660	67,566
Apr	241,243	$ 0.4220	$ 0.2890	101,805	69,719
May	377,915	$ 0.4220	$ 0.2890	159,480	109,217
Jun	416,091	$ 0.4220	$ 0.2890	175,590	120,250
Jul	468,093	$ 0.4220	$ 0.2890	197,535	135,279
Aug	455,578	$ 0.4220	$ 0.2890	192,254	131,662
Sep	411,003	$ 0.4220	$ 0.2890	173,443	118,780
Oct	363,220	$ 0.4220	$ 0.2890	153,279	104,971
Nov	241,090	$ 0.4220	$ 0.2890	101,740	69,675
Dec	273,026	$ 0.4220	$ 0.2890	115,217	78,905
Total Schedule 1 Revenues from Network Customers				1,669,083	**1,143,045**

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Surrebuttal Schedule EEC-19

Calculation of Schedule 2: Cost of Reactive Power (VAR) Production
Recommended Rates Effective January 1, 2006

Line No.	Power Factor	Gross Namplate KW	Power Factor Generator Nameplate	Weighted Power Factor
1	Steam Unit 1	77,400	0.85	10.9%
2	Steam Unit 2	195,000	0.85	27.4%
3	Steam Unit 3	195,000	0.85	27.4%
4	Gas Turbine 1	10,000	0.85	1.4%
5	Gas Turbine 2	20,000	0.90	3.0%
6	Gas Turbine 3	65,000	0.90	9.7%
7	Gas Turbine 4	42,000	0.85	5.9%
	Total Capacity	604,400		85.7%
8	**1 - Power Factor**			14.30%

		Account	Original Cost	Net Plant in Service
	AEPCO System Investment in Power Production Facilities			
9	Total Production Plant in Service		389,590,504	203,345,337
10	Turbogenerator Systems	314 & 344	55,169,579	26,798,200
11	Accessory Electric Equipment	315 & 345	19,941,398	9,686,381
	Separation of Production Plant Allocation to VAR Production			
12	Generator and Exciter Systems	(8) * (10)		3,831,291
13	Accessory Electric Equipment	(8) * (11)		1,384,845
14	Other Power Production Facilities	(9) - (12) - (13) * (0.25%)		495,323
15	Total Plant Allocated to VAR Production			5,711,459
16	TIER & Associated Required Rate of Return (AEPCO)		1.50	10.496%
17	Annualized Required Revenue Allocation to VAR Production			$ 599,446

	Schedule 2: Reactive Power (VAR) Production	**Billing Unit**	**Demand kW**	**$/KW/year**	**$/kW/month**
18	Network Service Rate	System 12 CP	497,598	$ 1.2047	$ 0.1000
19	Point-to-Point Rate	System 1 CP	637,093	$ 0.9409	$ 0.0780

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Surrebuttal Schedule EEC-20

Calculation of Schedule 4: Energy Imbalance
Recommended Rates Effective January 1, 2006

Southwest Transmission Proposed Rate

Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Per Books	Southwest Pro Forma Adjustments	Southwest Adjusted	Southwest Cost of Service: Energy	Southwest Schedule 4 Costs
Production Exp - Fuel - 501/547	62,295,417	(2,491,992)	59,803,425	57,819,080	57,819,080
Purchased Power Exp - 555	9,639,192	446,346	10,085,538	10,085,538	10,085,538
Production Exp - Transmission	8,036,486	-	8,036,486	77,291	77,291
Total	79,971,095	(2,045,646)	77,925,449	67,981,909	67,981,909
Total Energy Sales (kWh)					3,281,912,645
Southwest Transmission Proposed - Cost per kWh					$ 0.02071
Southwest Transmission Proposed - Cost per MWH					$ 20.71

Staff Recommended Rate

Costs: Energy Imbalance	**TY 2003**	**TY 2003**	**TY 2003**
Incremental Energy Costs	Southwest Cost of Service: Energy	Staff Adjustments to Cost of Service: Energy	Staff Recommended Schedule 4 Costs
Production Exp - Fuel - 501/547	57,819,080	(1,030,873)	56,788,207
Purchased Power Exp - 555	10,085,538	-	10,085,538
Production Exp - Transmission	77,291	-	77,291
Total	67,981,909	(1,030,873)	66,951,036
Total Energy Sales (kWh)			3,281,912,645
Staff Recommended - Cost per kWh			$ 0.02040
Staff Recommended - Cost per MWH			$ 20.40

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Surrebuttal Schedule EEC-21

Calculation of Schedule 3, 5, & 6
Recommended Rates Effective January 1, 2006

Cost of Ancillary Services:
Regulation and Frequency Response, Operating Reserve - Spinning, and Operating Reserve - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Production Plant	O&M Expenses	A&G Expenses	Tax Expenses	Depreciation Expenses	Required Return on Production Plant	Annual Revenue Requirement	Revenue Requirement per KW
Total to Allocate			25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	
ST1	77,400	21,981,781	1,524,786	576,612	201,239	453,324	1,309,577	4,065,538	$ 52.53
ST2	185,000	154,434,564	10,712,492	4,051,030	1,413,821	3,184,858	9,200,526	28,562,727	$ 154.39
ST3	186,000	147,491,658	10,230,891	3,868,908	1,350,260	3,041,676	8,786,898	27,278,634	$ 146.66
IC1/GT1	10,400	1,843,357	127,866	48,354	16,876	38,015	109,819	340,930	$ 32.78
GT2	17,600	2,898,287	201,042	76,026	26,533	59,771	172,667	536,039	$ 30.46
GT3	66,500	8,359,793	579,885	219,289	76,532	172,401	498,039	1,546,147	$ 23.25
GT4	42,400	28,572,620	1,981,965	749,499	261,577	589,245	1,702,230	5,284,516	$ 124.63
Total	585,300	365,582,060	25,358,928	9,589,717	3,346,839	7,539,289	21,779,757	67,614,530	$ 115.52

Schedule 3
Regulation and Frequency Response

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST1	77,400	$ 52.53	4,065,538
ST2	185,000	$ 154.39	28,562,727
ST3	186,000	$ 146.66	27,278,634
Total	448,400		59,906,898

Annual Generation Capacity Rate	$	133.601
Monthly Generation Capacity Rate	$	11.133
Required Reserve Percentage		3.99%
Schedule 3 Monthly Rate ($/KW)	**$**	**0.4440**

Schedule 5
Operating Reserves - Spinning

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
ST2	185,000	154	28,562,727
ST3	186,000	147	27,278,634
Total	371,000		55,841,360

Annual Generation Capacity Rate	$	150.516
Monthly Generation Capacity Rate	$	12.543
Required Reserve Percentage		5.35%
Schedule 5 Monthly Rate ($/KW)	**$**	**0.6710**

Schedule 6
Operating Reserves - Supplemental

Apache Generation Units	SRSG Name Plate Rating	Revenue Requirement per KW	Annual Revenue Requirement
GT2	17,600	$ 30.46	536,039
GT4	42,400	$ 124.63	5,284,516
Total	60,000		5,820,555

Annual Generation Capacity Rate	$	97.009
Monthly Generation Capacity Rate	$	8.084
Required Reserve Percentage		5.36%
Schedule 6 Monthly Rate ($/KW)	**$**	**0.4330**

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-04-0528

DIRECT

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2004

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EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

The direct testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $146,061,494 proposed by Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Applicant"). AEPCO's proposed revenues would provide a times interest earned ratio ("TIER") of 1.33 and a debt service coverage ("DSC") ratio of 0.91. The Applicant's proposed revenue fails to provide sufficient internally generated cash flow, directly or indirectly through incremental debt financing, for plant replacement, improvement and expansion requirements.

Capital Structure – The Applicant's actual end of test year capital structure was composed by 95.2 percent debt and 4.8 percent patronage equity. This is an excessively leveraged capital structure. This rate case is the appropriate time to address AEPCO's highly leveraged capital structure. The capital structure issue is important because a highly leveraged capital structure has potentially detrimental impacts for service reliability and rates. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64227, dated November 29, 2001) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff further recommends that the Commission restrict the distribution of future patronage dividends by AEPCO until it has achieved a capital structure composed of at least 30 percent patronage equity.

INTRODUCTION

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

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my position as a Public Utilities Analyst, I perform studies to estimate the cost of capital component of the revenue requirement in rate proceedings. I also perform other financial analyses.

Q. Please describe your educational background and professional experience.

A. In 2002, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Global Business with a specialization in finance. While attending Arizona State University, I successfully completed the Barrett Honors College curriculum. My course of studies included classes in corporate and international finance, investments, accounting, statistics, and economics. I began employment as a Staff Public Utilities Analyst in 2003. Since that time, I have provided recommendations to the Commission on financings and prepared various studies in the field of cost of capital and econometrics. I have also attended seminars related to general regulatory and business issues.

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

A. I discuss Arizona Electric Power Cooperative, Inc.'s ("AEPCO" or "Applicant") current capital structure and provide Staff's recommended operating income. I also provide the

times interest earned ("TIER") and debt service coverage ("DSC") ratios resulting from Staff's recommended operating income.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. This testimony is organized in three sections. Section I presents the Applicant's long-term debt and patronage equity balances. Section II discusses AEPCO's capital structure. Finally, Section III discusses Staff's recommended TIER and DSC ratios for the Applicant.

Q. Have you prepared any exhibits to your testimony?

A. Yes. I prepared three schedules (AXR-1 to AXR-3) that support Staff's recommendations.

Q. What is Staff's recommended operating income for the Applicant?

A. Staff recommends an operating income no less than $17,755,094 for AEPCO (which is the operating income that would result from the Applicant's proposed revenues).

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $17,755,094?

A. Operating income of $17,755,094 would produce a 1.33 TIER and a 0.91 DSC.

AEPCO'S LONG-TERM DEBT AND PATRONAGE AND EQUITY BALANCE

Q. What is the amount of AEPCO's long-term debt outstanding?

A. The Applicant had $218,909,935 in long-term debt outstanding as of November 1, 2004,

and it is expected to incur $13,313,164 in interest expense related to its long-term debt during the year.

Q. What were AEPCO's patronage equity balances for the years ended 2003, 2002 and 2001?

A. AEPCO's patronage equity balances for the years ended 2003, 2002 and 2001 were $10,754,721, $17,803,568 and $13,904,998, respectively.

AEPCO'S CAPTIAL STRUCTURE

Q. What was AEPCO's actual end of test year capital structure?

A. The Applicant's actual end of test year capital structure was composed by 95.2 percent debt and 4.8 percent patronage equity[1]. Schedule AXR-1 presents the Applicant's capital structures for the years 2001, 2002 and 2003.

Q. Is AEPCO concerned with its current capital structure?

A. Yes. In his direct testimony, the Applicant's witness, Mr. William K. Edwards, has emphasized the importance for AEPCO to develop a stronger patronage equity base. Moreover, Mr. Edwards recognizes and supports the efforts made by both the Commission and AEPCO to establish long-term goals for AEPCO's patronage equity (Decision No. 64227, dated November 29, 2001, and Decision No. 65210, dated September 20, 2002).

[1] Staff has calculated the capital structure by taking into account long-term debt and equity.

Q. How does AEPCO's capital structure compare to other Generation and Transmission ("G&T") utilities' capital structure?

A. Mr. William Edwards has compared AEPCO's capital structure to the Capital structure of 55 G&T utilities' capital structure. As mentioned in his testimony, AEPCO's capital structure is more leveraged than Mr. Edwards' G&T utilities sample (See Mr. Edwards Direct Testimony, Page 8, Line 16-17). Schedule AXR-2 presents the capital structure of some G&T cooperatives that are rated by *Standard & Poor's* ("S&P") and the Applicant's capital structure for the test year ended December 2003. The average capital structure of the G&T cooperatives is composed of 81.0 percent debt and 19.0 percent patronage equity as opposed to the Applicant's capital structure composed of 95.2 percent debt and 4.8 percent patronage equity.

Q. Is Staff concerned with the Applicant's actual end of test year capital structure?

A. Yes. AEPCO's capital structure is highly leveraged as it has remained for several years. The Applicant's capital structure has multiple potential negative effects including: (1) higher debt costs for new issuances; (2) reduced ability to incur new debt and finance capital improvements; and (3) places upward pressure on rates to cover debt service obligations.

Q. Has the Commission shown concern with highly leveraged cooperatives?

A. Yes. In Decision No. 58405 (dated September 3, 1993), the Commission stated that "...there is a balance to be struck between keeping rates competitive and eliminating negative equity, but we fail to see any strong commitment or serious steps taken on AEPCO's part to build its equity (Page 23, lines 6-9)". In addition, the Commission ordered Arizona Electric Power Cooperative ("AEPCO") (Decision No. 64227, dated

November 29, 2001) and SWTCO (Decision No. 64991, dated June 26, 2002) to establish long-range goals to improve their patronage equity positions. In addition, the Commission ordered Trico Electric Cooperative, Inc. ("Trico") to file a capital improvement plan with the Commission (Decision No. 67412, dated November 2, 2004). As discussed previously, highly leveraged capital structures present potentially negative consequences.

Q. Does the Rural Utilities Service ("RUS") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. AEPCO's audited financial statements for the years ended December 31, 2003 and 2002, state "RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative (See Exhibit GEP-1, note to financial statement 12)".

Q. Does the National Rural Utilities Cooperative Finance Corporation ("CFC") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. The CFC requires a borrower to have a capital structure composed of at least 30 percent patronage equity to distribute 100 percent of its net earnings as patronage dividends. If the borrower has a capital structure composed of less than 30 percent patronage equity, it would be able to distribute as patronage dividends only 30 percent of its patronage capital or operating margins for the preceding year.

Q. What approach does Staff recommend to improve AEPCO's capital structure?

A. Staff recommends steadily growing the Applicant's patronage equity by setting rates that balance the interest of the ratepayers and AEPCO's long-term financial health. AEPCO has not shown how its proposed rates will improve its highly leveraged capital structure in a reasonable timeframe. Staff anticipates that the Applicant will use the opportunity provided by rebuttal testimony to explain how its proposed rate will adequately satisfy its capital structure deficiency.

OPERATING INCOME, TIER AND DCS RATIOS

Q. What do the times interest earned ("TIER") and the debt service coverage ("DSC") ratios represent?

A. TIER represents the number of times operating income covers interest expense on long-term debt. A TIER greater than 1.0 means that operating income is greater than interest expense.

DSC represents the number of times internally generated cash covers required principal and interest payments on long-term debt. A DSC greater than 1.0 indicates that operating cash flow is sufficient to cover debt obligations.

Q. Do the Applicant's lenders have debt covenants for TIER and DSC?

A. Yes. The Rural Utilities Service ("RUS") requires AEPCO to maintain a minimum TIER of 1.05 and a minimum DSC of 1.0 on an annual average best two of three year basis.

Q. What TIER and DSC level does the Applicant claim will result from its proposed revenues?

A. The Applicant claims its proposed revenues would result in a 1.29 TIER and a 1.05 DSC. AEPCO's witness, Mr. Edwards, states in his direct testimony that "...these are minimum ratios to provide some financial stability and allow for equity improvement (Mr. Edwards Direct Testimony, Page 11, Line 4 & 5)".

Q. What TIER and DSC level does Staff conclude would result from the Applicant's proposed revenues?

A. Staff has calculated that AEPCO's proposed revenues would result in a TIER of 1.33 which also equates to a 0.91 DSC. The Applicant's proposed revenues are not sufficient to service its debt obligations.

Q. Has the Applicant demonstrated that its proposed revenues are sufficient to improve its equity position in a reasonable timeframe?

A. No. The Applicant has provided no support to demonstrate that its proposed revenues are sufficient to provide patronage equity growth to achieve a capital structure of at least 30 percent patronage equity in a reasonable timeframe.

Q. What does Staff recommend in regard to AEPCO's revenues, TIER, and DSC?

A. Staff recommends no reduction to AEPCO's proposed operating revenue. Staff's analysis shows that the Applicant's proposed revenues are inadequate to cover its debt service obligations. The Applicant's current financial situation and proposed revenues would not support additional debt financing such as its November 4, 2004 request for authorization for debt financing (Docket No. E-01773A-04-0793).

CONCLUSION

Q. Please summarize Staff's recommendations.

A. Staff recommends that the Commission adopt operating revenues of no less than those proposed by the Applicant. The Applicant's proposed revenues fail to provide sufficient internally generated cash flow to finance, directly or indirectly through additional future debt financing, plant replacement, improvement and expansion requirements. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64227, dated November 29, 2001) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission restrict the distribution of future patronage dividends by AEPCO until it has achieved a capital structure composed of at least 30 percent patronage equity.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AEPCO'S HISTORICAL CAPITAL STRUCTURE

Year	% Debt	% Patronage Equity
2001	93.6%	6.4%
2002	92.2%	7.8%
2003	95.2%	4.8%

Source: Based on the Applicant's filing

SAMPLE ELECTRIC COOPERATIVES' CAPITAL STRUCTURE

G&T Coops	% Debt[1]	% Patronage Equity[1]
Associated Electric Coop., Inc.	78.0%	22.0%
Arkansas Electric Coop., Inc.	56.6%	43.4%
Old Dominion Electric Cooperative	77.9%	22.1%
Basin electric Power Cooperative	61.1%	38.9%
Central Iowa Power	78.4%	21.6%
Oglethorpe Power	89.2%	10.8%
Seminole Electric Cooperative	90.5%	9.5%
Tri-state Generating & Transmission Assoc.	85.2%	14.8%
Hoosier Energy Rural Electric Coop., Inc.	88.1%	11.9%
Chugach Electric Association	74.4%	25.6%
Alabama Electric Coop., Inc.	91.3%	8.7%
Western Farmer's electric	91.7%	8.3%
Great River Energy	90.8%	9.2%
Average	81.0%	19.0%
Arizona Electric Power Cooperative, Inc.[2]	95.2%	4.8%

[1] Information based on annual reports for the year ended 2003
[2] Based on the Company's rate filing

AEPCOS' TIER and DSC With Staff's Recommended Rates[1]

1	Operating Income	$ 17,755,095	**TIER**	
2	Depreciation & Amort.	$ 7,539,289	[1+3] ÷ [5]	1.33
3	Income Tax Expense	$ -	**DSC**	
4			[1+2+3] ÷ [5+6]	0.91
5	Interest Expense	$ 13,313,164		
6	Repayment of Principal	$ 14,360,494		

[1] The amounts reflect Staff's pro forma adjustments and the Applicant's proposed revenue

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-04-0527

DIRECT

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2004

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EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0527

The direct testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $28,814,864 (excluding regulatory asset charge ("RAC") collections) proposed by Southwest Transmission Cooperative, Inc. ("SWTCO" or "Applicant") Staff calculates that the proposed revenues would provide a times interest earned ratio ("TIER") of 0.65 and a debt service coverage ("DSC") ratio of 0.81. Staff has also calculated a TIER of 1.13 and a DSC of 1.02 when including the RAC. The Applicant's proposed revenue fails to provide sufficient internally generated cash flow, directly or indirectly through incremental debt financing, for plant replacement, improvement and expansion requirements.

Capital Structure – The Applicant's actual end of test year capital structure was composed by 95.3 percent debt and 4.7 percent patronage equity. This is an excessively leveraged capital structure. This rate case is the appropriate time to address SWTCO's highly leveraged capital structure. The capital structure issue is important because a highly leveraged capital structure has potentially detrimental impacts for service reliability and rates. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64991, dated June 26, 2002) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff further recommends that the Commission restrict the distribution of future patronage dividends by SWTCO until it has achieved a capital structure composed of at least 30 percent equity.

INTRODUCTION

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

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my position as a Public Utilities Analyst, I perform studies to estimate the cost of capital component of the revenue requirement in rate proceedings. I also perform other financial analyses.

Q. Please describe your educational background and professional experience.

A. In 2002, I graduated summa cum laude from Arizona State University, receiving a Bachelor of Science degree in Global Business with a specialization in finance. While attending Arizona State University, I successfully completed the Barrett Honors College curriculum. My course of studies included classes in corporate and international finance, investments, accounting, statistics, and economics. I began employment as a Staff Public Utilities Analyst in 2003. Since that time, I have provided recommendations to the Commission on financings and prepared various studies in the field of cost of capital and econometrics. I have also attended seminars related to general regulatory and business issues.

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

A. I discuss Southwest Transmission Cooperative, Inc.'s ("SWTCO" or "Applicant") current capital structure and provide Staff's recommended operating income. I also provide the

times interest earned ("TIER") and debt service coverage ("DSC") ratios resulting from Staff's recommended operating income.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. This testimony is organized in three sections. Section I presents the Applicant's long-term debt and patronage equity balances. Section II discusses SWTCO's capital structure. Finally, Section III discusses Staff's recommended operating income, TIER and DSC ratios for the Applicant.

Q. Have you prepared any exhibits to your testimony?

A. Yes. I prepared three schedules (AXR-1 to AXR-3) that support Staff's recommendations.

Q. What is Staff's recommended operating income for the Applicant?

A. Staff recommends an operating income no less than $3,439,610 for SWTCO (which is the operating income that would result from the Applicant's proposed revenues).

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $3,439,610?

A. Staff has calculated that an operating income of $3,439,610 would allow SWTCO to achieve a TIER of 0.65 which also equates to a 0.81 DSC. Staff has also calculated a TIER of 1.13 and a DSC of 1.02 when including the Regulatory Asset Charge ("RAC") (Schedule AXR-4). Only by taking the RAC into account does the Applicant have the capacity to meet its debt service obligations.

times interest earned ("TIER") and debt service coverage ("DSC") ratios resulting from Staff's recommended operating income.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. This testimony is organized in three sections. Section I presents the Applicant's long-term debt and patronage equity balances. Section II discusses SWTCO's capital structure. Finally, Section III discusses Staff's recommended operating income, TIER and DSC ratios for the Applicant.

Q. Have you prepared any exhibits to your testimony?

A. Yes. I prepared three schedules (AXR-1 to AXR-3) that support Staff's recommendations.

Q. What is Staff's recommended operating income for the Applicant?

A. Staff recommends an operating income no less than $3,439,610 for SWTCO (which is the operating income that would result from the Applicant's proposed revenues).

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $3,439,610?

A. Staff has calculated that an operating income of $3,439,610 would allow SWTCO to achieve a TIER of 0.65 which also equates to a 0.81 DSC. Staff has also calculated a TIER of 1.13 and a DSC of 1.02 when including the Regulatory Asset Charge ("RAC") (Schedule AXR-4). Only by taking the RAC into account does the Applicant have the capacity to meet its debt service obligations.

SWTCO'S LONG-TERM DEBT AND PATRONAGE EQUITY BALANCE

Q. What is the amount of SWTCO's long-term debt outstanding?

A. The Applicant had $94,164,787 in long-term debt outstanding as of November 1, 2004, and it is expected to incur $5,302,088 in interest expense related to its long-term debt during the year.

Q. What were SWTCO's patronage equity balances for the years ended 2003, 2002 and 2001?

A. SWTCO's patronage equity balances for the years ended 2003, 2002 and 2001 were $4,240,180, $2,218,235 and $1,812,664, respectively.

SWTCO'S CAPTIAL STRUCTURE

Q. What was SWTCO's actual end of test year capital structure?

A. The Applicant's actual end of test year capital structure was composed by 95.3 percent debt and 4.7 percent patronage equity[1]. Schedule AXR-1 presents the Applicant's capital structures for the years 2001, 2002 and 2003.

Q. Is SWTCO concerned with its current capital structure?

A. Yes. In his direct testimony, the Applicant's witness, Mr. William K. Edwards, has emphasized the importance for SWTCO to develop a stronger equity base. Moreover, Mr. Edwards recognizes and supports the efforts made by both the Commission and SWTCO to establish long-term goals for SWTCO's patronage equity (Decision No. 64991, dated June 26, 2002).

[1] Staff has calculated the capital structure by taking into account long-term debt and equity.

Q. How does SWTCO's capital structure compare to other G&T utilities' capital structure?

A. Mr. William Edwards has compared SWTCO's capital structure to the Capital structure of 55 G&T utilities' capital structure. As mentioned in his testimony, SWTCO's capital structure is more leveraged than Mr. Edwards' G&T utilities sample (See Mr. Edwards Direct Testimony, Page 10, Line 18-21). Schedule AXR-2 presents the capital structure of some G&T cooperatives that are rated by *Standard & Poor's* ("S&P") and the Applicant's capital structure for the test year ended December 2003. The average capital structure of the G&T cooperatives is composed of 81.0 percent debt and 19.0 percent patronage equity as opposed to the Applicant's capital structure composed of 95.3 percent debt and 4.7 percent patronage equity.

Q. Is Staff concerned with the Applicant's actual end of test year capital structure?

A. Yes. SWTCO's capital structure is highly leveraged as it has remained for several years. The Applicant's capital structure has multiple potential negative effects including: (1) higher debt costs for new issuances; (2) reduced ability to incur new debt and finance capital improvements; and (3) places upward pressure on rates to cover debt service obligations.

Q. Has the Commission shown concern with highly leveraged cooperatives?

A. Yes. The Commission ordered SWTCO (Decision No. 64991, dated June 26, 2002) and Arizona Electric Power Cooperative ("AEPCO") (Decision No. 64227, dated November 29, 2001) to establish long-range goals to improve their patronage equity positions. In addition, the Commission ordered Trico Electric Cooperative, Inc. ("Trico") to file a capital improvement plan with the Commission (Decision No.67412, dated November 2,

2004). As discussed previously, highly leveraged capital structures present potentially negative consequences.

Q. Does the Rural Utilities Service ("RUS") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. SWTCO's audited financial statements for the years ended December 31, 2003 and 2002, state "RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative (See Exhibit GEP-1, note to financial statement 7)".

Q. Does the National Rural Utilities Cooperative Finance Corporation ("CFC") have any restrictions in regard to distribution of patronage dividends for highly leverage cooperatives?

A. Yes. The CFC requires a borrower to have a capital structure composed of at least 30 percent patronage equity to distribute 100 percent of its net earnings as patronage dividends. If the borrower has a capital structure composed of less than 30 percent patronage equity, it would be able to distribute as patronage dividends only 30 percent of its patronage capital or operating margins for the preceding year.

Q. What approach does Staff recommend to improve SWTCO's capital structure?

A. Staff recommends steadily growing the Applicant's patronage equity by setting rates that balance the interest of the ratepayers and SWTCO's long-term financial health. SWTCO

has not shown how its proposed rates will improve its highly leveraged capital structure in a reasonable timeframe. Staff anticipates that the Applicant will use the opportunity provided by rebuttal testimony to explain how its proposed rate will adequately satisfy its capital structure deficiency.

III. OPERATING INCOME, TIER AND DSC RATIOS

Q. What do the times interest earned ratio ("TIER") and debt service coverage ratio ("DSC") represent?

A. TIER represents the number of times operating income covers interest expense on long-term debt. A TIER greater than 1.0 means that operating income is greater than interest expense.

DSC represents the number of times internally generated cash covers required principal and interest payments on long-term debt. A DSC greater than 1.0 indicates that operating cash flow is sufficient to cover debt obligations.

Q. Do the Applicant's lenders have debt covenants for TIER and DSC?

A. Yes. The Rural Utilities Service ("RUS") requires SWTCO to maintain a minimum TIER of 1.05 and a minimum DSC of 1.0 on an annual average best two of three years basis.

Q. What TIER and DSC level does the Applicant claim will result from its proposed revenues?

A. The Applicant claims its proposed revenues would result in a 1.15 TIER and a 1.11 DSC. SWTCO's witness, Mr. Edwards, states in his direct testimony that "...these are minimum

ratios to provide some financial stability and *modest progress* toward equity goals [emphasis added] (Mr. Edwards Direct Testimony, Page 11, Line 4 & 5)". Moreover, Mr. Edwards recognizes that SWTCO has a long way to go towards improved financial strength.

Q. What TIER and DSC level does Staff conclude would result from the Applicant's proposed revenues?

A. Staff has calculated that SWTCO's proposed increase in revenues would result in a TIER of 0.65 which also equates to a 0.81 DSC. Staff has also calculated a TIER of 1.13 and a DSC of 1.02 when including the Regulatory Asset Charge ("RAC") (Schedule AXR-4). Only by taking the RAC into account does the Applicant have the capacity to meet its debt service obligations.

Q. Has the Applicant demonstrated that its proposed revenues are sufficient to improve its equity position in a reasonable timeframe?

A. No. The Applicant has provided not support to demonstrate that its proposed revenues are insufficient to provide patronage equity growth to achieve a capital structure of at least 30 percent patronage equity in a reasonable timeframe.

Q. What operating revenues does Staff recommend?

A. Staff recommends operating revenues no less than what SWTCO is proposing ($28,814,864 without taking into account the RAC or 31,374,790 including the RAC). Staff recognizes that the Applicant's proposed revenues barely allow the Applicant to

cover its debt service. Staff also recognizes that to improve its equity position in a reasonable timeframe, higher rates are needed.

CONCLUSION

Q. Please summarize Staff's recommendations.

A Staff recommends that the Commission adopt a revenue requirement no less than that proposed by the Applicant. The Applicant's proposed revenues fail to provide sufficient internally generated cash flow to finance, directly or indirectly through additional future debt financing, plant replacement, improvement and expansion requirements. The Applicant has not demonstrated that its proposed revenue is consistent with the Commission's order (Decision No. 64991, dated June 26, 2002) to establish long-range goals to improve its patronage equity position. Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission restrict the distribution of future patronage dividends by SWTCO until it has achieved a capital structure composed of at least 30 percent patronage equity.

Q. Does this conclude your direct testimony?

A. Yes, it does.

SWTCO'S HISTORICAL CAPITAL STRUCTURE

Year	Debt	Equity
2001	98.1%	1.9%
2002	97.5%	2.5%
2003	95.3%	4.7%

Source: Based on the Applicant's filing

SAMPLE G&T COOPERATIVES' CAPITAL STRUCTURE

G&T Coops	% Debt[1]	% Patronage Equity[1]
Associated Electric Coop., Inc.	78.0%	22.0%
Arkansas Electric Coop., Inc.	56.6%	43.4%
Old Dominion Electric Cooperative	77.9%	22.1%
Basin electric Power Cooperative	61.1%	38.9%
Central Iowa Power	78.4%	21.6%
Oglethorpe Power	89.2%	10.8%
Seminole Electric Cooperative	90.5%	9.5%
Tri-state Generating & Transmission Assoc.	85.2%	14.8%
Hoosier Energy Rural Electric Coop., Inc.	88.1%	11.9%
Chugach Electric Association	74.4%	25.6%
Alabama Electric Coop., Inc.	91.3%	8.7%
Western Farmer's electric	91.7%	8.3%
Great River Energy	90.8%	9.2%
Average	81.0%	19.0%
Southwest Transmission Cooperative, Inc.[2]	95.3%	4.7%

[1] Information based on annual reports for the year ended 2003
[2] Based on the Company's rate filing

SWTCO'S TIER and DSC With Staff's Recommended Rates[1]

1	Operating Income	$	3,439,610	**TIER Without RAC**	
2	Regulatory Asset Charge ("RAC")	$	2,559,926	[1+5] ÷ [7]	0.65
3	Total Regulated Revenues	$	5,999,536	**TIER With RAC**	
4	Depreciation & Amort.	$	6,852,107	[3+5] ÷ [7]	1.13
5	Income Tax Expense	$	-		
6					
7	Interest Expense	$	5,302,088	**DSC Without RAC**	
8	Repayment of Principal	$	7,358,610	[1+4+5] ÷ [7+8]	0.81
				DSC With RAC	
				[3+4+5] ÷ [7+8]	1.02

[1] The amounts reflect Staff's pro forma adjustments and Staff's minimum recommended revenue

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-04-0528

SURREBUTTAL

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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Fitch and Ratings' Article Attachment-1

EXECUTIVE SUMMARY
ARIZONA ELECTRIC POWER COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0528

The surrebuttal testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $148,397,723 proposed by Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Applicant"). AEPCO's proposed revenues would provide a times interest earned ratio ("TIER") of 1.50 and a debt service coverage ("DSC") ratio of 0.99. The Applicant's proposed revenue fails to provide sufficient internally generated operating cash flow to meet its debt service obligations.

Capital Structure – Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission adopt a patronage distribution restriction for SWTCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends the Commission require AEPCO to file another rate case within at most three (3) to five (5) years after the effective date of a decision in this proceeding.

INTRODUCTION

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

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Alejandro Ramirez who previously filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to respond to the rebuttal testimonies of Mr. Minson and Mr. Pierson. I also present Staff's position in regard to the Applicant's proposed operating income, times interest earned ratio ("TIER"), debt service coverage ration ("DSC"), and AEPCO's equity position.

I. UPDATED OPERATING REVENUES RECOMMENDATION

Q. What is Staff's updated recommended operating income for the Applicant?

A. Staff recommends an operating income of no less than $19,903,441, which is the same operating income that would result from the revenues proposed in AEPCO's rebuttal testimony.

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $19,903,441?

A. An operating income of $19,903,441 would produce a 1.50 TIER and a 0.99 DSC.

Q. Do you have any comments on AEPCO's updated recommended operating income of $19,903,441?

A. Yes. Although AEPCO's updated proposed operating income is higher than the proposed operating income in AEPCO's original filing, Staff is still concerned with the Applicant's capacity to service its current outstanding debt, finance future capital projects, and its capacity to improve its equity position.

Q. What TIER and DSC ratios is the Applicant claiming would result from AEPCO's updated proposed revenues?

A. AEPCO claims that its updated proposed revenues of $148,397,723 would produce a 1.62 TIER and a 1.05 DSC.

Q. Why are these ratios different from Staff's TIER and DSC?

A. Staff calculates TIER and DSC ratios differently from AEPCO [which calculates the TIER and DSC in the same manner as the Rural Utility Service ("RUS")]. AEPCO takes into account non-operating revenues when calculating the TIER and DSC while Staff does not. Staff does not take into account non-operating revenues when calculating TIER and DSC ratios because those revenues are not the direct result of AEPCO's regulated activities. Staff cannot foretell whether these non-operating revenues will continue in the future. A decrease in non-operating revenues may negatively impact AEPCO's ability to service its

debt; therefore, if AEPCO's TIER and DSC calculations provide a less reliable basis for determining debt service capacity.

Q. Why is Staff concerned with AEPCO's capacity to service its current outstanding debt?

A. Staff is concerned with AEPCO's capacity to service its current outstanding debt because the Applicant's proposed operating income would result in a 1.50 TIER and a 0.99 DSC (Staff's calculated TIER and DSC). As stated in Staff's direct testimony, the DSC ratio represents the number of times internally generated cash will cover payments on both interest and principal. A DSC equal to 0.99 means that if there is no change from the assumptions built into recommended rates, the Applicant cannot meet all of its existing debt service obligations with cash generated from operations. Only with recognition of non-operating cash flow does the Applicant barely cover both its principal and interest payments. Any detrimental change (even slight) in the economic environment resulting in erosion of AEPCO's operating or non-operating revenue or increasing expenses would exacerbate the Applicant's capacity to service its current debt obligations.

Q. Why is Staff concerned with AEPCO's capacity to finance future capital projects?

A. AEPCO's capacity to finance future capital projects may be negatively affected given that Staff has calculated a 0.99 DSC based on AEPCO's proposed revenues. Additional financing for capital projects would result in an even lower DSC for the Applicant. The Applicant has requested the Commission to authorize AEPCO to incur additional debt financing for $8.4 million (Docket No. E-01773A-04-0793). By Staff's calculations, AEPCO will not be able to service this additional debt with its proposed revenues alone. Therefore, Staff will recommend denial of this financing unless AEPCO modifies its

revenue request. In addition, any other future debt financing will be seriously compromised given the Applicant's proposed revenues.

Q. What is AEPCO's current financial situation?

A. AEPCO's witness and Chief financial Officer, Dirk Minson, stated in his rebuttal testimony that the Applicant is out of compliance with RUS. This non-compliance negatively impacts AEPCO's capacity to incur any new debt. An even more immediate and important effect is the potential limitation for AEPCO to draw any funds from currently authorized loans. This is one example of the Applicant's need to improve its financial position. Operating revenues that provide a DSC equal to 0.99 do not help mitigate AEPCO's immediate financial problems, and fail to recognize a solid solution for the long-run.

Q. What is Staff's current position on the Applicant's updated proposed operating income?

A. Staff recommends that the Commission approve operating revenues for AEPCO that would result in an operating income of no less of $19,903,441 (which is the same operating income that the Applicant is requesting). However, Staff expects the Applicant to address its precarious proposed revenue requirement soon. AEPCO must address this situation in the very near future because the proposed revenue provides for virtually no current borrowing capacity, severely limits future borrowing capacity and does little to improve its highly leveraged capital structure.

II. COMMENTS ON MR. MINSON'S REBUTTAL TESTIMONY

Q. Do you have any general comments on Mr. Minson's rebuttal testimony?

A. Yes. As Mr. Minson stated in his direct testimony, AEPCO and Staff recognize the need for a rate increase to improve the Applicant's financial position. Staff also recognizes that AEPCO had improved its equity position to 7 percent of the total assets by 2002 (compared with its negative equity position of 14.9 percent in 1991). In addition, Staff recognizes AEPCO's effort to decrease its member rates. However, it is Staff's position that AEPCO's rates should be sufficient to move toward a sound financial position while also taking into account the ratepayer impact.

Q. Do you have any comments in regard to Mr. Minson's recommended DSC of 1.05 as the basis to calculate the proposed revenue levels?

A. Yes. Previously in this testimony, it was explained that the Applicant's and Staff's TIER and DSC are calculated in a different manner. The Applicant's proposed DSC of 1.05 takes into account non-operating revenues where Staff does not. Therefore, the Applicant's updated proposed revenues will in fact produce a lower Staff DSC. Although RUS may provide additional financing to AEPCO if the Applicant's updated proposed revenues are approved by the Commission, AEPCO's capacity to service its debt payments may be reduced, leaving no cushion for unexpected events. The Applicant may find that its updated proposed revenues are insufficient to support any additional debt financing needed for capital improvements.

Q. Does Mr. Minson contest Staff's recommendation to improve AEPCO's equity position?

A. While Mr. Minson agrees with Staff that the Applicant should continue to build its equity position, he disagrees with Staff's recommendation that AEPCO should increase its equity position to 30 percent of the capital structure.

Q. Does Mr. Minson recommend a specific equity position goal for the Applicant?

A. No. Mr. Minson's opinion is that an equity position of 30 percent is simply too high. Mr. Minson refers to the Schedule presented by Staff in Direct testimony that shows that the average equity position for the sample generation and transmission ("G&T") companies is 19 percent. He also refers to the R.W. Beck 2002 survey which indicated that the equity ratio goal of the cooperatives surveyed was 17.5 percent.

Q. What is Staff's position in regard to AEPCO's equity position?

A. Staff's position is that AEPCO should improve its equity position to at least 30 percent. Staff's position reflects a prior Commission decision (Decision No. 64227, dated November 29, 2001), and AEPCO's need to achieve greater financial flexibility. Also, and article published by Fitch Ratings, a well known rating agency, stated that an equity-to-capitalization ratio between 25 to 30 percent is adequate for a generation and transmission cooperative (See Attachment 1).

Q. Do you have any comments in regard to Mr. Minson's statement that setting a 30 percent equity goal will result in AEPCO's inflexibility to react to economic and financial changes?

A. Yes, Staff understands Mr. Minson's concerns that there might be factors that may not allow AEPCO to achieve the 30 percent equity goal. Staff is aware that economic and financial conditions do change over time. Staff also understands the there is the need to balance reasonable rates and the financial health of the Applicant. However, it is Staff's position that the Applicant should commit to improve its equity position to at least 30 percent. Staff recommends consistently balancing the effort to achieve a healthy financial position with other considerations.

Q. Does Mr. Minson take any position in regard to Staff's recommendation of restricting future patronage distributions until the Applicant has achieved a 30 percent capital structure?

A. Yes. Mr. Minson states that AEPCO does not have any plans for the foreseeable future to make any patronage distributions. However, Mr. Minson proposes that if Commission places any restriction on patronage distributions, it should be the same restriction presented by the Applicant's debt covenants.

Q. Does Staff have any comments on the restriction of patronage distributions?

A. Yes. Instead of distributing patronage dividends, the Applicant could use those funds to fund, in full or at least partially, future capital projects, thereby increasing its equity position. As mentioned earlier in this testimony, Staff is concerned with AEPCO's current and future borrowing capacity. Staff supports the Commission adopting a patronage

distribution restriction for AEPCO that is in accordance with, or even more restrictive than, the Applicant's existing debt covenants.

Q. Do you have any other recommendations for AEPCO?

A. Yes. Given that the Applicant agrees with Staff that AEPCO needs to increase its equity position, but has not shown any specific plan or target to accomplish it, Staff recommends that the Commission order AEPCO to file an equity improvement plan by December 31, 2005. Staff also recommends that the Commission order AEPCO to file a status report with Director of the Utilities Division by March 30 each year showing its equity position and changes from the prior year. Staff strongly recommends that AEPCO consider filing rate cases more frequently. Staff further recommends that the Commission order AEPCO to file another rate case within at most three (3) to five (5) years after the effective date of an order in this proceeding.

CONCLUSION

Q. What is Staff's recommended operating income for AEPCO?

A. Staff recommends an operating income for AEPCO of no less than $19,903,441. A 1.50 TIER and a 0.99 DSC would result from Staff's minimum operating income. Staff is concerned with the Applicant's current and future capacity to service its debt. Staff is also concerned with the Applicant's borrowing capacity.

Staff further recommends that the Commission require AEPCO to improve its equity position to at least 30 percent. Staff also recommends that the Commission adopt a patronage distribution restriction for AEPCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends that the Commission require AEPCO to docket an equity improvement plan by December 31, 2005.

Staff further recommends the Commission require AEPCO to docket a calendar year status report by March 30 each year showing its equity position and changes from the prior year.

Staff further recommends the Commission require AEPCO to file another rate case within at most three (3) to five (5) years after the effective date of a decision in this proceeding.

Q. Does this conclude your surrebuttal testimony?

A. Yes it does.

AEPCOS' TIER and DSC With Staff's Updated Recommended Rates[1]

1	Operating Income	$ 19,903,441	**TIER**	
2	Depreciation & Amort.	$ 7,539,289	[1+3] ÷ [5]	1.50
3	Income Tax Expense	$ -	**DSC**	
4			[1+2+3] ÷ [5+6]	0.99
5	Interest Expense	$ 13,313,164		
6	Repayment of Principal	$ 14,360,494		

[1] The amounts reflect Staff's pro forma adjustments and Staff's recommended revenue

Fitch Initiates Coverage of Golden Spread Electric Cooperative with 'A-' Rating

02 Mar 2005 4:14 PM (EST)

Fitch Ratings-New York-March 2, 2005: Fitch Ratings assigns an initial senior secured rating of 'A-' to Golden Spread Electric Cooperative, Inc.'s (Golden Spread) $55 million 2005 private placement. The Rating Outlook is Stable. Proceeds will be used to repay Golden Spread for the acquisition and construction costs incurred to date and to complete the construction of a 145-mw gas-fired combustion turbine peaking unit. The 2005 financing will be priced in March 2005 with La Salle Capital as sole placement agent.

The foundation of Golden Spread's long-term rating derives from a pledge of revenues from the company's full-requirement contracts with its 16 members through the life of the bonds. In addition, bondholders will be secured by a lien on the 145-mw peaking units as well as surplus cash from Golden Spread's sale of energy from current and future affiliated power projects. Other positive credit factors include favorable intermediate-term partial-requirement power supply arrangements with Southwestern Public Service Company (SPS), a wholly owned subsidiary of Xcel Energy, experienced management and consultants, and a solid financial profile.

Credit concerns include Golden Spread's need to develop power supply to replace its SPS partial-requirement agreement that expires in 2012, its higher than average concentration of commercial and irrigation customers among its members' retail loads (representing more than 70% of member revenues), the

need to maintain adequate liquidity and financial margins in the future, and lean management team.

In 1984, 11 distribution utilities formed Golden Spread to consolidate their interests and provide power supply alternatives to SPS. In this role, Golden Spread negotiated a partial-requirement power supply arrangement and dispatch arrangement (both of which expire in 2012). These arrangements provides Golden Spread the flexibility to utilize at its discretion over 300 mw of SPS resources (with a fuel mix of 2/3 coal and 1/3 gas) and the full capacity of the Mustang Station, a 483-mw combined-cycle plant that has been on-line since 2000. As part of the dispatch arrangement with SPS, Golden Spread is able to sell its excess energy from Mustang at favorable rates that help reduce its wholesale cost of power. Fitch views these arrangements as positive and stable factors in Golden Spread's credit profile.

With the forthcoming expiration of the SPS partial-requirement agreement and the need to increase its power supply, Golden Spread is currently developing and implementing a generation expansion program. In the next seven years, Golden Spread's capital expenditures will total over $800 million (funded with approximately 80% debt and 20% cash) to fund various coal and gas-fired generation projects.

The 'A-' rating is based on Golden Spread's solid historical operations, and assumes the cooperative is successful in its implementation of a diversified and adequate power supply portfolio while maintaining sound financial results. Fitch recognizes the majority of the planned projects are in the early stages of development and that Golden Spread could modify its plan as the wholesale market and power supply alternatives change. Fitch is comforted by Golden Spread's track record in developing the Mustang Station and the experience of its management and long-time consultants. Nevertheless, unexpected delays or substantial project cost increases above projections could become a negative credit factor should they compromise Golden Spread's financial strength or if they significantly affect the members' retail customers' cost of power and financial viability.

Although the new projects will substantially increase Golden Spread's leverage

and annual debt service requirements, current and projected ratios are well above average for the rating category and include 2003 debt service coverage of 2.3 times (x) and equity-to-capitalization of 31%. Unaudited results for fiscal-year 2004 are in-line with historical levels. For the future, management expects to maintain a minimum debt service coverage ratio of 1.5x and equity-to-capitalization ratios between 25%-30%, which is good for a generation and transmission cooperative.

Golden Spread's future generation units could be funded as separate projects whereby a portion of a project's cash and equity would be segregated from Golden Spread and the 2005 bondholders. Fitch does not consider this risk as meaningful, since each of the projects would likely be serving a majority, if not all members, and operating margins and cash reserves at any individual project should not be significant.

Golden Spread has over $20 million in cash reserves and also maintains $110 million in available liquidity facilities. In aggregate, this liquidity provides over six months of operating expenses. In addition to these funds, Golden Spread has approximately $40 million in cash that is pledged to a future power project. Further bolstering its liquidity profile, Fitch views positively Golden Spread's competitive wholesale rates and a structure that automatically adjusts for changes in fuel and purchased power costs on a monthly basis. Golden Spread plans to use a portion of its current and projected cash balances over the next few years to partially fund the costs of its various planned generation projects. With lower levels of cash projected during that period, Fitch will look for Golden Spread to maintain sufficient levels of liquidity with available lines of credit and conservative revenue requirement projections.

Golden Spread is a not-for-profit generation and transmission cooperative providing electric service to 16 distribution cooperatives. Fifteen members are located in Texas' Panhandle, South Plains and Edward Plateau regions and one member is located in the Oklahoma Panhandle region. The service area of Golden Spread's Texas members represent approximately 24% of the land mass of Texas. In 2003, Golden Spread's membership increased to 16 members from the original 11. The 16 distribution members serve nearly 200,000 customers.

In 2004, Golden Spread's total revenues were almost $411 million, with 66% representing revenues under long-term member contracts and 34% from sales to SPS.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-04-0527

SURREBUTTAL

TESTIMONY

OF

ALEJANDRO RAMIREZ

PUBLIC UTILITIES ANALYST III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

APRIL 4, 2005

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Fitch and Ratings' Article Attachment-1

EXECUTIVE SUMMARY
SOUTHWEST TRANSMISSION COOPERATIVE, INC.
DOCKET NO. E-01773A-04-0527

The surrebuttal testimony of Staff witness Alejandro Ramirez addresses the following issues:

Operating Income, TIER and DSC Ratios – Staff recommends operating revenues no less than the $28,814,864 proposed by Southwest Transmission Cooperative, Inc. ("SWTCO" or "Applicant"). SWTCO's proposed revenues and the Regulatory Asset Charge ("RAC") would provide a times interest earned ratio ("TIER") of 1.64 and a debt service coverage ("DSC") ratio of 1.02. The Applicant's proposed revenue barely provides sufficient internally generated cash flow to meet its debt service obligations.

Capital Structure – Staff recommends that the Applicant improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

Staff also recommends that the Commission adopt a patronage distribution restriction for SWTCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends that the Commission require SWTCO to file another rate case within at most three (3) to five (5) years of the effective fate of a decision in this proceeding.

INTRODUCTION

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

A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Alejandro Ramirez who previously filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to respond to the rebuttal testimonies of Mr. Minson and Mr. Pierson. I also present Staff's position in regard to the Applicant's proposed operating income, times interest earned ratio ("TIER"), debt service coverage ration ("DSC") and SWTCO's equity position.

I. UPDATED OPERATING REVENUES RECOMMENDATION

Q. What is Staff's updated recommended operating income for the Applicant?

A. Staff recommends an operating income of no less than $6,146,732, which is the same operating income that would result from the updated revenues proposed in SWTCO's rebuttal testimony.

Q. What TIER and DSC ratios would result from Staff's minimum recommended operating income of $6,146,732?

A. An operating income of $6,146,732 would produce a 1.16 TIER and a 0.81 DSC without the Regulatory Asset Charge ("RAC") and a 1.64 TIER and a 1.02 DSC with the RAC.

Q. Do you have any comments on SWTCO's updated recommended operating income of $6,146,732?

A. Yes. Staff is still concerned with the Applicant's capacity to service its current outstanding debt, finance future capital projects, and improve its equity position.

Q. What TIER and DSC ratio is the Applicant claiming would result from SWTCO's updated proposed revenues?

A. SWTCO claims that its updated proposed revenues of $28,814,864 would produce a 1.17 TIER and a 1.02 DSC.

Q. Why are these ratios different from Staff's TIER and DSC?

A. Staff calculates TIER and DSC ratios differently from SWTCO [which calculates the TIER and DSC in the same manner as the Rural Utility Service ("RUS")]. SWTCO takes into account non-operating revenues when calculating the TIER and DSC while Staff does not. Staff does not take into account non-operating revenues when calculating TIER and DSC ratios because those revenues are not the direct result of SWTCO's regulated activities. Staff cannot foretell whether these non-operating revenues will continue in the future. A decrease in non-operating revenues may negatively impact SWTCO's ability to service its debt; therefore, SWTCO's TIER and DSC calculations provide a less reliable basis for determining debt service capacity.

Q. Why is Staff concerned with SWTCO's capacity to service its current outstanding debt?

A. Staff is concerned with SWTCO's capacity to service its current outstanding debt because the Applicant's proposed operating income, including the RAC, would result in a 1.64 TIER and a 1.02 DSC (Staff's calculated TIER and DSC). As stated in Staff's direct testimony, the DSC ratio represents the number of times internally generated cash will cover payments on both interest and principal. A Staff DSC equal to 1.02 barely covers SWTCO's current debt service. If there is no change from the assumptions built into recommended rates, the Applicant can cover both its principal and interest payments. However, any detrimental change (even slight) in the economic environment resulting in erosion of SWTCO's operating or non-operating revenue or increasing expenses would adversely affect the Applicant's capacity to service its current debt obligations.

Q. Why is Staff concerned with SWTCO's capacity to finance future capital projects?

A. SWTCO's capacity to finance future capital projects may be negatively affected given that—holding everything else equal—additional financing for capital projects may result in a DSC less than 1.00. A DSC less than 1.00 means insufficient cash flow is generated from operations to service existing debt obligations. The Applicant has requested the Commission to authorize SWTCO to incur additional debt financing for approximately $6 million (Docket No. E-04100A-05-0151). SWTCO may not be able to service this additional debt with its proposed revenues alone. In addition, SWTCO's capital structure is highly leveraged; therefore, not consistent with sound financial practices. Staff will recommend denial of this financing unless SWTCO modifies its revenue request. In addition, any other future debt financing will be seriously compromised given the Applicant's proposed revenues.

Q. Will SWTCO's proposed operating income resolve its current financial situation?

A. SWTCO's proposed operating revenues may help mitigate the Applicant's immediate financial problems, but SWTCO's proposal fails to provide any solid solution for the long-run.

Q. What is Staff's current position on the Applicant's updated proposed operating income?

A. Staff recommends that the Commission approve operating revenues for SWTCO that would result in an operating income of no less of $6,146,732 (which is the same operating income that the Applicant is requesting). However, Staff expects the Applicant to address its precarious proposed revenue requirement soon. SWTCO must address this situation in the very near future because the proposed revenue provides for virtually no current borrowing capacity, severely limits future borrowing capacity and does little to improve its highly leveraged capital structure.

II. COMMENTS ON MR. MINSON'S REBUTTAL TESTIMONY

Q. Do you have any comments in regard to Mr. Minson's recommended DSC of 1.02 as the basis to calculate the proposed revenue levels?

A. Yes. Although RUS may provide additional financing to SWTCO if the Applicant's updated proposed revenues are approved by the Commission (given that the proposed revenues result in a 1.02 RUS DSC with RAC), SWTCO's capacity to service its debt payments will be minimal, leaving no cushion for unexpected events. The Applicant may find that its updated proposed revenues are insufficient to support any additional debt financing needed for capital improvements.

Q. Does Mr. Minson contest Staff's recommendation to improve SWTCO's equity position?

A. While Mr. Minson agrees with Staff that the Applicant should continue to build its equity position, he disagrees with Staff's recommendation that SWTCO should increase its equity position to 30 percent of the capital structure.

Q. Does Mr. Minson recommend a specific equity position goal for the Applicant?

A. No. Mr. Minson's opinion is that an equity position of 30 percent is simply too high.

Q. What is Staff's position in regard to SWTCO's equity position?

A. Staff's position is that SWTCO should improve its equity position to at least 30 percent. Staff's position reflects prior a Commission decision (Decision No. 64991, dated June 26, 2002) and SWTCO's need to achieve greater financial flexibility. Also, and article published by Fitch Ratings, a well known rating agency, stated that an equity-to-capitalization ratio between 25 to 30 percent is adequate for a generation and transmission cooperative (See Attachment 1).

Q. Does Mr. Minson take any position in regard to Staff's recommendation of restricting future patronage distributions until the Applicant has achieved a 30 percent capital structure?

A. Yes. Mr. Minson states that SWTCO does not plan, for the foreseeable future, to make any patronage distributions. However, Mr. Minson proposes that if the Commission places any restriction on the patronage distributions, it should be the same restriction presented by the Applicant's debt covenants.

Q. Does Staff have any comments on the restriction of patronage distributions?

A. Yes. Instead of distributing patronage dividends, the Applicant could use those funds to fund, in full or at least partially, future capital projects, thereby increasing its equity position. As mentioned earlier in this testimony, Staff is concerned with SWTCO's current and future borrowing capacity. Staff supports the Commission adopting a patronage distribution restriction for SWTCO that is in accordance with, or even more restrictive than, the Applicant's existing debt covenants.

Q. Do you have any other recommendations for SWTCO?

A. Yes. Given that the Applicant agrees with Staff that SWTCO needs to increase its equity position, but has not shown any specific plan or target to accomplish it, Staff recommends that the Commission require SWTCO to file an equity improvement plan by December 31, 2005. Staff also recommends that the Commission require SWTCO to file a status report with Director of the Utilities Division by March 30 each year showing its equity position and changes from the prior year. Staff strongly recommends that SWTCO consider filing rate cases more frequently. Staff further recommends that the Commission require SWTCO to file another rate case within at most three (3) to five (5) years after the effective date of an order in this proceeding.

CONCLUSION

Q. What is Staff's recommended operating income for SWTCO?

A. Staff recommends an operating income for SWTCO of no less than $6,146,732. Staff is concerned with the Applicant's current and future capacity to service its debt. In addition, Staff is also concerned with the Applicant's borrowing capacity.

Staff further recommends that the Commission require SWTCO to improve its equity position to at least 30 percent. Staff also recommends that the Commission adopt a patronage distribution restriction for SWTCO that is no less restrictive than the Applicant's existing debt covenants.

Staff further recommends that the Commission require SWTCO to docket an equity improvement plan by December 31, 2005.

Staff further recommends that the Commission require SWTCO to docket a calendar year status report with Director of the Utilities Division by March 30 each year showing its equity position and changes from the prior year.

Staff further recommends that the Commission require SWTCO to file another rate case within at most three (3) to five (5) years of the effective fate of a decision in this proceeding.

Q. Does this conclude your surrebuttal testimony?

A. Yes it does.

SWTCO'S TIER and DSC With Staff's Recommended Rates[1]

1	Operating Income	$	6,146,732	**TIER Without RAC**	
2	Regulatory Asset Charge ("RAC")	$	2,559,926	[1+5] ÷ [7]	1.16
3	Total Regulated Revenues	$	8,706,658	**TIER With RAC**	
4	Depreciation & Amort.	$	4,144,985	[3+5] ÷ [7]	1.64
5	Income Tax Expense	$	-		
6					
7	Interest Expense	$	5,302,088	**DSC Without RAC**	
8	Repayment of Principal	$	7,358,610	[1+4+5] ÷ [7+8]	0.81
9				**DSC With RAC**	
10				[3+4+5] ÷ [7+8]	1.02

[1] The amounts reflect Staff's pro forma adjustments and Staff's minimum recommended revenue

Fitch Initiates Coverage of Golden Spread Electric Cooperative with 'A-' Rating

02 Mar 2005 4:14 PM (EST)

Fitch Ratings-New York-March 2, 2005: Fitch Ratings assigns an initial senior secured rating of 'A-' to Golden Spread Electric Cooperative, Inc.'s (Golden Spread) $55 million 2005 private placement. The Rating Outlook is Stable. Proceeds will be used to repay Golden Spread for the acquisition and construction costs incurred to date and to complete the construction of a 145-mw gas-fired combustion turbine peaking unit. The 2005 financing will be priced in March 2005 with La Salle Capital as sole placement agent.

The foundation of Golden Spread's long-term rating derives from a pledge of revenues from the company's full-requirement contracts with its 16 members through the life of the bonds. In addition, bondholders will be secured by a lien on the 145-mw peaking units as well as surplus cash from Golden Spread's sale of energy from current and future affiliated power projects. Other positive credit factors include favorable intermediate-term partial-requirement power supply arrangements with Southwestern Public Service Company (SPS), a wholly owned subsidiary of Xcel Energy, experienced management and consultants, and a solid financial profile.

Credit concerns include Golden Spread's need to develop power supply to replace its SPS partial-requirement agreement that expires in 2012, its higher than average concentration of commercial and irrigation customers among its members' retail loads (representing more than 70% of member revenues), the

need to maintain adequate liquidity and financial margins in the future, and lean management team.

In 1984, 11 distribution utilities formed Golden Spread to consolidate their interests and provide power supply alternatives to SPS. In this role, Golden Spread negotiated a partial-requirement power supply arrangement and dispatch arrangement (both of which expire in 2012). These arrangements provides Golden Spread the flexibility to utilize at its discretion over 300 mw of SPS resources (with a fuel mix of 2/3 coal and 1/3 gas) and the full capacity of the Mustang Station, a 483-mw combined-cycle plant that has been on-line since 2000. As part of the dispatch arrangement with SPS, Golden Spread is able to sell its excess energy from Mustang at favorable rates that help reduce its wholesale cost of power. Fitch views these arrangements as positive and stable factors in Golden Spread's credit profile.

With the forthcoming expiration of the SPS partial-requirement agreement and the need to increase its power supply, Golden Spread is currently developing and implementing a generation expansion program. In the next seven years, Golden Spread's capital expenditures will total over $800 million (funded with approximately 80% debt and 20% cash) to fund various coal and gas-fired generation projects.

The 'A-' rating is based on Golden Spread's solid historical operations, and assumes the cooperative is successful in its implementation of a diversified and adequate power supply portfolio while maintaining sound financial results. Fitch recognizes the majority of the planned projects are in the early stages of development and that Golden Spread could modify its plan as the wholesale market and power supply alternatives change. Fitch is comforted by Golden Spread's track record in developing the Mustang Station and the experience of its management and long-time consultants. Nevertheless, unexpected delays or substantial project cost increases above projections could become a negative credit factor should they compromise Golden Spread's financial strength or if they significantly affect the members' retail customers' cost of power and financial viability.

Although the new projects will substantially increase Golden Spread's leverage

and annual debt service requirements, current and projected ratios are well above average for the rating category and include 2003 debt service coverage of 2.3 times (x) and equity-to-capitalization of 31%. Unaudited results for fiscal-year 2004 are in-line with historical levels. For the future, management expects to maintain a minimum debt service coverage ratio of 1.5x and equity-to-capitalization ratios between 25%-30%, which is good for a generation and transmission cooperative.

Golden Spread's future generation units could be funded as separate projects whereby a portion of a project's cash and equity would be segregated from Golden Spread and the 2005 bondholders. Fitch does not consider this risk as meaningful, since each of the projects would likely be serving a majority, if not all members, and operating margins and cash reserves at any individual project should not be significant.

Golden Spread has over $20 million in cash reserves and also maintains $110 million in available liquidity facilities. In aggregate, this liquidity provides over six months of operating expenses. In addition to these funds, Golden Spread has approximately $40 million in cash that is pledged to a future power project. Further bolstering its liquidity profile, Fitch views positively Golden Spread's competitive wholesale rates and a structure that automatically adjusts for changes in fuel and purchased power costs on a monthly basis. Golden Spread plans to use a portion of its current and projected cash balances over the next few years to partially fund the costs of its various planned generation projects. With lower levels of cash projected during that period, Fitch will look for Golden Spread to maintain sufficient levels of liquidity with available lines of credit and conservative revenue requirement projections.

Golden Spread is a not-for-profit generation and transmission cooperative providing electric service to 16 distribution cooperatives. Fifteen members are located in Texas' Panhandle, South Plains and Edward Plateau regions and one member is located in the Oklahoma Panhandle region. The service area of Golden Spread's Texas members represent approximately 24% of the land mass of Texas. In 2003, Golden Spread's membership increased to 16 members from the original 11. The 16 distribution members serve nearly 200,000 customers.

In 2004, Golden Spread's total revenues were almost $411 million, with 66% representing revenues under long-term member contracts and 34% from sales to SPS.

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DEMPSEY

BEFORE THE ARIZONA CORPORATION COMMISSION

DOCKETED

SEP 03 1993

DOCKETED BY JDL

MARCIA WEEKS
CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
DALE H. MORGAN
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC., AN ARIZONA NON-PROFIT RURAL ELECTRIC COOPERATIVE CORPORATION, FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. U-1773-92-214 DECISION NO. 58405 **OPINION AND ORDER**

DATES OF HEARING: March 4, 5, 8, 9, April 8, 1993, (Hearing)
February 26, 1993,(Prehearing Conference)

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICER: Lyn Farmer

IN ATTENDANCE: Marcia Weeks, Chairman
Dale H. Morgan, Commissioner

APPEARANCES: JOHNSTON, MAYNARD, GRANT & PARKER, by Mr. Michael M. Grant, on behalf of Arizona Electric Power Cooperative, Inc.;

BROWN & BAIN, by Mr. Lex J. Smith, on behalf of Phelps Dodge Corporation;

Mr. K. Justin Reidhead, Chief Counsel, on behalf of the Residential Utility Consumer Officer; and

Ms. Janice M. Alward and Ms. Deborah R. Scott, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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EXHIBIT
S-15
Official Notice Taken

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DECISION NO. 58405

BY THE COMMISSION:

On August 3, 1992, Arizona Electric Cooperative, Inc. ("AEPCO" or "Applicant") filed with the Arizona Corporation Commission ("Commission") an application in Docket No. U-1773-92-214 for a permanent increase in electric rates.

Intervention was granted to the Residential Utility Consumer Office ("RUCO") on August 27, 1992; to Phelps Dodge Corporation ("Phelps Dodge") on September 17, 1992; to Cyprus Sierrita Corporation ("Cyprus") and to William R. Phillips and the Pueblo Del Sol Property Owners Association on December 2, 1992. On February 26, 1993, Intervenors Mr. Phillips and the Pueblo Del Sol Property Owners Association's request for withdrawal was granted.

By Procedural Order dated August 31, 1992, the matter was set for hearing on March 4, 1993. The hearing commenced as scheduled, and after a continuance, resumed and was concluded on April 8, 1993.

Three members of the public attended to comment on the application. At the hearing, testimony in support of the application was presented by AEPCO, Staff, RUCO, and Phelps Dodge.

The parties submitted opening briefs on May 14, and reply briefs on May 28, 1993.

INTRODUCTION

AEPCO is a generation and transmission cooperative, supplying power to six Class A, one Class B, and one Class C members.

AEPCO filed this rate application based on a test year ("TY") of the twelve month period ending December 31, 1991. The application sought an increase of $5.176 million in gross revenues. Subsequently, on November 13, 1992, AEPCO submitted its Revised Filing in support of its Application. The Revised Filing sought an increase of $5,040,000

million, or 6.38%.

Staff recommended a decrease of approximately $1.6 million in operating revenues and RUCO recommended a revenue decrease of approximately $898,000.

RATE BASE

AEPCO's revised filing included a proposed rate base of $289,769,000, and after adjustments made at hearing, AEPCO's final proposed rate base was $266,398,000. Staff made several adjustments to rate base including: exclusion of AEPCO's cash working capital allowance of $10,576,000; elimination of the balance of $987,000 of prepaid expenses; elimination of $15,764,000 in deferred charges; and elimination of $13,952,000 in member advances[1]; and exclusion of $581,981 as unreasonable costs associated with AEPCO's headquarters complex; for an adjusted rate base of $247,909,000. RUCO recommended an adjusted rate base of $267,117,000.

AEPCO opposed Staff's adjustment to eliminate a cash working capital allowance. Staff eliminated cash working capital allowance because AEPCO calculated the allowance based on a formula method using one-eighth of operation and maintenance expense. In its last two rate cases, AEPCO used both the formula approach and a lead lag study which demonstrated that AEPCO had a cash working capital need. We will allow a cash working capital allowance in this proceeding, but AEPCO should prepare a lead lag study in connection with its next rate filing in order to continue to support a cash working capital allowance.

We agree with Staff's adjustments eliminating the balance of

[1] Staff eliminated member advances from rate base but included the interest on the advances as a pro forma operating expense. See Exhibit A-9 DJE-2 Schedule C.

$987,000 of prepaid expenses, $15,764,000 in deferred charges and also eliminating $13,952,000 in member advances.

We find that AEPCO has met its burden of proof that the $581,000 in costs associated with the acquisition and remodeling of AEPCO's headquarters complex was prudent. Decision No. 57848 (May 14, 1992) approved the financing for construction of its new headquarters complex, and in response to a Finding of Fact, Staff re-examined the AEPCO headquarters building project. As a result of its re-examination, Staff believes that AEPCO spent $209,450 more than it should have spent for the purchase of Building 1000. Staff's analysis used the replacement method to determine the value.[2] In response to Staff's proposed adjustment, AEPCO presented evidence showing that it obtained an appraisal from the firm of Burke Hansen, Inc., a real estate appraisal and consulting firm, in April, 1988, prior to making its decision to purchase Building 1000. The building was appraised at $1,510,000, and AEPCO purchased the building for approximately $1.4 million. In response to Staff's assertion that there was no evidence that AEPCO negotiated with the owner, AEPCO presented evidence that it ran an economic analysis and determined that continued leasing of the building would be $600,000 - $1,000,000 more expensive than purchase at $1.4 million. Additionally, the building had been sold for $1.375 million about 22 months before AEPCO purchased it. Given these circumstances, we cannot say that AEPCO's purchase price of $1.4 million for Building 1000 was imprudent, and accordingly, we will not

[2] Mr. James R. Brown, Utilities Consultant/Electrical Engineer reviewed the commercial real estate listings in Benson and selected a reasonable price for commercial land in the area of the parcel, and used the average cost estimate for office buildings in the 1992 edition of the Richardson Engineering Services, Inc. Process Plant Construction Estimating Standards as a reasonable cost for a public utility building.

accept Staff's adjustment of $209,450.

Staff also argued that AEPCO spent $363,375 more than it should have for "office construction" and $8,156 more than it should have for "service construction". Staff's analysis used average construction costs applied to square footage of construction, to determine the amount of unreasonable cost. Although Staff's position was that the headquarters complex was spacious and opulent for a public utility, Staff attached no dollar figures to this concern.

AEPCO presented evidence which showed that it commissioned a Master Plan to determine its needs for the next 10-20 years; it hired a professional architect to design and oversee the construction project; it commissioned an engineering study to evaluate and make provision for the Benson area soil conditions to prevent another building collapse; it competitively bid the project; and it selected the low bidder to complete the work.

We agree with AEPCO that the construction costs were reasonable,[3] given the extra construction costs necessary to account for the subsurface conditions in the area. Accordingly, we will not accept Staff's adjustment to remove $371,531 from rate base. However, as we discussed in Decision No. 57848, AEPCO should file future financing applications before it proceeds with the project for which financing approval is requested, and we will order AEPCO to follow such a procedure.

With the adjustments approved herein, we find AEPCO's original cost less depreciation rate base ("OCRB") to be $259,066,000.

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[3] Staff's analysis showed the square foot cost for office buildings built of wood or steel studs ranged from $35 to $70. AEPCO paid $62.50 per square foot. The range in costs for service construction was from $28 to $46. AEPCO paid $40.82.

AEPCO did not file reconstruction cost new rate base information and, in its application, agreed that its rate of return may be premised upon its OCRB. Therefore, for purposes of this proceeding, AEPCO's OCRB is the same as its fair value rate base ("FVRB"). We find AEPCO's FVRB to be $259,066,000.

FAIR VALUE RATE BASE SUMMARY

Adjusted Rate Base (per AEPCO)	$289,769,000
Commission Approved Adjustments	
Prepaid Expenses	($987,000)
Deferred Charges	($15,764,000)
Member Advances	($13,952,000)
Commission Adjusted Rate Base	$259,066,000

OPERATING INCOME

REVENUES

AEPCO's adjusted total operating revenue for the TY was $133,808,000. AEPCO's adjusted TY revenues include annualized effects of changes in contract demands for customers other than the Class A jurisdictional members, but did not recognize any annualization of growth in sales to the Class A members or growth in non-firm sales. Staff and RUCO proposed revenue annualization adjustments for both Class A Member growth and for growth in non-firm sales.

Class A Member Growth

Staff proposed an adjustment to increase Class A member revenues by $980,000 with a corresponding adjustment to increase expenses by $460,000. RUCO proposed an adjustment to increase Class A member revenues by $1,212,000 with a corresponding adjustment to increase expenses by $633,000.

Consistent with its calculation of interest expense as of the end of TY, with its annualization of TY salaries and wages, and with AEPCO's annualization of changes in contract demands, Staff applied a

growth factor of 3.5% (1.72% annualization factor) to the Class A member revenues[4] to reach its proposed $980,000, reflecting load growth to the end of the TY. RUCO's adjustment increased AEPCO's TY Class A Member revenues to reflect the 1992 actual kilowatt hour increase in Class A member energy sales.

AEPCO opposed the adjustments to annualize Class A member revenues. It believes that use of a growth rate is inherently speculative and that use of 1992 Class A member energy sales moves entirely out of the TY.

We agree with Staff and RUCO that annualization of Class A member revenues is appropriate. Given our use of end of TY interest expense, rate base determination, and our agreement that end of TY expense levels are appropriate, we find that Staff's approach accurately reflects load growth among Class A members. Accordingly, we will increase Class A member revenues by $980,000 and increase operating expenses by $460,000.

Phelps Dodge Non-Firm Revenues

AEPCO's adjusted revenues included an adjustment to annualize and increase the demand revenues associated with a firm contract of 50 megawatts with Phelps Dodge approved by the Commission in 1991. This adjustment increased TY revenues by more than $7.2 million. AEPCO made another adjustment to decrease economy sales revenues by $4.5 million to reflect the fact that Phelps Dodge intended to replace much of its non-firm or interruptible purchases with this new firm contract. The net effect of the two adjustments was to increase

[4] Duncan Valley demand and energy revenues were eliminated because those revenues relate mainly to sales to one large customer, and would not grow in proportion to the growth in ultimate customers.

AEPCO's revenues by more than $2.7 million.

Staff proposed an adjustment to increase the non-firm revenues by $151,000 and RUCO proposed an adjustment to increase the non-firm revenues by $1.222 million.

AEPCO's adjustment assumed no net increase in energy sales as a result of the 50 MW firm contract, but its 1992 Operating Budget forecast an increase in non-firm sales to Phelps Dodge in addition to the increased firm sales. Actual 1992 data indicate that although sales were not as great as projected in the budget, they were significantly greater than the pro forma non-firm sales included by AEPCO in its adjustment. Staff's adjustment used the Phelps Dodge non-firm sales for the twelve months ended June 30, 1992[5], together with the applicable margin for the same time period, as the basis for determining the pro forma level of non-firm sales to be included in the TY. RUCO's adjustment did not use the 1992 market price, and therefore, its adjustment is overstated.

We agree with Staff, that based on a comparison of non-firm sales during the TY and during the first year of the Phelps Dodge firm contract, that the firm contract has not displaced the non-firm sales, and that an adjustment of $151,000 is appropriate.

Contract Charge Revenues

Staff also proposed a revenue adjustment to annualize contract charges. The agreements between AEPCO and the City of Mesa, the Arizona Power Pooling Association, Electrical District No. 2, and the Salt River Project allow AEPCO to recover certain expenses associated with Steam Units 2 and 3. Since AEPCO adjusted revenues to recover

[5] The Phelps Dodge 50 MW firm contract went into effect July 1, 1991.

those expenses, and we are reducing some of those pro forma adjustments, we must reduce the contract charge revenues calculated by AEPCO in the amount of $354,000.

Billing Credits

In its rate filing, AEPCO reduced the TY number of kWs by 43,654 kw to reflect the billing demand credits that AEPCO granted its member cooperatives. Staff proposed a $666,000 adjustment to add back the revenues associated with those kWs on the basis that the 43,654 kW were actual TY kW and that AEPCO should have received the revenue because billing demand credits have not been approved by the Commission.

RUCO proposed that AEPCO's adjustment to billing demand credits of $666,000 be reduced to $415,000. RUCO's adjustment distinguishes between billing credits given in accordance with the load shedding agreement ("Agreement") among Chemstar Inc. ("Chemstar"), Mohave Electric Cooperative, Inc. ("Mohave"), and AEPCO[6] ($415,000); and the billing credits given based upon interruptible tariffs of AEPCO's member cooperatives ($251,000). RUCO's adjustment allows a reduction in revenues only for those billing demand credits associated with the Agreement, and increases revenues by $251,000.

We agree with RUCO's adjustment to increase revenues by $251,000 to reflect the revenue associated with billing demand credits which we did not approve for AEPCO. We find that the Agreement does allow AEPCO to give billing credits to Mohave, who must then give the credit to Chemstar. Our approval of the Agreement was based on the recognition that Chemstar was likely to generate all its power in the

[6] Approved by the Commission in Decision No. 56694 (November 7, 1989).

absence of the contract, and upon Staff's determination that AEPCO and Mohave would be better off under the contract than if Chemstar generated all its own power. Our analysis included a comparison of margins for both AEPCO and Mohave, both under the then current rates and with the proposed contract. It is clear that the billing demand credit would initiate with AEPCO and flow through to Chemstar. The rates set in the Agreement were the rates charged to Mohave by AEPCO for coincident demand adjusted for losses, together with the energy charge AEPCO charged to Mohave, adjusted for losses. The Agreement provided that Mohave would bill Chemstar a surcharge of $0.0060 per kilowatt hour to recover its applicable operating costs and to provide a reasonable margin. Accordingly, it is clear that the Agreement intended to preserve Mohave's margin and did not intend Mohave to initiate the billing demand credits. Therefore, any billing demand credits would logically initiate with AEPCO, to whom the loss of Chemstar from its system would have the most damaging effect. However, as discussed hereinafter, we agree with Staff that the pricing of the billing demand credits needs to be reviewed and note that paragraph VI of the Agreement provides that "[t]he foregoing rates are subject to any changes in the rates of AEPCO or Mohave which may be established and approved for billing by the Arizona Corporation Commission from time to time."

Accordingly, we will adjust operating revenues by $251,000. With the adjustments approved herein, we find the TY operating revenues to be $134,836,000.

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EXPENSES

Total operating expenses according to AEPCO's books were $105,444,000 for the TY, and $107,098,000 after its pro-forma adjustments.

Legal Expense

AEPCO incurred approximately $1.4 million in TY legal expense. During the proceeding, AEPCO reduced its requested legal expenses to $1.33 million to reflect $41,836 in rail true-up expenses and $71,957 in expenses related to the Berkeley arbitration.[7]

RUCO proposed an adjustment of $346,000 to AEPCO's TY legal expense. RUCO's adjustment annualizes expenditures charged to the TY by comparing actual expenses for legal work on natural gas issues during a period of the TY and with expenses incurred during the same period in 1992.

Staff's witnesses presented two alternatives for legal expense disallowance determinations. Staff consultant, Mr. Effron recommended a disallowance of $380,000 as a result of his normalization adjustment based on the 1992 level of expense. Mr. Effron normalized the expense because he found the expenses for the coal and natural gas issues in 1991 were abnormally high, and based on the actual expense incurred in 1992, the legal expense for these activities is diminishing.

Staff expert witness, attorney Frederick J. Murrell, recommended that further investigation into attorney fees and the matters related

[7] On May 24, 1991, Mr. Arnold D. Berkeley (Arnold D. Berkeley, P.C., and the law firm Berkeley, Chaifetz & Nelson, hereafter referred to "Berkeley" or the "Berkeley firm") filed his Demand for Arbitration with the American Arbitration Association seeking to recover in excess of $67 million in legal fees from AEPCO. The panel's award was issued in September 1992 and AEPCO has appealed the award to the United States District Court, District of Arizona, which filed an order on May 6, 1993, in which the court found in favor of Arnold Berkeley.

to the fees is necessary and that the rates set in this proceeding be made interim pending the results of the investigation. Mr. Murrell recommended that the fees paid to Berkeley during the TY, in the amount of approximately $464,000 not be included in the level of legal expense used to set rates in this proceeding. Mr. Murrell cited two basis for this recommendation: that AEPCO has argued in Federal District court that the Berkeley firm should not be permitted to recover fees from AEPCO and that AEPCO is unable to determine whether the Berkeley fees included charges for work done in preparation of the case Berkeley filed against AEPCO; and because he believes that it was imprudent for AEPCO to have entered into the fee agreements with Berkeley. Mr. Murrell further recommended that 35 percent of the fees paid to the firm of Slover & Loftus[8] relating to its representation of AEPCO before the Federal Energy Regulatory Commission ("FERC") be excluded as time the firm had to spend becoming familiar with AEPCO's pending matters. The total effect of Mr. Murrell's recommendations results in a disallowance of legal expense for the TY of $661,000.

We agree with Staff and RUCO that TY legal expense for coal and natural gas issues was considerable higher than the actual expenses for 1992, and that an adjustment to normalize for the TY is therefore reasonable and appropriate. We also agree with Mr. Murrell that the fees paid to the Berkeley firm during the test year should not be included in legal expenses used to set rates in this proceeding, and 35% of the fees paid to Slover & Loftus should be excluded as well. Accordingly, we will reduce TY legal expense by $661,000.

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[8] Slover & Loftus was retained by AEPCO when AEPCO terminated Berkeley in June 1991.

Rate Case Expense

In it rebuttal, AEPCO proposed an adjustment to include rate case expense, which it had not included in its initial and revised filings. Because AEPCO was not proposing any rate level increase, AEPCO hoped its rate case expenses could be held to a minimum and did not include a pro forma adjustment. After AEPCO received Staff and Intervenor data requests and direct testimony, it revised its estimate and included $265,000 in rate case expense, amortized over three years, for an adjustment of $88,000. Staff opposed the adjustment, believing that AEPCO should have presented this adjustment in its direct case and that there is no satisfactory explanation why the expense was not included. Staff also believes that AEPCO did not bear its burden of demonstrating that it had $265,000 in rate case expense. RUCO believes the appropriate amount of recoverable rate case expense is $140,000, the actual amount incurred as of December 31, 1991. RUCO proposes amortizing this amount over a period of five years, for an annual rate case expense of $28,000.

We agree with Staff that AEPCO should have included its rate case expense in its initial and revised filings. However, there is no question but that AEPCO incurred rate case expense and to penalize the cooperative under these circumstances would be inappropriate. We agree with RUCO that rate case expense in the amount of $140,000 is appropriate, and that an amortization period of five years is consistent with prior intervals between AEPCO's filings. Accordingly, we will increase AEPCO's TY operating expenses by $28,000.

EPRI Dues

In its rebuttal, AEPCO also made an adjustment to add the first quarter dues assessment of the Electric Power Research Institute

("EPRI") for 1991. AEPCO had not included the amount in its original schedule preparation because it was booked in December, 1990. The adjustment would increase operating expenses by $117,000 in the TY. Staff believes that the adjustment should have been included in AEPCO's direct case and recommends that the Commission should not permit rate recovery. RUCO recommends that no adjustment be made because it believes that a portion of the dues collected are spent on lobbying, advocacy, and promotional activities which do not benefit ratepayers. In response to a RUCO data request, AEPCO provided an invoice which "[a]lmost, but not totally" convinced RUCO's witness that none of EPRI's dues go to the Edison Electric Institute. We find that an adjustment of $117,000 to operating expenses to include the first quarter EPRI dues is appropriate. The record in this proceeding does not establish that any portion of the EPRI dues are used for lobbying, advocacy, or promotional activities, and therefore it would be inappropriate to disallow recovery of that expense.

Pension Expense

AEPCO included $1,015,000 of pension costs in TY operating expenses, but subsequently agreed with Staff and RUCO to remove the adjustment because it did not incur any pension costs in the TY and has been advised that its required contributions to the National Rural Electric Cooperative Association ("NRECA") Pension Fund would not recommence in 1993.

Staff recommended that if the moratorium ended during the period in which rates from this case are in effect, given the Company's financial position, AEPCO should be authorized to defer any actual pension payments for future recovery. Staff recommended that the recovery not be automatic and should not take place prior to the next

rate case, when it would be determined what deferred costs, if any, should be recoverable. AEPCO proposed that if pension payments do resume, they be recovered through an automatic surcharge or a deferral mechanism coupled with assurance of recovery. Staff and RUCO opposed AEPCO's proposal.

We concur with all parties to eliminate the $1,015,000 adjustment for pension expense and concur with Staff and RUCO that deferral of pension costs (if any such costs occur during the interim between rate filings) should be authorized, but recovery should not be automatic. The pension costs should be recovered only after the Commission has had a chance review the costs in a base rate proceeding. Accordingly, we will disallow the pension costs adjustment in the amount of $1,015,000.

Wages and Salaries

AEPCO in its revised filing proposed to adjust wages and salaries by $1,168,155 to reflect increases taking place in 1991 and 1992, and to reflect the approved TY staffing level rather than the actual TY staffing level.

Consistent with its revenue annualization to the end of TY level, Staff proposed an adjustment to salaries and wages of $1,107,00, including the adjustments to payroll taxes and payroll related benefits, to reflect the effect of increases in employee levels taking place through the end of 1991. RUCO adjusted AEPCO's original payroll adjustment by $225,000. Staff, RUCO, and AEPCO used different numbers of employees in their adjustment. We agree with Staff that an adjustment is necessary to reflect the effect of the wage increase and the year end annualized employee level, and accordingly we will adopt Staff's adjustment of $1,107,000 - a reduction to AEPCO's adjustment

in the amount of $61,000.

Load Research Project

During the TY, AEPCO incurred costs associated with the load research project in the amount of $144,000. Staff and RUCO opposed this adjustment, noting the costs will not be reoccurring in nature and because the charges booked during the TY were significantly higher than the expenses in 1990. In its rebuttal case, AEPCO stated that the costs were undertaken at the behest of the Commission and Staff in order to develop better power requirements study, integrated planning and cost of service information, and proposed to amortize the costs over a period of three years - an annual expense level of $48,000. Staff accepted this proposal and recommended the TY expense of $144,000 be reduced by $96,000 to reflect the three-year amortization.

We agree with AEPCO and Staff that it is appropriate to amortize the $144,000 load research project expense over a period of three years and accordingly, we will adjust operating expenses by $96,000.

Year End Audit Adjustments and Achievement Sharing

AEPCO included a $337,000 pro forma adjustment to accrue payroll properly as of the end of the year and also an adjustment to include $371,000 to recognize Achievement Sharing Awards based on 1991 results. AEPCO, Staff, and RUCO all agree that the adjustment to accrue year-end payroll and $71,000 of accrual of Achievement Sharing awards are not appropriate, but Staff and RUCO proposed further reductions to AEPCO's adjustment. RUCO eliminated the pro forma adjustment for Achievement Sharing awards based on its analysis that the program does not appear to promote any additional company savings over the actual TY. Staff included the $219,000 Achievement Sharing expense booked in 1991 because based on Staff's review of the program,

the goals appear to be mainly oriented to cost control and do not appear to discriminate in favor of upper management.

We agree with Staff that the actual expense booked to the Achievement Sharing program should be allowed, and therefore, we will adjust operating expenses to reduce AEPCO's adjustment by $489,000.

Miscellaneous

AEPCO accepted the following adjustments proposed by Staff and/or RUCO: computer lease expense adjustment of ($44,000); gross revenue tax removal ($214,000)[9]; DSM cost removal ($66,000[10]); and medical, dental, and life insura^[nce of $72,000. We concur and will approve those adjustments.

Depreciation Expense

AEPCO's actual TY depreciation expense was $10,988,000. AEPCO made a pro forma adjustment of $525,000 to recognize depreciation on $15 million of post TY capital projects. AEPCO's adjusted TY depreciation expense was $11,513,000.

Staff excluded the $525,000 depreciation associated with the post TY capital projects, noting that it would create a mismatch between depreciation expense and other elements in the determination of AEPCO's revenue deficiency or excess. Staff proposed to increase depreciation expense by $198,000 over the actual TY expense, based on the annualized level of depreciation on the end of TY plant in service. This is $327,000 less than the pro forma adjustment proposed by AEPCO.

RUCO proposed an adjustment to reduce AEPCO's adjusted

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[9] The gross revenue tax will in the future be recovered through a bill add-on.

[10] AEPCO accepted the DSM cost removal adjustment subject to its ability to recover the costs in conjunction with the PPFAC.

depreciation expense by $215,000. RUCO recommended allowing only the actual amount AEPCO spent on plant additions in 1992 into rate base[11], thereby disallowing the balance of the requested $15 million. Accordingly, RUCO proposed to adjust actual TY depreciation expense to include an additional $310,000 in depreciation associated with the new plant.

Additionally, Staff recommended a further reduction in depreciation expense of $7000 related to the portion of the AEPCO headquarters building cost which Staff found to be unreasonable.

Consistent with our determination of TY rate base, revenues, and other expenses, we agree with Staff that depreciation expense should be increased by $198,000 over the actual TY expense, based on the annualized level of depreciation on the end of TY plant in service. Accordingly, we will reduce depreciation expense by $327,000. Consistent with our determination of rate base, we will not adopt Staff's proposed $7000 adjustment.

Property Taxes

AEPCO also proposed an adjustment to increase property taxes by $375,000 associated with post TY capital additions. Consistent with our decision hereinabove, we will disallow that adjustment. Accordingly, property tax expense will be reduced by $375,000.

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[11] $8,871,418

OPERATING INCOME SUMMARY

Consistent with the foregoing discussion, the following statement details the adjusted TY net operating income for ratemaking purposes:

Adjusted Operating Revenue (per AEPCO)	$133,808,000
Commission Approved Adjustments	
Class A Revenues	980,000
Phelps Dodge Revenues	151,000
Contract Charge Revenues	(354,000)
Billing Demand Credits	251,000
Commission Adjusted Operating Revenue	$134,836,000
Adjusted Operating Expenses (per AEPCO)	$107,098,000
Commission Approved Adjustments	
Legal Expense	(661,000)
Rate Case	28,000
EPRI dues	117,000
Pension	(1,015,000)
Wages & Salary	(61,000)
Load Research	(96,000)
Payroll	(337,000)
Achievement Sharing	(152,000)
Computer Lease	(44,000)
DSM	(66,000)
Insurance	72,000
Sales Growth	460,000
Depreciation	(327,000)
Gross Revenue Tax	(214,000)
Property Tax	(375,000)
Commission Adjusted Operating Expenses	$104,427,000
Net Operating Income/Operating Margins	$ 30,409,000

NON-OPERATING INCOME AND EXPENSE

Interest Expense

AEPCO's TY interest expense on long-term debt was $28,979,000. AEPCO proposed three adjustments. One adjustment reclassified interest income on the Carbon Coal advance as a credit against interest on long-term debt, another added interest related to borrowings to finance post TY plant additions, and the third adjustment annualized interest on long-term debt based on the end of TY interest rate and levels of long-term debt. AEPCO's pro forma adjustments resulted in TY adjusted interest expense of $27,766,000.

Staff proposed interest expense on long-term debt of $28,939,000, which is from the Company's schedule D-2 and is calculated by applying the effective interest rates to the outstanding long-term debt as of the end of the TY. Staff did not reclassify the interest income on the Carbon Coal advance, but left it in other income. Staff did not include interest on long-term debt related to the $15 million post TY capital additions.

We agree with Staff's treatment of interest expense and accordingly, we will recognize $28,939,000 as TY interest expense.

Interest Income and Other Nonoperating Income

Consistent with our determination of interest expense, we find the interest income to be $3,483,000; other income to be $78,000; interest income during construction of $542,000; other interest expense to be ($993,000); for a total of $3,110,000 in interest income and other nonoperating income.

TIER

The parties disagree about which Times Interest Earned Ratio ("TIER") should be used to determine AEPCO's revenue requirement.

Appropriate TIER Level

AEPCO recommends a TIER of 1.20. AEPCO's recommendation is based on several factors, including: the need to strengthen its financial position in order to build toward positive equity and meet the conditions of the new Rural Electrification Administration ("REA") rules[12]; that the 1.20 TIER would produce a 1.5% energy rate decrease

[12] In January 1992, the REA published new rules (C.F.R. Part 1710) which set minimum TIER and debt service coverage ("DSC") levels for power supply borrowers (generation and transmission cooperatives) of 1.05 and 1.00, respectively; which requires maintenance of the annual TIER and DSC levels on both a prospective and retrospective basis; and which, as a condition for obtaining a loan, require G&Ts with total equity of less than twenty percent to

for Class A members; and that the recommended TIER is consistent with past decisions of the Commission concerning AEPCO and with recent AEPCO member cooperative cases. In the TY, AEPCO achieved a 1.06 TIER on an actual basis and a TIER of 1.00 on an adjusted basis. In the TY, AEPCO's actual and adjusted DSC were 1.14 and 1.11, respectively. AEPCO had negative equity of approximately $49 million at the end of the TY.

AEPCO's witness, Mr. David J. Hedberg, Director of Rates and Special Projects at the National Rural Utilities Cooperative Finance Corporation ("CFC"), prepared a model to determine the appropriate TIER level, using AEPCO's projections of loads, expenses, and construction requirements. According to Mr. Hedberg's model, with a 1.2 TIER, AEPCO's equity to total capitalization would be positive beginning in the year 2000 and AEPCO would reach the REA's targeted 20% equity level by the year 2011. Using the model with a TIER of 1.125, positive equity would occur in 2003, and in the year 2011 the equity would be 9.66%.[13]

RUCO recommended a TIER of 1.12 and a DSC of 1.38. RUCO's TIER witness, Mr. Larry Dobesh, Ph.D., considered several factors in reaching his recommended TIER, including: the new rules adopted by the REA; CFC eligibility requirements for long-term loans; the business and financial condition for the industry and AEPCO; rates; and other actions such as increasing operating efficiency and reducing

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develop and follow a ten-year equity development plan designed to achieve reasonable progress toward increasing equity as a percentage of assets; without raising power costs or retail rates for electricity unreasonably, placing an unreasonable burden on rate payers, or substantially reducing the borrower's ability to compete with neighboring utilities or other energy sources.

[13] AEPCO's equity position at TY end was -14%.

costs. Dr. Dobesh criticized AEPCO's model for its use of a very slow growth rate while projecting administrative and general expenses to grow much faster.

Staff's consultant, Mr. David Parcell, recommended that a TIER within the range of 1.10 to 1.15 (1.125 midpoint) is appropriate and balances the ratepayers' interests with those of AEPCO. Staff believes that such a TIER will provide sufficient funds to permit AEPCO to move toward a positive equity level, safeguard ratepayers from being placed under an unreasonable burden, and will provide adequate funds to maintain AEPCO's financial health and to meet the loan requirements of its lenders.

There are two primary issues involved in this proceeding concerning the appropriate TIER level. The first is determining the proper financial ratios necessary for AEPCO to continue to meet the minimum default levels set out in AEPCO's current loan documents, as well as the new minimum TIER and DSC levels adopted by the REA in §1710.114. The second is to ensure that the ratios allow AEPCO, as a power supply borrower with less than 20 percent equity who intends to obtain a loan or loan guarantee from the REA, to build equity and achieve reasonable progress toward increasing equity as a percentage of total assets, in compliance with §1710.116.

As noted by CFC's Mr. Hedberg, because AEPCO's equity holders are also member/customers, there is an inherent conflict between the members' desire to hold down rates and the need to improve AEPCO's financial condition by retaining equity. Since its last rate increase in 1984, AEPCO has reduced member rates by 18% and refunded $16 million. During the same timeframe, AEPCO's equity level remained negative, and during the TY was at approximately the same level as it

was when, in Decision No. 55435 (February 12, 1987), the Commission concluded that "only by careful management of its resources can . . . (AEPCO) . . . correct its present excessive negative equity problems." Although AEPCO's members benefit from reduced rates, it is in the long-term best interests of AEPCO and its members that AEPCO move toward positive equity. We realize that there is a balance to be struck between keeping rates competitive and eliminating negative equity, but we fail to see any strong commitment or serious steps taken on AEPCO's part to build its equity. No party to this proceeding has asserted that AEPCO's current rates are at a level which substantially reduce AEPCO's ability to compete with neighboring utilities or other energy sources. Accordingly, we will set a TIER that we believe will meet the REA and CFC requirements, and at the same time, allow AEPCO to build equity. However, as part of AEPCO's equity development plan, we expect AEPCO's management to take other actions to increase its operating efficiency and reduce costs, and thereby further build AEPCO's equity. We find that a TIER level of 1.16 is appropriate for the reasons set forth hereinabove.

AUTHORIZED REVENUES

A TIER of 1.16 will result in a required operating income of $33,569,240. This would be an 12.96 percent rate of return on the FVRB which we find is reasonable under the circumstances of this case. This is $50,240 more than the adjusted TY operating income of $33,519,000 and no increase in gross annual revenues is necessary.

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RATE DESIGN

AEPCO's current rate levels are $15.25 per kW of demand and $0.02535[14] per kWh of energy. Based on Staff's recommended revenue requirements, Staff proposed AEPCO's demand charge should remain at $15.25 per kW of demand coincident with the Arizona Power Pooling Association monthly peak, and the energy charge should be set at $0.02132 per kWh. The results of RUCO's analysis significantly shift the allocation of generation and transmission rate base and operating expenses from demand to energy. RUCO recommended a demand charge of $9.00 per kilowatt-month and an energy rate of $0.03736 per kwh.

Phelps Dodge recommended that rates for AEPCO's Class A members be differentiated according to the voltage level at which power and energy are delivered to the Class A member customers. It recommended that low voltage level customers should have a demand charge of $15.4258/kW and an energy charge of $0.02468 kWh and that high voltage customers have a demand charge of $15.3421/kW and an energy charge of $0.02458 kWh. Phelps Dodge also recommended that AEPCO be ordered to file within two years a complete cost-of-service study at which time a rate design proceeding should be convened.

We find that AEPCO's current rate design should not be altered in this proceeding. The lack of information concerning the cost of providing service prevents us from adopting a rate design other than the one currently in place. Accordingly, we will order AEPCO to conduct a fully allocated embedded cost of service study, just as we ordered AEPCO to conduct in our Decision No. 53034 (1982).

Given our determination that no increase or decrease in revenues

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[14] AEPCO's energy charge is $0.03179 per kWh, along with a fuel adjustor of -$0.00644 per kWh.

is appropriate, the demand charge should remain $15.25 per KW and the energy charge should be $0.02228 per kWh.

AEPCO proposed a tariff provision regarding waiver of the power factor adjustment under certain circumstances, and Staff has agreed. We concur that the tariff provision should be approved.

MISCELLANEOUS

Interim Rates

On the first day of hearing, Staff moved for a continuance of the hearing. An in camera proceeding was held where Staff informed the Hearing Officer and the parties of allegations concerning AEPCO's management. Staff began an investigation into the allegations and the investigation is still in process. Staff has recommended that any rates established in this proceeding be made interim, subject to the completion of Staff's investigative audit. Staff asserts that by doing so, we will have the opportunity to re-establish new rates if any of the allegations that are under investigation prove to affect the underlying financial information which supports AEPCO's rate filing.

AEPCO opposes the establishment of interim rates in this proceeding, stating that interim rates are proper only in certain unique instances: in emergency situations; in confiscatory situations such as the period between a court decision and a remand to the Commission; and in a hearing to determine whether a Certificate of Convenience and Necessity should be transferred. AEPCO suggested other remedies such as the power pursuant to A.R.S. §40-252 to re-open a previous Order, and the power to commence an inquiry into rates upon its own motion.

We concur with Staff that we may need to re-examine the rates

authorized herein, if any of the allegations under investigation prove to affect the underlying financial information upon which we have based our Decision. Accordingly, we believe that the record should remain open in this proceeding for a period of not more than six months after the issuance of this Decision to allow for consideration of the investigative audit results and the issuance of a Final Order in this proceeding.

Purchase Power and Fuel Adjustment Clause

Staff made the following recommendations concerning the Purchase Power and Fuel Adjustment Clause ("PPFAC"):

- AEPCO should refund the accumulated fuel bank balance as of the effective date of this order to the Class A members through a one-time billing credit;
- in determining the amount to be refunded, certain fuel related expenses such as legal and consulting fees should be eliminated from the fuel cost charged against the accumulated fuel bank;
- the fuel and purchase power base cost should be set at $0.01714/kwh and the fuel adjustor be set at zero;
- long-term capacity demand charges should no longer be recovered through the PPFAC; and
- the balance of preapproved deferred DSM costs at the time of the effective date of this order should be offset against the accumulated fuel bank balance to be refunded to Class A members.

AEPCO agrees that the DSM costs should be offset against the accumulated fuel bank balance, but disagrees with Staff's other recommendations. AEPCO recommended the new fuel and purchased power base cost be set at $0.01661/kWh with a zero adjuster; it opposed Staff's recommendation to eliminate long-term capacity demand charges; it opposed a one-time refund of the fuel bank balance; and AEPCO

opposed Staff's recommendation that certain legal expenses associated with fuel related issues previously charged against the bank balance in the TY be added back.

We agree with Staff and AEPCO that the balance of the preapproved DSM costs should be offset against the accumulated fuel bank balance to be refunded.

We agree with Staff that long-term capacity demand charges should not continue to be recovered through the PPFAC. Although AEPCO argues that it would be faced with annual rate filings to recover scheduled price and volume changes in its purchased power contracts, we agree with Staff that the contracts themselves contain adjustors to reflect increases in purchased capacity costs, and that the demand charges associated with growth in system sales will be recovered through AEPCO's base rates and tariffs which include a component to cover these fixed costs. AEPCO's argument that it would be inherently unfair to change the configuration of the PPFAC after it had negotiated long-term contracts is without merit. Our Decision No. 57364 (May 2, 1991) noted that the types of costs included in the PPFAC should be reviewed at the time of the next rate PPFAC proceeding or rate case, which ever occurred first and also stated "[o]ur concerns are heightened by the fact that the Company's PPFAC includes demand costs." Therefore, AEPCO has been on notice that demand charges in the PPFAC was an issue of concern to the Commission. We will note, however, to the extent that increases in purchased capacity costs are not recovered under the contract adjustor, AEPCO's margins from its non-Class A members may decrease, and therefore the non-operating margins available to AEPCO may also decrease. We agree with

Staff that short-term purchase power contracts[15] where the combined demand cost and energy cost are less than the cost of generation or other purchased energy being displaced by the purchased power are available, AEPCO should be able to include demand and capacity costs in the fuel adjustor.

As of October 31, 1992, AEPCO's fuel bank balance showed a cumulative overcollection of $5,168,000. Staff has recommended that the amount to be refunded be increased by $686,000, the amount AEPCO included in the PPFAC during the TY as legal expense related to fuel expense. Staff further recommended that it is inappropriate to pass legal expenses through the PPFAC, as those expenses are more appropriately addressed in the base rate cost of service.

AEPCO argued that over $415,000 of the legal expense was incurred to obtain a more than $1.8 million rail refund which AEPCO credited to the PPFAC; and that $243,000 was spent to secure a $750,000 refund. AEPCO also argued that Staff had repeatedly audited the practice without objection[16] and that the Commission specifically approved the appropriateness of netting such fuel-related legal costs against amounts credited to or flowed to the members in Decision No. 55792 (November 24, 1987). As a result, AEPCO has not factored these types of fuel related expenses into its general cost of service.

We agree that we have allowed AEPCO to include legal expense related to fuel issues in the PPFAC in past Decisions. We believe now that it is no longer appropriate to flow through these expenses, but we disagree with Staff that the expenses included in the TY should be

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[15] Staff defines "short-term contract" to be less than six months.

[16] Decision No. 53932 (1984); Decision No. 54468 (1985); and Decision No. 57364 (1991).

added back into the fuel bank balance, since we had previously approved such treatment. However, since AEPCO has not included any allowance for these type of expenses in its calculation of the base rate cost of service, we will allow AEPCO to defer legal expenses related to fuel expense incurred after the effective date of this Decision for possible recovery in its next rate case.

AEPCO proposed that instead of a refund by a one-time billing credit, the adjustor be set at zero and that once the impact of uncertainties of fuel and purchased power costs can be predicted in terms of timing and costs, the PPFAC can be adjusted through a PPFAC hearing and the adjustor established accordingly. We agree that AEPCO should refund $5,095,000 (which is the difference between the bank balance of $5,168,000 as of October 30, 1992, offset by the eight preapproved DSM Program costs of $73,000 as of November 30, 1992) to Class A members over a twelve month period at a rate of -$0.00326/kwh or until the full amount is completely refunded or until further order of the Commission. Furthermore, AEPCO should supply the Commission supplemental information in its monthly fuel adjustor reports specifying the overcollected bank balance that was refunded in each month. With the establishment of a new fuel and purchase power base cost herein, it is appropriate to "zero out" the accumulated bank balance.

The current fuel and purchase power cost is $0.01984/kwh[17]. We find the appropriate fuel and purchase power base cost to be $0.01714/kwh and agree that the adjustor should be set at zero.

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[17] The current base cost is $0.02628/kwh, with a negative adjustor of $0.00644/kwh.

Demand Side Management Programs

Billing Control Credits

AEPCO's DSM program includes development of controlled loads which can be interrupted on AEPCO's peak. AEPCO has requested approval of the following footnote to its tariff:

> In order to facilitate and encourage demand side management, load control and similar programs on the AEPCO system, Class A members may be afforded billing demand adjustments and/or control credits as may be agreed upon from time-to-time by AEPCO and the Class A member.

In response to Staff's recommendation, AEPCO proposed phasing out existing interruptible customers and providing the Commission with a study and proposal for future customers.[18]

Staff made the following recommendations concerning AEPCO's billing demand credit program:

- AEPCO should immediately discontinue its billing demand credit program which credits the bills of member Cooperatives when customers on interruptible tariffs are not interrupted;
- the footnote concerning billing credits should be removed from the tariff proposed by AEPCO in this rate filing;
- AEPCO should conduct a detailed study on the value of interruptible power to AEPCO and submit a report on its analysis within six months of the effective date of this Decision;
- along with its report, AEPCO should submit a proposed tariff rider for interruptible power whereby participating member utilities would pay a reduced demand rate for kW subject to interruption; and

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[18] See Exhibit A-16 Pierson rejoinder, pages 4-6.

- AEPCO's alternative proposal of phasing out the billing demand credit over a three-year period should not be approved because a three-year period is too long to continue an improperly priced program, the present program was never approved by the Commission, and because once approved, the rate cannot be altered in three years without a rate setting procedure.

We agree with the recommendations made by Staff concerning the billing demand credit program and will adopt those recommendations. As discussed above, the billing demand credits approved in the Chemstar agreement are not to be discontinued but should be re-evaluated, and in conjunction with the study ordered herein, AEPCO should also study the re-pricing of those credits.

Other DSM issues

Staff made several recommendations concerning DSM programs including:

- the costs associated with the eight pre-approved DSM programs that are in the DSM deferral account on the effective date of the final order should be applied to the over-recovered bank balance in AEPCO's PPFAC;

- AEPCO should recover future costs of pre-approved DSM programs through its PPFAC[19], with monthly reports listing DSM cost information, and with program costs to be recovered including administrative expenses, monitoring expense, the value of any incentives, the costs of demonstration facilities, and reimbursements to member Cooperatives for these activities;

- AEPCO should submit proposed programs to Staff for pre-approval and Staff will conduct a cost/benefit analysis and will consider the reasonableness of any customer incentives proposed by AEPCO and new programs may be added or existing programs terminated anytime during the year subject to Staff approval;

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[19] Phelps Dodge proposed cost recovery through a kW demand surcharge rather than through the PPFAC.

- AEPCO should submit semi-annual reports to Staff within 30 days of the conclusion of the reporting period with the following information listed separately for each program: a brief description of the program; program modifications; programs terminated; the level of participation; costs incurred during the reporting period and cumulatively over the life of the program disaggregated by type of cost; a description of monitoring activities and results; kW and kWh savings; and a description of problems encountered and proposed solutions;

- the ground source heat pump portions of the Residential HVAC Retrofit program and the Energy Efficient Home Program should not be approved at this time because of uncertain costs and benefits of the program at one of the member cooperatives; and

- the air conditioner upgrade portion of the Residential HVAC Retrofit program should not be approved because it is not cost-effective for society.

AEPCO is in agreement with most of Staff's DSM recommendations, including that cost recovery of pre-approved DSM programs should be through the PPFAC. AEPCO disagrees with Staff's recommendation not to approve the ground source heat pump and the air conditioner upgrade portions of the Residential HVAC Retrofit program. AEPCO believes the disagreement on this issue grows out of a data disagreement over the assumptions to be used when evaluating the program. In order to resolve this disagreement, AEPCO proposes that the Commission allow the costs associated with the program incurred to date be recovered in the deferral account and continuation of the program until at least December 31, 1993. AEPCO believes that the load research program currently underway on the AEPCO system will provide additional information this Fall and will allow a more informed decision to be made whether to continue the program in 1994.

We agree with the DSM recommendations made by Staff and with the proposed continuation of the ground source heat pump and air

conditioner programs until December 31, 1993, in order to analyze the additional data that will be available. At that time, Staff should analyze the data generated from the load research program and make a determination on approval of the programs. Accordingly, we will adopt the Staff recommendations on DSM with the modification proposed by AEPCO.

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Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. AEPCO is a non-profit generation and transmission cooperative supplying power to its six Class A, one Class B, and one Class C members.

2. On August 3, 1992 AEPCO filed an application for a permanent increase in its electric rates based on a TY ending December 31, 1991.

3. Notice of the application and hearing was provided to AEPCO's members.

4. AEPCO's FVRB is determined to be $259,066,000 which is the same as its OCRB.

5. AEPCO's present rates and charges produced adjusted TY operating income of $33,519,000, based upon operating revenues of $134,836,000 and operating expenses of $104,427,000.

6. The rates and charges approved herein are $15.25 per KW of demand and $0.02228 per kWh of energy.

7. The rates and charges approved herein will yield a rate of return of 12.96 percent on AEPCO's FVRB, which is reasonable under the circumstances of this case.

8. The REA requires AEPCO to maintain a TIER of 1.05 and a DSC of 1.0.

9. With the rates authorized herein, AEPCO's TIER will increase to 1.16.

10. Based on the most recent purchased power costs of AEPCO, a new base fuel charge of $0.01714/kwh should be made effective September 1, 1993, said base fuel charge to remain in effect until further Order.

11. AEPCO should refund $5,095,000 (which is the difference between the bank balance of $5,168,000 as of October 30, 1992, offset by the eight preapproved DSM Program costs of $73,000 as of November 30, 1992) to Class A members over a twelve month period at a rate of -$0.00326/kwh or until the full amount is completely refunded or until further order of the Commission. Furthermore, AEPCO should supply the Commission supplemental information in its monthly fuel adjustor reports specifying the overcollected bank balance that is refunded in each month.

12. Staff's recommendations concerning AEPCO's DSM program are reasonable, and we will approve the program with the exception that we will allow the continuation of the ground source heat pump and air conditioner programs until December 31, 1993, in order to analyze the additional data that will be available.

13. AEPCO should file future financing applications before it proceeds with the project for which financing approval is requested.

14. Staff is currently conducting an investigative audit of AEPCO which may have an impact on the rates to be charged by AEPCO.

15. AEPCO should be authorized to establish a deferral account to include legal expenses associated with fuel issues, with recovery

determined in its next rate proceeding.

16. AEPCO should be authorized to defer any actual pension payments for future recovery in its next rate proceeding.

17. AEPCO should conduct a fully allocated embedded cost-of-service study in conjunction with its next rate filing.

CONCLUSIONS OF LAW

1. AEPCO is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §40-250 and 40-251.

2. The Commission has jurisdiction over AEPCO and the subject matter of the application.

3. Notice of the application was given in accordance with law.

4. The rates and charges proposed by AEPCO are not just and reasonable.

5. The rates and charges authorized herein are consistent with the Findings of Fact, and are just and reasonable.

6. AEPCO should be authorized to change its base fuel charge to $0.01714/kwh.

7. The docket in this matter should remain open for a period of not more than six months to allow for consideration of Staff's audit results and for the issuance of a Final Order in this proceeding.

ORDER

IT IS THEREFORE ORDERED that Arizona Electric Power Cooperative, Inc. is hereby directed to file on or before September 1, 1993, a schedule of electric rates and charges, and tariffs consistent with the Discussion, Findings, and Conclusions of the Commission hereinabove.

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IT IS FURTHER ORDERED that the schedule of rates and charges and tariffs shall be effective for service provided on and after September 1, 1993.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. be, and the same is, hereby, authorized and directed to implement a new base fuel charge of $0.017141/kwh effective for all usage on and after September 1, 1993.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall notify its customers of the rates and charges authorized hereinabove and the effective date of the same by means of an insert in its next regular monthly billing.

IT IS FURTHER ORDERED that Arizona Electric Power Company, Inc. shall refund $5,095,000 to Class A members over a twelve month period at a rate of -$0.00326/kwh or until the full amount is completely refunded or until further order of the Commission.

IT IS FURTHER ORDERED that Arizona Electric Power Company, Inc. shall supply the Commission supplemental information in its monthly fuel adjustor reports specifying the overcollected bank balance that is refunded in each month.

IT IS FURTHER ORDERED that Arizona Eletric Power Company, Inc. shall file future financing applications before it proceeds with the project for which financing approval is requested.

IT IS FURTHER ORDERED that Staff's proposed demand side management program is approved with the exception that the ground source heat pump and air conditioner programs will continue until at least December 31, 1993.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall conduct a lead-lag study to determine its cash

working capital requirement with its next rate filing.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall conduct a fully allocated embedded cost-of-service study in conjunction with its next rate filing.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall establish a deferral account to include legal expenses associated with fuel issues that are incurred after the effective date of this Decision, for possible recovery in a future rate proceeding.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall establish a deferral account to include any actual pension payments made after the effective date of this Decision, for possible recovery in a future rate proceeding.

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IT IS FURTHER ORDERED that the docket in this matter shall remain open for a period of not more than six months from the effective date of this Decision to allow for consideration of the results of the investigative audit being conducted by Staff and for the issuance of a Final Order in this proceeding.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 3 day of September, 1993.

JAMES MATTHEWS
EXECUTIVE SECRETARY

DISSENT
LF

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DOCKET NO.: DOCKET NO. U-1773-92-214

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MEMORANDUM

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: February 7, 2005

RE: STAFF REPORT ON DSM POLICY FOR THE GENERIC PROCEEDING CONCERNING ELECTRIC RESTRUCTURING ISSUES, ET AL (DOCKET NOS. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069)

Attached is the final Staff Report including a proposed Demand Side Management Policy as required by Decision No. 65743 (Track B).

EGJ:E1C/BEK:red

Originator: Erin Casper and Barbara Keene

Attachment: Original and 14 Copies

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EXHIBIT
S-16
ADMITTED

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STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

GENERIC PROCEEDING CONCERNING
ELECTRIC RESTRUCTURING ISSUES, ET AL

DOCKET NO. E-00000A-02-0051, ET AL

STAFF REPORT ON DEMAND SIDE MANAGEMENT POLICY

FEBRUARY 7, 2005

STAFF ACKNOWLEDGMENT

The Staff Report on Demand Side Management Policy for the Generic Proceeding Concerning Electric Restructuring Issues, Docket Nos. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, and E-01933A-02-0069, was the responsibility of the Staff members listed below.

Erin Casper
Public Utilities Analyst

Barbara Keene
Public Utilities Analyst

EXECUTIVE SUMMARY
STAFF REPORT ON DSM POLICY
DOCKET NOS. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, AND E-01933A-02-0069

The Arizona Corporation Commission ("Commission") issued Decision No. 65743 ("Track B") on March 14, 2003. In that Decision, the Commission ordered Staff to facilitate a workshop process to explore the development of a demand-side management ("DSM") policy. The exploration was to include an examination of the possible costs and benefits of the policy. Staff was ordered to file a report within 12 months of Decision No. 65743 informing the Commission of the progress achieved in the workshops, including a recommendation on whether hearings should be held.

The first DSM Workshops were held from October 2003 through February 2004. Utilities provided information concerning the DSM programs they are currently pursuing and historical costs and savings. Workshop participants developed primary criteria for evaluating DSM opportunities and presented proposals for DSM programs.

Staff filed its DSM Workshop Progress Report on March 15, 2004. The Progress Report covered current utility DSM activities, historical utility DSM savings and costs, energy service company DSM activities, primary screening criteria for evaluating DSM opportunities, DSM opportunities for each market segment, and proposals for DSM programs and policies. In that report, Staff recommended that the DSM Workshops continue to occur on a monthly basis to address outstanding issues, including the development of a proposed DSM policy. Staff intended to file a final report and possibly recommendations after the Workshops had concluded. Staff further proposed that a recommendation on whether to hold a hearing be deferred until the final Staff Report.

Additional DSM Workshops were held from March through November 2004. Through a lot of hard work, the Workshop participants developed a DSM Policy for Arizona. There were some parts of the Policy in which the group could not achieve consensus. Staff has chosen positions for those issues and has rearranged sections or reworded sections of the policy for better organization and clarity. This Staff Report contains explanations for every section of the Policy as well as participant positions on the controversial issues. Staff recommends that a hearing on the DSM Policy not be held due to the wide range of participation in the Workshop process.

Staff intends to convert the DSM Policy into proposed rules for Commission consideration within 60 days of filing this report. Staff recommends that the Commission adopt this policy as part of the rulemaking process.

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Introduction

The Arizona Corporation Commission ("Commission") issued Decision No. 65743 ("Track B") on March 14, 2003. In that Decision, the Commission ordered Staff to facilitate a workshop process to explore the development of a demand-side management ("DSM") policy. The exploration was to include an examination of the possible costs and benefits of the policy. Staff was ordered to file a report within 12 months of Decision No. 65743 informing the Commission of the progress achieved in the workshops, including a recommendation on whether hearings should be held.

The first DSM Workshops were held on October 30, 2003; December 5, 2003; January 15, 2004; and February 13, 2004. Staff filed its DSM Workshop Progress Report on March 15, 2004.[1] The Progress Report covered current utility DSM activities, historical utility DSM savings and costs, energy service company DSM activities, primary screening criteria for evaluating DSM opportunities, DSM opportunities for each market segment, and proposals for DSM programs and policies. In that report, Staff recommended that the DSM Workshops continue to occur on a monthly basis to address outstanding issues, including the development of a proposed DSM policy. Staff intended to file a final report and possible recommendations after the Workshops had concluded. Staff further proposed that a recommendation on whether to hold a hearing be deferred until the final Staff Report.

Additional DSM Workshops were held on March 26, 2004; April 28, 2004; May 20, 2004; June 22, 2004; July 23, 2004; August 20, 2004; September 14, 2004; September 23, 2004; October 26, 2004; and November 22, 2004. Through a lot of hard work, the Workshop participants developed a DSM Policy for Arizona.

Staff's proposed version of the DSM Policy is presented in Schedule 3. There were some parts of the Policy in which the group could not achieve consensus. Staff has chosen positions for those issues and has rearranged sections or reworded sections for better organization and clarity. This Staff Report contains explanations for every section of the Policy as well as participant positions on the controversial issues. Each section of the Staff Report contains the applicable language from the Policy in bold italics.

Staff recommends that a hearing on the DSM Policy not be held due to the wide range of participation in the Workshops. Participants included representatives from utilities, state agencies, cities, counties, energy efficiency and environmental advocacy groups, utility investors, energy service companies, electrical districts, product distributors, and large industrial consumers. A list of participating organizations is in Schedule 1.

Staff intends to convert the DSM Policy into proposed rules for Commission consideration within 60 days of filing this report. Staff recommends that the Commission adopt this policy as part of the rulemaking process.

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[1] http://www.cc.state.az.us/utility/electric/DSM-03-15-04.pdf

Explanation of the DSM Policy

1. *Policy Statement*

The Arizona Corporation Commission ("Commission") recognizes that demand-side management ("DSM") can provide benefits to energy customers, utilities, and the environment. DSM shall be advanced and implemented in a cost-effective and prudent manner, while maintaining reasonable energy costs for consumers.

This section sets forth the Commission's statement of support for DSM. Cost-effective DSM provides benefits for energy customers, utilities, and the environment. At the same time, the Commission recognizes that energy costs must remain reasonable.

2. *Applicability*

This policy is applicable to all electric and natural gas utilities subject to the jurisdiction of the Commission that are classified as Class A according to A.A.C. R14-2-103(A)(3)(q), except for utilities that are electric transmission-only cooperatives. Smaller utilities may voluntarily participate either individually or in a group.

The proposed DSM Policy would be applicable to all electric and natural gas utilities classified as Class A according to A.A.C. R14-2-103(A)(3)(q). An exception is made for utilities that are electric transmission-only cooperatives (currently only Southwest Transmission Cooperative). Electric and natural gas utilities are classified as Class A if their annual operating revenues (gross utility operating revenues derived from jurisdictional operations) exceed $5,000,000. According to annual reports filed with the Commission in 2004, the following electric utilities would be classified as Class A and therefore subject to the DSM Policy:

Arizona Electric Power Cooperative
Arizona Public Service Company
Graham County Electric Cooperative
Mohave Electric Cooperative
Morenci Water and Electric Company
Navopache Electric Cooperative
Sulphur Springs Valley Electric Cooperative
Trico Electric Cooperative
Tucson Electric Power Company
UNS Electric

The following natural gas utilities would be classified as Class A:

Southwest Gas Corporation
UNS Gas

The above utilities would be subject to the requirements of the DSM Policy. However, other utilities could voluntarily participate. Electric distribution cooperatives subject to the DSM Policy could cooperate with their generation cooperative to develop DSM programs.

3. DSM Definition

DSM is the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand ("kW"), and/or to reduce energy consumption ("kWh" or "therms") in a cost-effective manner. DSM may include energy efficiency, load management, and demand response.

Energy Efficiency is products, services, or practices aimed at saving energy in end-use applications generally by substituting technically more advanced (compared to what is presently used in a specific situation) equipment or practices to produce the same or an improved level of end-use service with less energy use. Examples include high-efficiency appliances; efficient lighting products and systems; high-efficiency heating, ventilating, and air conditioning ("HVAC") systems or control modifications; advanced electric motor drives; efficient building design; and efficient operation and maintenance practices.

Load Management consists of deliberate actions sponsored by a utility to reduce peak demands or improve system operating efficiency. Examples include direct control of customer demands through utility-initiated interruption or cycling, thermal storage, and education to encourage customers to shift loads.

Demand response includes all intentional modifications to electric and natural gas consumption patterns of customers affecting the timing or quantity of customer demand and usage. For the purposes of this policy, demand response programs are used to reduce customer energy usage in response to prices, market conditions, or threats to system reliability. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated curtailment, voluntary curtailment, and direct load control/cycling.

This section defines DSM. There are three categories of DSM: energy efficiency, load management, and demand response.

Historically, the Commission has considered DSM to be only energy efficiency. Load management and demand response programs had been approved by the Commission, but those

programs had not been considered to be DSM, and the costs of those programs were not eligible to be recovered through DSM funding mechanisms. Through the Workshop process it was determined that load management and demand response are also components of DSM, but funding those two types of programs should not reduce the funding for energy efficiency.

4. Key Terms

Adjustment mechanism: ***a provision of a rate schedule, authorized in advance by the Commission, which allows for increases and decreases in rates reflecting increases and decreases in specific costs incurred by a utility.***

Baseline: ***the level of electric and/or natural gas demand and/or consumption and associated costs that would have occurred in the absence of the DSM program.***

Combined heat and power ("CHP"): ***distributed generation using a primary energy source to simultaneously produce electrical energy and useful process heat.***

Distributed generation ("DG"): ***electric generation sited at a customer premises (customer side of the meter) providing electric energy to the customer load on that site.***

Incremental benefits: ***improvements in societal welfare, including but not limited to avoided environmental impacts and the avoided fuel cost, purchased power cost, new capacity cost, transmission cost, and/or distribution cost.***

Incremental costs: ***the additional cost of DSM programs and measures relative to baseline cost.***

Market transformation: ***strategic efforts to induce lasting structural or behavioral changes in the market that result in increased adoption of energy-efficient technologies, services, and practices.***

Net benefits: ***incremental benefits resulting from DSM minus the incremental costs of DSM.***

Societal Test: ***a cost-effectiveness test of the net benefits of DSM measures and programs that starts with the Total Resource Cost Test but includes non-market benefits to society, such as reduced environmental effects of energy production and delivery, due to DSM.***

Total Resource Cost Test: ***a cost-effectiveness test that measures the net benefits of a DSM program as a resource option, including both incremental measure and utility costs. The TRC test excludes incentives paid by utilities. The TRC test also excludes non-market benefits to society, such as reduced environmental effects of energy production and delivery.***

Utility Cost Test: ***a cost-effectiveness test that measures the net change in a utility's revenue requirement resulting from a DSM program. The test compares the reduction in marginal energy and demand costs with utility program costs, incentive payments, and increased supply costs for a period in which load is increased. This test does not include any net costs incurred by participants.***

This section defines various terms used throughout the Policy. It differs from the version developed by the Workshop participants in that Staff added a definition of "baseline", clarified that the "total resource cost test" excludes incentives paid by utilities, rearranged wording in the definition of "incremental benefits" for clarity, and moved the table on Comparison of Cost-Effectiveness Tests to the section on *Cost Effectiveness*.

In comments provided after the final workshop, an electric utility indicated concern that the definition of "distributed generation ("DG")" requires the generation to be sited on the customer side of the meter at a customer premises. The utility would like the definition to be "electric generation sited at or near a customer premises providing electric energy to the customer load on that site." The utility feels that the change would allow utility-sited projects used to serve certain load pockets to be considered DG.

Staff opposes this change in the definition of "distributed generation" because utility-sited generation would not fit under the definition of DSM. Although utility-sited generation may have merit as a supply resource, it is not DSM because it does not shift peak load to off-peak hours, reduce peak demand, or reduce energy consumption. Utility-sited generation is a utility supply source no matter where the generating unit is located. On the other hand, customer-sited generation can help to reduce the customer's demand for electricity from the utility. A utility would not be precluded from working with a customer on a project, but the project would have to be located at the customer's premises and meet the definition of DSM to qualify for DSM funding.

5. *Goals and Objectives*

Policy Objectives

1. ***Achieve cost-effective energy savings and peak demand reductions.***

2. ***Advance market transformation to achieve cost-effective DSM benefits through approaches that achieve sustainable savings and reduce the need for future market interventions.***

3. ***Ensure a level of program funding adequate to achieve the DSM targets.***

4. ***Implement DSM programs that provide an opportunity for all utility customer segments to participate.***

5. ***Allocate a portion of DSM resources to the low-income customer segment.***

<u>DSM Goals</u>

The Commission shall establish DSM goals for all applicable utilities that consider and are consistent with the characteristics of each specific utility's service territory and the approach to DSM in that service territory. Examples of DSM goals may include percentage reductions in load growth; benefits in dollars; net benefit goals; savings in kW, kWh, therms, gallons, or BTUs; savings as a percent of total resources to meet load; expenditures on DSM as a percent of retail revenue; or amount of spending on DSM programs.

<u>Program Goals</u>

Program goals shall be established by the Commission for DSM benefits, energy savings, and/or peak demand reductions for utilities subject to the DSM policy.

Goals for peak demand reductions in kW or therms may be met in part with demand response programs that are designed to reduce load during peak usage hours.

The *Goals and Objectives* section articulates both the general purpose and specific targets of DSM measures. The implementation of successful programs that meet DSM goals will help to accomplish the Policy objectives.

Portfolio and program-specific goals should be set by the Commission for each individual utility, taking into consideration the unique characteristics of each particular service territory and its DSM history. Workshop participants emphasized that goals should be flexible and should reflect updated market intelligence as it becomes available.

Staff clarified the titles of the "Policy Objectives" and "DSM Goals" subsections to convey that the objectives stated are the objectives of the *Policy* and the examples of goals are possible targets of *DSM measures*. This section was reorganized following the final DSM Workshop to state the "Policy Objectives" first, followed by "DSM Goals" and "Program Goals."

6. <u>Portfolio Plans</u>

Utilities shall submit to the Commission a DSM portfolio plan within six months of the adoption of this DSM policy through the rulemaking process (i.e., six months after the rules are adopted). The portfolio plan shall include:

1. ***An overall DSM portfolio goal;***
2. ***Descriptions of DSM programs to be undertaken in compliance with the Commission's DSM policy;***
3. ***Estimated levels of energy and capacity savings, utility costs, societal benefits and costs, and other benefits (quantified where reasonably possible) of the planned programs;***
4. ***Marketing and delivery plans, including an implementation schedule;***
5. ***Measurement and evaluation plans; and***
6. ***A description of the administration of the programs.***

Utilities shall file subsequent DSM portfolio plans biennially with the Commission for approval. Specific program plans can be filed for approval at any time. If programs are filed for approval contemporaneously with the DSM portfolio plan, the items of information listed in the Commission Review and Approval of DSM Programs section set forth below must be included in the filing.

Existing Commission-approved plans and programs will continue in effect until the Commission takes action on a new plan.

Staff may develop standard tables, outlines, and guidelines for the plans.

The *Portfolio Plans* section sets forth the guidelines utilities must follow in submitting their DSM portfolio plans to the Commission. This section provides a list of items to be included in the plans as well as a timeframe for filing the initial and subsequent plans.

Throughout the course of the Workshops, parties discussed the frequency for submission of portfolio plans. Some parties felt that portfolio plans should be submitted annually while others preferred to submit plans on a biennial basis. Staff considered the different viewpoints and recommends biennial portfolio plan submission with the option for the Commission to order a Company to file sooner than the biennial deadline. Staff also recognizes that a Company would have the option to file a revised DSM portfolio plan prior to the biennial deadline. Staff finds that this flexibility will minimize administrative burden while providing a means to address potential problems that might arise in interim years.

The title of this section was changed from *Planning* to *Portfolio Plans* to clarify that the planning requirements of the section refer to DSM *portfolios*.

7. ***<u>Commission Review and Approval of DSM Programs</u>***

Prior to implementing a new DSM program, utilities must obtain Commission approval. Utilities shall file a copy of the program proposal with Docket Control and notify interested

parties of the filing. Interested parties have 20 calendar days to file written comments about the proposed program.

Each program proposal shall include the following items:

1. ***Description of the program;***
2. ***Objectives and rationale for the program;***
3. ***Market segment at which the program is aimed;***
4. ***Estimated level of program participation;***
5. ***Estimate of baseline;***
6. ***Estimated societal benefits and savings from the program;***
7. ***Estimated societal costs of the programs;***
8. ***Marketing and delivery strategy;***
9. ***Utility costs and budget;***
10. ***Implementation schedule;***
11. ***Monitoring and evaluation plan; and***
12. ***Proposed performance incentives.***

Staff shall recommend approval of a DSM program if it is consistent with the Commission's DSM policy. Staff may request modifications of proposed or on-going programs to ensure consistency with the Commission's DSM policy. However, the Commission shall allow utilities adequate time to notify customers of program modifications.

The *Commission Review and Approval of DSM Programs* section sets forth the guidelines utilities must follow in submitting DSM programs to the Commission. This section provides a list of items to be included in program proposals as well as guidelines for the program approval process.

Parties discussed this process at several Workshops and emphasized that it is important for the Commission to allow utilities enough time to notify customers of any modifications to existing programs before implementing the changes.

The title of this section was changed from *Commission Review and Approval* to *Commission Review and Approval of DSM Programs* to indicate that the Commission review and approval process discussed in this section refers to DSM *programs.*

8. <u>Parity and Equity</u>

Each utility shall develop and propose DSM programs for residential, non-residential, and low income customers so that all customer segments have the opportunity to benefit from DSM.

DSM funds collected from residential and non-residential customer segments shall be allocated proportionately to those customer groups to the extent reasonable.

DSM funds collected from ratepayers of a given utility shall be allocated to DSM programs for customers in that utility's service territory to the extent reasonable.

The utility costs of DSM programs for low-income customers shall be borne by all customer classes.

All customers shall pay to support DSM through a non-bypassable mechanism.

Self-direction[2] may be reviewed by the Commission in utility rate cases or other forums.

This section explains that DSM programs shall be developed for, and funds collected proportionately from, both residential and non-residential customer segments. It also requires programs to be developed for low-income customers, but that the costs of those programs shall be paid by all customer classes. In addition, DSM costs would be non-bypassable so that customers who obtain generation or natural gas from a competitive supplier would continue to pay the DSM costs because DSM is a system benefit for all.

This section differs from the version developed by the Workshop participants in that Staff moved one sentence and replaced "commercial" and "industrial" with "non-residential." "Non-residential" includes customer sectors that might not be considered "commercial" or "industrial," such as schools and government facilities.

The concept of "self-direction" was a controversial issue in the Workshops. According to proponents of self-direction, the term is an option made available to qualifying customers of sufficient size in which the amount of money paid by the qualifying customer through a DSM adjustment mechanism is made directly available for use by that customer for DSM investments. The size threshold for qualification would be based on the dollar amount of expected contributions to the DSM adjustment mechanism made by the customer, considering all of the customer's accounts in a given utility territory. Commercial and industrial customer representatives recommend a threshold of $6,000 per year as qualification for self-direction. The Commission would have oversight over the self-direction program but not have to approve individual applications. DSM investments would include labor, engineering, construction, and materials. Reporting requirements should protect confidentiality and not unduly burden the customer.

Some utility representatives have unanswered questions concerning self-direction. Those questions are:

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[2] *Self-direction is an option made available to qualifying customers of sufficient size, in which the amount of money paid by each qualifying customer toward a DSM adjustor is tracked for an individual customer and is made available for use by the customer for DSM investments upon application by the customer.*

- What are the criteria to determine if a customer is eligible to self-direct?
- Is self-direction an option for large institutional customers?
- What happens if the customer's load fluctuates?
- Can customers aggregate their loads to meet any minimum load requirements?
- What are the reporting requirements for the utility and the customer when a customer is self-directing its DSM investments?
- What accounting and tax implications might arise from a self-directed DSM investment?
- If a utility is required to reduce energy by a certain amount, would the energy saved by the self-directed customer be applied toward the overall energy savings goal of the utility?
- Can DSM funds be used to fund a Self-Direction Administrator?
- What is considered an eligible project?
- Is there a cap on the amount of funds to be received each year?
- Can a self-directed customer "bank" its resources for two or more years?
- Will projects initiated prior to Commission approval of a policy be eligible for self-direction credit?
- Would a 50 percent credit be made available to customers as allowed by Utah Power & Light Company when an energy audit demonstrates that there are no remaining DSM projects with a payback period of eight years or less?

Staff neither endorses nor opposes self-direction. Staff believes the thirteen questions need to be addressed either in individual utility rate cases or other forums. This section of the policy contains the statement that self-direction may be reviewed by the Commission in rate cases or other forums.

The issue of exemption was also discussed in the Workshops but is not addressed in the DSM Policy. Consensus on the issue was not achieved in the Workshops. Representatives of large commercial and industrial customers describe the concept of exemption as follows: a customer whose single-site usage is at least 20 MW and can demonstrate an active DSM program could request an exemption from a DSM adjustment mechanism. Again, utility representatives have the following unanswered questions:

- What is the appropriate size threshold to qualify a customer for exemption?
- Would the threshold be the same in all service territories?
- What happens if that size threshold fluctuates?
- Who would be responsible for reporting and monitoring the customer's active DSM program?
- Would distributed generation be considered an active DSM program?
- Would exempt customers be responsible for contributing to programs for low-income customers?

- If a utility is required to reduce energy by a certain amount, would the energy saved by the exempted customer be applied toward the energy savings goal of the utility?
- Could customers aggregate their loads to meet any minimum load requirements?
- Would the customer be exempt only for the life-cycle of the project?

9. <u>Portfolio and Program Reporting Requirements</u>

Utilities shall report annually to the Commission on the progress of their DSM portfolios including each pre-approved DSM program. Annual reports shall be due on March 1 of each year. At a minimum, the reports shall include:

1. ***Predetermined overall DSM portfolio goals;***
2. ***A description of the progress towards meeting the portfolio goals;***
3. ***A list of the programs included in the DSM portfolio organized by customer segment;***
4. ***Findings from any research projects;***
5. ***Information on each program including:***
   a. ***A brief description of each program;***
   b. ***Predetermined program goals, objectives, and savings targets;***
   c. ***The level of customer participation for each program;***
   d. ***Costs incurred during the reporting period disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;***
   e. ***A description and results of evaluation and monitoring activities;***
   f. ***Savings in kW, kWh, therms, gallons, and BTUs;***
   g. ***Benefits and net benefits in dollars;***
   h. ***Program-specific performance incentive calculations;***
   i. ***Problems encountered and proposed solutions;***
   j. ***Proposed program modifications; and***
   k. ***Proposed program terminations.***

Utilities shall file quarterly status reports that shall consist of a tabular summary of expenditures compared to the budget. Quarterly reports shall be due 45 days after the end of a calendar quarter.

All reports shall be available to the public and filed in Docket Control. These reporting requirements shall supercede other DSM reporting requirements as determined by the Commission for each Utility.

Staff may develop standard tables, outlines, and guidelines for reports.

This section describes the timing and types of information that the utilities would have to provide to the Commission so that Staff and the Commission could monitor the utilities' progress

in achieving their DSM goals. Staff modified this section of the Policy by adding portfolio reporting requirements to the program reporting requirements. Staff also rearranged some of the sentences, shortened the sentence on the quarterly reports by removing the reference to goals, and added the phrase regarding Commission determination for each utility to the sentence on other DSM reporting requirements.

The Policy requires annual reports with considerable details and brief quarterly reports with information on expenditures compared to budget. Staff recommends that these reporting requirements supercede other DSM reporting requirements to eliminate redundancy and utility burden. The Commission would have to determine in a proceeding, such as the portfolio plan approval or a rate case, which current reporting requirements would be replaced. Currently, A.A.C. R14-2-213 requires Class A and B electric utilities to file energy conservation plans with annual updates when changes occur. In addition, various Commission decisions require some electric and natural gas utilities to file DSM reports, but the requirements vary by utility.

10. <u>Cost Recovery</u>

Utilities shall recover their net incremental costs to plan, design, implement, and evaluate DSM programs. In order to qualify for cost recovery, each program must be:

1. ***Approved prior to implementation;***
2. ***Implemented in accordance with the approved program plan; and***
3. ***Monitored and evaluated for cost-effectiveness.***

Utilities shall monitor and evaluate DSM programs to reliably ensure that they are cost-effective. Utilities shall propose modification or termination of programs that are failing to meet expected results.

To effectively implement programs, cost recovery shall be concurrent (on an annual basis) with DSM spending.

DSM funds may be used for market studies, consortium membership, labor costs for portfolio development, and other items for which the costs are difficult to allocate to individual DSM programs.

To the extent goods and services used for DSM have value for other utility functions, programs, or services, funding shall be divided and allocated proportionately.

Utilities shall allocate costs in accordance with Generally Accepted Accounting Principles.

The *Cost Recovery* section describes the types of costs that may be recovered by DSM funds.

During the Workshops, parties discussed the treatment of costs incurred prior to portfolio and/or program approval and costs that are not associated with any particular program. Examples of these types of expenses include costs for portfolio planning, program planning, market studies, consortium memberships, and other general costs that are not necessarily associated with a particular approved program. Utility participants expressed the desire for certainty about the recovery of these types of costs.

The Policy allows utilities to recover program implementation and evaluation costs, costs incurred prior to portfolio and/or program approval, and costs that are not associated with any particular program. However, a program must be approved prior to implementation in order for a utility to recover program implementation costs.

Utilities should allocate costs that are not associated with any particular program in accordance with Generally Accepted Accounting Principles. Because DSM accounting principles relate to cost recovery, Staff eliminated the separate *DSM Accounting Principles* section and added that language to the *Cost Recovery* section.

11. Performance Incentives and Lost Revenue

Performance incentives for achieving or exceeding Commission-designated goals may be appropriate as determined by the Commission.

The Commission shall determine whether a utility may be allowed to recover lost net revenue.

This section states that the Commission may set performance incentives for achieving or exceeding DSM goals. Also, the Commission would determine whether a utility would be allowed to recover lost net revenue.

The Workshop participants did not reach consensus on the issue of lost net revenue. The utilities are in favor of recovering lost net revenues, while energy efficiency advocates and others are against it. One electric utility mentioned that the ability of a utility to cover fixed costs is linked to customer energy usage. Thus, DSM results in a utility being less able to recover fixed costs. Recovery of lost net revenues helps utilities to be indifferent with respect to making investments in supply-side or demand-side resources. In addition, the Energy Policy Act of 1992 required state utility commissions to consider the impact of net lost revenue in ratemaking treatment of DSM. The Commission considered the issue in Resource Planning Decision No. 58643. In Decision No. 58643, the Commission stated "Based upon evidence presented in this proceeding, recovery of program costs and lost net revenues and possibly a reward or profit for DSM, should be considered, recognizing that preferences for a particular recovery mechanism vary among the parties."

Opponents of lost net revenue recovery argue that the utility should not need incentives to implement DSM because DSM should be treated like any supply or demand resource. If a utility does not have a fuel or purchased power adjustment mechanism, the utility assumes the risk and reward for procuring resources. The utility has an incentive to reduce peak load and thereby reduce costs. DSM reduces procurement expense and generation expense because it is the marginal supply source that is being reduced by DSM savings.

Also, when a utility experiences customer growth, revenue might not actually be lost. Revenue grows with customer growth. DSM can help mitigate the capacity constraints that may accompany customer growth.

In addition, recovery of lost net revenue can eat up a DSM budget and lead to less benefit per dollar spent. The utility benefits from DSM energy savings because of reduced operating costs. Allowing recovery of lost revenues could mean double recovery. Essentially, ratepayers would be charged for energy they did not consume.

In this report, Staff is not taking a position either in favor of or opposed to the concept of lost net revenue recovery for utilities that implement DSM programs and recognizes that the Commission shall make this determination on a case by case basis.

During the Workshops, participants also discussed the concept of penalties or sanctions for companies that either fail to meet stated goals or fail to comply with the DSM Policy or potential rules. Both Staff and Workshop participants recognize that the Commission always has the ability to take action against companies that fail to comply with orders or rules. In general, parties expressed concern that penalties tied to performance create a strong disincentive for utilities to expand their DSM efforts. Moreover, the possibility of facing penalties for failing to meet DSM program goals certainly discourages companies from exploring creative program offerings or cutting edge technologies that may not be fully developed. To the extent that penalties discourage or limit utilities' participation in DSM, Staff is not in favor of incorporating penalties tied to performance into DSM portfolios or programs. At a minimum, Commission procedures to possibly assess penalties and/or other remedies for lack of performance must be consistent with the rules and procedures codified in A.A.C. R14-3-101 through R14-3-113.

12. Funding Mechanisms

Funding shall be provided either through base rates, a surcharge mechanism, and/or an adjustment mechanism. Until such funding can be established for a utility in a rate case, the utility may request that the Commission grant the authority to establish a deferral account.

This section lists various funding mechanisms available for DSM cost recovery. Workshop participants prefer the use of an adjustment mechanism because it can provide flexibility and allow for funding changes outside of a rate case. A sentence to that effect was in

the Policy, but Staff felt it was more appropriate for it to be addressed in the report instead of in the Policy.

In general, Staff does not favor the use of deferral accounts because they shift cost recovery from current ratepayers that are benefiting from the costs incurred to future ratepayers. However, Staff recognizes that deferral accounts can be useful in certain situations. For example, a utility that is under a rate moratorium may wish to implement DSM programs but would not necessarily be allowed to increase its rates to recover the costs. A deferral account would allow that utility to participate in DSM during its rate moratorium by deferring cost recovery. Staff recognizes that the Commission shall determine whether to approve a deferral account for DSM cost recovery on a case by case basis.

13. Applications Eligible for Funding

DSM programs promoting energy efficiency, demand response, load management, or combined heat and power on the customer side of the meter that reduce peak demand or conserve energy may be approved by the Commission.

DSM funds may be used for research and development such as applied technology assessment.

CHP projects may be eligible for funding if they include heat or energy recovery which is used to displace space heating, water heating, or other loads.

Non-CHP Distributed Generation (DG) may be used by customers as a means to help them participate in a demand response program.

This section describes the types of applications that would be eligible for DSM funding. Staff merged the Research and Development section into this section because it related to one type of application. Staff also reworded the sentence on combined heat and power (CHP) for clarity.

One distributed generation representative was concerned about references to distributed generation (DG) being in the DSM Policy when DG proceedings are being considered in the Arizona Public Service Company ("APS") rate case. However, potential DG proceedings resulting from the APS rate case would not be dealing with the DSM aspects of DG but rather with issues such as interconnection requirements and backup power needs.

An electric utility has concerns with two elements of this section related to DG. One issue is the reference to "the customer side of the meter." The other issue is that DG projects that are not CHP may be approved by the Commission. The utility feels that a stand-alone DG project should not be eligible for DSM funding because it is simply a generation (supply-side)

alternative rather than a demand-side option and may not be more efficient than large scale conventional generation sources.

In response to the first issue, Staff supports requiring DG to be on the customer side of the meter for DSM funding. Utility-sited DG would not fit under the definition of DSM as explained in this report under *Key Terms*. In response to the second issue, the intent of the DSM Policy is to allow non-CHP DG to be used by a customer to participate in a demand response program. Without the demand response program, the non-CHP DG would not be considered to be DSM. To clarify the situation, Staff has removed the words "distributed generation" from the first sentence in the section. Staff has also added "non-CHP" to the sentence about DG and moved that sentence to the end of the section.

Workshop participants agreed not to include renewable resources as DG for purposes of this DSM Policy. Renewable resources are included in the Environmental Portfolio Standard rules, and the Workshop participants did not want to double count any resource.

14. <u>Cost Effectiveness</u>

The incremental benefits to society of the overall DSM portfolio shall exceed the incremental costs to society of the overall DSM portfolio. The incremental benefits to society of the individual DSM programs shall exceed the incremental costs to society of the individual DSM programs.

Cost-effectiveness shall be determined by the Societal Test. Costs to society equal the total incremental costs of the DSM program (including incremental utility costs and incremental customer/vendor costs). The benefits to society include avoided environmental impacts and the avoided fuel cost, purchased power cost, new capacity cost, transmission cost, and distribution cost.

Other economic factors such as the costs and benefits associated with reliability may be included in the analysis. Electric utilities may consider savings of natural gas; natural gas utilities may consider savings of electricity. The analysis shall reflect the expected life of the savings resulting from DSM measures. Uncertainty about future streams of costs or benefits should be reflected in cost/benefit or other analyses where practicable and appropriate. In addition to the cost-effectiveness test, a utility or program administrator should consider the impact on rates, economic development, customer costs, and other economic impacts.

Environmental costs or the value of environmental improvements shall be quantified when possible, reasonable, and cost-efficient. At a minimum, utilities shall make a good faith effort to quantify water consumption savings and air emission reductions until such time that an environmental externalities quantification procedure is adopted by the Commission. Upon adoption of a policy, utilities shall implement the policy adopted by the Commission. Other environmental impacts may be considered qualitatively.

The standard cost effectiveness analysis may not be appropriate for certain types of DSM programs.

1. ***Market Transformation Programs: Cost effectiveness shall be measured by the success of a program in achieving results, such as market effects compared to its costs.***

2. ***Educational Programs: Utilities shall attempt to estimate the energy and peak demand savings that result from educational efforts that raise awareness about energy use and opportunities for saving energy.***

3. ***R&D and Pilot Programs: Individual research and development and pilot programs do not have to demonstrate cost-effectiveness.***

4. ***Low Income Programs: Measures included in low-income programs shall be generally cost-effective.***

The following table illustrates the differences between the various cost-effectiveness tests.

Comparison of Cost-Effectiveness Tests

	Participant Test	*Utility Cost Test*	*Total Resource Cost Test*	*Societal Test*
Benefits	• *incentives received* • *bill reductions*	• *avoided utility costs*	• *avoided utility costs*	• *avoided utility costs* • *avoided environmental impacts*
Costs	• *bill increases* • *incremental participant costs*	• *incremental utility costs, including incentives paid by utility*	• *incremental utility costs, excluding incentives paid by utility* • *incremental participant costs*	• *incremental utility costs, excluding incentives paid by utility* • *incremental participant costs*

The *Cost-Effectiveness* section describes the process by which the cost-effectiveness of the overall DSM portfolio and each individual DSM program will be evaluated. Both the overall DSM portfolio and each individual DSM program must be cost-effective.

There are several recognized methods to test for cost-effectiveness including the Participant Test, Utility Cost Test, Total Resource Cost Test, Ratepayer Impact Measure, and the Societal Test. Each method varies in the types of costs and/or benefits that are considered. The

Commission's 1991 Resource Planning Decision[3] established that the Societal Test should be used for the purpose of evaluating cost-effectiveness. The Societal Test evaluates whether the incremental benefits to society exceed the incremental costs to society. As opposed to several of the other methods of measuring cost-effectiveness, the Societal Test does account for the environmental impacts of DSM measures.

Workshop participants discussed the notion of environmental externalities at length. The group generally agreed that there are environmental impacts of DSM measures. Some participants were adamantly in favor of quantifying environmental impacts of DSM measures both in physical units and in dollars. However, several utility representatives observed that currently there is no guidance or policy from the Arizona Corporation Commission that addresses the appropriate methodology to measure the values of environmental externalities. Until such time that an environmental impact quantification procedure is adopted by the Commission, utilities should make a good faith effort to quantify externalities such as water consumption savings and air emission reductions. Workshop participants requested that the Staff Report note their desire to work with any group established to quantify environmental externalities.

There are certain types of DSM programs for which the Societal Test is not an appropriate method to evaluate cost-effectiveness. Research and Development, Pilot Programs, Educational Efforts, Market Transformation Programs, and Low Income Programs do not have easily quantifiable benefits. Some of these programs also have disproportionately large administrative costs. The Policy addresses the unique aspects of these types of programs.

Following the final DSM Workshop, this section was reorganized to better explain that DSM portfolios and programs must be cost-effective as measured by the Societal Test which includes the incremental costs to the utility and to the participant, the avoided utility costs, and avoided environmental impacts. In addition, the table showing the comparison of cost-effectiveness tests was moved from the *Key Terms* section to the *Cost-Effectiveness* section to illustrate the differences in costs and benefits included in each test.

15. Baseline Estimation

The baseline for determining the incremental costs and benefits of a DSM program shall be a reasonable estimate of the level of electric and/or natural gas demand and/or consumption and associated costs that would have occurred in the absence of the DSM program.

For demand response programs, customer load profile information may be used to verify baseline consumption patterns and the peak demand savings resulting from demand response actions.

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[3] Decision No. 57589

The *Baseline Estimation* section defines the term and establishes the context in which it is used.

DSM portfolios and individual programs must be cost-effective. In the course of the cost-effectiveness evaluation, incremental costs will be compared to incremental benefits of a DSM measure. In order to calculate incremental costs and benefits of any activity, the evaluator must identify a baseline state which would have occurred in the absence of the activity. For the purpose of this Policy, the baseline state for determining the incremental costs and benefits of a DSM measure is the level of electricity and/or natural gas consumption and/or demand and the associated costs that would have occurred in the absence of the DSM measure. In the case of a Demand Response measure, it may be necessary to examine a customer's load profile in order to establish a baseline.

Staff reworded one sentence in the *Baseline Estimation* section slightly to clarify that the baseline state is a level of electric and/or natural gas demand and/or consumption plus associated costs.

16. Fuel Neutrality

Ratepayer-funded DSM shall be developed and implemented in a fuel-neutral manner. For those installations/applications that have multiple fuel choices, the baseline used in the cost effectiveness analysis shall utilize the same fuel source as the installation/application.

Electric utility program funds shall be used for electric measures. Natural gas utility program funds shall be used for natural gas measures. However, either natural gas utilities or electric utilities may fund thermal envelope improvements.

It has been the Commission's practice that rate-payer funded initiatives be "fuel neutral." (The fuel referred to here is the customer's fuel, i.e., natural gas or electricity.) The *Fuel Neutrality* section maintains this requirement in the DSM Policy and describes what fuel neutrality means in the context of DSM.

This issue received a great deal of attention throughout the Workshop process. Participants addressed the subject of fuel neutrality from many different perspectives because topics such as cost-effectiveness and baseline estimation are strongly linked to fuel neutrality. The main idea, with which most participants agreed, is that rate-payer funds should not be used to influence customers to change fuels for a particular end-use. Participants did not necessarily agree on what constitutes "influencing customers" to switch fuels. Moreover, it is very difficult to determine whether certain programs are fuel neutral or not.

An example of a complicated situation is the case of a customer living in a house with both electric and natural gas infrastructure. Currently, the customer (Al) has natural gas-fired heating. The rest of Al's appliances are powered by electricity. Al knows that his electric

cooking range is very old, not particularly energy efficient, and probably should be replaced soon. In addition, Al prefers cooking with gas and has wanted to switch to a gas range since he bought his house. Al is aware that both the local natural gas and electric utility companies are planning to offer DSM programs that will give rebates on high-efficiency natural gas and electric ranges, respectively. In accordance with the *Fuel Neutrality* section of the DSM Policy, neither utility will promote fuel switching in advertising its DSM program. For example, the gas company will *not* say, "You can receive a rebate if you replace your electric range with a brand-new high efficiency natural gas range."

The concepts of cost-effectiveness and baseline estimation, described in Sections 14 and 15 respectively, are linked with the precept of fuel neutrality. As the natural gas and electric utilities prepare to file their DSM program plans for approval, they each must demonstrate that their program is cost-effective. Both electric and natural gas utilities will need to present the baseline level of energy efficiency for cooking ranges in the local market. However, in order to remain fuel neutral, the gas company will have to present a baseline level of energy efficiency for natural gas ranges while the electric company will need to provide information on the baseline level of energy efficiency for electric ranges in that market. Regardless of whether some potential participants like Al currently have electric-powered ranges, the fuel neutrality condition requires the gas company to use a natural gas-fired appliance as the baseline to calculate the cost-effectiveness of its rate-payer funded rebate program. Likewise, the electric company must use an electric range as its baseline level of energy efficiency.

Whether Al has switched to a gas-fired range due to the gas utility's rebate opportunity, or simply because he prefers cooking with gas, the gas and electric companies have designed and promoted their respective programs in a fuel-neutral manner. If Al participates in the natural gas company's DSM program and purchases a high-efficiency natural gas-fired range to replace his old, inefficient electric range, Staff would not consider the situation to violate the fuel neutrality requirement.

Fuel Neutrality remained one of the few divisive topics covered at the DSM Workshops. There were many discussions regarding the appropriateness of a Policy that strictly prohibits fuel switching and what types of programs constitute fuel switching. The following controversial Policy language, highlighted in italics, was discussed at length: Electric/Natural gas utility program funds shall be used for electric/natural gas measures *that reduce electricity/natural gas use*. Representatives from the electric utilities viewed this statement without the italicized language as tolerant towards programs that could lead to fuel switching. Others viewed this language (excluding the italicized phrase) as maintaining the Policy of fuel neutrality while allowing for flexibility in evaluating a program when the baseline state is uncertain. Staff finds the italicized language to be in conflict with the fuel-neutral cooking range example described above. In that example, DSM funds are used in a fuel-neutral manner in part to provide a rebate for a high-efficiency gas range which will not technically reduce the customer's natural gas usage. For this reason, Staff has eliminated the language in italics.

During the course of the DSM Workshops, participants also discussed the concept of using source energy in the cost-effectiveness analysis. This controversial concept was included in the *Fuel Neutrality* section of the draft Policy. However, after significant consideration, Staff removed language that referred to both site and source energy.

First, there are different interpretations of the terms "source energy" and "site energy." Site energy refers to the amount of electric and/or natural gas demand and/or consumption used at the end use site. For example, the consumption of a light bulb that consumes 100 watts for 10 hours would be considered 1 kWh of "site energy." However, the "source energy" used by that light bulb is the total amount of kWh that must be produced by a power plant to generate, transmit, and distribute the 1 kWh of "site energy." Due to transmission and distribution losses and required reserves, the "source energy" will be greater than the 1 kWh of "site energy." Traditionally, Staff has interpreted "source energy" as end-use consumption (site energy) plus losses and required reserves. Instead of simply accounting for savings at the customer site, Staff has used source energy to calculate electric and/or natural gas demand and/or consumption savings from DSM measures.

Alternatively, some Workshop participants proposed to use a methodology used in California that tracks source energy in terms of the total amount of energy input required by a given level of end use consumption. For example, the California methodology considers the type and amount of fuel used to generate the electricity consumed by the 100 watt bulb compared to the total energy input used to generate the electricity consumed by the high efficiency 50 watt bulb. For electricity, the source energy is measured in British Thermal Units ("Btu") per kWh generated. In order to effectively use this analysis, the multiplier used to convert kWh to Btu per kWh must be based on the electric generation portfolio for a specific end use location. For example, central Arizona is served by a generation portfolio consisting of mainly nuclear, coal, and natural-gas fired generation. To obtain a reasonable estimate of the proper multiplier for central Arizona, one must calculate the weighted average of the heat rates (Btu required to produce one kWh) for each generator within the portfolio serving central Arizona. To apply the proper weighting to the heat rates, one must determine the generation resources that will be used to meet the forecasted load profile in that area. Once the Btu /kWh multiplier is determined, one can convert the end use kWh consumption of the light bulbs into Btu consumption. Those parties in favor of this methodology maintain that this type of analysis is required to accurately compare the energy efficiency and/or potential savings of end uses that can use more than one fuel source such as the cooking range example above. In the absence of Arizona-specific multipliers, proponents of this methodology propose to use fixed source energy multipliers[4] that equate to around 13,754 Btu/kWh to convert electricity and around 105,060 Btu/therm to convert natural gas.

See Schedule 2 for a comparison of Staff's interpretation of "source energy" to an alternative analysis used by the State of California.

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[4] Fixed multipliers are also referred to as "Time Dependent Valuation of Energy" (TDV). For electricity, a TDV of 1 equals 3,413 Btu/kWh. For natural gas, a TDV of 1 equals 100,000 Btu/therm. The TDV values proposed by proponents of this methodology are 4.03 for electricity and 1.0506 for natural gas.

Staff finds that the California methodology (converting all types of end use consumption to source energy measured in Btu) has the potential to accurately compare the energy consumption of an electric range to that of a gas-fired range. However, this requires a thorough analysis of the specific generation portfolio and demand characteristics of the geographic area in question. To date, such a study has not been conducted for any of the markets in Arizona. Absent an Arizona-specific study, Staff cannot validate any Btu/kWh multiplier that might be used to convert electric consumption to Btu consumption. Moreover, Staff finds that this sort of conversion is not required for the cost-effectiveness analysis of DSM programs because the cost-effectiveness of an electric DSM measure must be based on an electric baseline while the cost-effectiveness of a gas DSM measure must be based on a natural gas baseline. For these reasons, Staff removed language that referred to site and source energy from the *Fuel Neutrality* section.

Staff notes that in the case of DSM programs that reduce the demand and/or consumption of both electricity and natural gas, the avoided costs of saving both resources are included in the cost-effectiveness analysis. For example, an electric utility may include both the avoided cost of electricity and the avoided cost of natural gas that will result from the energy efficiency measures included in a Thermal Envelope program such as new home construction. Traditionally, Staff would use its production costing model to calculate the avoided cost of electricity, and Staff would obtain utility information on the avoided cost of natural gas. Staff would base electric savings on a baseline level of electricity demand and/or consumption and natural gas savings on a baseline level of natural gas consumption. In this case, Staff would not convert the electricity or natural gas savings into common units (Btu) but would calculate the avoided cost of each.

*17. **Monitoring, Evaluation, and Research***

Utilities shall monitor and evaluate all DSM programs to reliably ensure that they are cost-effective. Monitoring and evaluation should:

1. ***Determine participation rates, energy savings, and demand reductions;***
2. ***Assess the utility's program implementation process;***
3. ***Provide information on whether to continue, modify, or terminate a program; and***
4. ***Determine the persistence and reliability of DSM.***

Evaluation and research may also be conducted for program planning, product development, and program improvement. Evaluation and research includes market studies, market research, and other technical research for planning purposes.

The purpose of monitoring, evaluation, and research is to identify any problems associated with DSM programs, evaluate whether DSM programs are cost-effective, and ensure that they are being implemented as planned. The *Monitoring, Evaluation, and Research* section

of the Policy directs utilities to undertake these efforts to gather information and assess the success of DSM programs.

Evaluation and research may also prove helpful in program planning or product development efforts.

18. Program Administration and Implementation

Utilities may use energy service companies and/or other external resources to implement DSM programs.

The Commission may establish independent program administrators who would be subject to the relevant requirements of this policy.

There is a wide range of potential program administration options. The *Program Administration and Implementation* section of the Policy brings attention to the administration options that involve a party other than the utility and the program participant.

The familiar end of the administrative spectrum allows the utility to administer and implement the DSM program. For example, the utility would handle the tasks associated with recruiting and enrolling program participants, funding and implementing the DSM measure, and following up with the participants to monitor and evaluate the DSM program. Currently, this is the way in which most Arizona DSM programs are handled.

The opposite end of the continuum is an independent state-wide or regional DSM program administrator. In this scenario, the Commission would establish an independent third party to collect DSM funds from the utility companies and allocate those funds through DSM programs across utility jurisdictions. The independent administrator would handle the funding and implementation of all DSM programs, and all DSM funds would flow through that entity.

Within the range of administrative options there are many alternatives that involve both the utility and an outside party. One option is that the utility may handle the recruitment and enrollment of participants but contract with another entity to implement the program. For example, the utility company may recruit and enroll heating, ventilation, and air conditioning ("HVAC") contractors for a program that focuses on training and certification but hire independent trainers to perform the training and certify the participants.

Workshop participants and Staff generally agreed that the DSM Policy should allow for the full range of administration and implementation options.

19. Leveraging and Cooperation

Utilities shall make reasonable use of cost sharing, leveraging, or other opportunities available from customers, vendors, manufacturers, government agencies, other utilities, and others that increase the effectiveness of the DSM program and/or lower its costs.
Workshops to discuss DSM activities may be held periodically to provide interested parties the opportunity for input.

The *Leveraging and Cooperation* section of the Policy is intended to encourage utilities to work together on DSM programs whenever it is cost-effective and beneficial to both the utilities and the program participants.

For example, cost sharing and standardization between utilities offering a DSM program directed towards residential new construction could reduce vender and participant confusion, reduce administrative expenses, and reach more of the market. If two contiguous utilities are administering a thermal envelope program with different parameters and requirements, contractors working in both markets will have to comply with two sets of rules in order to participate. In addition, the utilities would need to promote their programs separately, requiring two full administrative cost burdens. Some of these barriers and costs could be avoided through utility cooperation.

Another example of utility cooperation could entail contractor training. According to many Workshop participants, a major factor in achieving energy efficiency in HVAC is proper installation of the equipment. Utilities could potentially work together to offer joint installation training programs for HVAC contractors.

In October of 2004, the Southwest Energy Efficiency Project in conjunction with Nevada Power Company sponsored a conference on Regional Cooperation in Energy Efficiency Program Implementation in the Southwest. Attendees from Arizona included Staff, Arizona Public Service, Tucson Electric Power, and Southwest Gas. Participants discussed the current state of energy efficiency programs and policies in the Southwest, models of regional collaboration such as the Northwest Energy Efficiency Alliance, barriers to cooperation between utilities, and opportunities for collaboration. Workshop participants formed several working groups to address specific opportunities such as residential new construction, HVAC, commercial kitchens, and commercial building design. The topics discussed at the conference were consistent with this section of the DSM Policy.

The DSM Policy also encourages periodic Workshops to facilitate utility cooperation in DSM activities.

20. <u>Other Approaches to DSM</u>

In general, the Commission supports other approaches to DSM, including building codes, appliance efficiency standards, shared savings legislation, and actions in other forums that would complement the DSM policy herein.

Staff and Workshop participants recognize that demand-side management can provide benefits to energy customers, utilities, and the environment. This Policy deals with DSM measures sponsored by utility companies to reduce the demand and/or consumption of electricity and/or natural gas. However, Staff recommends that the Commission consider supporting other strategies to reduce the demand and/or consumption of electricity and/or natural gas that may reach beyond its jurisdiction to the extent that such tactics complement the DSM Policy herein (such as, supporting legislation for appliance sufficiency standards).

Conclusion

Staff concludes that a hearing on the DSM Policy is not necessary. The Workshop process facilitated extensive discussion among a wide range of participants. Although a few issues remained unresolved by the final Workshop, the participants agreed on much of the DSM Policy herein.

Staff intends to convert the DSM Policy into proposed rules for Commission consideration within 60 days of filing this report. Staff recommends that the Commission adopt this policy as part of the rulemaking process.

Schedule 1
List of Participating Organizations

AHS
ANL Distributors/Volttech, Inc.
APS Energy Services
Arizona Clean Energy Industries Alliance
Arizona Competitive Power Alliance
Arizona Corporation Commission Staff
Arizona Electric Power Cooperative
Arizona Energy Office
Arizona Public Service
Arizona Solar Energy Association
Arizona Utility Investors Association
Brayden Automation Corp.
Buck-Taylor Consulting
City of Scottsdale
Demand Response and Advanced Metering Coalition
Department of Emergency and Military Affairs
Desert Energy
DCSI
Ecos Consulting
El Paso Corp.
Energy Strategies
Grand Canyon State Electric Cooperative Association
ICF Consulting
Johnson Controls, Inc.
Law Office of Bob Lynch
LightLogix Inc.
Maricopa County
Martinez & Curtis
Mohave Electric Coop
Morenci Water and Electric
Moyes Storey
Murphy Consulting
Natural Lighting
Navopache Electric Cooperative
ON Semiconductor
Ormond Group
Phelps Dodge
Pinnacle West Capital Corporation
Renewable Energy Leadership Group
Residential Utility Consumer Office
RHA
Salt River Project

So Cool Energy
Southwest Energy Efficiency Project
Southwest Gas
Sulphur Springs Valley Electric Cooperative
Transcon
Tucson Electric Power
UNS Electric
UNS Gas
Western Resource Advocates

Schedule 2
Source Energy Analysis

Source Energy - Traditional Staff Interpretation

	Staff Interpretation Source Energy[1] kWh	Loss Factor[2] % of Source	Losses[3] kWh	Site Energy[4] kWh
Standard 100 watt bulb for 10 hours	1.0309	3.0%	0.0309	1.00
High-Efficiency 50 watt bulb for 10 hours	0.5155	3.0%	0.0155	0.50
Energy Savings in kWh from DSM measure	0.5155			0.50

[1] Energy produced at the power plant level

[2] Loss Factors typically refer to a percentage of production site (source energy) energy lost in the transmission and distribution of the energy

[3] Source Energy x Loss Factor

[4] Source Energy - Losses

Source Energy - California Method

	Site Energy[1] kWh	Conversion Factor[2] Btu / kWh	Source Energy[3] Btu
Standard 100 watt bulb for 10 hours	1.00	10,329	10,329
High-Efficiency 50 watt bulb for 10 hours	0.50	10,329	5,165
Energy Savings from DSM measure	0.50 kWh		5,165 Btu

[1] Energy consumed by the bulb

[2] Example of a Conversion Factor that is based on a Time Dependent Valuation of Electricity (TDV Electricity) value of 3

[3] Source Energy in kWh x Conversion Factor = Energy input (measured in Btu) required to produce the electricity (measured in kWh) consumed by the light bulb

Schedule 3
Proposed
Arizona Corporation Commission
Demand-Side Management Policy

Policy Statement

The Arizona Corporation Commission ("Commission") recognizes that demand-side management ("DSM") can provide benefits to energy customers, utilities, and the environment. DSM shall be advanced and implemented in a cost-effective and prudent manner, while maintaining reasonable energy costs for consumers.

Applicability

This policy is applicable to all electric and natural gas utilities subject to the jurisdiction of the Commission that are classified as Class A according to A.A.C. R14-2-103(A)(3)(q), except for utilities that are electric transmission-only cooperatives. Smaller utilities may voluntarily participate either individually or in a group.

DSM Definition

DSM is the planning, implementation, and evaluation of programs to shift peak load to off-peak hours, to reduce peak demand ("kW"), and/or to reduce energy consumption ("kWh" or "therms") in a cost-effective manner. DSM may include energy efficiency, load management, and demand response.

Energy Efficiency is products, services, or practices aimed at saving energy in end-use applications generally by substituting technically more advanced (compared to what is presently used in a specific situation) equipment or practices to produce the same or an improved level of end-use service with less energy use. Examples include high-efficiency appliances; efficient lighting products and systems; high-efficiency heating, ventilating, and air conditioning ("HVAC") systems or control modifications; advanced electric motor drives; efficient building design; and efficient operation and maintenance practices.

Load Management consists of deliberate actions sponsored by a utility to reduce peak demands or improve system operating efficiency. Examples include direct control of customer demands through utility-initiated interruption or cycling, thermal storage, and education to encourage customers to shift loads.

Demand response includes all intentional modifications to electric and natural gas consumption patterns of customers affecting the timing or quantity of customer demand and usage. For the purposes of this policy, demand response programs are used to reduce customer energy usage in

response to prices, market conditions, or threats to system reliability. Demand response programs may include dynamic pricing/tariffs, price-responsive demand bidding, contractually obligated curtailment, voluntary curtailment, and direct load control/cycling.

Key Terms

Adjustment mechanism: a provision of a rate schedule, authorized in advance by the Commission, which allows for increases and decreases in rates reflecting increases and decreases in specific costs incurred by a utility.

Baseline: the level of electric and/or natural gas demand and/or consumption and associated costs that would have occurred in the absence of the DSM program.

Combined heat and power ("CHP"): distributed generation using a primary energy source to simultaneously produce electrical energy and useful process heat.

Distributed generation ("DG"): electric generation sited at a customer premises (customer side of the meter) providing electric energy to the customer load on that site.

Incremental benefits: improvements in societal welfare, including but not limited to avoided environmental impacts and the avoided fuel cost, purchased power cost, new capacity cost, transmission cost, and/or distribution cost.

Incremental costs: the additional cost of DSM programs and measures relative to baseline cost.

Market transformation: strategic efforts to induce lasting structural or behavioral changes in the market that result in increased adoption of energy-efficient technologies, services, and practices.

Net benefits: incremental benefits resulting from DSM minus the incremental costs of DSM.

Societal Test: a cost-effectiveness test of the net benefits of DSM measures and programs that starts with the Total Resource Cost Test but includes non-market benefits to society, such as reduced environmental effects of energy production and delivery, due to DSM.

Total Resource Cost Test: a cost-effectiveness test that measures the net benefits of a DSM program as a resource option, including both incremental measure and utility costs. The TRC test excludes incentives paid by utilities. The TRC test also excludes non-market benefits to society, such as reduced environmental effects of energy production and delivery.

Utility Cost Test: a cost-effectiveness test that measures the net change in a utility's revenue requirement resulting from a DSM program. The test compares the reduction in marginal energy and demand costs with utility program costs, incentive payments, and increased supply costs for a period in which load is increased. This test does not include any net costs incurred by participants.

Goals and Objectives

Policy Objectives

1. Achieve cost-effective energy savings and peak demand reductions.

2. Advance market transformation to achieve cost-effective DSM benefits through approaches that achieve sustainable savings and reduce the need for future market interventions.

3. Ensure a level of program funding adequate to achieve the DSM targets.

4. Implement DSM programs that provide an opportunity for all utility customer segments to participate.

5. Allocate a portion of DSM resources to the low-income customer segment.

DSM Goals

The Commission shall establish DSM goals for all applicable utilities that consider and are consistent with the characteristics of each specific utility's service territory and the approach to DSM in that service territory. Examples of DSM goals may include percentage reductions in load growth; benefits in dollars; net benefit goals; savings in kW, kWh, therms, gallons, or BTUs; savings as a percent of total resources to meet load; expenditures on DSM as a percent of retail revenue; or amount of spending on DSM programs.

Program Goals

Program goals shall be established by the Commission for DSM benefits, energy savings, and/or peak demand reductions for utilities subject to the DSM policy.

Goals for peak demand reductions in kW or therms may be met in part with demand response programs that are designed to reduce load during peak usage hours.

Portfolio Plans

Utilities shall submit to the Commission a DSM portfolio plan within six months of the adoption of this DSM policy through the rulemaking process (i.e., six months after the rules are adopted). The portfolio plan shall include:

1. An overall DSM portfolio goal;
2. Descriptions of DSM programs to be undertaken in compliance with the Commission's DSM policy;
3. Estimated levels of energy and capacity savings, utility costs, societal benefits and costs, and other benefits (quantified where reasonably possible) of the planned programs;

4. Marketing and delivery plans, including an implementation schedule;
5. Measurement and evaluation plans; and
6. A description of the administration of the programs.

Utilities shall file subsequent DSM portfolio plans biennially with the Commission for approval. Specific program plans can be filed for approval at any time. If programs are filed for approval contemporaneously with the DSM portfolio plan, the items of information listed in the *Commission Review and Approval of DSM Programs* section set forth below must be included in the filing.

Existing Commission-approved plans and programs will continue in effect until the Commission takes action on a new plan.

Staff may develop standard tables, outlines, and guidelines for the plans.

Commission Review and Approval of DSM Programs

Prior to implementing a new DSM program, utilities must obtain Commission approval. Utilities shall file a copy of the program proposal with Docket Control and notify interested parties of the filing. Interested parties have 20 calendar days to file written comments about the proposed program.

Each program proposal shall include the following items:

1. Description of the program;
2. Objectives and rationale for the program;
3. Market segment at which the program is aimed;
4. Estimated level of program participation;
5. Estimate of baseline;
6. Estimated societal benefits and savings from the program;
7. Estimated societal costs of the programs;
8. Marketing and delivery strategy;
9. Utility costs and budget;
10. Implementation schedule;
11. Monitoring and evaluation plan; and
12. Proposed performance incentives.

Staff shall recommend approval of a DSM program if it is consistent with the Commission's DSM policy. Staff may request modifications of proposed or on-going programs to ensure consistency with the Commission's DSM policy. However, the Commission shall allow utilities adequate time to notify customers of program modifications.

Parity and Equity

Each utility shall develop and propose DSM programs for residential, non-residential, and low income customers so that all customer segments have the opportunity to benefit from DSM.

DSM funds collected from residential and non-residential customer segments shall be allocated proportionately to those customer groups to the extent reasonable.

DSM funds collected from ratepayers of a given utility shall be allocated to DSM programs for customers in that utility's service territory to the extent reasonable.

The utility costs of DSM programs for low-income customers shall be borne by all customer classes.

All customers shall pay to support DSM through a non-bypassable mechanism.

Self-direction[5] may be reviewed by the Commission in utility rate cases or other forums.

Portfolio and Program Reporting Requirements

Utilities shall report annually to the Commission on the progress of their DSM portfolios including each pre-approved DSM program. Annual reports shall be due on March 1 of each year. At a minimum, the reports shall include:

1. Predetermined overall DSM portfolio goals;
2. A description of the progress towards meeting the portfolio goals;
3. A list of the programs included in the DSM portfolio organized by customer segment;
4. Findings from any research projects;
5. Information on each program including:
    a. A brief description of each program;
    b. Predetermined program goals, objectives, and savings targets;
    c. The level of customer participation for each program;
    d. Costs incurred during the reporting period disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;
    e. A description and results of evaluation and monitoring activities;
    f. Savings in kW, kWh, therms, gallons, and BTUs;
    g. Benefits and net benefits in dollars;
    h. Program-specific performance incentive calculations;
    i. Problems encountered and proposed solutions;
    j. Proposed program modifications; and
    k. Proposed program terminations.

[5] Self-direction is an option made available to qualifying customers of sufficient size, in which the amount of money paid by each qualifying customer toward a DSM adjustor is tracked for an individual customer and is made available for use by the customer for DSM investments upon application by the customer.

Utilities shall file quarterly status reports that shall consist of a tabular summary of expenditures compared to the budget. Quarterly reports shall be due 45 days after the end of a calendar quarter.

All reports shall be available to the public and filed in Docket Control. These reporting requirements shall supercede other DSM reporting requirements as determined by the Commission for each Utility.

Staff may develop standard tables, outlines, and guidelines for reports.

Cost Recovery

Utilities shall recover their net incremental costs to plan, design, implement, and evaluate DSM programs. In order to qualify for cost recovery, each program must be:

1. Approved prior to implementation;
2. Implemented in accordance with the approved program plan; and
3. Monitored and evaluated for cost-effectiveness.

Utilities shall monitor and evaluate DSM programs to reliably ensure that they are cost-effective. Utilities shall propose modification or termination of programs that are failing to meet expected results.

To effectively implement programs, cost recovery shall be concurrent (on an annual basis) with DSM spending.

DSM funds may be used for market studies, consortium membership, labor costs for portfolio development, and other items for which the costs are difficult to allocate to individual DSM programs.

To the extent goods and services used for DSM have value for other utility functions, programs, or services, funding shall be divided and allocated proportionately.

Utilities shall allocate costs in accordance with Generally Accepted Accounting Principles.

Performance Incentives and Lost Revenue

Performance incentives for achieving or exceeding Commission-designated goals may be appropriate as determined by the Commission.

The Commission shall determine whether a utility may be allowed to recover lost net revenue.

Funding Mechanisms

Funding shall be provided either through base rates, a surcharge mechanism, and/or an adjustment mechanism. Until such funding can be established for a utility in a rate case, the utility may request that the Commission grant the authority to establish a deferral account.

Applications Eligible for Funding

DSM programs promoting energy efficiency, demand response, load management, or combined heat and power on the customer side of the meter that reduce peak demand or conserve energy may be approved by the Commission.

DSM funds may be used for research and development such as applied technology assessment.

CHP projects may be eligible for funding if they include heat or energy recovery which is used to displace space heating, water heating, or other loads.

Non-CHP Distributed Generation (DG) may be used by customers as a means to help them participate in a demand response program.

Cost Effectiveness

The incremental benefits to society of the overall DSM portfolio shall exceed the incremental costs to society of the overall DSM portfolio. The incremental benefits to society of the individual DSM programs shall exceed the incremental costs to society of the individual DSM programs.

Cost-effectiveness shall be determined by the Societal Test. Costs to society equal the total incremental costs of the DSM program (including incremental utility costs and incremental customer/vendor costs). The benefits to society include avoided environmental impacts and the avoided fuel cost, purchased power cost, new capacity cost, transmission cost, and distribution cost.

Other economic factors such as the costs and benefits associated with reliability may be included in the analysis. Electric utilities may consider savings of natural gas; natural gas utilities may consider savings of electricity. The analysis shall reflect the expected life of the savings resulting from DSM measures. Uncertainty about future streams of costs or benefits should be reflected in cost/benefit or other analyses where practicable and appropriate. In addition to the cost-effectiveness test, a utility or program administrator should consider the impact on rates, economic development, customer costs, and other economic impacts.

Environmental costs or the value of environmental improvements shall be quantified when possible, reasonable, and cost-efficient. At a minimum, utilities shall make a good faith effort to quantify water consumption savings and air emission reductions until such time that an

environmental externalities quantification procedure is adopted by the Commission. Upon adoption of a policy, utilities shall implement the policy adopted by the Commission. Other environmental impacts may be considered qualitatively.

The standard cost effectiveness analysis may not be appropriate for certain types of DSM programs.

1. Market Transformation Programs: Cost effectiveness shall be measured by the success of a program in achieving results, such as market effects compared to its costs.

2. Educational Programs: Utilities shall attempt to estimate the energy and peak demand savings that result from educational efforts that raise awareness about energy use and opportunities for saving energy.

3. R&D and Pilot Programs: Individual research and development and pilot programs do not have to demonstrate cost-effectiveness.

4. Low Income Programs: Measures included in low-income programs shall be generally cost-effective.

The following table illustrates the differences between the various cost-effectiveness tests.

Comparison of Cost-Effectiveness Tests

	Participant Test	Utility Cost Test	Total Resource Cost Test	Societal Test
Benefits	• incentives received • bill reductions	• avoided utility costs	• avoided utility costs	• avoided utility costs • avoided environmental impacts
Costs	• bill increases • incremental participant costs	• incremental utility costs, including incentives paid by utility	• incremental utility costs, excluding incentives paid by utility • incremental participant costs	• incremental utility costs, excluding incentives paid by utility • incremental participant costs

Baseline Estimation

The baseline for determining the incremental costs and benefits of a DSM program shall be a reasonable estimate of the level of electric and/or natural gas demand and/or consumption and associated costs that would have occurred in the absence of the DSM program.

For demand response programs, customer load profile information may be used to verify baseline consumption patterns and the peak demand savings resulting from demand response actions.

Fuel Neutrality

Ratepayer-funded DSM shall be developed and implemented in a fuel-neutral manner. For those installations/applications that have multiple fuel choices, the baseline used in the cost effectiveness analysis shall utilize the same fuel source as the installation/application.

Electric utility program funds shall be used for electric measures. Natural gas utility program funds shall be used for natural gas measures. However, either natural gas utilities or electric utilities may fund thermal envelope improvements.

Monitoring, Evaluation, and Research

Utilities shall monitor and evaluate all DSM programs to reliably ensure that they are cost-effective. Monitoring and evaluation should:

1. Determine participation rates, energy savings, and demand reductions;
2. Assess the utility's program implementation process;
3. Provide information on whether to continue, modify, or terminate a program; and
4. Determine the persistence and reliability of DSM.

Evaluation and research may also be conducted for program planning, product development, and program improvement. Evaluation and research includes market studies, market research, and other technical research for planning purposes.

Program Administration and Implementation

Utilities may use energy service companies and/or other external resources to implement DSM programs.

The Commission may establish independent program administrators who would be subject to the relevant requirements of this policy.

Leveraging and Cooperation

Utilities shall make reasonable use of cost sharing, leveraging, or other opportunities available from customers, vendors, manufacturers, government agencies, other utilities, and others that increase the effectiveness of the DSM program and/or lower its costs.

Workshops to discuss DSM activities may be held periodically to provide interested parties the opportunity for input.

Other Approaches to DSM

In general, the Commission supports other approaches to DSM, including building codes, appliance efficiency standards, shared savings legislation, and actions in other forums that would complement the DSM policy herein.

EXHIBIT
S-17
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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
APR - 7 2005
DOCKETED BY

COMMISSIONERS

JEFF HATCH-MILLER Chairman
WILLIAM A. MUNDELL
MARC SPITZER
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

DECISION NO. 67744

OPINION AND ORDER

DATES OF PROCEDURAL CONFERENCES: August 13, 2003, January 6, February 18, April 7, 15, 28 May 26, June 14, August 18, and October 27, 2004

DATES OF HEARING: November 8, 9, 10, 29, 30, December 1, 2, and 3, 2004

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

IN ATTENDANCE: Marc Spitzer, Chairman
William A. Mundell, Commissioner
Jeff Hatch-Miller, Commissioner
Mike Gleason, Commissioner
Kristin K. Mayes, Commissioner

APPEARANCES: Mr. Thomas L. Mumaw and Ms. Karilee S. Ramaley, PINNACLE WEST CAPITAL CORPORATION; Mr. Jeffrey B. Guldner and Ms. Kimberly Grouse, SNELL & WILMER, L.L.P., on behalf of Arizona Public Service Company;

Mr. C. Webb Crockett, FENNEMORE CRAIG, P.C., on behalf of AECC and Phelps Dodge;

Mr. Patrick J. Black, FENNEMORE CRAIG, P.C., on behalf of Panda Gila River;

Mr. S. David Childers, LOW & CHILDERS, P.C., Mr. James M. Van Nostrand, and Ms. Katherine McDowell STOEL RIVES, L.L.P., on behalf of Arizona Competitive Power Alliance;

Mr. Lawrence V. Robertson, Jr., MUNGER

CHADWICK, on behalf of Southwestern Power Group II, Mesquite Power, and Bowie Power Station, LLC, and Mr. Theodore Roberts, SEMPRA ENERGY RESOURCES, on behalf of Mesquite Power;

Mr. Scott S. Wakefield, Chief Counsel, and Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

Mr. Walter W. Meek, President, on behalf of the Arizona Utility Investors Association;

Mr. Raymond S. Heyman, Ms. Laura E. Schoeler, and Ms. Laura Sixkiller, ROSHKA, HEYMAN & DeWULF, on behalf of UniSource Energy Services;

Major Allen G. Erickson on behalf of the Federal Executive Agencies;

Mr. Jay I. Moyes, MOYES STOREY, on behalf of PPL Sundance and PPL Southwest Generation Holdings;

Mr. Nicolas J. Enoch, LUBIN & ENOCH, on behalf of the International Brotherhood of Electrical Workers;

Mr. William P. Sullivan and Mr. Michael A. Curtis, MARTINEZ & CURTIS, P.C., on behalf of the Town of Wickenburg, Arizona;

Mr. Bill Murphy, MURPHY CONSULTING and Mr. Douglas V. Fant, LAW OFFICES OF DOUGLAS V. FANT, on behalf of the Arizona Cogeneration Association;

Mr. Marvin S. Cohen, SACKS TIERNEY, P.A., on behalf of Constellation NewEnergy and Strategic Energy;

Mr. Andrew W. Bettwy and Ms. Karen S. Haller, on behalf of Southwest Gas Corporation;

Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST, and Ms. Anne C. Ronan, on behalf of Western Resources Advocates and Southwest Energy Efficiency Project;

Mr. Jesse A. Dillon, on behalf of PPL Services Corporation;

Mr. Brian Babiars and Ms. Cynthia Zwick, WESTERN ARIZONA COUNCIL OF GOVERNMENTS, on behalf of Arizona Community Action Association;

Mr. Paul R. Michaud, MICHAUD LAW FIRM, on behalf of Dome Valley Energy Partners, LLC;

Mr. Michael L. Kurtz, BOEHM, KURTZ & LOWRY, on behalf of Kroger Company;

Mr. Christopher Kempley, Chief Counsel, Mr. Jason D. Gellman and Ms. Janet F. Wagner, Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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BY THE COMMISSION:

I. DISCUSSION

On June 27, 2003, Arizona Public Service Company ("APS" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a rate increase and for approval of a purchased power contract. The application states that the $175.1 million rate increase is needed to maintain the Company's credit ratings and attract new capital on reasonable terms, recover its cost of service, and permit APS to earn a fair rate of return on the fair value of its assets devoted to public service. The application requested that the Commission recognize the higher fuel and purchased power expenses being incurred by the Company; allow APS to include in rates at cost of service certain generation assets of Pinnacle West Energy Corporation ("PWEC"); permit APS to recover the $234 million write-off taken under the 1999 Settlement Agreement; and provide for the recovery of all prudently incurred costs to comply with the Commission's Retail Electric Competition Rules, A.A.C. R14-2-1601, *et seq.* ("Electric Competition Rules"), including the one-third of costs associated with the planned divestiture of generation from APS to PWEC that was not previously deferred. APS also requested approval of depreciation and amortization rates and a review of its long-term purchased power contract with PWEC if the assets are not rate based.

On July 25, 2003, the Utilities Division Staff ("Staff") of the Commission filed a letter stating that the application was found sufficient and classified the applicant as a Class A utility.

By Procedural Order issued August 6, 2003, a Procedural Conference was scheduled for August 13, 2003, and intervention was granted to the Arizonans for Electric Choice and Competition ("AECC"), the Federal Executive Agencies ("FEA"), the Kroger Company ("Kroger"), the Residential Utility Consumer Office ("RUCO"), the Arizona Utility Investors Association, Inc., ("AUIA") and Phelps Dodge Corporation and Phelps Dodge Mining Company ("Phelps Dodge").

By various Procedural Orders, intervention was granted to: the International Brotherhood of Electrical Workers, AFL-CIO, CLC, Local Unions 387, 640 and 769 (collectively, "IBEW"), the Arizona Cogeneration Association/Distributed Generation Association of Arizona ("ACA" or "DEAA"), Panda Gila River, L.P. ("Panda"), Arizona Water Company ("AWC"), Southwest Gas Corporation ("SWG"), Western Resource Advocates ("WRA"), Constellation NewEnergy, Inc.

("CNE"), Strategic Energy, L.L.C. ("SEL"), Dome Valley Energy Partners, LLC ("DVEP"), UniSource Energy Services ("UES"), Arizona Community Action Association ("ACAA"), Arizona Competitive Power Alliance ("Alliance"), the Town of Wickenburg ("Wickenburg")[1], the Arizona Solar Energy Industries Association ("AriSEIA"), the Arizona Association of Retired Persons ("AARP"), Southwest Energy Efficiency Project ("SWEEP"), PPL Sundance, LLC ("PPL Sundance"), PPL Southwest Generation Holdings, LLC ("PPL Southwest"), Southwestern Power Group II, LLC ("SWPG"), Mesquite Power, LLC ("Mesquite") and Bowie Power Station, LLC ("Bowie").

On November 5, 2003, Staff filed a Motion to Consolidate ("Motion") the preliminary inquiry created by Decision No. 65796 and by Procedural Order the Motion was granted, authorizing Staff to include its report in this docket.

II. PRE-SETTLEMENT POSITIONS OF PARTIES

	APS	Staff	RUCO	Settlement Agreement
Revenue requirement	+$175.1 M	-$142.7 M	-$53.6 M	+$75.5 M
Return on Equity	11.5 %	9.0%	9.5%	10.25 %
Debt cost	5.8 %	5.8%	5.8%	5.8%
Capital Structure	50/50	55/45	55/45	55/45
Cost of Capital	8.67 %	7.3%	7.43%	7.8 %
PWEC assets	$848 M	-	[2]	$700 M

III. SETTLEMENT AGREEMENT

a. Introduction

On August 18, 2004, a Settlement Agreement signed by 22 parties[3] was docketed with the Commission. AWC, SWG, and UES do not oppose the Settlement Agreement, and the AARP made public comment supporting it. The only party opposed to the Commission's adoption of the Settlement Agreement that presented testimony and evidence is the Arizona Cogeneration

[1] On August 18, 2004, Wickenburg moved to withdraw its intervention.
[2] Phase 1.
[3] APS, ACAA, Alliance, AECC, AriSEIA, AUIA, Bowie, CNE, DVEP, FEA, IBEW, Kroger, Mesquite, Phelps Dodge, PPL Southwest, PPL Sundance, RUCO, SWEEP, SWPG, Staff, SEL, and WRA.

Association/Distributed Generation Association of Arizona.[4]

APS' central objectives in settling were to preserve the company's financial integrity;[5] resolve the issue of asset "bifurcation"; and to determine the company's future public service obligations.

Staff believes that the Settlement Agreement is in the public interest because: it is fair to ratepayers because it precludes inappropriate utility profits and results in just and reasonable rates; it is fair to the utility because it provides revenues necessary to provide reliable electric service along with an opportunity for a reasonable profit; the proposal balances many diverse interests including those of low-income customers, the renewable energy sector, Demand Side Management ("DSM") advocates, merchant generators, and retail energy marketers; it allows APS to rate base the PWEC assets, which are the generating plants originally built by APS' affiliate, PWEC, at a value that is significantly below their book value; potentially anti-competitive effects that may be associated with rate basing the PWEC assets are addressed through a self-build moratorium, a competitive solicitation in 2005, through workshops to address future resource planning and acquisition issues, and by adopting cost-based unbundling for generation and revenue cycle services in the rate design for general service customers, encouraging those customers to shop for competitive services; the Settlement Agreement resolves long, complex litigation by resolving issues associated with prior Commission decisions that are on appeal; the Settlement Agreement facilitates the provision of electric service at the lowest reasonable rates; it provides additional discounts to low-income APS customers, increases funding for advertising these discounts, and increases funding for APS' low-income weatherization program; and because it includes a comprehensive DSM proposal intended to foster the development of new DSM programs while ensuring that the expenditures will be reasonable and subject to appropriate Commission oversight.[6]

RUCO noted that this rate case allowed sufficient opportunity for it to fully audit the Company's cost-of-service study and allowed all parties to be included in the negotiations. RUCO points to the very substantial, nearly universal consensus reached in the Settlement Agreement as

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[4] New Harquahala Generating Company, LLC and Panda made statements objecting to the rate basing of the PWEC assets.

[5] Defined as the ability to attract capital on reasonable terms and earn a reasonable return. Tr. p. 420.

[6] Summary of settlement testimony of Ernest Johnson.

indicating that the public interest has been served. According to RUCO, the "ultimate expression of the agreement having met the Public Interest is the degree to which rate increases have been minimized without jeopardizing the financial integrity of the applicant."[7]

The Alliance's central objective is to continue towards a viable and effective wholesale market into which Alliance members can sell their power. According to the Alliance, there are several key provisions in the Settlement Agreement that accomplish that goal: the restrictions on self-build coupled with the high growth rate in APS' service territory; and the 1,000 megawatt Request for Proposal ("RFP") in 2005. The Settlement Agreement also preserves the financial stability and creditworthiness of the Alliance's target customer – APS.[8]

b. **Revenue Requirements**

For ratemaking purposes and for purposes of the Settlement Agreement, the parties agree that APS will receive a total increase of $75.5 million over its adjusted 2002 test year ("TY") revenue of $1,791,584,000. This represents an increase in base rates of $67.6 million and a Competition Rules Compliance Charge ("CRCC") surcharge collecting $7.9 million. Pursuant to the Settlement Agreement filed on August 18, 2004, as corrected in the hearing, the Company's fair value rate base ("FVRB") is $5,054,426,000.[9] According to the Settlement Agreement, this revenue increase will allow the Company the opportunity to earn a fair value rate of return of 5.92 percent. According to the Company and Staff, the revenue requirement contained in the Settlement Agreement provides sufficient revenues for APS to provide adequate and reliable service.[10]

c. **PWEC Asset Treatment**

The Settlement Agreement provides that APS will acquire and rate base generation units owned by PWEC.[11] Those units include: West Phoenix CC-4; West Phoenix CC-5; Saguaro CT-3; Redhawk CC-1; and Redhawk CC-2 ("PWEC assets"). Pursuant to the Settlement Agreement, the

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[7] Summary of settlement testimony of Stephen Ahearn.
[8] Tr. p. 458.
[9] Paragraph 4 to the Settlement Agreement states the FVRB is $6,281,885,000, however, during the hearing, that amount was corrected to $5,054,426,000. Tr. p. 692.
[10] Tr. p. 810.
[11] On November 10, 2004, PWEC filed a letter with the Commission indicating that it would abide by the provisions of the Settlement Agreement that require PWEC to take or refrain from taking any action in order to carry out the intent of the Settlement Agreement.

original cost rate base ("OCRB") of the PWEC assets will be $700 million which is $148 million less than the original cost of the assets as of December 31, 2004. According to the Settlement Agreement, this represents a reasonable estimate of the value of the remaining term of the Track B contract between APS and PWEC.[12] APS agrees to forgo any present or future claims of stranded costs associated with these PWEC assets. According to the Settlement Agreement, APS is required to seek approval of certain aspects of the asset transfer from the Federal Energy Regulatory Commission ("FERC"). APS agreed to file a request for FERC approval within 30 days of the Commission's approval of the Settlement Agreement, and the parties have agreed not to oppose the FERC application. The Settlement Agreement provides for a bridge purchased power agreement ("Bridge PPA") to be implemented once new rates are put in place, until the actual date of the transfer of assets. APS and PWEC will execute a cost-based PPA which will be based on the value of the PWEC assets, and fuel costs and off-system sales revenue will flow into the power supply adjustor ("PSA"). If FERC denies the asset transfer, then the Bridge PPA will become a 30 year PPA, with prices reflecting cost-of-service as if the PWEC assets were rate-based at the $700 million amount in the Settlement Agreement, and with the associated fuel costs and off-system sales revenue flowing through the PSA. The basis point credit established in Decision No. 65796 will continue as long as the debt between APS and PWEC associated with the PWEC assets is outstanding. Credit for amounts deferred after December 31, 2004 will be accounted for in APS' next rate case. The Settlement Agreement also provides that West Phoenix CC-4 and West Phoenix CC-5 will be deemed "local generation" and during must-run conditions, generation from the West Phoenix facilities will be available at FERC-approved cost-of-service prices to electric service providers ("ESPs") serving direct access loads in the Phoenix load pocket.

Treatment of the PWEC assets requires not only a regulatory ratemaking type analysis, but also an analysis of how rate basing these assets fits with the Commission's overall plan for wholesale and retail electric competition in Arizona.

For the last ten years, the Commission has studied, discussed, and deliberated about electric

[12] Docket Nos. E-00000A-02-0051 et al.

competition through workshops, rulemakings, hearings, and open meetings. Several versions of electric competition rules have been adopted, and litigation concerning Commission decisions has been conducted. Throughout this time, the Commission has always maintained its intent to encourage competition in the electric industry. In the wake of the California energy crisis the Commission opened dockets to examine changing industry and market conditions and introspectively analyzed their impact on Arizona's existing rules. The Commission reacted in a measured manner to flawed rules in other jurisdictions and corrected, but did not change, its course.

The Commission continues to support competition as yielding economic and environmental benefits to Arizona consumers. The $148,000,000 discount from book for the rate-based PWEC assets is indicative of these benefits. Recent transactions reflected in the record, including below-cost sales, foreclosures and bankruptcies, establish that the shareholders of the power plants' builders absorbed the costs and bore the brunt of a declining market, rather than Arizona ratepayers. The discounted conveyance of the PWEC assets to APS is further support for this proposition. APS' request and the Settlement Agreement's provision allowing APS to acquire the PWEC assets and put them in rate base raises the issue of whether such action would undermine the Commission's stated intent to encourage retail and wholesale competition. The terms of the Settlement Agreement taken as a whole indicate to us that the answer to that question is "no".

During the hearing on the Settlement Agreement, the parties presented evidence demonstrating that the PWEC acquisition was the most beneficial option for ratepayers. Staff testified that the responses to APS' last formal RFP did not indicate to Staff that the market would provide a superior alternative to the rate basing of the PWEC assets. The testimony indicates that growth in APS' service territory is a minimum of 3 percent per year. APS argued that even with rate basing the PWEC assets, APS' needs would not be met, and it would have to procure additional power to meet the needs of its customers. The Settlement Agreement provides that APS will issue an RFP for an additional 1000 megawatts, thereby giving other market participants an opportunity to compete. The organization created to represent the interests of the merchant community, the Alliance, supports the transfer of assets, because it believes that resolving the broader issues of overall market structure, the self-build guidelines and future RFPs, together with the reduction in

litigation risk will further its overall goal of promoting a viable and effective wholesale market. The key provision that the Alliance relies on is the 1,000 megawatt RFP in 2005 that provides a degree of certainty regarding the timing of an initial increment of APS' future needs to be met from the wholesale market. Also, the Alliance believes that opportunities will exist for its members because of the self-build limitation and the high growth rate in Arizona. The proponents of retail competition also support the asset transfer; in large part because APS agrees to forgo any present or future claims of stranded costs associated with the PWEC assets, because rates are unbundled, and because of the treatment of the West Phoenix facilities.

We believe that nothing in the Settlement Agreement prevents the continued development of electric competition. Any potential anti-competitive effects of the asset transfer will be addressed through the competitive solicitations, the self-build moratorium,[13] and Staff's workshops to address future resource planning and acquisition issues. As discussed below, the evidence indicates that the asset transfer captures the benefit of the competitive procurement that took place as a result of the Track B proceeding.

The original cost of the PWEC assets at December 31, 2004 was $848 million. Traditionally, when a utility builds plant, unless there is a finding of imprudency, that portion of the plant that is used and useful is put into rate base and the utility is allowed an opportunity to earn a reasonable rate of return on that investment. This situation is different from the traditional rate case. APS did not build the PWEC assets; they were built by APS' affiliate during a time when the Commission intended APS to divest itself of generation. During the proceeding on APS' financing application, concern was raised that APS and its affiliates took actions that gave it an unfair advantage as compared to its potential competitors. In Decision No. 65796, which granted APS' financing request, we directed Staff to conduct a preliminary inquiry into the issue of APS and its affiliate's compliance with our electric competition rules, Decision No. 61973, and applicable law. The Settlement Agreement provides that the preliminary inquiry will be concluded with no further action by the

[13] Neither APS nor PWEC will build the Redhawk Units 3 & 4. PWEC's February 2003 self-certification filing with the Commission stated that the two remaining units pursuant to its Certificate of Environmental Compatibility ("CEC") would not be built. Tr. pp. 594-5.

Commission. Accordingly, we make no finding as to why or for whom the PWEC assets were built, and base our resolution of the rate basing issue solely on the merits of the terms of acquisition. We believe that if there were a serious threat to competition, we would hear from those affected, loudly and strongly. Therefore, we were keenly interested in the position of the members of the Alliance, as they are one type of entity that could be harmed. The Alliance supports the acquisition of the PWEC assets by APS. Every person or entity that will be affected by the rate basing of the PWEC assets had the opportunity to participate and present evidence and testimony on this issue. Although two independent power producers made comments objecting to the acquisition without an RFP, neither presented any evidence that demonstrated that competition would be harmed, nor rebutted the testimony and evidence concerning APS' recent RFP.

Initially Staff recommended that the PWEC assets not be rate based, but after analyzing the Company's rebuttal testimony and evidence, agreed that a reduction of $148 million in original cost rate base made the acquisition beneficial to ratepayers. The evidence in the record is substantial that APS' analysis of other options versus rate basing PWEC assets showed that: using an "other build" analysis, rate basing the PWEC assets would cost $300-600 million less than cost to build other plants such as Combustion Turbines ("CT"); using a comparable sales analysis showed that other recent sales had a per kW cost in excess of $527 and the PWEC assets are at $417; when compared to the offers resulting from the recent RFP conducted by APS, the PWEC assets (when valued at the before discount $848 million level) showed benefits of $600-900 million; and using a discounted cash flow analysis the PWEC assets had a savings of $250 million to $1 billion.

As part of the settlement, APS agreed to reflect an original cost rate base value of $700 million, representing a $148 million disallowance. The effect of a reduction in rate base is to immediately reduce the revenue requirement, and to preserve that diminished revenue requirement for the life of the plant.

The analyses showing that the rate basing of the PWEC assets will result in lower rates than other options, together with no showing that such an acquisition would harm the development of a competitive wholesale or retail market indicate that it is reasonable and in the public interest for APS to acquire and rate base the PWEC assets as set forth in the Settlement Agreement.

d. Cost of Capital

The Settlement Agreement adopts a capital structure of 55 percent long-term debt and 45 percent equity for ratemaking purposes. The parties agree that a 10.25 percent return on common equity and a 5.8 percent embedded cost of long-term debt is appropriate.

e. Power Supply Adjustor (PSA)

The Settlement Agreement provides that a PSA be implemented and remain in effect for a minimum of five years, with reviews available during APS' next rate case, or upon APS' filing its report on the PSA four years after rates are implemented in this rate case. Regardless of the review/report, the PSA cannot be abolished until five years have expired. The Settlement Agreement provides that APS will file a plan of administration as part of its tariff filing that describes how the PSA will operate. According to the Settlement Agreement, the PSA will have the following characteristics:

- Includes both fuel and purchased power;
- The adjustor rate will initially be set at zero and will thereafter be reset on April 1 of each year, beginning with April 1, 2006. APS will submit a publicly available report on March 1 showing the calculation of the new rate, which will become effective unless suspended by the Commission;
- Incentive mechanism where APS and its customers share 10 percent and 90 percent, respectively, the costs and savings;
- Bandwidth that limits annual change in adjustor of plus or minus $0.004 per kilowatt hour, with additional recoverable or refundable amounts recorded in balancing account;
- Surcharge possible if balancing account reaches plus or minus $50 million and Commission approves;
- Off-system sales margins credited to PSA balance;
- Recovery of prudent, direct costs of contracts for hedging fuel and purchased power costs;
- Interest on balancing account will accrue based on the one-year nominal Treasury constant maturities rate;
- The Commission or its Staff may review the prudence of fuel and power purchases at any

time;

- The Commission or its Staff may review any calculations associated with the PSA at any time; and
- Any costs flowed through the adjustor are subject to refund if the Commission later determines that the costs were not prudently incurred.

The Settlement Agreement provides that APS shall provide monthly reports to Staff's Compliance Section and to RUCO detailing all calculations related to the PSA, and shall also provide monthly reports to Staff about APS' generating units, power purchases, and fuel purchases. An APS officer must certify under oath that all the information provided in the reports is true and accurate to the best of his or her information and belief. The Settlement Agreement also provides that direct access customers and customers served under rates E-36, SP-1, Solar-1, and Solar-2 are excluded from paying PSA charges. Under the Settlement Agreement, the PSA remains in effect for 5 years, and if after that, the Commission abolishes the PSA, it must provide for any under- or over-recovery and can adjust base rates to reflect costs for fuel and purchased power. The parties agree that a base cost of fuel and purchased power of $.020743 per kWh should be reflected in APS' base rates.

Decision No. 61973 (October 6, 1999) adopting the previous APS settlement, required APS to request, and the Commission to approve, a "power supply adjuster" mechanism to recover the cost of providing power for standard offer and/or provider of last resort customers.

In Decision No. 66567 (November 18, 2003), the Commission approved the concept of a Purchased Power Adjustor ("PPA") which included purchased power costs and did not include the cost of fuel. The Decision noted that the adjustor mechanism approved therein may be modified or eliminated in this rate case. As noted in that Decision, there are advantages and disadvantages to adjustor mechanisms:

Advantages: 1) the reporting requirements and forecasts facilitate utility planning and Staff overview of costs; 2) an adjustor that works correctly, over time, reduces the volatility of a utility's earnings and the risk reduction can be reflected in the cost of equity capital in a rate case and result in lower rates; 3) adjustors can create price signals to consumers, but the effectiveness is reduced considerably when a band is included; 4) adjustors can help reduce the frequency of rate cases; 5)

regulatory lag between the incurrence of an expense and its recovery is reduced and generational inequities are also reduced.

Disadvantages: 1) adjustors can reduce incentives to minimize costs; 2) an adjustor that includes fuel or purchased power costs potentially biases capital investment decisions towards those with lower capital costs and higher fuel costs; 3) adjustors create another layer of regulation to rate cases, increasing the cost of regulation to the utility, its customers, and to the Commission; 4) an adjustor can shift a disproportionate proportion of the risk of forced outages and systems operations from shareholders to ratepayers; 5) adjustors result in piecemeal regulation – an adjustor reflects an increase in one expense but ignores offsetting savings in other costs; 6) adjustors are complex and often difficult for analysts to read and interpret, and are difficult to explain to customers; 7) proper monitoring of adjustor filings and audits require the devotion of significant Staff resources; and 8) rates are less stable, resulting in rates changing frequently, making it difficult for customers to plan energy consumption and the purchase of energy consuming appliances.

Although we recently approved the concept of a PSA, we are concerned about the PSA as proposed in the Settlement Agreement. The benefits of this PSA are that over time, the utility's earnings will be stabilized, thereby preserving its financial integrity and in the longer term, improve the likelihood that the company will attract capital on reasonable terms, to the benefit of ratepayers. Further, as part of the negotiations, the parties were able to agree on a lower overall revenue increase because a PSA was to be implemented. AECC pointed out that if an adjustor remains in effect for long enough, it becomes a credit, and therefore, the PSA should remain in effect for five years.[14]

The disadvantages are real and significant – from a customer standpoint, adjustors are difficult to understand and they can cause annual price increases. From a regulatory standpoint, they require significant Commission staff resources to properly monitor filings, costs, and compliance and to respond to consumer inquiries and complaints. The most significant change that will occur with a PSA is the shifting of the risk that fuel costs will increase above the base rates established in the Settlement Agreement. Currently, if fuel costs or any other costs rise above the level embedded in

[14] Tr. p. 1249.

the existing rate structure, the company's shareholders feel the impact. Likewise, if the costs decrease, the shareholders benefit. Under a PSA, the shareholders are insulated from the change in costs, because now the ratepayers are obligated to pay the additional costs. Further, the testimony was clear that costs are going to be increasing, not only because natural gas prices will increase, but also because APS' "mix" of fuel will change as growth occurs.[15] That mix will include an increasing amount of natural gas to supply the new generation. When compared to APS' other fuel sources such as nuclear or coal, natural gas is a substantially higher cost fuel. So here, the PSA will not only be collecting additional revenues due to fuel price increases, but also increases due to growth that is met with generation from a high cost fuel.[16]

Although the Settlement Agreement provides that APS will increase its demand side management and renewables, and we agree that those resources are increasingly important, they will not likely have a significant ameliorating cost impact in the near future. We disagree with the parties that a 90/10 sharing is sufficient incentive for APS to continue to effectively hedge its natural gas costs. Going from a 100 percent at-risk position to 10 percent at-risk almost seems like a "free pass," especially when a revenue increase is added. Although the Settlement Agreement provides that all costs will be subject to review for prudency before they can be recovered, prudency reviews, especially transactions in the wholesale market, can be difficult to conduct after the fact. Although we have confidence in our Staff's ability to conduct prudency reviews, we do not believe they provide as much incentive to APS on the front end to hedge costs as exists today without a PSA. The band-width limit will help limit drastic increases, but ultimately, APS will be able to recover all the costs from ratepayers.[17]

Accordingly, for these reasons, we believe that provisions of the PSA need to be modified to protect the ratepayers. We agree that the use of an adjustor when fuel costs are volatile prevents a

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[15] As growth occurs, the per unit cost of fuel will increase. Tr. p. 1238. Currently, nuclear is 32 percent of sales and represents 7.4 percent of the costs of generation; coal is 45 percent of sales and 29.7 percent of generation costs; natural gas is 18 percent of sales and 47.4 percent of generation costs; and purchased power is 5 percent of sales and 15.5 percent of generation costs. Tr. p. 1257. In five years, natural gas is expected to be 29-30 percent of sales. TR. p. 1258.

[16] See discussion Tr. p. 1259, PSA will always be increasing.

[17] Staff's late-filed exhibit S-35 filed December 14, 2004 in response to a request from Commissioner Mundell to extrapolate the effects of the PSA over several years, contained an error and on March 9, 2005, Staff filed a corrected exhibit.

utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

Further, we will limit the amount of "annual net fuel and purchased power costs" (as shown in Staff Exhibit 23)[18] that can be used to calculate the annual PSA to no more than $776,200,000. Any fuel or purchased power costs above that level will not be recovered from ratepayers. We believe that this "cap" on fuel and purchased power costs will further encourage APS to manage its costs, and will help to prevent large account balances from occurring in one year. Because the PSA actually adjusts for growth, putting a "cap" on recovery of these costs will help insure that APS will file a rate application when necessary.[19] Since there is no moratorium on filing a rate case, APS can file a rate case to reset base rates if it deems it necessary because that cap is reached. Further, although the Settlement Agreement provides that the PSA will be in effect for 5 years, if APS files a rate case

[18] For example, under "Average Usage Scenario One", the line reads "Annual Net Fuel and Purchased Power Costs: $524,600,000."

[19] See S-35 filed March 9, 2005, Scenario 11A – even when the price of gas remains constant, the PSA adjustor increases, because the adjustor uses total costs (not price) which reflects the growth which is being met by the higher priced fuel, natural gas.

prior to the expiration of that 5 year term or if we find that APS has not complied with the terms of the PSA, we believe that the Commission should be able to eliminate the PSA if appropriate. Finally, we will not allow any fuel costs from 2005 that were incurred prior to the effective date of this Decision to be included in the calculation of the PSA implemented in 2006. We believe that these additional provisions to the PSA will help to lessen the detrimental impact to ratepayers of this change to an adjustor mechanism.

Implementing an adjustor mechanism will have a significant impact upon both APS and its customers. For many years now, in their monthly bills, APS customers have paid rates that reflect the costs that APS is allowed to recover for providing that service. With the implementation of an adjustor, those ratepayers will be obligated to pay additional amounts for service they received in the previous year. This represents a major shift in responsibility for increased costs, from APS and its shareholders to ratepayers. According to APS, such a shift is necessary for the company to preserve its financial integrity.

Although the parties submitted a written statement describing the calculation of off-system sales in response to a question from Commissioner Mundell, we are concerned that the method may not capture the full margin on each sale.[20] Additionally, we want to make sure that off-system sales are not being made below costs – Staff needs to study ways to insure that these off-system sales margins are being determined accurately and that ratepayers are receiving the full 90 percent of the benefits. Accordingly, we will direct Staff to establish a method that accurately reflects the appropriate fuel costs and revenue for off-system sales, so that the full margin is known and properly accounted for. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

In response to Commissioner Gleason's suggestion to set up a webpage explaining its bill, APS indicated that it was planning to have a new bill format, and agreed to also set up a website to

[20] For example, a wholesale contract may have an embedded cost of fuel built into the price of the energy that is different from the cost of fuel use to generate the energy – if the "sales margin" is defined as the difference between the actual cost of fuel and the revenue from the sale, the true sales margin will not be captured. We also take administrative notice of FERC Docket No. PA04-11-000 and the FERC's December 16, 2004 Order Approving Audit Reports and Directing Compliance Actions, specifically relating to treatment of off-system sales.

explain the bills. Because the implementation of an adjustor will be a major change in the way that customers are billed, we believe that APS should also implement a customer education program explaining how its PSA will work and we will order APS to maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. It is important that the customer education program be implemented in a timely fashion, before this summer. APS needs to make its customers aware that with the implementation of an adjustor, ratepayers will be obligated to pay additional amounts for service they received in the previous year. It is essential, and only fair, that customers understand that their usage this summer can have an effect on their electric bills the following year.

Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program. Finally, given our concerns and the modifications we require to the PSA, we will require the parties to the Settlement Agreement to submit a PSA Plan of Administration that reflects the determinations in this Decision, for our approval.

f. Depreciation

The Settlement Agreement adopts Staff's recommended service lives, and Appendix A to the Settlement Agreement sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property as agreed to by the parties. The parties agree that the Statement of Financial Accounting Standards ("SFAS") 143 will not be adopted for ratemaking purposes.

g. $234 Million Write-Off

The Settlement Agreement provides that APS will not recover the $234 million write-off attributable to Decision No. 61973 in this case, nor shall APS seek to recover the write-off in any subsequent proceeding. The ESP and large consumer witnesses testified that this provision was critical to the development of flourishing retail markets and will help direct access service from being undercut by future stranded costs claims.

h. Demand Side Management ("DSM")

Demand-side management ("DSM") is "the planning, implementation, and evaluation of

programs to shift peak load to off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh) in a cost-effective manner."[21]

DSM is addressed in three areas of the Settlement Agreement: in the funding, programs, plans and reporting provisions; in the study of rate design modifications; and in the competitive procurement process.

Funding for DSM comes in both base rates ($10 million per year) and through implementation of an adjustor (average of $6 million per year).[22] DSM funding will be used for "approved eligible DSM-related items," including "energy-efficiency DSM programs,"[23] a performance incentive,[24] and low income bill assistance.[25] APS is obligated to spend $13 million in 2005 on DSM projects.[26]

Appendix B to the Settlement Agreement is a preliminary plan ("Preliminary Plan") for eligible DSM-related items for 2005. The Preliminary Plan includes $6.9 million for commercial, industrial, and small business customer programs, including new construction, retrofitting existing facilities, training and education, design assistance, and financial incentives; it includes $6.2 million for residential customers, including new construction and existing homes and HVAC, education, training, expanded low income weatherization, and bill assistance; $1.3 million for measurement, evaluation, and research; and $1.6 million for performance incentive.[27] Within 120 days of the Commission's approval of the Preliminary Plan, APS will, with input and assistance from the collaborative working group, submit a Final Plan for Commission approval.

In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

The adjustor will collect DSM costs that are above the $10 million annual level included in

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[21] Direct testimony of Barbara Keene, February 3, 2004.
[22] APS will spend at least $48 million during calendar years 2005-2007.
[23] "Energy-efficient DSM" is defined as "the planning, implementation and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices." Settlement Agreement par. 40.
[24] Id. par. 45.
[25] Id. par. 42.
[26] Tr. p. 969.
[27] APS' share of DSM net economic benefits, capped at 10 percent of total DSM expenditures.

base rates. The adjustor rate will initially be set at zero, and will be adjusted yearly on March 1, based upon the account balance and the appropriate kWh or kW charge. The DSM adjustor will apply to both standard offer and direct access customers.

The Settlement Agreement does not provide for the recovery of net lost revenues. The Settlement Agreement provides that if during 2005 through 2007, APS does not spend at least $30 million of the base rate allowance for approved and eligible DSM-related items; the unspent amount will be credited to the account balance for the DSM adjustor.

On residential customers' bills, the DSM adjustor will be combined with the EPS adjustor and be called an "Environmental Benefits Surcharge."[28] As part of its tariff compliance filing, within 60 days of this Decision, APS must file a Plan of Administration for Staff review and approval.

Pursuant to the Settlement Agreement, APS is required to "implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance."[29] The working group will review the plans, but APS is responsible for demonstrating appropriateness of its programs to the Commission. APS is required to conduct a study to review and evaluate whether large customers should be allowed to self-direct DSM investments and file the study within one year. APS is also required to study rate designs that encourage energy efficiency, discourage wasteful and uneconomic use of energy, and reduce peak demand. The plan for the study and analysis of rate design modifications must be presented to the collaborative DSM working group within 90 days, and APS must submit to the Commission the final results as part of its next rate case, or within 15 months of this Decision, whichever is first. APS is required to develop and propose appropriate rate design modifications. Additionally, APS is required to file mid-year and end-year reports on each DSM program. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

Pursuant to the Settlement Agreement, APS is to invite DSM resources to participate in its RFP and other competitive solicitations, and must evaluate them in a consistent and comparable

[28] Settlement Agreement par. 50.
[29] Id. par. 54.

manner.

SWEEP supports the DSM provisions in the Settlement Agreement. Although it originally recommended that the Commission should substantially increase energy efficiency by setting target goals of 7 percent of total energy resources needed to meet retail load in 2010 from energy efficiency and 17 percent in 2020, it agreed that the Settlement Agreement's requirement of DSM funding is reasonable and justified given the cost-effective benefits that will be achieved. SWEEP believes that the level of funding in the Settlement Agreement is a valuable and meaningful step towards encouraging and supporting energy efficiency for APS customers, especially since the Commission can approve additional DSM program funding through the adjustment mechanism.

In response to questioning from Commissioner Spitzer, the witness for SWEEP testified that DSM is the most efficient way to mitigate market and fuel price increases and it reduces customer vulnerability to price volatility, by reducing the need for new power plant construction and new transmission lines.[30] Even customers who do not participate in the DSM programs will benefit, both from an economic perspective as well as from the environmental and health standpoint.[31] The Preliminary DSM Plan attached as Exhibit B to the Settlement Agreement is a good start towards developing cost-effective DSM programs. However, we are concerned that our approval of the Settlement Agreement and Exhibit B may result in stakeholders focusing too narrowly when attempting to comply with the DSM goals of this Order. Particularly, we note that there are no demand response programs included in Exhibit B. Given the response by APS' customers to last summer's outage as discussed by Commissioner Hatch-Miller,[32] it is clear that when proper signals are given, customers will respond by reducing their demand.

We also think it is clear that the traditional demand response programs that define "off-peak" hours as between 9:00 p.m. to 9:00 a.m. are ineffective in creating an incentive to residential ratepayers to shift their electricity consumption to "off peak" hours. Common sense indicates that a substantial number of ratepayers cannot or are not able to take advantage of such programs as 9:00 p.m. is an unrealistic time to commence the "off peak" period because most ratepayers are either

[30] Tr. p. 877.
[31] Tr. p. 930.
[32] See discussion Tr. pp. 1384-1394.

asleep or preparing to sleep at that time.[33] Further, the start time begins many hours after the actual peak has subsided. Finally, the inconvenience of a 9:00 p.m. start time assures that the demand response to "off peak" hours and programs is miscalculated. Therefore, in an effort to expedite APS' addressing demand response programs, we will order APS to file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

We believe that it would be beneficial, perhaps in conjunction with the rate design time-of-use study and the use of "advanced" or "smart" meters, to evaluate and implement programs designed to reduce APS' summer peak demand. Accordingly, we will encourage submission of such DSM programs.

i. Environmental Portfolio Standard and other Renewables Programs

The Settlement Agreement addresses renewable energy in three areas: a special renewable energy solicitation; the environmental portfolio standard ("EPS") and in the competitive procurement of power.

The Settlement Agreement requires APS to issue a special RFP in 2005 seeking at least 100 MW and at least 250,000 MWh per year of renewable energy resources including solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas) or geothermal for delivery beginning in 2006. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005. APS also will seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources. Among other requirements, the renewable resources must be no more costly than 125 percent of the reasonably estimated market price of conventional resource alternatives and APS can acquire out-of-state resources to meet the goal if sufficient in-state qualified bids are not received. However, if APS determines that it cannot meet this requirement through in-state resources, it must bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

[33] We do not need a study, workshop or to evaluate the proposed test demand programs to convince us regarding residential demand programs in this matter.

The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

The special RFP does not displace APS' requirements under the EPS. APS will continue to collect $6 million annually in base rates and the existing EPS surcharge, which provided $6.5 million during the test year, will be converted to an adjustment mechanism, which will allow for Commission-approved changes to APS' EPS funding.

The Settlement Agreement does not alter the existing EPS or the current level of funding, but it changes the EPS surcharge into an adjustor so that the Commission has the flexibility to change funding levels and rates in the future. APS' current rates and surcharge total $12.5 million and pursuant to the Settlement Agreement, $6 million of this amount will be recovered in base rates and $6.5 million in the EPS adjustor.

Under the Settlement Agreement, APS will allow and encourage all renewable resources to participate in its competitive power procurement.

In response to a request from Commissioner Spitzer, several parties filed late-filed exhibits concerning the recently enacted American Jobs Creation Act of 2004. According to APS, the Act provides for a domestic production deduction for its generation activities, and also extends renewable electricity production credits through 2005 and expands the types of renewable resources eligible for the credits.[34] In its December 10, 2004 response, WRA stated that "renewable energy appears to be at a disadvantage relative to gas-fired generation because the tax burden tends to fall more heavily on capital intensive projects such as renewable energy generation. Therefore, such tax burden differentials may add further support for the preference for renewable energy in the settlement agreement and for production tax credits as means to 'level the playing field' between gas-fired

[34] Previously, only wind, closed-loop biomass and poultry waste were included, and now open-loop biomass, geothermal energy, solar energy, small irrigation power, and municipal solid waste are included as qualified energy resources.

resources and renewable energy."

j. Competitive Procurement of Power

The Settlement Agreement provides that APS will issue an RFP or other competitive solicitation(s) in 2005 seeking long-term resources of not less than 1000 MW for 2007 and beyond. "Long-term" resource is defined as acquisition of a generating facility or an interest in one, or any PPA of 5 years or longer. No APS affiliate will participate in this RFP/solicitation, and in the future will not participate unless an independent monitor is appointed. Further, APS will not self-build any facility with an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. As defined in the Settlement Agreement, "self-build" does not include the acquisition of a generating unit or interest in one from a non-affiliated merchant or utility generator, the acquisition of temporary generation needed for system reliability, distributed generation of less than 50 MW per location, renewable resources, or the up-rating of APS generation.

We generally agree that the self-build moratorium proposed in the Agreement is useful for addressing the potentially anti-competitive effects that may be associated with rate-basing the PWEC assets. However, to fully realize the benefits of the moratorium for that purpose, the moratorium should apply to the acquisition of a generating unit or interest in one from any merchant or utility generator, as well as to building new units. Accordingly, we will modify the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator. Consistent with the definition in the Settlement Agreement, "self-build" will not include the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or up-rating of APS generation, which up-rating shall not include the installation of new units.

Similarly, we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation[35] issued before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to

[35] Competitive solicitation includes a RFP issued pursuant to Paragraph 78 of the Settlement Agreement or any solicitation issued by APS in using its Secondary Procurement Protocol pursuant to Paragraph 80 of the Settlement Agreement.

any generating facility or interest in any generating facility ultimately acquired by APS. APS will continue to use its Secondary Procurement Protocol except as modified by the Settlement Agreement or by Commission decision. The Commission's Staff will schedule workshops on resource planning, focusing on developing needed infrastructure and a flexible, timely, and fair competitive procurement process. As discussed above, the rate basing of PWEC assets, at a discount, should not be construed as an abandonment of competition by this Commission. The industry-wide question, "how will new generation be built and by whom?", is particularly trenchant in Arizona due to high forecast growth in customer load. The self-build moratorium agreed to by APS is consistent with the Commission's support for competitive wholesale electricity markets.

The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

By integrating solar generation with the existing generation and transmission infrastructure at coal fired facilities, it may be possible to create synergies that take advantage of existing site infrastructure to lower the cost of building and operating solar electric generation, while reducing the environmental impact of coal fired generation. Generation from a solar electric project will add fuel-free, net-plant energy output resulting in environmental benefits and lower energy specific water usage. A long-term benefit of such a strategy would be that after all life extension measures are exhausted for the fueled power complexes, there will be many decades of useful life remaining in the transmission assets serving these sites. These valuable assets could be utilized by emission and water free solar generation built incrementally over the next decades in the expansive buffer zone property around many of the existing coal plants.

k. <u>Regulatory Issues</u>

In the Settlement Agreement, the parties acknowledge that APS has the obligation to plan for and serve all customers in its certificated service area and to recognize through its planning, the existence of any Commission direct access program and the potential for future direct access

customers. Any change in retail access as well as the resale by APS and other Affected Utilities of Revenue Cycle Services to ESPs will be addressed through the Electric Competition Advisory Group ("ECAG") or similar process. The parties acknowledge that APS may join a FERC-approved Regional Transmission Organization ("RTO") or entity and may participate in those activities without further order or authorization from the Commission.

l. **Competition Rules Compliance Charge ("CRCC")**

Included in the total test year revenue requirement is approximately $8 million for the Competition Rules Compliance Charge. APS will recover $47.7 million plus interest through a CRCC of $0.000338/kWh over a collection period of 5 years. When that amount is collected, the CRCC will immediately terminate, and if the amount is under or over recovered, then APS must file an application for the appropriate remedy.

m. **Low Income Programs**

APS will increase funding for marketing its E-3 and E-4 tariffs to a total of $150,000 as set forth in the Settlement Agreement. The parties' intent is to insulate eligible low income customers from the effects of the rate increase resulting from the Settlement Agreement. On December 17, 2004, the ACAA filed a response to Commissioner Mayes' question about automatic enrollment in utility discount programs, indicating that they have initiated a discussion with the Arizona Department of Economic Security ("DES") to facilitate the automatic enrollment in utility discount programs, as well as other agency managed programs. ACAA is in the process of adding the utility discount application forms to its website, which will allow the form to be sent electronically to the appropriate entity for processing. Concerning marketing efforts, ACAA stated that it engages in various outreach efforts throughout the state, providing information about the E-3 discount program available through APS. ACAA indicated that DES is currently charged with the official marketing of the program, but there is currently no affirmative marketing of the program "as their resources are severely limited." Also in response to Commissioner Mayes' request, APS filed information concerning its low income programs. APS stated that it has renewed its conversations with DES and ACAA, requesting feedback on increasing participation through automated signup for the E-3 and E-4 programs. Both agencies expressed interest and APS states that it will continue to work with both

agencies to determine the efficiency and practicality of such a streamlined approach.

The Commission believes that APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

n. **Returning Customer Direct Access Charge ("RCDAC")**

The Settlement Agreement provides that APS can recover from Direct Access customers the additional cost that would otherwise be imposed on other Standard Offer customers if and when the former return to Standard Offer from their competitive suppliers. The RCDAC shall not last longer than 12 months for any individual customer. The charge will apply only to individual customers or aggregated groups of 3 MW or greater who do not provide APS with one year's advance notice of intent to return to Standard Offer service. APS will file a Plan of Administration as part of its tariff compliance filing.

o. **Service Schedule Changes**

The Settlement Agreement adopts several of APS' proposed changes to service schedules, including Schedule 3, but with the retention of the 1,000 foot construction allowance for individual residential customers and also with any individual residential advances of costs being refundable. Several APS customers made public comment about the line extension policy and how it has not been modified in a long time. We will direct Staff to work with APS to review its line extension policy and determine whether the construction allowance should be modified.

p. **Nuclear Decommissioning**

The decommissioning costs as recommended by APS are adopted as set forth in Appendix I to the Settlement Agreement.

q. **Transmission Cost Adjustor ("TCA")**

The Settlement Agreement establishes a transmission cost adjustor ("TCA") to ensure that any potential direct access customers pay the same for transmission as Standard Offer customers.

The TCA is limited to recovery of costs associated with changes in APS' open access transmission tariff ("OATT") or equivalent tariff. The TCA goes into effect when the transmission component of retail rates exceeds the test year base amount of $0.00476[36] per kWh by 5 percent and APS obtains Commission approval of a TCA rate.

r. **Distributed Generation**

Generally, distributed generation is small-scale power generation units strategically located near customers and load centers. According to the ACA/DEAA, the benefits of distributed energy systems include: greater grid reliability; increased grid stability (voltage support along transmission lines); increased system efficiency (reduction in transmission line losses); increased efficiency; flexibility; decreased pressure on natural gas (demand and cost); leverage of resources; and sustainable installations.

The Settlement Agreement provides that Staff shall schedule workshops to consider outstanding issues affecting distributed generation and shall refer to the results of the prior distributed generation workshops for issues to study.

ACA/DEAA presented its objectives at hearing as follows: a DG workshop with strong Staff leadership; clear goals, ground rules, milestones, and deadlines; participants with authority; continuing reports to ACC and management; and a process to bring contested issues to the Commission for resolution. None of the proponents of the Settlement Agreement oppose Commission adoption of these objectives.

In its post-hearing brief, ACA/DEAA listed the following guidelines as "overriding criteria": 1) rates must be fair; 2) rates should be designed to send as efficient as possible pricing signals to consumers; 3) impediments to customer choices, such as unnecessarily difficult and expensive interconnection to the grid, should be eliminated to the maximum extent possible; 4) all generators should be treated fairly – large and small; and 5) proposals, if implemented, should not interfere with the Commission's public policy goals. ACA/DEAA made 3 recommendations: 1) Rate Design – the Commission should adopt an experimental rate for partial requirement customers. The proposal

[36] Paragraph 106 of the Settlement Agreement contains a typo; the amount "$0.000476" should actually be "$0.00476," Tr. p. 1168.

would mimic SRP's E-32 rate, which includes time of day rates and summer/winter rates. ACA/DEAA proposed to limit participation to 50 MWs of new customer load each year for 5 years – both generation and supplemental load. It appears that this is the first alternative rate schedule that ACA/DEAA has proposed, and no party has had an opportunity to evaluate and comment on the proposal. Accordingly, we decline to adopt the proposal in this docket, but we believe that this proposal may be a good starting point for discussion in the DG workshop.

ACA/DEAA further recommended that the Texas standard is best suited for application to the APS system and that the provisions of California rule 21 would serve as a second choice for DG standards in Arizona. ACA/DEAA also recommended that the Commission consider a program to install self generation to reduce the electricity on the power grid. We believe that both of these recommendations should also be discussed and developed during the course of the workshop.

The proponents of the Settlement Agreement recommend that specific issues concerning DG should be addressed in workshops devoted to distributed generation. Paragraphs 108 and 109 direct Staff to schedule workshops to address outstanding DG issues. They believe that such a process would use the work done in previous workshops and would also address the technical aspects of connecting distributed generation in a way that would apply to all regulated utilities in Arizona. To be successful, the process would require a strict timetable for producing recommendations for the Commission's consideration. The proponents argue that Schedule E-32 should not be redesigned to meet the specialized needs of partial requirements service, but that the rate design for partial requirements service should be addressed in the workshop. Approximately 95,000 full requirement customers receive service under Schedule E-32, and according to the proponents, it is an integral part of the Settlement Agreement. The proponents believe that ACA/DEAA's proposal to put the rate increase in the energy portion would create a massive subsidy from higher load factor customers to lower load factor customers. The demand related charges are necessary for pricing the capacity related costs of the APS system for the full requirement customers. The proponents argue that DG requires partial requirement service – which is a very specialized product that includes maintenance power, standby power, and supplemental power – and it should have its own rate, which can be addressed in the proposed DG workshop.

We agree with ACA/DEAA that DG can have significant benefits to APS and to its ratepayers and we want to encourage the growth of DG that can provide those benefits. Additionally, we find some of the suggestions made in ACA/DEAA's post hearing brief persuasive. However, our decision is rooted in the record made in this case, and those suggestions were not fully delineated, nor subjected to cross examination at the Hearing. At this point, we agree with the participants that the E-32 schedule should not be modified to accommodate the particular needs associated with DG. Therefore, we believe that the parties should address the issue of an appropriate rate schedule for DG during the workshop process, and direct the parties to develop a schedule that is designed particularly for DG customers. Further, we direct the parties to begin the process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

s. **Bark Beetle Remediation**

APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed the test year levels of tree and brush control. In the next rate case, the Commission will determine the reasonableness, prudence, and allocation of the costs, and will determine the appropriate amortization period.

t. **Rate Design**

Attached to the Settlement Agreement is Appendix J, which sets forth the rates adopted in the Settlement Agreement. The rates are designed to permit APS to recover an additional $67.5 million in base revenues, including an additional 3.94 percent for the residential rate class and a 3.57 percent increase for the general service rate class. The rates were designed to move toward costs and remove subsidizations, thereby promoting equity among customers. The base rates will also permit cost-based unbundling of distribution and revenue cycle services, including metering, and meter reading and billing. The parties believe that this will give appropriate price signals necessary for shopping. APS will continue on-peak and off-peak rates for winter billing for all residential time-of-use customers under Schedules ET-1 and ECT-1R. Within 180 days APS will submit a study to Staff that examines other ways APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, making those periods more reflective of actual system peak time periods. APS shall also include in the aforementioned study a cost-benefit analysis

of Surepay, APS' automatic payment program. The Company is to examine the cost effectiveness of the program and to explore the possibility of offering a discount to those customer who participate in Surepay. The Settlement Agreement adopts APS' proposed experimental time-of-use periods for ET-1 and ECT-1R. For general service customers, the existing on-peak time periods will remain the same and the summer rate period will begin in May and conclude in October. The general service rate schedules will also permit cost-based unbundling of generation and revenue cycle services and will be differentiated by voltage levels. An additional primary service discount of $2.74/kW for military base customers served directly from APS substations will be adopted. The Settlement Agreement modifies Schedule E-32 in order to simplify the design, make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. Changes include the addition of an energy block for customers with loads under 20 kW and an additional demand billing block for customers with loads greater than 100 kW. A time-of-use option will also be available to E-32 customers. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-32-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand[37] and that the initial rate block for residual off-peak delivery should be applied only to the first 100kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings. As discussed above, ACA/DEAA objected to the company's E-32 schedule. One of ACA/DEAA's concern was the almost doubling of the demand charge. The Commission has open dockets involving APS' metering and bill estimation procedures, including the estimation of demand. Although we are not resolving those issues in this rate case, we are concerned that APS properly meter, read meters and bill its customers timely and accurately.[38] It is imperative, especially given

[37] Instead of remaining at the initial level of $7.722 per kW-month, after the first 100 kW of demand, the unbundled residual off-peak demand charge for delivery at Secondary voltage will be reduced to $3.497; after the first 100kW of demand, the unbundled residual off-peak demand charge for delivery at Primary voltage will be reduced to $2.877, with both of these changes incorporated into the bundled rate as well.

[38] Also, we note that apparently APS is deleting a bill estimation procedure for EC-1 and ECT-1R. It is not clear whether these are the tariffs that Staff has alleged APS has not been following, but nothing in this Decision will affect our ability to make findings in Docket Nos. E-01345A-04-0657, et al. or impose any appropriate fines, sanctions, or remedies in those dockets.

the increase in the demand charge, that APS reduce the instances where it estimates demand.

In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

Several schedules are "frozen" and APS will provide notice approved by Staff to those customers that those rates will be eliminated in APS' next rate case. Such notice will be provided at the conclusion of this docket and at the time that APS files its next rate case.

u. <u>Litigation and other issues</u>

The Settlement Agreement provides that APS will dismiss with prejudice all appeals of Decision No. 65154, the Track A Order, and APS and its affiliates will dismiss litigation related to Decision Nos. 65154 and 61973 and/or any alleged breach of contract, and APS and its affiliates shall forgo any claim that APS, PWEC, Pinnacle West Capital Corporation or any of APS' affiliates were harmed by Decision No. 65154, and the Preliminary Inquiry ordered in Decision No. 65796 shall be concluded with no further action by the Commission, once the Settlement Agreement is approved in

accordance with Section XXI of the Settlement Agreement by a Commission Decision that is final and no longer subject to judicial review.

The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

v. **Summary**

This Settlement Agreement resolves numerous significant, complex, and conflicting issues affecting many parties with very different perspectives and interests. As with every settlement, the give and take nature of negotiations ends up with a product that no one party initially proposed. The key question when deciding whether to approve such a settlement is whether the end result resolves the important issues fairly and reasonably when taken together as a whole, and in such a way that will promote the public interest. We believe that the Settlement Agreement reached by these 22 parties, with the modifications that we make herein, reaches such a result. Our agreement to rate base the PWEC assets does not mean that we are retreating from our commitment to encourage the development of competition, and we expect APS and its affiliates to fully comply with all the pro-competition requirements in the Settlement Agreement and other Commission decisions and rules. Additionally, our adoption of a PSA will be a significant change for APS customers, and we expect APS to educate and inform its customers about all aspects of that adjustor charge in a way that will minimize confusion and misunderstandings. We also expect APS to have the required information posted to its website and its customer education program up and running before June 1, 2005, in order to allow customers the opportunity to implement their own conservation measures. Finally, we want to make it clear to APS that our adoption of a PSA does not relieve it of its obligation to effectively and efficiently manage its fuel costs, and that we will closely monitor APS' performance.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

IV. FINDINGS OF FACT

1. APS is a public service corporation principally engaged in furnishing electricity in the State of Arizona. APS provides either retail or wholesale electric service to substantially all of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States.

2. On June 27, 2003, APS filed with the Commission an application for a $175.1 million rate increase and for approval of a purchased power contract.

3. Notice of the application was provided in accordance with the law.

4. Intervention was granted to AECC, FEA, Kroger, RUCO, AUIA, Phelps Dodge, IBEW, ACA/DEAA, Panda, AWC, SWG, WRA, CNE, SEL, DVEP, UES, ACAA, Alliance, Wickenburg, AriSEIA, AARP, SWEEP, PPL Sundance, PPL Southwest, SWPG, Mesquite, and Bowie.

5. By Procedural Order issued August 15, 2003, the hearing was set to commence on April 7, 2004, and procedural dates were established for the filing of testimony and evidence.

6. On February 6, 2004, APS filed a Motion to Amend the Rate Case Procedural Schedule, and a procedural conference was held on February 18, 2004 to discuss the Motion.

7. By Amended Rate Case Procedural Order issued on February 20, 2004, the hearing date was rescheduled for May 25, 2004 and other procedural dates were modified.

8. On April 6, 2004, Staff filed a Motion to Amend the Procedural Schedule and on April 8, 2004, Staff filed a Memorandum indicating that representatives of APS had contacted Staff about the possibility of conducting settlement negotiations.

9. A public comment hearing was held on April 7, 2004.

10. On April 13, 2004, APS filed its Response to Staff's Motion and Staff Notice of Settlement Negotiations and requested a temporary suspension of the procedural schedule in order for settlement discussions to take place.

11. Pursuant to Procedural Orders issued April 7 and 12, 2004, a procedural conference to discuss Staff's Motion was held on April 15, 2004. By Procedural Order issued April 16, 2004, new

procedural dates were established and another procedural conference was scheduled for April 28, 2004.

12. The April 28, 2004 procedural conference was held as scheduled and by Procedural Order issued April 29, 2004, the procedural schedule was stayed and another procedural conference was scheduled for May 26, 2004.

13. Pursuant to procedural conferences held on May 26 and June 14, 2004, and Procedural Orders issued on May 26, June 18, and July 20, 2004, the stay was extended in order to allow the parties to discuss settlement.

14. At the August 18, 2004 Procedural Conference, the parties announced that they had reached a settlement, and the Settlement Agreement was docketed on that date.

15. On August 20, 2004, an Amended Rate Case Procedural Order was issued setting the hearing on the Settlement Agreement to commence on November 8, 2004.

16. The hearing was held as scheduled on November 8, 9, 10, 29, 30 and December 1, 2, and 3, 2004. Public comment was taken and testimony from the proponents of the Settlement Agreement was presented in panel format, and testimony from the ACA/DEAA was also presented in a panel format.

17. The Test Year ending 2002 Plant in Service was $4,876,901,000, excluding transmission plant, and including the PWEC assets as of December 31, 2004.

18. APS' FVRB is $5,054,426,000 and a 5.92 fair value rate of return is appropriate.

19. It is just and reasonable to authorize a total annual revenue increase in the amount of $75,500,000, consisting of an increase in base rates of approximately 3.77 percent or $67.6 million, and an increase in the CRCC surcharge of approximately .44 percent, which will collect $7.9 million.

20. A Power Supply Adjustor as set forth in the Settlement Agreement and as modified herein, is in the public interest.

21. APS is authorized to acquire the PWEC generation assets and rate base those assets at a value of $700 million as of December 31, 2004, under the terms and conditions as set forth in the Settlement Agreement and herein.

22. The Settlement Agreement will allow APS the opportunity to earn a reasonable rate of

return on its investment, will provide revenues sufficient for the Company to provide efficient and reliable service, and will allow for continued development of electric competition in Arizona.

23. APS shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs. APS shall submit its plan to implement its customer education program within 30 days of the effective date of this Decision to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program. Furthermore, APS shall post the required information on its website within 30 days of the effective date of this Decision.

24. The parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

25. The depreciation rates and the costs for nuclear decommissioning as set forth in the Settlement Agreement are reasonable and appropriate.

26. Testimony was offered at the hearing that there was an inadvertent omission in Appendix J to the Settlement Agreement for Rate E-32-TOU in that the delivery-related demand charge for Rate E-032-TOU should have been reduced after the first 100 kW of demand for residual off-peak demand and that the initial rate block for residual off-peak delivery should be applied only to the first 100 kW of combined on-peak and residual off-peak demand. We will, therefore, direct APS to modify Rate E-32-TOU in accordance with these changes in its compliance filings.

27. We direct the parties to begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

28. In its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, APS shall also include a cost-benefit analysis of Surepay, APS' automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

29. APS shall file additional time-of-use programs that are similar to the Time Advantage

and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

30. In a response (dated August 18, 2004) to a question from Commissioner Mundell regarding the break-over points for tiered rates, the parties to the Settlement Agreement indicated that rate E-12 has the most customers. The response also stated that the average use by a customer on rate E-12 is 770 kWh per month. Rate E-12 has three tiers with break-over points at 400 kWh per month and 800 kWh per month. Paragraph 57 of the Settlement Agreement requires APS to conduct a rate design study analyzing rate design modifications to promote energy efficiency, conservation, and reduce peak demand. As part of the study, we will require that one of the rate design modifications that APS shall investigate is to lower the first break-over point in rate E-12 to 350 kWh per month and lower the second break-over point to 750 kWh per month. In addition, the charge (rate) per kWh in the first tier (less than 350 kWh per month) should be lowered, while the rate for the third tier (over 750 kWh per month) should be raised. We will require that APS propose this type of rate design, or something very similar, for rate E-12 in its next rate case. We believe this type rate design, coupled with the DSM measures outlined in this Order, will encourage customers, especially high-use customers, to conserve energy (thereby lowering overall demand) and/or move to time-of-use rates (thereby lowering peak demand). If APS or any party to the next APS rate case believes this type rate design would be detrimental to APS and/or its customers, that party shall provide a detailed explanation and examples as to how and why this type rate design would be detrimental.

31. In order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

32. All DSM year-end reports filed at the Commission by APS must be certified by an Officer of the Company.

33. We are modifying the definition of "self-build" to include the acquisition of a generating unit or interest in a generating unit from any merchant or utility generator, and we will require APS to obtain the Commission's expressed approval for APS' acquisition of any generating facility or interest in a generating facility pursuant to a RFP or other competitive solicitation issued

before January 1, 2015. Our determination herein should not be construed as signaling in any manner the ultimate regulatory treatment that can or will be accorded to any generating facility or interest in a generating facility ultimately acquired by APS.

34. The workshops conducted by Staff on the development of needed infrastructure shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations. APS' aging coal fired plants face an increasingly emissions regulated future which may require sizeable investments to improve emissions control performance.

35. The Settlement Agreement also provides that renewable resources acquired through the special RFP or future solicitations shall be subject to the Commission's customary prudence review. And while the Settlement Agreement further stipulates that a renewable resource purchase shall not be found imprudent solely because the cost of the renewable resource exceeds market price, we stipulate conversely that a renewable resource purchase shall not be rendered prudent solely by virtue of the resource's cost being below 125 percent of market price.

36. In order to take advantage of any available federal tax credits for renewable energy production, APS should issue the 100 MW RFP no later than May 15, 2005.

37. If Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

38. We agree that the use of an adjustor when fuel costs are volatile prevents a utility's financial condition from deteriorating. We are less inclined, however, to adopt an adjustor as a way to keep pace with load growth. Although APS' rebuttal testimony indicated that its fixed costs would increase in relation to its load growth, we are concerned about the potential for single-issue ratemaking and whether APS' fixed costs will increase in the same proportion as its fuel costs. According to the late-filed exhibits, the majority of the increased fuel costs are caused by increased load growth, rather than price volatility in fuel. In effect, the adjustor as designed provides annual step increases in rates. We believe APS must have an incentive to file a rate case so that we can

determine the accuracy of its assertion about expenses. Therefore, we will adopt an adjustor that collects or refunds the annual fuel costs that differ from the base year level. However, we will limit the adjustor to 4 mil from the base level over the entire term of the PSA and will cap the balancing account to an aggregate amount of $100 million. Should the Company seek to recover or refund a bank balance pursuant to Paragraph 19E of the Settlement Agreement, the timing and manner of recovery or refund of that existing bank balance will be addressed at such time. In no event shall the Company allow the bank balance to reach $100 million prior to seeking recovery or refund. Following a proceeding to recover or refund a bank balance between $50 million and $100 million, the bank balance shall be reset to zero unless otherwise ordered by the Commission.

39. Within three years of the effective date of this Decision, Staff shall commence a procurement review of APS' fuel, purchased power, generating practices and off-system sales practices.

40. Because we are concerned about the impact of the PSA on low-income customers, the PSA shall not apply to the bills of individuals who are enrolled in the Company's Energy Support program.

41. APS should work to make its low-income assistance programs widely available, including to Native Americans living inside the Company's service territory. Within six months of the effective date of this Order, APS shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance program. The plan should be filed with the Commission and made available to Tribal authorities within APS' service territory.

42. The Commission is also concerned that service reliability on rural Tribal lands has become degraded. Therefore, within six months of the effective date of this Order, APS should compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas. Moreover, APS shall participate in any future dockets related to enhancing reliability statewide.

V. CONCLUSIONS OF LAW

1. Arizona Public Service Company is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-222, 250, 251, and 376.

2. The Commission has jurisdiction over Arizona Public Service Company and the subject matter of the application.

3. Notice of the application was provided in accordance with the law.

4. The Settlement Agreement, with the modifications and additional provisions contained herein, resolves all matters raised by APS' rate application in a manner that is just and reasonable, and promotes the public interest.

5. The fair value of APS' rate base is $5,054,426,000, and 5.92 percent is a reasonable rate of return on APS' rate base.

6. The rates, charges, and conditions of service established herein are just and reasonable.

7. APS should be directed to file revised tariffs consistent with the Settlement Agreement and the findings contained in this Order.

VI. ORDER

IT IS THEREFORE ORDERED that the Settlement Agreement attached hereto as Attachment A as modified herein is approved.

IT IS FURTHER ORDERED that Arizona Public Service Company is hereby directed to file with the Commission on or before March 31, 2005, revised schedules of rates and charges consistent with Exhibit A and the findings herein.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after April 1, 2005.

IT IS FURTHER ORDERED that Arizona Public Service Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing and by posting on its website, in a form approved by the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement a customer education program explaining how its PSA will work and shall maintain on its website information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall submit its plan to implement its customer education program to the Director of the Utilities Division for review and Staff shall keep the Commission apprised of the consumer education program.

IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision, Arizona Public Service Company shall post on its website, information explaining the billing format, rates, and charges, including up-to-date information about the PSA and current gas costs.

IT IS FURTHER ORDERED that Arizona Public Service Company shall implement and comply with the terms of the Settlement Agreement including filing all reports, studies, and plans as set forth in the Settlement Agreement and as modified herein.

IT IS FURTHER ORDERED that the parties to the Settlement Agreement shall submit a PSA Plan of Administration that reflects the determinations in this Decision for Commission approval within 60 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall forgo any present or future claims of stranded costs associated with any of the PWEC assets.

IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall schedule workshops on resource planning issues and distributed generation issues within 90 days of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company shall modify Rate E-32-TOU in accordance with the discussion and findings herein.

IT IS FURTHER ORDERED that the parties shall begin the DG workshop process by evaluating the three recommendations made by ACA/DEAA in its post hearing brief.

IT IS FURTHER ORDERED that in its study to be filed within 180 days of the effective date of this Decision concerning flexibility of on- and off-peak time periods and other time-of-use characteristics, Arizona Public Service Company shall also include a cost-benefit analysis of Surepay, Arizona Public Service Company's automatic payment program. The Company shall examine the cost effectiveness of the program and explore the possibility of offering a discount to those customers who participate in Surepay.

IT IS FURTHER ORDERED that Arizona Public Service Company shall file additional time-of-use programs that are similar to the Time Advantage and Combined Advantage Plans with different peak schedule(s) and tariff(s) options, within six months of the effective date of this Decision.

IT IS FURTHER ORDERED that Arizona Public Service Company's rate design study shall include the issues addressed in Findings of Fact No. 30, and Arizona Public Service Company shall propose a rate design addressing these issues in its next rate case.

IT IS FURTHER ORDERED that in order to help the state's public and charter schools mitigate the effects of the rate increase, the DSM Working Group should make every effort to target DSM programs to schools and to make the implementation of DSM in schools a top priority.

IT IS FURTHER ORDERED that all DSM year-end reports filed at the Commission by Arizona Public Service Company must be certified by an Officer of the Company.

IT IS FURTHER ORDERED that Arizona Public Service Company shall comply with Findings of Facts No. 33 when acquiring a generating unit or an interest in one.

IT IS FURTHER ORDERED that the resource planning workshops shall include consideration of the feasibility and implementation of an expanded use of utility-scale solar electric generation integrated with existing coal fired operations.

IT IS FURTHER ORDERED that in order to take advantage of any available federal tax credits for renewable energy production, Arizona Public Service Company shall issue the 100 MW RFP no later than May 15, 2005.

IT IS FURTHER ORDERED that if Arizona Public Service Company determines that it cannot meet the goal for renewable energy resources as set forth in Paragraph 69 of the Settlement Agreement, through in-state resources, it shall bring its proposal to purchase out-of-state resources to Staff and obtain Commission approval before making the out-of-state purchase.

IT IS FURTHER ORDERED that within three years of the effective date of this Decision, Staff shall commence a procurement review of Arizona Public Service Company's fuel, purchased power, generating practices and off-system sales practices.

IT IS FURTHER ORDERED that the PSA shall not apply to the bills of individuals who are

enrolled in the Company's Energy Support program.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall develop an outreach plan that will enable it to better inform the state's Tribes about the Company's low-income assistance programs. The plan shall be filed with the Commission and made available to Tribal authorities within Arizona Public Service Company's service territory.

IT IS FURTHER ORDERED that within six months of the effective date of this Decision, Arizona Public Service Company shall compile its SAIFI, CAIDI and SAIDI numbers for all Tribal territories it serves and provide to the Commission a report on proposed options for improving reliability in these areas, and Arizona Public Service Company shall participate in any future dockets related to enhancing reliability statewide.

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IT IS FURTHER ORDERED that the Commission's Utilities Division Staff shall initiate a rulemaking proceeding to modify A.A.C. R14-2-1618 within 120 days of the effective date of this Decision.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER | COMMISSIONER

COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 7th day of April, 2005.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT

DISSENT

SERVICE LIST FOR: ARIZONA PUBLIC SERVICE COMPANY

DOCKET NO.: E-01345A-03-0437

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ATTACHMENT A

PROPOSED SETTLEMENT

OF

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY

REQUEST FOR RATE ADJUSTMENT

PROPOSED SETTLEMENT
OF
DOCKET NO. E-01345A-03-0437
ARIZONA PUBLIC SERVICE COMPANY
REQUEST FOR RATE ADJUSTMENT

The purpose of this agreement ("Agreement") is to settle disputed issues related to Docket No. E-01345A-03-0437, Arizona Public Service Company's application to increase rates. This Agreement is entered into by the following entities:

Arizona Public Service Company ("APS")
Arizona Competitive Power Alliance
Federal Executive Agencies
Constellation NewEnergy, Inc.
Strategic Energy, L.L.C.
Southwest Energy Efficiency Project
Western Resource Advocates
Mesquite Power, L.L.C.
PPL Sundance Energy, L.L.C.
PPL Southwest Generation Holdings, L.L.C.
Arizonans for Electric Choice and Competition
Phelps Dodge Mining Company
Arizona Utility Investors Association
Southwestern Power Group II, LLC
Bowie Power Station
Arizona Community Action Association
IBEW, AFL-CIO, CLC, Local Unions 387, 640, and 769
Kroger Co.
Dome Valley Energy Partners, L.L.C.
Arizona Solar Energy Industries Association
Residential Utility Consumer Office
Staff, Arizona Corporation Commission

These entities shall be referred to collectively as "Parties." The following numbered paragraphs comprise the Parties' Agreement.

RECITALS

1. The purpose of this Agreement is to settle all issues presented by Docket No. E-01345A-03-0437 in a manner that will promote the public interest.

2. The Parties agree that the negotiation process undertaken in this matter was open to all Intervenors and provided all Intervenors with an equal opportunity to participate. All Intervenors were notified of the settlement process and encouraged to participate.

3. The Parties agree that the terms of this Agreement will serve the public interest by providing a just and reasonable resolution of the issues presented by APS' rate case, Docket No. E-01345A-03-0437. The adoption of this Agreement will further serve the public interest by allowing the Parties to avoid the expense and delay associated with litigation.

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TERMS AND CONDITIONS

I. Revenue Requirement

4. For ratemaking purposes and for the purposes of this Agreement, the Parties agree that APS will receive a total increase of $75,500,000 over its adjusted 2002 test year revenue of $1,791,584,000. This amount is equal to an approximate 3.77 percent increase in base rates plus an approximate .44 percent increase for the Competition Rules Compliance Charge discussed in Section XI of this Agreement. This equals a total increase of approximately 4.21 percent over APS' adjusted test year revenue.

5. For ratemaking purposes and for the purposes of this Agreement, the Parties agree that APS shall have a fair value rate base of $6,281,885,000. The revenue increase established in this Agreement will provide APS with an opportunity to earn a fair value rate of return of 5.92 percent.

II. PWEC Asset Treatment

6. In consideration of the provisions of this Agreement as a whole, the Parties agree that it is in the public interest for APS to acquire and to rate base the following units currently owned by Pinnacle West Energy Corporation ("PWEC"): West Phoenix CC-4, West Phoenix CC-5, Saguaro CT-3, Redhawk CC-1, and Redhawk CC-2 (collectively, the "PWEC Assets"). The generation costs related to these units will be recovered in the generation component of unbundled rates; the ancillary service costs related to these units will be recovered in the transmission component of unbundled rates.

7. The PWEC Assets shall have an original cost rate base value of $700 million, which represents a $148,000,000 disallowance from the original cost of these assets as of December 31, 2004. This disallowance represents a reasonable estimate of the value to APS' ratepayers of the remaining term of the Track B contract between APS and PWEC.

8. APS will forego any present or future claims of stranded costs associated with any of the PWEC Assets.

9. The Parties recognize that APS is required to seek approval of certain aspects of the asset transfer from the Federal Energy Regulatory Commission ("FERC"). APS will use its best efforts to obtain such approval. APS shall file a request for FERC approval of the asset transfer no sooner than the date of the Commission's approval of this matter but no later than thirty days after such approval. If the Commission approves the Agreement without material change, APS shall be authorized to inform FERC that the Parties support APS' efforts to obtain FERC approval of the specific asset transfer set forth in this Agreement. If the Commission approves the Agreement with one or more material changes, APS shall not claim the support of any Party that is adversely affected by the material change(s) without first obtaining that Party's consent. No Party shall file with FERC any objection to the asset transfer, and no Party shall be

obligated to intervene or to join or file any pleadings in support of FERC approval of the asset transfer.

10. 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"), which will be based on the value of the PWEC Assets established in Paragraph 7. During the term of the Bridge PPA, APS will flow fuel costs related to the PWEC Assets and off-system sales revenue related to the PWEC Assets through the power supply adjustor ("PSA") addressed in Section IV below. 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.

11. The Bridge PPA shall remain in effect until FERC issues a final order approving the transfer of the PWEC assets to APS and such transfer is completed. For purposes of this paragraph, a "final order" is an order that is no longer subject to appeal.

12. If FERC issues an order denying APS' request to acquire the PWEC Assets, the Bridge PPA will become a thirty-year PPA. Prices in this thirty-year PPA will reflect cost-of-service as determined by the Commission in APS' rate proceedings as if APS had acquired and rate-based the PWEC Assets at the value established in Paragraph 7. During the term of the thirty-year PPA, APS will flow fuel costs related to the PWEC Assets and off-system sales revenue related to the PWEC Assets through the PSA addressed in Section IV below. Unless otherwise ordered by the Commission, any demand and non-fuel energy charges incurred under this long-term PPA will be excluded from recovery under the PSA and will instead be reflected in APS' base rates. Except as specifically set forth in this Paragraph, this Agreement does not establish the regulatory or ratemaking treatment of the long-term PPA.

13. If FERC issues an order approving APS' request to acquire the PWEC Assets 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 this 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.

14. The 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.

15. The Parties agree that West Phoenix CC-4 and West Phoenix CC-5 shall be deemed to be "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 shall be available at FERC-approved cost-of-service prices to electric service providers serving direct access load in the Phoenix load pocket.

III. Cost of Capital

16. The Parties agree that a capital structure of 55% long-term debt and 45% common equity shall be adopted for ratemaking purposes.

17. The Parties agree that a return on common equity of 10.25% is appropriate.

18. The Parties agree that an embedded cost of long-term debt of 5.8% is appropriate.

IV. Power Supply Adjustor

19. A Power Supply Adjustor ("PSA") shall be adopted with the following characteristics.

a. The PSA shall include both fuel and purchased power.

b. The adjustor rate, initially set at zero, will be reset on April 1, 2006 and thereafter on April 1st of each subsequent year. APS will submit a publicly available report that shows the calculation of the new rate on March 1, 2006 and thereafter on March 1st of each subsequent year. The adjustor rate shall become effective with the first billing cycle in April unless suspended by the Commission.

c. There 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.

d. There shall be a bandwidth which shall limit the change in the adjustor rate to plus or minus $0.004 per kilowatt hour ("kWh") per year. Any additional recoverable or refundable amounts shall be recorded in a balancing account and shall carry over to the subsequent year or years. The carryover amount shall not be subject to further sharing as described above in Paragraph 19.c in the subsequent year or years.

e. When the size of the balancing account reaches either plus or minus $50 million, APS will have forty-five days to file for Commission approval of a surcharge to amortize the over-recovered/under-recovered balance and to reset the balancing account to zero. If APS does not want to reset the balance to zero, it shall file a report explaining why. Commission action shall be required to establish or revise a surcharge created pursuant to this provision.

f. Subject to paragraphs 19.c and 19.d, ratepayers shall receive the benefits of all off-system sales margins through a credit to the PSA balance.

g. The PSA is the appropriate mechanism for recovery of the prudent direct costs of contracts used for hedging fuel and purchased power costs.

h. The balancing account shall accrue interest based on the one-year nominal Treasury constant maturities rate. This rate is contained in the Federal Reserve Statistical Release, H-15, or its successor publication.

i. The Commission or its Staff may review the prudence of fuel and power purchases at any time.

j. The Commission or its Staff may review any calculations associated with the PSA at any time.

k. Any costs flowed through the adjustor shall be subject to refund if the Commission later determines that the costs were not prudently incurred.

20. Beginning sixty days from the effective date of a Commission order approving this Agreement, APS shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PSA. These monthly reports shall thereafter be due on the first day of the third month following the end of the reporting month. These reports shall be publicly available and shall contain, at a minimum, the following items:

a. Bank balance calculation, including all inputs and outputs.

b. Total power and fuel costs.

c Customer sales in both kWh and dollars by customer class.

d. The number of customers by customer class.

e. A detailed listing of all items excluded from the PSA calculations.

f. A detailed listing of any adjustments to adjustor reports.

g. Total off-system sales margins.

h. System losses in MW and MWh.

i. Monthly maximum retail demand in MW.

j. Identification of a contact person and phone number from APS for questions.

21. Beginning sixty days from the effective date of a Commission order approving this Agreement, APS shall provide additional reports to Staff each month including information as set forth in paragraphs 22, 23, and 24 about APS' generating units, power purchases, and fuel purchases. These monthly reports shall thereafter be due on the first day of the third month

following the end of the reporting month. These additional reports may be provided confidentially.

22. The information for each generating unit shall include, at a minimum, the following items:

a. The net generation, in MWh per month, and twelve months cumulatively.

b. The average heat rate, both monthly and twelve-month average.

c. The equivalent forced-outage rate, both monthly and twelve-month average.

d. The outage information for each month, including, but not limited to event type, start date and time, end date and time, description.

e. Total fuel costs per month.

f. The fuel cost per kWh per month.

23. At a minimum, the information on power purchases shall consist of the following items per seller:

a. The quantity purchased in MWh.

b. The demand purchased in MW to the extent specified in contract.

c. The total cost for demand to the extent specified in contract.

d. The total cost for energy.

Information on economy interchange purchases may be aggregated. These reports shall also include an itemization of off-system sales margins.

24. At a minimum, the information on fuel purchases shall consist of the following information:

a. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge and incremental cost.

b. Natural gas commodity costs, categorized by short term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume, by contract.

25. Within sixty days after Commission approval of this Agreement, APS shall provide the information specified in paragraphs 20-24 relating to the base cost of fuel and purchased power adopted for the test year settlement revenue requirement.

26. An APS Officer shall certify under oath that all information provided in the reports required under Paragraphs 20 through 25 is true and accurate to the best of his or her information and belief.

27. Direct access customers and customers served under Rates E-36, SP-1, Solar-1, and Solar-2 shall be excluded from paying charges under the PSA.

28. The minimum life of the PSA shall be five years measured from the date that rates resulting from this proceeding go into effect. No later than four years from the date of the PSA's implementation, APS shall file a report that addresses the PSA's operation, its merits, and its shortcomings and that provides recommendations, with supporting testimony, as to whether the PSA should remain in effect. The Commission shall consider whether to continue the PSA after APS has filed its PSA report or during APS' next rate case, whichever comes first. If the PSA is reviewed during an APS rate case that concludes before the expiration of the five-year period, or if the Commission's review of APS' PSA report concludes before the expiration of the five-year period, any recommendations to abolish the PSA shall not take effect until the five-year period has expired.

29. If the Commission decides to retain the PSA after the review described in paragraph 28, the Commission may nonetheless, in conformance with applicable procedural requirements, abolish the PSA at any time after the five-year period has expired and need not conduct a rate case to do so.

30. If the Commission abolishes the PSA, the Commission shall make appropriate provision for any under-recovery or over-recovery that exists at the time of termination. The Commission may also adjust APS' base rates as appropriate to ensure that they reflect the costs for fuel and purchased power.

31. The Parties agree to a base cost of fuel and purchased power of $0.020743 per kWh. This amount shall be reflected in APS' base rates.

32. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the PSA shall operate.

V. Depreciation

33. APS has agreed to adopt Staff's proposed service lives as set forth in Staff's direct testimony, including the service lives proposed by Staff for the PWEC Assets. The Parties further agree that APS shall be allowed a jurisdictional net salvage allowance as reflected in APS' direct testimony.

34. The attached Appendix A sets forth the remaining service lives, net salvage allowance, annual depreciation rates, and reserve allocation for each category of APS depreciable property agreed to by the Parties for purposes of this proceeding and authorized by the Commission's approval of this Agreement.

35. APS will separately record and account for net salvage such that it can be identified both as a component to annual depreciation expense and in accumulated reserves for depreciation.

36. Amortization rates currently in effect, which are shown in Appendix A, are to remain in effect.

37. For the purposes of this proceeding, the Parties agree that SFAS 143 shall not be adopted for ratemaking purposes.

VI. $234 Million Write-Off

38. APS shall not recover the $234 million write-off attributable to Decision No. 61973, the Commission order that approved the 1999 APS Settlement Agreement.

39.. APS shall not seek to recover the above $234 million write-off in any subsequent proceeding.

VII. Demand Side Management ("DSM")

40. Included in APS' total test year settlement base rate revenue requirement is an annual $10 million base rate DSM allowance for the costs of approved "eligible DSM-related items," as defined in this paragraph. In addition to expending the annual $10 million base rate allowance, APS will be obligated to spend on average at least another $6 million annually on approved eligible DSM-related items, such additional amounts to be recovered by means of a DSM adjustment mechanism as described in paragraph 43 herein. Accordingly, APS will be obligated under this Settlement Agreement to spend at least $48 million ($30 million in base rates and at least another $18 million during calendar years 2005 – 2007, with the latter amount to be recovered by the aforementioned DSM adjustment mechanism) on approved eligible DSM-related items, all as provided in this Section VII. For purposes of this Agreement, "eligible DSM-related items" shall include and be limited to "energy-efficiency DSM programs", as also defined in this paragraph; a "performance incentive" in accordance with paragraph 45; and "low income bill assistance" as specified in paragraph 42. For purposes of this Agreement, "energy-efficiency DSM" shall be defined as the planning, implementation and evaluation of programs that reduce the use of electricity by means of energy-efficiency products, services, or practices.

41. All DSM programs must be pre-approved before APS may include their costs in any determination of total DSM costs incurred. APS may apply the costs of programs already approved by Staff or the Commission prior to the effective date of Commission approval of this Agreement to the annual $10 million base rate DSM allowance and to the additional spending on eligible DSM-related items provided for in paragraphs 40 and 44. After the Commission issues an order approving the terms of this Agreement, APS shall submit proposed DSM programs to the Commission for approval.

42. The annual $10 million base rate DSM allowance referenced above shall include at least $1 million annually for the low income weatherization program. Up to $250,000 of the $1 million provided for the low income weatherization program may be applied to low income bill assistance during any calendar year. If APS does not expend the entire $250,000 on low income bill assistance, the balance shall be available for low income weatherization. APS shall file an application for Commission approval of the low income weatherization program, including bill assistance and administrative costs, within sixty days of the Commission's approval of this Agreement.

43. A DSM adjustment mechanism will be established in this proceeding for any approved DSM expenditures in excess of the annual $10 million base rate DSM allowance. The adjustor rate, initially set at zero, will be reset on March 1, 2006 and thereafter on March 1st of each subsequent year. Before March 1st, beginning in 2006, APS shall file a request with supporting documentation to revise its DSM adjustor rate. The per-kWh charge for the year will 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 will pay a per kW charge instead of a per kWh charge. To calculate the per kW charge, the account balance shall first be allocated to the General Service class based upon the number of kWh consumed by that class. General Service customers that are not demand billed shall pay the DSM adjustor rate on a per kWh basis. The remainder of the account balance allocated to the General Service class shall then be divided by the kW billing determinant for the demand billed customers in that class to determine the per kW DSM adjustor charge. The DSM adjustor will be applied to both standard offer and direct access customers.

44. As provided for in paragraph 40, and in addition to the annual $10 million base rate DSM allowance, APS will spend on average at least $6 million annually on approved eligible DSM-related items to be recovered by the DSM adjustor mechanism established in paragraph 43. APS may gradually phase-in its DSM spending, but will be obligated to expend no less than $48 million, $30 million in base rates and at least $18 million to be recovered through the DSM adjustment mechanism established under paragraph 43, all on approved and eligible DSM-related items over the initial three-year period of calendar years 2005 through 2007. Moreover, APS will be obligated to expend at least $13 million on approved and eligible DSM-related items during 2005 (subject to the Commission's timely approval of sufficient programs), with such $13 million spending obligation to be pro-rated for 2005 to the extent Commission approval of the Final Plan called for in paragraph 48 occurs after January 1, 2005. In no event will such pro-ration reduce APS' 2005 obligation below the annual $10 million base rate DSM allowance. Consistent with paragraph 43, all required and approved spending on eligible DSM-related items above the annual $10 million base rate allowance will be recovered by APS only on an "after-the-fact" basis through the DSM adjustment mechanism.

45. APS will be permitted to earn and recover a performance incentive based on a share of the net economic benefits (benefits minus costs) from the energy-efficiency DSM programs approved in accordance with paragraph 41. Such performance incentive will be capped at 10% of the total amount of DSM spending, inclusive of the program incentive, provided for in this Agreement (e.g., $1.6 million out of the $16 million average annual spending referenced in paragraphs 40 and 44 or $4.8 million over the initial three-year period). Any such performance

incentive collected by APS during a test year will be considered as a credit against APS' test year base revenue requirement. The specific performance incentive will be set forth in and approved as a part of the Final Plan referenced in paragraph 48.

46. This Agreement does not provide for the recovery of net lost revenues. Except to the extent reflected in a test year used to establish APS rates in future rate proceedings, or unless otherwise authorized by the Commission in a separate non-rate case proceeding, APS shall not recover or seek to recover net lost revenues on a going-forward basis. In no event will APS recover or seek to recover net lost revenues incurred in periods prior to such test year or for periods prior to the Commission's authorization of net lost revenue recovery in a separate non-rate case proceeding. In addition, no recovery of net lost revenues by APS will reduce the DSM spending commitments embodied in this Agreement or be considered as an eligible DSM-related item for purposes of this Section.

47. Attached as Appendix B is a preliminary plan ("Preliminary Plan") for eligible DSM-related items for calendar 2005, including a listing and brief description of programs, program concepts and program strategies and tactics. The Preliminary Plan also provides a preliminary allocation of the $16 million referenced in paragraph 40. The Preliminary Plan will be considered and approved by the Commission as part of this Agreement.

48. Within 120 days of the Commission's approval of the Preliminary Plan, APS will, with input and assistance from the collaborative created pursuant to paragraph 54, file with the Commission a final 2005 DSM plan ("Final Plan") that is consistent with the approved Preliminary Plan. The Final Plan will be submitted to the Commission for its consideration and approval. As part of the Commission's review, Staff shall report its recommendation to the Commission regarding the Final Plan, including its recommendations regarding the program budgets, estimates of energy savings and load reductions, and the cost-effectiveness of such Final Plan.

49. APS may request Commission approval for DSM program costs and performance incentives that exceed the $16 million ($48 million over three-year level) referenced in paragraph 40. Such additional DSM programs may include demand-side response and additional energy efficiency programs.

50. For residential billing purposes, APS shall combine the DSM adjustor with the EPS adjustor addressed in paragraph 63 and shall reflect such combined billing charge as an "Environmental Benefits Surcharge." For the billing of general service and other non-residential customers, APS may but is not required to provide for such combined billing of the EPS and DSM adjustment mechanisms. In any event, each such adjustor shall be separately set forth in the Company's rate schedules and shall be separately accounted for in the Company's books, records, and reports to the Commission.

51. If, notwithstanding the provisions of paragraphs 40 and 44, APS does not expend during calendar years 2005 through 2007 at least $30 million (in total) of the base rate allowance referenced in paragraph 40 for approved and eligible DSM-related items, as that latter term is defined in paragraph 40, the unspent amount of the $30 million will be credited to the account balance for the DSM adjustor described in Paragraph 43 in 2008.

52. Beginning in 2005, APS will file mid-year and end-year reports in Docket Control containing the following information separately for each DSM program:

a. A brief description of the program.

b. Program modifications.

c. Program goals, objectives, and savings targets.

d. Programs terminated.

e. The level of participation.

f. A description of evaluation and monitoring activities and results.

g. kW and kWh savings.

h. Benefits and net benefits, both in dollars, as well as performance incentive calculation.

i. Problems encountered and proposed solutions.

j. Costs incurred during the reporting period disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs.

k. Findings from all research projects.

l. Other significant information.

Each report will be due on the first day of the third month after the conclusion of the reporting period.

53. Direct access customers shall be eligible to participate in APS DSM programs.

54. APS shall implement and maintain a collaborative DSM working group to solicit and facilitate stakeholder input, advise APS on program implementation, develop future DSM programs, and review DSM program performance. The DSM working group shall review APS' draft program plans and reports before APS submits them to the Commission. APS shall, however, retain responsibility for demonstrating to the Commission the appropriateness of any program proposed by APS. Any DSM program proposed by APS may be modified by the Commission as it finds appropriate. If APS does not submit a DSM program proposal considered by the collaborative DSM working group to the Commission, any member of the working group may submit the proposal directly to the Commission for its review and approval with such modifications as the Commission finds appropriate. In such instance, the member or members submitting a proposal shall have the responsibility for demonstrating the appropriateness of that

program to the Commission. At a minimum, Staff, RUCO, AECC, the Arizona State Energy Office, WRA and SWEEP will be invited to participate with APS in the above collaborative DSM working group. Commission Staff shall continue to exercise its responsibility to review and make independent recommendations to the Commission in connection with any DSM program proposal submitted by APS or any other member of the working group.

55. APS shall conduct a study to review and evaluate the merits of allowing large customers to self-direct any DSM investments. In conducting this study, APS shall seek the input of the collaborative DSM working group provided by paragraph 54. This study shall be filed within one year of the Commission's approval of this Agreement.

56. Any customer who can demonstrate an active DSM program and whose single site usage is twenty MW or greater may file a petition with the Commission for exemption from the DSM adjustor. The public shall have 20 days to comment on such petition. In considering any petition pursuant to this paragraph, the Commission may consider the comments received and any other information that is relevant to the customer's request.

57. 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. To that end, APS will conduct a study analyzing rate design modifications that could include, among others, consideration of mandatory TOU rates (e.g., for E-32 general service customers) and/or expanded use of inclining block rates. A plan for such study and analysis of rate design modifications shall be presented to the collaborative DSM working group described in paragraph 54 within 90 days of the Commission's approval of this Agreement. APS will submit to the Commission the final results of this study and analysis of rate design modifications as part of its next general rate application or within 15 months of approval of this Agreement, whichever occurs first. If the study and analysis indicate that one or more of the rate design modifications studied is reasonable, cost-effective and practical, APS shall develop and propose to the Commission any appropriate rate design modifications.

58. The DSM activities provided for in this section are in addition to any DSM acquired as part of the competitive procurement process described in Section IX.

59. The Commission will address other issues, such as DSM goals, cost-effectiveness, and evaluation, in a generic proceeding.

60. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the DSM adjustor shall operate. Commission Staff shall review and approve the plan of administration in connection with its overall compliance review following APS' compliance filings in this docket.

VIII. Environmental Portfolio Standard and other Renewables Programs

61. Included in APS' total test year settlement revenue requirement and existing EPS surcharge revenues is $12.5 million for renewables as defined in the Commission's environmental portfolio standard ("EPS"), A.A.C. R14-2-1618 ("Rule 1618").

62. APS shall recover $6 million of the above $12.5 million in the base rates provided for in this Agreement.

63. APS shall also recover costs for EPS-eligible renewables through the EPS surcharge, which shall be established in this case as an adjustment mechanism to allow for specific Commission-approved changes to APS' EPS funding. The initial charge will be the same as contained in the current EPS surcharge tariff, including caps. If the Commission amends the EPS surcharge set forth in Rule 1618 or approves additional EPS funding pursuant to paragraph 64 of this Agreement, any change in EPS funding requirements resulting from such actions shall be collected from APS' customers in a manner that maintains the proportions between customer categories embodied in the current EPS surcharge. These adjustments may be made outside a rate case.

64. Prior to spending additional funds, APS may apply to the Commission to increase its EPS funding beyond that provided in base rates and the EPS surcharge. In its application, APS shall provide the following information:

a. APS shall explain why it has been unable to meet the standard.

b. APS shall account for all EPS funds that it has collected from ratepayers and shall describe how they were spent.

c. APS shall support the prudence and cost effectiveness of all its EPS expenditures.

d. APS shall demonstrate that it has appropriately managed its EPS funding and programs.

e. If APS has chosen to expend EPS funding on technologies, programs, or other items that do not represent the least cost method for meeting the standard established in Rule 1618, APS shall identify each such instance and explain why it chose to employ other than the least cost alternative.

f. APS shall set forth a plan for meeting the standard and shall support the cost effectiveness of each element of the plan. Where the plan does not employ the least cost alternative, APS shall identify each such instance and shall explain why it is reasonable to elect a more expensive alternative.

g. APS shall provide the proposed budget that it believes would allow it to meet the standard and shall explain the cost effectiveness of every item addressed in the budget.

h. In its application, APS shall address whether ratepayers would benefit from partial or phased implementation of the plan and associated budget provided in response to paragraphs 64.f and 64.g.

i. APS shall identify any potential impacts on ratepayers of additional EPS funding and shall consider how any adverse impacts may be mitigated.

The Commission, in its discretion, may deny APS' application for additional EPS funding. APS may not file an application pursuant to this paragraph until one year after the termination of the rulemaking docket resulting from paragraph 68.

65. The EPS surcharge shall be recovered from both standard offer and direct access customers. APS shall separately account for EPS revenue collected from direct access customers, and such revenue shall be available to electric service providers for funding their EPS obligations.

66. For billing purposes, APS may combine the EPS adjustor with the DSM adjustor as addressed in paragraph 50.

67. After the Commission issues an order approving the terms of this Agreement, renewables programs directly involving APS' retail customers will be submitted to the Commission for approval.

68. The Commission will address issues such as modifying EPS goals or requirements in a generic proceeding. Staff will initiate a rulemaking proceeding to modify Rule 1618 within 120 days of the Commission's approval of this Agreement.

69. APS will issue a special RFP in 2005 seeking at least 100 MW and at least 250,000 MWh per year of any of the following types of renewable energy resources for delivery beginning in 2006: solar, biomass/biogas, wind, small hydro (under 10 MW), hydrogen (other than from natural gas), or geothermal. APS will, either in this solicitation or in subsequent procurements for renewables, seek to acquire at least ten percent of its annual incremental peak capacity needs from renewable resources. The renewable resources solicited by this RFP or future solicitations issued pursuant to this paragraph shall be subject to the following conditions:

a. Resources need not provide firm capacity, but APS will take into consideration the degree of the resource's firmness in determining the appropriate capacity value to assign to such resource.

b. Individual resources must be capable of providing at least 20,000 MWh of renewable energy annually.

c. Resources must be deliverable to the APS system, either directly or through displacement (tradable tags or credits alone will not suffice), and the costs of integrating a specified resource into the APS system will be considered in determining whether a proposed resource meets the pricing requirements of this paragraph.

d. Resources may be, but need not be, EPS-eligible.

e. Purchased power agreements ("PPAs") offering renewable energy must be for a minimum term of five years, but may be for terms, including renewal options, of as long as thirty years.

f. Respondents to this renewable energy RFP must offer products with either fixed prices or relatively stable prices that do not vary with either the price of natural gas or of electricity.

g. Renewable resources must be no more costly, on a levelized cost per MWh basis, than 125% of the reasonably estimated market price of conventional resource alternatives.

h. If APS purchases renewable resources through a PPA, the portion of the cost of those resources that is at or below market price may be recovered through the PSA similar to other PPA costs.

i. If APS purchases through a PPA renewable resources that are not eligible for EPS recovery, the portion of the cost of those resources that is above market price may be recovered through the PSA similar to other PPA costs.

j. If APS purchases through a PPA renewable resources that are eligible to meet EPS requirements, the portion of the cost of those resources that is above market price will be recovered from EPS funds; however, such recovery of cost premiums from EPS funds in any year shall be limited to the kWh, expanded by any applicable multipliers, necessary to meet then-existing EPS requirements for that year. If the portion of the cost that is above market price exceeds the amount that is available from the EPS funds as indicated above, or if the EPS funding is exhausted, the remainder may be recovered through the PSA.

k. The net proceeds from the sale of any environmental credits or tags attributable to the renewable resources acquired pursuant to this paragraph shall be credited to the EPS account.

l. Where feasible, utilization of in-state renewable resources is desirable, subject to the limitations and requirements set forth above, but if APS does not receive sufficient in-state qualified bids, APS is free to acquire qualifying out-of-state resources to meet its initial goal of at least 100 MW or its subsequent goal of acquiring at least ten percent of its incremental capacity needs from renewable resources.

m. Renewable resources acquired through this RFP or pursuant to Section IX that otherwise qualify for EPS treatment will be considered as applying to any EPS standard.

n. Renewable resources acquired through this RFP, through future solicitations for renewables, or pursuant to Section IX shall be subject to the Commission's

customary prudence review. The fact that the cost of resources acquired pursuant to this paragraph exceeds market price shall not, in and of itself, render such purchases imprudent.

70. At least thirty days before APS issues the final RFP for renewable resources pursuant to this section, APS will circulate a draft of the RFP to potentially interested parties. At least ten days before APS issues the final RFP, APS will conduct an informal meeting with potential bidders and other interested parties to allow an opportunity for comments and discussion regarding the RFP.

71. If, by December 31, 2006, APS has failed to acquire at least 100 MW of renewable resources pursuant to the RFP described in paragraph 69, APS shall, no later than January 31, 2007, file a notice with the Commission describing the shortfall in renewable resources, explaining the circumstances leading to the shortfall, and recommending actions to the Commission. This notice shall be sent to all Parties of record in this case. Any interested person may request that the Commission conduct a proceeding .

72. The provisions of this section shall not displace APS' requirements under the EPS or any modifications to the EPS.

73. APS will allow and encourage all renewable resources (whether or not EPS-eligible), distributed generation, and DSM proposals to participate in the 2005 RFP or similar competitive solicitation discussed in Section IX.

IX. Competitive Procurement of Power

74. APS will not pursue any self-build option having an in-service date prior to January 1, 2015, unless expressly authorized by the Commission. For purposes of this Agreement, "self-build" does not include the acquisition of a generating unit or interest in a generating unit from a non-affiliated merchant or utility generator, the acquisition of temporary generation needed for system reliability, distributed generation of less than fifty MW per location, renewable resources, or the up-rating of APS generation, which up-rating shall not include the installation of new units.

75. As part of any APS request for Commission authorization to self-build generation prior to 2015, APS will address:

a. The Company's specific unmet needs for additional long-term resources.

b. The Company's efforts to secure adequate and reasonably-priced long-term resources from the competitive wholesale market to meet these needs.

c. The reasons why APS believes those efforts have been unsuccessful, either in whole or in part.

d. The extent to which the request to self-build generation is consistent with any applicable Company resource plans and competitive resource acquisition rules or orders resulting from the workshop/rulemaking proceeding described in paragraph 79.

e. The anticipated life-cycle cost of the proposed self-build option in comparison with suitable alternatives available from the competitive market for a comparable period of time.

76. Nothing in this section shall be construed as relieving APS of its existing obligation to prudently acquire generating resources, including but not limited to seeking the above authorization to self-build a generating resource or resources prior to 2015.

77. The issuance of any RFP or the conduct of any other competitive solicitation in the future shall not, in and of itself, preclude APS from negotiating bilateral agreements with non-affiliated parties.

78. Notwithstanding its ability to pursue bilateral agreements with non-affiliates for long-term resources, 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. For purposes of this section, "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 such RFP or other competitive solicitation(s) for long-term resources, and neither PWEC nor any other APS affiliate will participate in future APS competitive solicitations for long-terms resources without the appointment by the Commission or its Staff of an independent monitor.

c. Nothing in this section shall be construed as obligating APS to accept any specific bid or combination of bids.

d. All renewable resources, distributed generation, and DSM will be invited to compete in such 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.

79. The Commission Staff will schedule workshops on resource planning issues to 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 rulemaking.

80. APS will continue to use its Secondary Procurement Protocol except as modified by the express terms of this Agreement or unless the Commission authorizes otherwise.

X. Regulatory Issues

81. The Parties acknowledge that APS has the obligation to plan for and serve all customers in its certificated service area, irrespective of size, and to recognize, in its planning, the existence of any Commission direct access program and the potential for future direct access customers. This section does not bar any Party from seeking to amend APS' obligation to serve.

82. Changes in retail access shall be addressed through the Electric Competition Advisory Group ("ECAG") or other similar process. The ECAG process or similar proceeding shall address, among other things, the resale by Affected Utilities of Revenue Cycle Services ("RCSs") to Electric Service Providers ("ESPs").

83. The Parties further acknowledge that APS currently has the ability, subject to applicable regulatory requirements, to self-build or buy new generation assets for native load, subject to paragraph 81, and subject to the conditions in Section IX of this Agreement.

84. The Parties acknowledge that APS may join a FERC-approved Regional Transmission Organization ("RTO") or an entity or entities performing the functions of an RTO. APS may participate in those activities or similar activities without further order or authorization from the Commission. This paragraph does not establish the ratemaking treatment for costs related to those activities.

85. This section is not intended to create or confirm an exclusive right for APS to provide electric service within its certificated area where others may legally also provide such service, to diminish any of APS' rights to serve customers within its certificated area, or to prevent the Commission or any other governmental entity from amending the laws and regulations relative to public service corporations.

XI. Competition Rules Compliance Charge ("CRCC")

86. Included in the total test year revenue requirement is approximately $8 million for the CRCC. APS may recover $47.7 million plus interest calculated in accordance with paragraph 19.h through a CRCC of $0.000338/kWh over a collection period of five years.

87. When the above amount is recovered, the CRCC will terminate immediately. If any amount remains unrecovered/overrecovered after the end of the five year period, APS shall file an application with the Commission to adjust the CRCC to recover/refund the balance.

88. The CRCC shall be a separate surcharge, i.e., it shall not be included in base rates. The CRCC shall be assessed against all customers except for those served on rate schedules Solar -1 or Solar-2.

89. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the CRCC shall operate.

XII. Low Income Programs

90. APS shall increase funding for marketing its E-3 and E-4 tariffs to a total of $150,000.

91. APS shall increase its E-3 tariff discount levels as follows in Table 1 below:

Table 1 – E-3 Discount Levels		
Usage Level	Current Discount	New Discount
0-400 kWh	30 %	40 %
401-800 kWh	20 %	26 %
801-1200 kWh	10 %	14 %
Over 1200 kWh	$10.00	$13.00

92. APS shall increase its E-4 tariff discount levels as follows in Table 2 below:

Table 2 – E-4 Discount Levels		
Usage Level	Current Discount	New Discount
0-800 kWh	30 %	40 %
801-1400 kWh	20 %	26 %
1401-2000 kWh	10 %	14 %
Over 2000 kWh	$20.00	$26.00

93. It is the Parties' intent to insulate eligible low income customers from the effects of the rate increase resulting from this Agreement. With the revisions to the E-3 and E-4 tariff discounts set forth above, eligible low income customers will receive a net reduction in rates.

XIII. Returning Customer Direct Access Charge

94. The Returning Customer Direct Access Charge ("RCDAC") shall be established, subject to the following conditions approved in Decision No. 66567:

a. The charge shall apply only to individual customers or aggregated groups of customers of 3 MW or greater.

b. The charge shall not apply to a customer who provides APS with one year's advance notice of intent to take Standard Offer service.

c. The RCDAC rate schedule shall include a breakdown of the individual components of the potential charge, definitions of the components, and a general framework that describes the way in which the RCDAC would be calculated.

95. The RCDAC shall only be established to recover from Direct Access customers the additional costs, both one-time and recurring, that these customers would otherwise impose on other Standard Offer customers if and when the former return to standard offer service from their competitive suppliers. The RCDAC shall not last longer than twelve months for any individual customer.

96. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the RCDAC shall operate.

XIV. Service Schedule Changes

97. The Company's proposed Schedule 1 changes shall be adopted as modified by Staff. Attached as Appendix C is Schedule 1 with the modifications provided for by this Agreement.

98. The Company's changes to Schedule 3 proposed in its direct testimony shall be adopted but with the retention of the 1,000-foot construction allowance for individual residential customers and also with any individual residential advances of costs being refundable. Attached as Appendix D is Schedule 3 with the modifications provided for by this Agreement.

99. The Company's changes to Schedule 7 proposed in its direct testimony shall be adopted except that the changes reflecting current ANSI standards shall not be made at this time and the words "meter maintenance and testing program" will remain. Attached as Appendix E is Schedule 7 with the modifications provided for by this Agreement.

100. The Company's changes to Schedule 10 proposed in its direct testimony shall be adopted except for the amendments described in Staff's direct testimony, which shall be interpreted as consistent with the current provisions of A.A.C. R14-2-1612. Attached as Appendix F is Schedule 10 with the modifications provided for by this Agreement.

101. Schedules 4 and 15 as set forth in APS' Application shall be approved. Appendix G is Schedule 4 with the modifications provided for by this Agreement. Appendix H is Schedule 15 with the modifications provided for by this Agreement.

102. The Commission may change the service schedules as a result of the ECAG or other similar process.

XV. Nuclear Decommissioning

103. Decommissioning costs shall be as proposed in APS' direct testimony. Attached as Appendix I is the level of decommissioning costs authorized and included in APS' total settlement test year revenue requirement.

XVI. Transmission Cost Adjustor

104. A transmission cost adjustor ("TCA") shall be established in order to ensure that any potential direct access customers will pay the same for transmission as standard offer customers. The TCA shall be limited to recovery (refund) of costs associated with changes in APS' open access transmission tariff ("OATT") or the tariff of an RTO or similar organization.

105. Whenever APS files an application with FERC to change its transmission rates, it shall file a notice with the Commission of its application. APS shall at the same time also provide a copy of its application to the Director of the Utilities Division.

106. The TCA shall not take effect until the transmission component of retail rates exceeds the test year base of $0.000476 per kWh by five percent. When this trigger amount is reached, APS may file for Commission approval of a TCA rate.

107. As part of the tariff compliance filing set forth in Paragraph 135, APS shall file a plan of administration that describes how the TCA shall operate.

XVII. Distributed Generation

108. Commission Staff shall schedule workshops to consider outstanding issues affecting distributed generation. Staff shall refer to the results of prior distributed generation workshops when determining the specific issues that will benefit from further study.

109. If necessary, the workshops may be followed with rulemaking.

XVIII. Bark Beetle Remediation

110. APS is authorized to defer for later recovery the reasonable and prudent direct costs of bark beetle remediation that exceed test year levels of tree and brush control. The deferral account established for this purpose shall not accrue interest.

111. In the Company's next general rate proceeding, the Commission will determine the reasonableness, the prudence, and the appropriate allocation between distribution and transmission of these costs. The Commission will also determine an appropriate amortization period for the approved costs.

XIX. Rate Design

112. The rates set forth in this Agreement are designed to permit APS to recover an additional $67.5 million in base revenues as compared to adjusted test year base revenues.

113. APS' residential rate class will generate an additional 3.94% of base revenue compared with adjusted test year base revenue. Each bundled residential rate schedule will have the same basic structure (i.e., number and size of blocks, time-of-use time periods) as APS' existing base rates. Base rate levels shall recover the required revenue and shall permit cost-based unbundling of Distribution and Revenue Cycle Services, including Metering, Meter Reading, and Billing, to the degree practical.

114. Schedule E-10 and Schedule EC-1 will continue to be frozen and will not be eliminated in this proceeding. APS will provide notice to customers on these schedules that these rates will be eliminated in its next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. E-10 and EC-1 will each generate an additional 4.82% of base revenue compared with adjusted test year base revenue.

115. Schedules E-12, ET-1, and ECT-1R will each generate an additional 3.8% of base revenue compared with adjusted test year base revenue.

116. APS will continue on-peak and off-peak rates for winter billing periods for all residential time-of-use customers served under Schedules ET-1 and ECT-1R. Within 180 days of a final decision in this proceeding, APS will submit a study to Staff that examines ways in which APS can implement more flexibility in changing APS' on- and off-peak time periods and other time-of-use characteristics, including making on-peak periods more reflective of the times of actual system peak. Before designing its study, APS shall consult with Staff to ensure that the study will address all relevant issues. Time-of-use issues will be reexamined in APS' next rate case.

117. APS' proposed experimental time-of-use periods for ET-1 and ECT-1R will be adopted. Annual reports evaluating the outcomes of adopting these additional time-of-use periods will be filed with Staff. The first report will be due 12 months from the date of a decision in this matter. The report shall make a recommendation regarding the continuation of the experimental time-of-use periods. Before preparing its report, APS shall consult with Staff to ensure that the report will address all relevant issues. These experimental time-of-use periods will be reexamined in APS' next rate case.

118. The existing 11:00 AM to 9:00 PM on-peak time periods shall remain for general service customers served on time-of-use schedules. The summer rate period shall begin with the first billing cycle in May and conclude with the last billing cycle in October. As part of APS' compliance filing, APS and Staff shall meet and confer to review the General Service schedules to ensure that they are consistent with the rate design principles set forth in this Agreement.

119. General Service rate schedules will be modified such that Schedules E-32, E-32R, E-34, E-35, E-53, E-54, and the contracts shown in the General Service section of the H schedules attached to APS' rate Application will each generate approximately 3.5% of additional base revenue compared with adjusted test year base revenue. The settlement rate designs for these rate schedules shall permit cost-based unbundling of Generation and Revenue Cycle Services, including Metering, Meter Reading, and Billing, to the degree practical. With regard to Schedules E-32, E-34, and E-35, the non-system-benefits revenue requirement assigned to the General Service class will be used to establish first the unbundled component of generation at cost and then the unbundled component of revenue cycle services at cost.

120. APS will establish an additional Primary Service Discount of $2.74/kW for military base customers served directly from APS substations.

121. Schedule E-32 has been modified in an effort to simplify the design, to make it more cost-based, and to smooth out the rate impact across customers of varying sizes within the rate schedule. Changes to Schedule E-32 include the addition of an energy block for customers with loads under 20 kW and an additional demand billing block for customers with loads greater than 100 kW. In addition, a time-of-use option will be made available to E-32 customers without restriction as to number of participants.

122. Schedules E-20, E-30, E-40, E-51, E-59 and E-67 will be increased by 5% compared to adjusted test year base revenue. Schedule E-20 shall be frozen. Schedules E-22, E-23 and E-24 will be frozen to new customers and will not be eliminated in this proceeding. APS will provide notice to customers on schedules E-21, E-22, E-23, and E-24 that these rates will be eliminated in APS' next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. E-21, E-22, E-23, and E-24 will be increased by 5% compared to adjusted test year base revenue. Rate levels shall recover the required base revenue and permit cost-based unbundling of Generation and Revenue Cycle Services to the degree practical.

123. Frozen rates E-38 (Agricultural Irrigation Service) and E-38T (Agricultural Irrigation Service Time of Use option) will continue to be frozen and will not be eliminated in this proceeding. APS will provide notice to customers on these schedules that these rates will be eliminated in APS' next rate proceeding. Such notice shall be approved by Staff and shall be provided on these customers' bills at the conclusion of this proceeding and at the time that APS files its next rate case. Schedule E-38, Schedule E-38T, and Schedule E-221 (including options) will be increased to generate an additional 5% of base revenue compared with adjusted test year base revenue.

124. Dusk to Dawn Lighting (Schedule E-47) and Street Lighting Service (Schedule E-58) will be modified as proposed in APS' Application. Specific charges in these schedules will be increased to generate an additional 5% in base revenue compared with adjusted test year base revenue.

125. Except as modified by this Agreement and to the extent not inconsistent with this Agreement, APS' rate design as proposed in its Application is adopted. As part of APS'

compliance filing, APS and Staff shall meet and confer to review APS' rate schedules to ensure that they are consistent with the rate design principles set forth in this Agreement.

126. The specific rate designs for each of the residential rate schedules and for general service rate schedules E-32, E-32 TOU, E-34, and E-35 are set forth in Appendix J. The remaining rates shall be filed by APS as otherwise provided for in this Agreement and in accordance with the compliance filing called for in paragraph 135.

XX. Litigation and Other Issues

127. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, APS shall dismiss with prejudice all of its appeals of Commission Decision No. 65154, the Track A order, and APS and its affiliates shall also dismiss any and all litigation related to Decision Nos. 65154 and 61973 and/or any alleged breach of contract.

128. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, APS and its affiliates shall forego any claim that APS, PWEC, Pinnacle West Capital Corporation ("PWCC"), or any of APS' affiliates were harmed by Commission Decision No. 65154.

129. Upon approval of this Agreement in accordance with Section XXI by a Commission order that is final and no longer subject to judicial review, the Preliminary Inquiry, ordered in Commission Decision No. 65796, shall be concluded with no further action by the Commission.

XXI. Commission Evaluation of Proposed Settlement

130. The Parties agree that all currently filed testimony and exhibits shall be accepted into the Commission's record as evidence.

131. The Parties recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

132. This Agreement shall serve as a procedural device by which the Parties will submit their proposed settlement of APS' pending rate case, Docket No. E-01345A-03-0437, to the Commission. Except for paragraphs 9, 137, 138, 139, 140, and 143, this Agreement will not have any binding force or effect until its provisions are adopted as an order of the Commission.

133. The Parties further recognize that the Commission will independently consider and evaluate the terms of this Agreement.

134. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Parties shall abide by the terms as approved by the Commission.

135. Within sixty days after the Commission issues an order in this matter. APS shall file compliance tariffs for Staff review and approval. Subject to such review and approval, such compliance tariffs will become effective upon filing for billing cycles on and after that date.

136. If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Parties may withdraw from this Agreement, and such Party or Parties may pursue without prejudice their respective remedies at law. For the purposes of this Agreement, whether a term is material shall be left to the discretion of the Party choosing to withdraw from the Agreement. If a Party withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Parties, except for Staff, shall support the application for rehearing by filing a document to that effect with the Commission. Staff shall not be obligated to file any document or take any position regarding the withdrawing Party's application for rehearing.

XXII. Miscellaneous Provisions

137. Nothing in this Agreement shall be construed as an admission by any of the Parties that any of the positions taken by any Party in this proceeding is unreasonable or unlawful. In addition, acceptance of this Agreement by any of the Parties is without prejudice to any position taken by any Party in these proceedings.

138. This Agreement represents the Parties' mutual desire to compromise and settle disputed issues in a manner consistent with the public interest. None of the positions taken in this Agreement by any of the Parties may be referred to, cited, or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except in furtherance of this Agreement.

139. This case presents a unique set of circumstances and has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because the Agreement, as a whole, with its various provisions for settling the unique issues presented by this case, is consistent with their long-term interests and with the broad public interest. The acceptance by any Party of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

140. All negotiations relating to this Agreement are privileged and confidential. No Party is bound by any position asserted in negotiations, except as expressly stated in this Agreement. Evidence of conduct or statements made in the course of negotiating this Agreement shall not be admissible before this Commission, any other regulatory agency, or any court.

141. The "Definitive Text" of the Agreement shall be the text adopted by the Commission in an order that approves all material terms of the Agreement, including all modifications made by the Commission in such an order.

142. Each of the terms of the Definitive Text of the Agreement is in consideration and support of all other terms. Accordingly, the terms are not severable.

143. The Parties shall support and defend this Agreement before the Commission. Subject to paragraph 9, if the Commission adopts an order approving all material terms of this Agreement, the Parties will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

DATED this 18th day of August, 2004.

ARIZONA CORPORATION COMMISSION

By _____
Ernest G. Johnson
Director Utilities Division
1200 West Washington
Phoenix, AZ 85007

ARIZONA PUBLIC SERVICE COMPANY

By _____
Steven M. Wheeler
Executive Vice President

RESIDENTIAL UTILIY CONSUMER OFFICE

By _____
Stephen Ahearn, Director

STRATEGIC ENERGY, L.L.C.

By _____
Andrew Washburn
Interim President and Chief Financial Officer

WESTERN RESOURCE ADVOCATES

By _____
David Berry
Senior Policy Advisor
P. O. Box 1064
Scottsdale, AZ 85252-1064

DECISION NO. 67744

ARIZONANS FOR ELECTRIC CHOICE
AND COMPETITION

By _____
Its President

ARIZONA COMPETITIVE POWER ALLIANCE

By _____
Greg Patterson, Director

DECISION NO. 67744

PHELPS DODGE MINING COMPANY

By Dennis Bialot

Its Senior Vice President

SOUTHWEST ENERGY EFFICIENCY PROJECT

By _____
Tim Hogan

DECISION NO. 67744

ARIZONA COMMUNITY ACTION
ASSOCIATION

By _____
Its Executive Director

ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION

By _____
Sean M. Seitz, President

TOWN OF WICKENBURG

By_____
Its_____

TOWN OF WICKENBURG IS MOVING TO WITHDRAW ITS INTERVENTION IN THIS DOCKET.

PPL SUNDANCE ENERGY, LLC

By _____
Jay I. Moyes, Counsel

PPL SOUTHWEST GENERATION HOLDINGS, LLC

By _____
Jay I. Moyes, Counsel

CONSTELLATION NEWENERGY, INC.

By _____
Aaron Thomas, Vice President, West Region

FEDERAL EXECUTIVE AGENCIES

By _____
Its Counsel
Allen G. Erickson, Major, USA

ARIZONA UTILITY INVESTORS
ASSOCIATION

By Walter W. Meek
Its President

KROGER CO.

By Michael P. Kurtz
Its outside counsel

BOWIE POWER STATION, LLC

By Tom Cwray
Tom C. Wray, General Manger

SOUTHWESTERN POWER GROUP, II, LLC

By Tom Cwray
Tom C. Wray, General Manager

MESQUITE POWER, L.L.C.

By /s/ Michael R. Niggli
Michael R. Niggli,
President

IBEW, AFL-CIO, CLC, LOCAL UNIONS 387, 640, AND 769

By _____ 8/17/04

Its Attorney

ARIZONA COGENERATION ASSOCIATION

By_____
Its_____

ARIZONA UTILITY INVESTORS ASSOCIATION

By_____
Its_____

SOUTHWESTERN POWER GROUP, II, L.L.C.

By_____
Its_____

BOWIE POWER STATION, L.L.C.

By_____
Its_____

IBEW, AFL-CIO, CLC, LOCAL UNIONS 387, 640, AND 769

By_____
Its_____

KROGER CO.

By_____
Its_____

DOME VALLEY ENERGY PARTNERS, L.L.C.

By D. E. L. Elefonte
Its Executive Vice President

MESQUITE POWER, L.L.C.

By_____
Its_____

DECISION NO. 67744

APPENDIX A

ARIZONA PUBLIC SERVICE
Depreciation Rate Summary
Related to Electric Plant at December 31, 2002

	Depreciable Group	Depreciation Rate (A)	Service Life Rate (B)	Net Salvage Rate (C)
		A = (B + C)		
STEAM PRODUCTION PLANT				
FERC 311	Structures and Improvements	2.84%	2.37%	0.47%
FERC 312	Boiler Plant Equipment	3.50%	2.92%	0.58%
FERC 314	Turbogenerator Units	2.98%	2.49%	0.50%
FERC 315	Accessory Electric Equipment	2.70%	2.25%	0.45%
FERC 316	Miscellaneous Power Plant Equipment	4.14%	3.45%	0.69%
NUCLEAR PRODUCTION PLANT				
FERC 321	Structures and Improvements	2.60%	2.60%	0.00%
FERC 322	Reactor Plant Equipment	2.86%	2.80%	0.06%
FERC 322.1	Reactor Plant Equipment - Steam Generators	10.32%	8.82%	1.50%
FERC 323	Turbogenerator Units	2.90%	2.84%	0.06%
FERC 324	Accessory Electric Equipment	2.78%	2.73%	0.05%
FERC 325	Miscellaneous Power Plant Equipment	3.59%	3.52%	0.07%
OTHER PRODUCTION PLANT				
FERC 341	Structures and Improvements	2.69%	2.56%	0.13%
FERC 342	Fuel Holders, Products and Accessories	2.87%	2.74%	0.14%
FERC 343	Prime Movers	1.25%	1.25%	0.00%
FERC 344	Generators and Devices	3.38%	3.38%	0.00%
FERC 345	Accessory Electric Equipment	2.26%	2.26%	0.00%
FERC 346	Miscellaneous Power Plant Equipment	2.58%	2.58%	0.00%
TRANSMISSION PLANT (1)				
FERC 353	Station Equipment	1.52%	1.52%	0.00%
FERC 354	Towers and Fixtures	2.08%	1.54%	0.54%
FERC 356	Overhead Conductors and Devices	2.32%	1.72%	0.60%
	(1) Rates will apply to ACC Jurisdictional Assets in these Accounts			
DISTRIBUTION PLANT				
FERC 361	Structures and Improvements	2.10%	1.91%	0.19%
FERC 362	Station Equipment	2.04%	2.04%	0.00%
FERC 364	Poles, Towers and Fixtures - Wood	2.64%	2.40%	0.24%
FERC 364.1	Poles, Towers and Fixtures - Steel	2.03%	1.93%	0.10%
FERC 365	Overhead Conductors and Devices	1.99%	1.81%	0.18%
FERC 366	Underground Conduit	1.20%	1.14%	0.06%
FERC 367	Underground Conductors and Devices	3.18%	3.03%	0.15%
FERC 368	Line Transformers	2.30%	2.19%	0.11%
FERC 369	Services	2.60%	2.36%	0.24%
FERC 370	Meters	2.84%	2.84%	0.00%

ARIZONA PUBLIC SERVICE
Depreciation Rate Summary
Related to Electric Plant at December 31, 2002

	Depreciable Group	Depreciation Rate (A)	Service Life Rate (B)	Net Salvage Rate (C)
		A = (B + C)		
FERC 370.1	Electronic Meters	3.61%	3.61%	0.00%
FERC 371	Installations On Customers Premises	2.33%	1.94%	0.39%
FERC 373	Street Lighting and Signal Systems	3.10%	2.58%	0.52%
GENERAL PLANT				
FERC 390	Structures and Improvements	2.93%	2.55%	0.38%
FERC 391	Office Furniture and Equipment - Furniture	4.16%	4.16%	0.00%
FERC 391.1	Office Furniture and Equipment - PC Equipme	11.43%	11.43%	0.00%
FERC 391.2	Office Furniture and Equipment - Equipment	4.17%	4.17%	0.00%
FERC 393	Stores Equipment	0.00%	0.00%	0.00%
FERC 394	Tools, Shop and Garage Equipment	4.61%	4.61%	0.00%
FERC 395	Laboratory Equipment	5.07%	5.07%	0.00%
FERC 397	Communication Equipment	4.74%	4.74%	0.00%
FERC 398	Miscellaneous Equipment	3.85%	3.85%	0.00%

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ARIZONA PUBLIC SERVICE
Amortization Rate Summary
Related to Electric Plant at December 31, 2002

Amortization Group		Amortization Rate
INTANGIBLES		
FERC 301	Organization	0.00%
FERC 302	Franchise and Consents	4.00%
FERC 303L	PV Unit 2 Sale & Leaseback-Software	Over Life of lease
FERC 303	Misc Intangible-Contributed Plant	10.00%
FERC 303	Misc Intangible -Mexico Tie	20.00%
FERC 3031	Computer Software-5year life	20.00%
FERC 3032	Computer Software-10year life- Projects greater than $10 million	10.00%
PRODUCTION		
FERC 321-325	PV Unit 2 & Common-Sale & Leaseback	Over Life of lease
LAND RIGHTS		
FERC 3303	Limited Term Land Rights-Hydro Plants	Over Remaining Life of Plant
FERC 3503	Limited Term Land Rights-Transmission Lines	Over Life of Land Right
FERC 3503	Limited Term Land Rights-SCE	Over Life of Land Right
FERC 3603	Limited Term Land Rights-Distribution Lines	Over Life of Land Right
DISTRIBUTION PLANT		
FERC 361-368-371	Distribution Plant Leased Property	Over Life of Each Lease
GENERAL PLANT		
FERC 390	Buildings- Leasehold Improvements	Over Life of Each Lease
FERC 391	Capital Lease-Computer Equipment	Over Life of Each Lease
FERC 392	Capital Lease-Transportation Vehicles	Over Life of Each Lease
FERC 392	Transportation Vehicles	Depreciated by Vehicle Class(1)
FERC 396	Power Operated Equipment	Depreciated by Vehicle Class(1)
FERC 397	PV Common Sale & Lease Back	Over Life of Lease

(1) The depreciation study did not include accounts 392 or 396, therefore no changes are being proposed in this study. See attached schedule for rate by Vehicle Class.

ARIZONA PUBLIC SERVICE COMPANY
PROPOSED AND CURRENTLY USED RATES

Transportation Equipment (392)

Class	Description	Proposed Rates for 2004	(1995) Current Rates
01	Passenger Sedans	15.00%	15.00%
03	Compact Autos	13.33%	13.33%
09	Compact Pickup	11.43%	11.43%
10	Commerical Vehicles to 5 Ton	9.25%	9.25%
11	Commerical Vehicles, 4-Wheel Drive	10.57%	10.57%
12	Conv. Dr. 5-10 Ton, Truck	7.50%	7.50%
13	Conv. Dr. 2 1/2 Ton w/Single-Person Aerial	7.27%	7.27%
14	4-Wheel Dr. 5-10 Ton, Truck	7.00%	7.00%
15	Conv. Dr. 10-15 Ton, Tractor, Dump Truck, Backhoe	5.38%	5.38%
16	Conv. Dr. 18-32 Ton, Line Construction with Aerial	5.33%	5.33%
17	4-Wheel Dr. 10-15 Ton, Truck	6.92%	6.92%
19	Trucks, 18-32 Ton, Tractor, Platform Dump, Hydrolift	5.83%	5.83%
22	Trucks, 15-25 Ton 6X6	6.54%	6.54%
26	Fork Lift, Electric, to 4,000#	6.67%	6.67%
27	Fork Lift, Gasoline, to 4,000#	4.69%	4.69%
28	Fork Lift, 8-10 Ton Capacity	6.67%	6.67%
29	Wheeled Backhoe/Loader & Backfiller	5.83%	5.83%
30	Motor Grader	10.00%	10.00%
32	D4 Caterpillar (Small)	7.50%	7.50%
35	Trailer, to 5,000# GVW	3.25%	3.25%
36	Trailer, 5,000-10,000# GVW	4.11%	4.11%
37	Trailer, 10,000-20,000# GVW	3.75%	3.75%
38	Trailer, 20,000-50,000# GVW	4.69%	4.69%
39	Trailer, Over 50,000# GVW	5.00%	5.00%
41	Trailer-Mounted Industrial Equipment	4.93%	4.93%
42	Mobile Crane 45 Ton	10.00%	10.00%

Note: The depreciation study did not include accounts 392 or 396, therefore no changes are being proposed.

ARIZONA PUBLIC SERVICE COMPANY
PROPOSED AND CURRENTLY USED RATES

Power Operated Equipment (396)

Class	Description	Proposed Rates for 2004	(1995) Current Rates
12	Conv. Dr. 5-10 Ton, Truck	7.50%	7.50%
13	Conv. Dr. 2 1/2 Ton w/Single-Person Aerial	7.27%	7.27%
14	4-Wheel Dr. 5-10 Ton, Truck	7.00%	7.00%
15	Conv. Dr. 10-15 Ton, Tractor, Dump Truck, Backhoe	5.38%	5.38%
16	Conv. Dr. 18-32 Ton, Line Construction with Aerial	5.33%	5.33%
17	4-Wheel Dr. 10-15 Ton, Truck	6.92%	6.92%
18	4-Wheel Dr. 15-20 Ton, Truck	6.92%	6.92%
19	Trucks, 18-32 Ton, Tractor, Platform Dump, Hydrolift	5.83%	5.83%
20	Truck, 18-32 Ton, Hole Digger, Hydrocrane & Carrier	7.00%	7.00%
22	Trucks, 15-25 Ton 6X6	6.54%	6.54%
23	Small Trencher	10.00%	10.00%
24	Medium Trencher	6.25%	6.25%
26	Fork Lift, Electric, to 4,000#	6.67%	6.67%
27	Fork Lift, Gasoline, to 4,000#	4.69%	4.69%
28	Fork Lift, 8-10 Ton Capacity	6.67%	6.67%
29	Wheeled Backhoe/Loader & Backfiller	5.83%	5.83%
30	Motor Grader	10.00%	10.00%
31	Snow Vehicles-Crawlers	10.00%	10.00%
32	D4 Caterpillar (Small)	7.50%	7.50%
33	D7 Caterpillar (Medium)	7.50%	7.50%
34	D8 Caterpillar (Heavy)	7.50%	7.50%
35	Trailer, to 5,000# GVW	3.25%	3.25%
38	Trailer, 20,000-50,000# GVW	4.69%	4.69%
40	Wire Tensioners	8.50%	8.50%
41	Trailer-Mounted Industrial Equipment	4.93%	4.93%
42	Mobile Crane 45 Ton	10.00%	10.00%

Note: The depreciation study did not include Accounts 392 and 396, therefore no changes are being proposed.

PINNACLE WEST ENERGY CORPORATION
Depreciation Rate Summary
Related to Electric Plant at December 31, 2002

	Depreciable Group	Depreciation Rate (A)	Service Life Rate (B)	Net Salvage Rate (C)
		A = (B + C)		
OTHER PRODUCTION				
FERC 341	Structures and Improvements	2.08%	1.98%	0.10%
FERC 342	Fuel Holders, Products & Accessories	2.14%	2.04%	0.10%
FERC 343	Prime Movers	2.14%	2.10%	0.04%
FERC 344	Generators and Devices	2.94%	2.86%	0.08%
TRANSMISSION				
FERC 353	Station Equipment	1.74%	1.74%	0
FERC 355	Poles and Fixtures - Steel	2.08%	1.81%	0.27%
FERC 356	Overhead Conductors and Devices	2.45%	1.81%	0.63%

DECISION NO. 67744

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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 Structures and Improvements									
Cholla Unit 1	06-2017	75 - S1.5	(20)	2,144,789	1,841,738	732,009	14.0	52,286	2.44%
Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,179	2,101,615	3,925,000	29.0	135,345	2.69%
Cholla Unit 3	06-2035	75 - S1.5	(20)	9,583,277	5,184,966	6,314,966	29.9	211,203	2.20%
Cholla Common	06-2035	75 - S1.5	(20)	36,234,550	19,318,431	24,163,029	29.9	808,128	2.23%
Four Corners Units 1-3	06-2016	75 - S1.5	(20)	15,972,927	10,628,079	8,539,433	13.3	642,063	4.02%
Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,585	5,124,992	5,909,710	26.8	220,512	2.40%
Four Corners Common	06-2031	75 - S1.5	(20)	3,946,871	2,227,796	2,508,448	26.8	93,599	2.37%
Navajo Units 1-3	06-2026	75 - S1.5	(20)	27,152,517	12,197,389	20,385,631	22.8	894,107	3.29%
Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	2,084,288	2,461,278	17.1	143,934	3.80%
Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,446,832	1,989,759	946,439	11.3	83,756	3.42%
Yucca Unit 1	06-2016	75 - S1.5	(20)	462,567	452,608	102,472	13.1	7,822	1.69%
Total Account 311				115,950,066	63,151,661	75,988,418		3,292,754	2.84%
312 Boiler Plant Equipment									
Cholla Unit 1	06-2017	48 - L2	(20)	26,431,681	17,605,653	14,112,364	13.4	1,053,162	3.98%
Cholla Unit 2	06-2033	48 - L2	(20)	140,612,492	86,692,363	82,042,627	22.0	3,729,210	2.65%
Cholla Unit 3	06-2035	48 - L2	(20)	100,448,965	60,203,467	60,335,291	22.9	2,634,729	2.62%
Cholla Common	06-2035	48 - L2	(20)	22,626,051	11,328,185	15,823,076	24.8	638,027	2.82%
Four Corners Units 1-3	06-2016	48 - L2	(20)	197,139,757	115,304,816	121,262,892	12.7	9,548,259	4.84%
Four Corners Units 4-5	06-2031	48 - L2	(20)	111,591,873	64,306,071	69,604,177	22.1	3,149,510	2.82%
Four Corners Common	06-2031	48 - L2	(20)	3,290,391	2,152,160	1,796,309	22.8	78,785	2.39%
Navajo Units 1-3	06-2026	48 - L2	(20)	149,350,243	69,950,378	109,269,914	20.6	5,304,365	3.55%
Ocotillo Units 1-2	06-2020	48 - L2	(20)	24,152,351	17,905,382	11,077,439	15.2	728,779	3.02%
Saguaro Units 1-2	06-2014	48 - L2	(20)	24,387,712	16,568,160	12,699,094	11.1	1,144,063	4.69%
Total Account 312				800,031,516	462,014,635	498,023,184		28,008,889	3.50%
314 Turbogenerator Units									
Cholla Unit 1	06-2017	65 - R2	(20)	10,417,373	7,459,687	5,041,161	14.0	360,083	3.46%
Cholla Unit 2	06-2033	65 - R2	(20)	28,551,889	15,518,951	18,743,316	27.5	681,575	2.39%
Cholla Unit 3	06-2035	65 - R2	(20)	39,626,197	16,959,280	30,592,156	29.7	1,030,039	2.60%
Cholla Common	06-2035	65 - R2	(20)	631,278	335,591	421,943	29.0	14,550	2.30%
Four Corners Units 1-3	06-2016	65 - R2	(20)	36,412,926	24,829,283	18,866,228	13.1	1,440,170	3.96%
Four Corners Units 4-5	06-2031	65 - R2	(20)	14,488,238	7,086,302	10,299,584	26.3	391,619	2.70%
Four Corners Common	06-2031	65 - R2	(20)	1,726,164	1,349,968	721,429	23.3	30,963	1.79%
Navajo Units 1-3	06-2026	65 - R2	(20)	24,387,110	14,479,672	14,784,860	22.0	672,039	2.76%
Ocotillo Units 1-2	06-2020	65 - R2	(20)	15,517,601	11,437,238	7,183,883	16.8	427,612	2.76%
Saguaro Units 1-2	06-2014	65 - R2	(20)	16,259,698	13,244,927	6,266,711	11.2	559,528	3.44%

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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)
	Total Account 314				188,018,474	112,700,899	112,921,270		5,608,177	2.98%
315	Accessory Electric Equipment									
	Cholla Unit 1	06-2017	60 - R2.5	(20)	4,756,906	3,592,717	2,115,570	13.9	152,199	3.20%
	Cholla Unit 2	06-2033	60 - R2.5	(20)	42,235,618	25,070,631	25,612,111	26.8	955,676	2.26%
	Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	16,267,820	19,632,827	28.5	688,871	2.30%
	Cholla Common	06-2035	60 - R2.5	(20)	4,476,001	2,380,788	2,990,413	28.7	104,196	2.33%
	Four Corners Units 1-3	06-2016	60 - R2.5	(20)	16,353,282	9,525,599	10,098,339	13.2	765,026	4.68%
	Four Corners Units 4-5	06-2031	60 - R2.5	(20)	9,183,206	5,039,778	5,980,069	25.9	230,891	2.51%
	Four Corners Common	06-2031	60 - R2.5	(20)	2,596,719	2,104,631	1,011,432	21.0	48,163	1.85%
	Navajo Units 1-3	06-2026	60 - R2.5	(20)	20,226,194	11,727,970	12,543,463	22.0	570,157	2.82%
	Ocotillo Units 1-2	06-2020	60 - R2.5	(20)	2,407,622	2,023,821	865,325	16.3	53,087	2.20%
	Saguaro Units 1-2	06-2014	60 - R2.5	(20)	2,654,661	2,355,021	830,572	11.2	74,158	2.79%
	Total Account 315				134,807,415	80,088,776	81,680,122		3,642,425	2.70%
316	Miscellaneous Power Plant Equipment									
	Cholla Unit 1	06-2017	40 - R2	(20)	2,315,189	1,189,333	1,588,894	13.5	117,696	5.08%
	Cholla Unit 2	06-2033	40 - R2	(20)	4,846,431	2,631,492	3,184,225	22.1	144,083	2.97%
	Cholla Unit 3	06-2035	40 - R2	(20)	4,138,531	1,990,199	2,976,038	23.8	125,044	3.02%
	Cholla Common	06-2035	40 - R2	(20)	7,096,069	2,439,747	6,075,536	25.8	235,486	3.32%
	Four Corners Units 1-3	06-2016	40 - R2	(20)	4,330,612	925,502	4,271,232	13.1	326,048	7.53%
	Four Corners Units 4-5	06-2031	40 - R2	(20)	3,304,340	1,402,561	2,562,647	23.0	111,419	3.37%
	Four Corners Common	06-2031	40 - R2	(20)	8,133,224	3,483,659	6,276,210	23.2	270,526	3.33%
	Navajo Units 1-3	06-2026	40 - R2	(20)	11,805,250	5,248,830	8,917,470	20.2	441,459	3.74%
	Ocotillo Units 1-2	06-2020	40 - R2	(20)	3,711,192	1,301,603	3,151,827	16.2	194,557	5.24%
	Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,340,385	2,488,844	10.9	228,334	7.16%
	Yucca Unit 1	06-2016	40 - R2	(20)	452,868	359,801	183,641	12.2	15,053	3.32%
	Total Account 316				53,324,730	22,313,112	41,676,564		2,209,705	4.14%
	TOTAL STEAM PRODUCTION PLANT				1,292,132,201	740,269,083	810,289,558		42,761,950	
	NUCLEAR PRODUCTION PLANT									
321	Structures and Improvements									
	Palo Verde Unit 1	12-2024	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 Reclamati	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	261,989,961	370,777,040		16,452,433	2.60%
322	Reactor Plant Equipment									
	Palo Verde Unit 1	12-2024	70 - R1	(2)	359,545,213	153,616,828	213,119,289	20.6	10,345,597	2.88%

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Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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)
	Palo Verde Unit 2	12-2025	70 - R1	(2)	176,362,235	72,582,559	107,306,921	21.5	4,991,020	2.83%
	Palo Verde Unit 3	03-2027	70 - R1	(2)	322,750,700	121,218,478	207,987,236	22.6	9,202,975	2.85%
	Palo Verde Water Reclamati	03-2027	70 - R1	(2)	123,313	7,176	118,603	23.0	5,157	4.18%
	Palo Verde Common	03-2027	70 - R1	(2)	26,449,873	9,583,436	17,395,434	22.6	769,709	2.91%
	Total Account 322				885,231,334	357,008,477	545,927,484		25,314,457	2.86%
322.1	Reactor Plant Equipment - Steam Generators									
	Palo Verde Unit 1	12-2005	Square	(17)	30,722,375	27,569,149	8,376,030	3.0	2,792,010	9.09%
	Palo Verde Unit 2	12-2003	Square	(17)	15,870,053	15,868,635	2,699,327	1.0	2,699,327	17.01%
	Palo Verde Unit 3	12-2007	Square	(17)	25,413,317	20,039,935	9,693,646	5.0	1,938,729	7.63%
	Total Account 322.1				72,005,745	63,477,719	20,769,003		7,430,066	10.32%
323	Turbogenerator Units									
	Palo Verde Unit 1	12-2024	60 - S0	(2)	117,808,078	51,570,896	68,593,344	19.9	3,446,902	2.93%
	Palo Verde Unit 2	12-2025	60 - S0	(2)	76,754,224	32,432,468	45,856,840	20.8	2,204,656	2.87%
	Palo Verde Unit 3	03-2027	60 - S0	(2)	142,895,088	55,838,987	89,914,003	21.8	4,124,496	2.89%
	Palo Verde Water Reclamati	03-2027	60 - S0	(2)	217,707	76,585	145,476	22.0	6,613	3.04%
	Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	346,554	901,803	22.2	40,622	3.32%
	Total Account 323				338,898,976	140,265,490	205,411,466		9,823,287	2.90%
324	Accessory Electric Equipment									
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	53,444,066	64,361,007	20.0	3,218,050	2.79%
	Palo Verde Unit 2	12-2025	45 - R3	(2)	50,119,388	21,982,186	29,139,590	20.9	1,394,239	2.78%
	Palo Verde Unit 3	03-2027	45 - R3	(2)	89,143,623	36,343,481	54,583,014	22.1	2,469,820	2.77%
	Palo Verde Common	03-2027	45 - R3	(2)	17,918,193	7,299,463	10,977,094	22.0	498,959	2.78%
	Total Account 324				272,676,374	119,069,196	159,060,705		7,581,068	2.78%
325	Miscellaneous Power Plant Equipment									
	Palo Verde Unit 1	12-2024	35 - R0.5	(2)	29,671,405	11,770,905	18,493,928	17.7	1,044,855	3.52%
	Palo Verde Unit 2	12-2025	35 - R0.5	(2)	26,389,406	8,702,844	18,214,350	18.7	974,029	3.69%
	Palo Verde Unit 3	03-2027	35 - R0.5	(2)	27,284,046	9,445,478	18,384,249	19.2	957,513	3.51%
	Palo Verde Water Reclamati	03-2027	35 - R0.5	(2)	88,819	27,706	62,889	19.5	3,225	3.63%
	Palo Verde Common	03-2027	35 - R0.5	(2)	48,459,510	15,382,218	34,046,482	19.4	1,754,973	3.62%
	Total Account 325				131,893,186	45,329,151	89,201,899		4,734,595	3.59%
	TOTAL NUCLEAR PRODUCTION PLANT				2,333,472,616	987,139,994	1,391,147,596		71,335,907	
	HYDRO PRODUCTION PLANT									
331	Structures and Improvement	12-2004	200-SQ	0	100,878	100,878	0	0.0	0	0.00
332	Reservoirs, Dams and Water	12-2004	200-SQ	0	991,936	1,105,086	(113,150)	0.0	0	0.00

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	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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)	
333	Water Wheels, Turbines and	12-2004	200-SQ	0	157,196	157,196	0	0.0	0	0.00	
334	Accessory Electric Equipmer	12-2004	200-SQ	0	627,611	627,611	0	0.0	0	0.00	
335	Miscellaneous Power Plant E	12-2004	200-SQ	0	126,018	126,018	0	0.0	0	0.00	
336	Roads, Railroads and Bridge	12-2004	200-SQ	0	77,427	77,427	0	0.0	0	0.00	
	Hydro Decomissioning Costs				-	7,864,531	5,335,469	2.0	2,667,735		
	TOTAL HYDRO PRODUCTION PLANT				2,081,068	10,058,747	5,222,319		2,667,735		
	OTHER PRODUCTION PLANT										
341	Structures and Improvements										
	Douglas CT	08-2017	80 - S1	(5)	4,562	4,148	642	13.9	46	1.01%	
	Ocotillo CT 1 - 2	06-2017	80 - S1	(5)	328,749	230,819	114,367	14.5	7,887	2.40%	
	Saguaro CT	06-2017	80 - S1	(5)	1,288,525	466,971	885,980	14.4	61,526	4.77%	
	Solar Unit 1		12 - SQ	0	375,512	383,809	(8,297)	3.6	0	0.00%	(2)
	West Phoenix CT 1 - 2	06-2017	80 - S1	(5)	510,951	419,492	117,007	14.2	8,240	1.61%	
	West Phoenix Combined Cy	06-2031	80 - S1	(5)	6,706,722	2,438,522	4,603,536	28.1	163,827	2.44%	
	Yucca CT 1 - 4	06-2016	80 - S1	(5)	452,751	222,815	252,574	13.4	18,849	4.16%	
	Total Account 341				9,667,772	4,166,576	5,965,809		260,376	2.69%	
342	Fuel Holders, Products and Accessories										
	Douglas CT	08-2017	70 - S1	(5)	137,759	100,065	44,582	14.0	3,184	2.31%	
	Ocotillo CT 1 - 2	06-2017	70 - S1	(5)	719,859	517,984	237,868	14.0	16,991	2.36%	
	Saguaro CT	06-2017	70 - S1	(5)	1,304,977	1,019,500	350,726	14.0	25,052	1.92%	
	West Phoenix CT 1 - 2	06-2017	70 - S1	(5)	1,437,533	1,123,270	386,140	14.0	27,581	1.92%	
	West Phoenix Combined Cy	06-2031	70 - S1	(5)	19,343,993	2,649,135	17,662,058	27.7	637,619	3.30%	
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,859,228	534,600	12.9	41,442	1.28%	
	Total Account 342				26,176,338	8,269,182	19,215,973		751,870	2.87%	
343	Prime Movers										
	Douglas CT	06-2017	70 - L1.5	0	1,101,449	999,227	102,222	14.2	7,199	0.65%	(1)
	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	8,102,851	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	14.2	43,530	0.55%	(1)
	Total Account 343				32,606,644	26,858,659	5,747,985		408,237	1.25%	
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%	

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Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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)
	West Phoenix Combined Cyc	06-2031	37 - R3	(2)	81,920,222	11,983,119	71,575,507	26.2	2,731,890	3.33%
	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	81,748,531		3,705,166	3.38%
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 Cyc	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	9,606	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 Cyc	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	2,621,235	2,757,240		138,878	2.58%
	TOTAL OTHER PRODUCTION PLANT				202,716,436	80,031,011	126,097,259		5,703,052	

(1) Staff's reallocation of reserves caused account to have a remaining Net Book Value. APS selected the longest life of other plant in that FERC account to calculate remaining life.

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

TRANSMISSION PLANT										
352	Structures and Improvements	50 - R4	(5)	27,618,299	12,484,016	16,515,198	35.2	469,182	1.70%
352.5	Structures and Improvements - SCE 500 KV Line			409,725	424,897	(15,172)		13,316	3.25% (a)
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 I			7,747,282	7,349,363	397,919		251,787	3.25% (a)
354	Towers and Fixtures	60 - R3	(35)	83,464,531	46,097,366	66,579,751	38.3	1,738,375	2.08%
354.5	Towers and Fixtures - SCE 50(			13,752,584	17,477,965	(3,725,381)		446,959	3.25% (a)
355	Poles and Fixtures - Wood	48 - R1.5	(35)	91,126,939	27,541,958	95,479,410	38.5	2,479,985	2.72%
355.1	Poles and Fixtures - Steel	55 - R3	(15)	83,067,888	22,833,440	72,694,631	45.1	1,611,854	1.94%
355.5	Poles and Fixtures - SCE 500 I			930,308	692,575	237,733		30,235	3.25% (a)
356	Overhead Conductors and Dev	55 - R3	(35)	205,771,417	94,269,668	183,521,747	38.5	4,766,799	2.32%
356.5	Overhead Conductors and Devices - SCE 500 KV Line			22,653,515	28,947,611	(6,294,096)		736,239	3.25% (a)
357	Underground Conduit	48 - S1.5	(10)	10,444,362	4,087,064	7,401,734	35.7	207,331	1.99%
358	Underground Conductors and I	40 - R3	(10)	18,551,254	9,702,854	10,703,525	26.3	406,978	2.19%

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DECISION NO.

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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)	
TOTAL TRANSMISSION PLANT					994,274,409	402,048,829	742,093,250		19,697,167		
DISTRIBUTION PLANT											
361	Structures and Improvements		45 - R2.5	(10)	25,815,042	10,429,908	17,966,638	33.1	542,799	2.10%	
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, Towers and Fixtures - W		38 - R0.5	(10)	284,200,711	81,128,434	231,492,348	30.9	7,491,662	2.64%	
364.1	Poles, Towers and Fixtures - S		50 - R3	(5)	53,919,651	5,601,820	51,013,814	46.6	1,094,717	2.03%	
365	Overhead Conductors and Dev		53 - O1	(10)	218,856,780	33,437,453	207,305,005	47.7	4,346,017	1.99%	
366	Underground Conduit		86 - O1	(5)	425,723,116	26,924,767	420,084,505	82.4	5,098,113	1.20%	
367	Underground Conductors and I		29 - L1	(5)	805,505,783	258,865,205	586,915,867	22.9	25,629,514	3.18%	
368	Line Transformers		36 - R3	(5)	486,837,053	235,537,009	275,641,897	24.6	11,204,955	2.30%	
369	Services		37 - S2	(10)	242,404,812	91,086,515	175,558,778	27.9	6,292,429	2.60%	
370	Meters		29 - L0	0	91,330,710	34,836,184	58,494,526	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 Customers Pr		50 - O2	(20)	25,335,831	3,863,126	26,539,871	45.0	589,775	2.33%	
373	Street Lighting and Signal Syst		35 - R2	(20)	57,185,737	22,716,125	45,906,759	25.9	1,772,462	3.10%	
TOTAL DISTRIBUTION PLANT					2,984,164,052	865,761,802	2,300,633,578		72,966,640		
GENERAL PLANT											
390	Structures and Improvements		39 - R1	(15)	96,667,435	24,085,116	87,082,434	30.7	2,836,561	2.93%	
391	Office Furniture and Equipmen		20 - SQ	0	19,919,640	11,543,613	8,376,027	10.1	829,310	4.16%	
391.1	Office Furniture and Equipmen		8 - R3	0	38,654,946	15,103,632	23,551,314	5.3	4,418,633	11.43%	
391.2	Office Furniture and Equipmen		22 - R1	0	7,652,923	2,932,191	4,720,732	14.8	318,968	4.17%	
393	Stores Equipment		20 - SQ	0	1,227,371	1,235,746	(8,375)	2.8	0	0.00%	(2)
394	Tools, Shop and Garage Equip		20 - SQ	0	12,673,031	4,673,542	7,999,489	13.7	583,904	4.61%	
395	Laboratory Equipment		20 - L1	0	1,350,583	531,270	819,313	12.0	68,504	5.07%	
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 - S1.5	0	1,336,404	481,755	854,649	16.6	51,454	3.85%	
TOTAL GENERAL PLANT					273,792,024	101,284,512	187,027,627		13,576,672		
TOTAL DEPRECIABLE PLANT STUDIED					8,082,832,804	3,186,573,978	5,562,511,188		228,709,123		

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

(a) Assets related to the 500 KV SCE Transmission Line are Depreciated at a rate of 3.25%.

STEAM PRODUCTION PLANT NOT STUDIED			
311	Structures and Improvements - West Phoenix	0	80,895
312	Boiler Plant Equipment - West Phoenix Units	0	300,097
312	Boiler Plant Equipment - Yucca Unit 1	425,323	441,994
314	Turbogenerator Units - West Phoenix Units 4	0	314,612
314	Turbogenerator Units - Yucca Unit 1	184,918	188,319

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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 - West Phoenix				33,968	83,338				
315	Accessory Electric Equipment - Yucca Unit 1				182,084	185,435				
316	Misc. Power Plant Equipment-West Phoenix U				17,267	0				
	TOTAL STEAM PRODUCTION PLANT NOT STUDIED				843,558	1,594,590				
	GENERAL PLANT NOT STUDIED									
392	Vehicles				28,410,886	20,605,998				
396	Power Operated Equipment				27,947,651	18,603,989				
	TOTAL GENERAL PLANT NOT STUDIED				56,358,537	39,209,987				
	OTHER PROPERTY NOT STUDIED									
	Intangible Plant									
301	Organization				73,639					
302	Franchises and Consents				883,584					
303	Miscellaneous Intangible Plant				201,550,375					
	Leased Property									
321	Structures and Improvements				1,633,193					
322	Reactor Plant Equipment				9,670,223					
323	Turbogenerator Units				2,705,885					
324	Accessory Electric Equipment				944,788					
325	Miscellaneous Power Plant Equipment				563,135					
361	Structures and Improvements				195,512					
368	Line Transformers				179,394					
371	Installations On Customers Premises				60,386					
390	Structures and Improvements				11,160,324					
397	Communication Equipment				245,938					
	TOTAL OTHER PROPERTY NOT STUDIED				229,866,377	120,727,768				
	TOTAL DEPRECIABLE PLANT IN SERVICE				8,369,701,276	3,348,106,323				
	NONDEPRECIABLE PLANT									
310	Land and Land Rights				3,295,288					
320	Land and Land Rights				3,399,728					
330	Land and Land Rights				64,500					
340	Land and Land Rights				28,192					
350	Land and Land Rights				50,808,274					
360	Land and Land Rights				26,755,119					
389	Land and Land Rights				7,327,436					
	TOTAL NONDEPRECIABLE				91,678,517					
	TOTAL PLANT IN SERVICE				8,461,379,793					

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) = (9)*100/(100+(-4))	(12)=(11)/(5)	(13) = (9) *(-4)/100+(-4)	(14)=(13)/(5)
PLANT IN SERVICE													
STEAM PRODUCTION PLANT													
311 Structures and Improvements													
Cholla Unit 1	06-2017	75 - S1.5	(20)	2,144,789	1,841,738	732,009	14.0	52,286	2.44%	$43,572	2.03%	$8,714	0.41%
Cholla Unit 2	06-2033	75 - S1.5	(20)	5,022,179	2,101,615	3,925,000	29.0	135,345	2.69%	112,787	2.25%	22,557	0.45%
Cholla Unit 3	06-2035	75 - S1.5	(20)	9,583,277	5,184,968	6,314,968	29.9	211,203	2.20%	176,002	1.84%	35,200	0.37%
Cholla Common	06-2035	75 - S1.5	(20)	36,234,550	19,318,431	24,183,029	29.9	808,128	2.23%	673,440	1.86%	134,688	0.37%
Four Corners Units 1-3	06-2016	75 - S1.5	(20)	15,972,927	10,828,079	8,539,433	13.3	642,063	4.02%	535,052	3.35%	107,010	0.67%
Four Corners Units 4-5	06-2031	75 - S1.5	(20)	9,195,585	5,124,992	5,909,710	26.8	220,512	2.40%	183,760	2.00%	36,752	0.40%
Four Corners Common	06-2031	75 - S1.5	(20)	3,941,871	2,227,796	2,508,449	26.8	93,599	2.37%	77,999	1.98%	15,600	0.40%
Navajo Units 1-3	06-2026	75 - S1.5	(20)	27,152,517	12,197,389	20,385,631	22.8	894,107	3.29%	745,089	2.74%	149,018	0.55%
Ocotillo Units 1-2	06-2020	75 - S1.5	(20)	3,787,972	2,084,288	2,461,278	17.1	143,934	3.80%	119,945	3.17%	23,989	0.63%
Saguaro Units 1-2	06-2014	75 - S1.5	(20)	2,448,832	1,989,759	946,439	11.3	83,756	3.42%	69,796	2.85%	13,959	0.57%
Yucca Unit 1	06-2016	75 - S1.5	(20)	482,567	452,608	102,472	13.1	7,822	1.69%	6,519	1.41%	1,304	0.28%
Total Account 311				115,950,066	63,151,661	75,988,418		3,292,754	2.84%	2,743,962	2.37%	548,792	0.47%
312 Boiler Plant Equipment													
Cholla Unit 1	06-2017	48 - L2	(20)	28,431,681	17,805,653	14,112,364	13.4	1,053,182	3.98%	877,635	3.32%	175,527	0.66%
Cholla Unit 2	06-2033	48 - L2	(20)	140,612,492	88,892,363	82,042,627	22.0	3,729,210	2.65%	3,107,675	2.21%	621,535	0.44%
Cholla Unit 3	06-2035	48 - L2	(20)	100,443,685	60,203,467	60,335,291	22.9	2,634,729	2.62%	2,195,607	2.19%	439,121	0.44%
Cholla Common	06-2035	48 - L2	(20)	22,623,051	11,328,185	15,823,076	24.8	638,027	2.82%	531,889	2.35%	106,338	0.47%
Four Corners Units 1-3	06-2016	48 - L2	(20)	197,113,757	115,304,816	121,262,892	12.7	9,548,259	4.84%	7,956,883	4.04%	1,591,377	0.81%
Four Corners Units 4-5	06-2031	48 - L2	(20)	111,591,873	64,306,071	69,804,177	22.1	3,149,510	2.82%	2,624,592	2.35%	524,918	0.47%
Four Corners Common	06-2031	48 - L2	(20)	3,290,391	2,152,160	1,796,309	22.8	78,785	2.39%	65,655	2.00%	13,131	0.40%
Navajo Units 1-3	06-2026	48 - L2	(20)	149,359,243	69,950,378	109,269,914	20.6	5,304,365	3.55%	4,420,304	2.96%	884,061	0.59%
Ocotillo Units 1-2	06-2020	48 - L2	(20)	24,151,351	17,905,382	11,077,439	15.2	728,779	3.02%	607,316	2.51%	121,463	0.50%
Saguaro Units 1-2	06-2014	48 - L2	(20)	24,381,712	16,568,160	12,699,094	11.1	1,144,063	4.69%	953,385	3.91%	190,677	0.78%
Total Account 312				800,031,516	462,014,835	498,023,184		28,008,889	3.50%	23,340,741	2.92%	4,668,148	0.58%
314 Turbogenerator Units													
Cholla Unit 1	06-2017	65 - R2	(20)	10,417,373	7,459,687	5,041,161	14.0	360,083	3.46%	300,069	2.88%	60,014	0.58%
Cholla Unit 2	06-2033	65 - R2	(20)	28,531,889	15,518,951	18,743,316	27.5	681,575	2.39%	567,979	1.99%	113,596	0.40%
Cholla Unit 3	06-2035	65 - R2	(20)	39,628,197	16,959,280	30,592,158	29.7	1,030,039	2.60%	858,366	2.17%	171,673	0.43%
Cholla Common	06-2035	65 - R2	(20)	633,278	335,591	421,943	29.0	14,550	2.30%	12,125	1.92%	2,425	0.38%
Four Corners Units 1-3	06-2016	65 - R2	(20)	38,412,926	24,829,283	18,868,228	13.1	1,440,170	3.96%	1,200,142	3.30%	240,028	0.66%
Four Corners Units 4-5	06-2031	65 - R2	(20)	14,488,238	7,088,302	10,299,584	26.3	391,619	2.70%	326,349	2.25%	65,270	0.45%
Four Corners Common	06-2031	65 - R2	(20)	1,726,184	1,349,968	721,429	23.3	30,963	1.79%	25,802	1.49%	5,160	0.30%
Navajo Units 1-3	06-2026	65 - R2	(20)	24,387,110	14,479,672	14,784,860	22.0	672,039	2.76%	560,033	2.30%	112,007	0.46%
Ocotillo Units 1-2	06-2020	65 - R2	(20)	15,517,801	11,437,238	7,183,683	18.8	427,612	2.76%	356,343	2.30%	71,269	0.46%
Saguaro Units 1-2	06-2014	65 - R2	(20)	16,259,698	13,244,927	6,266,711	11.2	559,528	3.44%	466,273	2.87%	93,255	0.57%
Total Account 314				188,018,474	112,700,899	112,921,270		5,608,177	2.98%	4,673,481	2.49%	934,696	0.50%
Accessory Electric Equipment													
Cholla Unit 1	06-2017	60 - R2.5	(20)	4,758,906	3,592,717	2,115,570	13.9	152,199	3.20%	126,833	2.67%	25,367	0.53%
Cholla Unit 2	06-2033	60 - R2.5	(20)	42,235,818	25,070,631	25,612,111	26.8	955,876	2.26%	796,396	1.89%	159,279	0.38%
Cholla Unit 3	06-2035	60 - R2.5	(20)	29,917,206	16,287,820	19,632,827	28.5	688,871	2.30%	574,059	1.92%	114,812	0.38%
Cholla Common	06-2035	60 - R2.5	(20)	4,476,001	2,380,788	2,990,413	28.7	104,196	2.33%	86,830	1.94%	17,366	0.39%
Four Corners Units 1-3	06-2016	60 - R2.5	(20)	18,353,282	9,525,599	10,098,339	13.2	765,026	4.68%	637,521	3.90%	127,504	0.78%
Four Corners Units 4-5	06-2031	60 - R2.5	(20)	9,163,206	5,039,778	5,980,069	25.9	230,891	2.51%	192,409	2.10%	38,482	0.42%
Four Corners Common	06-2031	60 - R2.5	(20)	2,596,719	2,104,631	1,011,432	21.0	48,163	1.85%	40,136	1.55%	8,027	0.31%
Navajo Units 1-3	06-2026	60 - R2.5	(20)	20,226,194	11,727,970	12,543,463	22.0	570,157	2.82%	475,131	2.35%	95,026	0.47%
Ocotillo Units 1-2	06-2020	60 - R2.5	(20)	2,407,622	2,023,821	865,325	16.3	53,087	2.20%	44,240	1.84%	8,848	0.37%

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
	Saguaro Units 1-2	06-2014	80 - R2.5	(20)	2,654,661	2,355,021	830,572	11.2	74,156	2.79%	61,799	2.33%	12,360	0.47%
	Total Account 315				134,807,415	80,088,778	81,680,122		3,642,425	2.70%	3,035,354	2.25%	607,071	0.45%
316	Miscellaneous Power Plant Equipment													
	Cholla Unit 1	06-2017	40 - R2	(20)	2,315,189	1,189,333	1,686,894	13.5	117,696	5.08%	98,080	4.24%	19,616	0.85%
	Cholla Unit 2	06-2033	40 - R2	(20)	4,846,431	2,631,492	3,184,225	22.1	144,083	2.97%	120,069	2.48%	24,014	0.50%
	Cholla Unit 3	06-2035	40 - R2	(20)	4,136,531	1,990,199	2,976,038	23.8	125,044	3.02%	104,203	2.52%	20,841	0.50%
	Cholla Common	06-2035	40 - R2	(20)	7,096,069	2,439,747	6,075,536	25.8	235,486	3.32%	196,238	2.77%	39,248	0.55%
	Four Corners Units 1-3	06-2018	40 - R2	(20)	4,330,612	925,602	4,271,232	13.1	326,048	7.53%	271,707	6.27%	54,341	1.25%
	Four Corners Units 4-5	06-2031	40 - R2	(20)	3,304,340	1,402,561	2,582,647	23.0	111,419	3.37%	92,850	2.81%	18,570	0.56%
	Four Corners Common	06-2031	40 - R2	(20)	8,133,224	3,483,659	6,278,210	23.2	270,528	3.33%	225,439	2.77%	45,088	0.55%
	Navajo Units 1-3	06-2028	40 - R2	(20)	11,605,250	5,248,830	8,917,470	20.2	441,459	3.74%	367,882	3.12%	73,576	0.62%
	Ocotillo Units 1-2	06-2020	40 - R2	(20)	3,711,192	1,301,603	3,151,827	16.2	194,557	5.24%	162,131	4.37%	32,426	0.87%
	Saguaro Units 1-2	06-2014	40 - R2	(20)	3,191,024	1,340,385	2,488,844	10.9	228,334	7.16%	190,279	5.96%	38,056	1.19%
	Yucca Unit 1	06-2018	40 - R2	(20)	452,868	359,801	183,841	12.2	15,053	3.32%	12,544	2.77%	2,509	0.55%
	Total Account 316				53,324,730	22,313,112	41,676,564		2,209,705	4.14%	1,841,421	3.45%	368,284	0.69%
	TOTAL STEAM PRODUCTION PLANT				1,292,132,201	740,269,083	810,289,558		42,761,950		35,634,959		7,126,992	
	NUCLEAR PRODUCTION PLANT													
321	Structures and Improvements													
	Palo Verde Unit 1	12-2024	65 - R2.5	0	161,039,432	69,557,944	91,481,488	21.2	4,315,165	2.68%	4,315,165	2.68%	0	0.00%
	Palo Verde Unit 2	12-2025	65 - R2.5	0	88,415,370	38,859,061	49,556,209	22.0	2,252,555	2.55%	2,252,555	2.55%	0	0.00%
	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%	4,139,822	2.59%	0	0.00%
	Palo Verde Water Reclamati	03-2027	65 - R2.5	0	125,593,913	51,122,827	74,471,086	23.2	3,209,961	2.56%	3,209,961	2.56%	0	0.00%
	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%	2,534,931	2.58%	0	0.00%
	Total Account 321				632,767,021	261,989,961	370,777,040		16,452,433	2.60%	16,452,433	2.60%	0	0.00%
322	Reactor Plant Equipment													
	Palo Verde Unit 1	12-2024	70 - R1	(2)	359,545,213	153,818,828	213,119,289	20.6	10,345,597	2.88%	10,142,742	2.82%	202,855	0.06%
	Palo Verde Unit 2	12-2025	70 - R1	(2)	176,362,235	72,682,559	107,306,921	21.5	4,991,020	2.83%	4,893,156	2.77%	97,863	0.06%
	Palo Verde Unit 3	03-2027	70 - R1	(2)	322,750,700	121,218,478	207,987,236	22.6	9,202,975	2.85%	9,022,525	2.80%	180,450	0.06%
	Palo Verde Water Reclamati	03-2027	70 - R1	(2)	123,313	7,176	118,603	23.0	5,157	4.18%	5,056	4.10%	101	0.08%
	Palo Verde Common	03-2027	70 - R1	(2)	26,449,873	9,583,438	17,395,434	22.6	769,709	2.91%	754,617	2.85%	15,092	0.06%
	Total Account 322				885,231,334	357,008,477	545,927,484		25,314,457	2.86%	24,818,095	2.80%	496,362	0.06%
322.1	Reactor Plant Equipment - Steam Generators													
	Palo Verde Unit 1	12-2005	Square	(17)	30,722,376	27,569,149	8,376,030	3.0	2,792,010	9.09%	2,386,333	7.77%	405,677	1.32%
	Palo Verde Unit 2	12-2003	Square	(17)	16,870,053	15,868,635	2,699,327	1.0	2,699,327	17.01%	2,307,117	14.54%	392,210	2.47%
	Palo Verde Unit 3	12-2007	Square	(17)	25,413,317	20,039,935	9,693,646	5.0	1,938,729	7.63%	1,657,033	6.52%	281,696	1.11%
	Total Account 322.1				72,005,745	63,477,719	20,769,003		7,430,066	10.32%	6,350,484	8.82%	1,079,582	1.50%
323	Turbogenerator Units													
	Palo Verde Unit 1	12-2024	60 - S0	(2)	117,808,078	61,570,896	68,593,344	19.9	3,446,902	2.93%	3,379,315	2.87%	67,586	0.06%
	Palo Verde Unit 2	12-2025	60 - S0	(2)	78,754,224	32,432,468	45,858,840	20.8	2,204,658	2.87%	2,161,427	2.82%	43,229	0.06%
	Palo Verde Unit 3	03-2027	60 - S0	(2)	142,895,088	55,838,987	89,914,003	21.8	4,124,496	2.89%	4,043,623	2.83%	80,872	0.06%
	Palo Verde Water Reclamati	03-2027	60 - S0	(2)	217,707	76,585	145,478	22.0	6,613	3.04%	6,483	2.98%	130	0.06%
	Palo Verde Common	03-2027	60 - S0	(2)	1,223,879	346,554	901,803	22.2	40,622	3.32%	39,825	3.25%	797	0.07%
	Total Account 323				338,898,976	140,265,490	205,411,468		9,823,287	2.90%	9,630,674	2.84%	192,613	0.06%
324	Accessory Electric Equipment													

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Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
	Palo Verde Unit 1	12-2024	45 - R3	(2)	115,495,170	53,444,066	64,381,007	20.0	3,218,050	2.79%	3,154,951	2.73%	63,099	0.05%
	Palo Verde Unit 2	12-2025	45 - R3	(2)	50,119,388	21,982,186	29,139,590	20.9	1,394,239	2.78%	1,366,901	2.73%	27,338	0.05%
	Palo Verde Unit 3	03-2027	45 - R3	(2)	89,143,623	36,343,481	54,583,014	22.1	2,469,820	2.77%	2,421,392	2.72%	48,428	0.05%
	Palo Verde Common	03-2027	45 - R3	(2)	17,918,193	7,299,463	10,977,094	22.0	496,959	2.78%	489,175	2.73%	9,784	0.05%
	Total Account 324				272,676,374	119,069,196	159,080,705		7,581,068	2.78%	7,432,419	2.73%	148,648	0.05%
325	Miscellaneous Power Plant Equipment													
	Palo Verde Unit 1	12-2024	35 - R0.5	(2)	29,671,405	11,770,905	18,493,928	17.7	1,044,855	3.52%	1,024,367	3.45%	20,487	0.07%
	Palo Verde Unit 2	12-2025	35 - R0.5	(2)	26,389,406	8,702,844	18,214,350	18.7	974,029	3.69%	954,931	3.62%	19,099	0.07%
	Palo Verde Unit 3	03-2027	35 - R0.5	(2)	27,284,046	9,445,478	18,384,249	19.2	957,513	3.51%	938,738	3.44%	18,775	0.07%
	Palo Verde Water Reclamati	03-2027	35 - R0.5	(2)	88,819	27,708	62,889	19.5	3,225	3.63%	3,162	3.56%	63	0.07%
	Palo Verde Common	03-2027	35 - R0.5	(2)	48,959,610	15,382,218	34,046,482	19.4	1,754,973	3.62%	1,720,562	3.55%	34,411	0.07%
	Total Account 325				131,393,188	45,329,151	89,201,899		4,734,595	3.59%	4,641,760	3.52%	92,835	0.07%
	TOTAL NUCLEAR PRODUCTION PLANT				2,333,372,816	987,139,994	1,391,147,596		71,335,907		69,325,866		2,010,041	
	HYDRO PRODUCTION PLANT													
331	Structures and Improvement	12-2004	200-SQ	0	100,878	100,878	0	0.0	0	0.00	0	0.00%	0	0.00%
332	Reservoirs, Dams and Wate	12-2004	200-SQ	0	991,936	1,105,086	(113,150)	0.0	0	0.00	0	0.00%	0	0.00%
333	Water Wheels, Turbines and	12-2004	200-SQ	0	157,196	157,196	0	0.0	0	0.00	0	0.00%	0	0.00%
334	Accessory Electric Equipmer	12-2004	200-SQ	0	827,611	827,611	0	0.0	0	0.00	0	0.00%	0	0.00%
335	Miscellaneous Power Plant I	12-2004	200-SQ	0	126,018	126,018	0	0.0	0	0.00	0	0.00%	0	0.00%
336	Roads, Railroads and Bridge	12-2004	200-SQ	0	77,427	77,427	0	0.0	0	0.00	0	0.00%	0	0.00%
	Hydro Decomissioning Costs				-	7,884,531	5,335,469	2.0	2,667,735		2,667,735	100.00%	0	0.00%
	TOTAL HYDRO PRODUCTION PLANT				2,081,068	10,058,747	5,222,319		2,667,735		2,667,735		0	
	OTHER PRODUCTION PLANT													
341	Structures and Improvements													
	Douglas CT	06-2017	80 - S1	(5)	4,562	4,148	642	13.9	46	1.01%	44	0.96%	2	0.05%
	Ocotillo CT 1 - 2	06-2017	80 - S1	(5)	328,749	230,819	114,367	14.5	7,887	2.40%	7,512	2.28%	376	0.11%
	Saguaro CT	06-2017	80 - S1	(5)	1,158,525	468,971	885,980	14.4	61,526	4.77%	58,597	4.55%	2,930	0.23%
	Solar Unit 1		12 - SQ	0	375,512	383,809	(8,297)	3.6	0	0.00% (2)	0	0.00%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	80 - S1	(5)	510,951	419,492	117,007	14.2	8,240	1.61%	7,848	1.54%	392	0.08%
	West Phoenix Combined Cy	06-2031	80 - S1	(5)	6,706,722	2,438,522	4,803,538	28.1	163,827	2.44%	156,026	2.33%	7,801	0.12%
	Yucca CT 1 - 4	06-2016	80 - S1	(5)	452,751	222,815	252,574	13.4	18,849	4.16%	17,951	3.96%	898	0.20%
	Total Account 341				9,387,772	4,168,576	5,985,809		260,376	2.69%	247,977	2.56%	12,399	0.13%
342	Fuel Holders, Products and Accessories													
	Douglas CT	06-2017	70 - S1	(5)	137,759	100,065	44,582	14.0	3,184	2.31%	3,033	2.20%	152	0.11%
	Ocotillo CT 1 - 2	06-2017	70 - S1	(5)	719,859	517,984	237,868	14.0	16,991	2.36%	16,181	2.25%	809	0.11%
	Saguaro CT	06-2017	70 - S1	(5)	1,304,977	1,019,500	350,726	14.0	25,052	1.92%	23,859	1.83%	1,193	0.09%
	West Phoenix CT 1 - 2	06-2017	70 - S1	(5)	1,437,533	1,123,270	388,140	14.0	27,581	1.92%	26,268	1.83%	1,313	0.09%
	West Phoenix Combined Cy	06-2031	70 - S1	(5)	19,343,993	2,849,135	17,662,058	27.7	637,819	3.30%	607,257	3.14%	30,363	0.16%
	Yucca CT 1 - 4	06-2016	70 - S1	(5)	3,232,217	2,859,228	534,600	12.9	41,442	1.28%	39,468	1.22%	1,973	0.06%
	Total Account 342				28,176,338	8,269,182	19,215,973		751,870	2.67%	716,066	2.74%	35,803	0.14%
343	Prime Movers													
	Douglas CT	06-2017	70 - L1.5	0	1,101,449	999,227	102,222	14.2	7,199	0.65% (1)	7,199	0.65%	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%	70,912	1.06%	0	0.00%
	Saguaro CT	06-2017	70 - L1.5	0	8,102,651	6,657,234	1,445,417	13.8	104,740	1.29%	104,740	1.29%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	70 - L1.5	0	8,802,836	6,220,272	2,582,364	14.2	181,857	2.07%	181,857	2.07%	0	0.00%
	Yucca CT 1 - 4	06-2016	70 - L1.5	0	7,920,584	7,302,457	618,127	14.2	43,530	0.55% (1)	43,530	0.55%	0	0.00%

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
	Total Account 343				32,606,644	26,858,659	5,747,985		408,237	1.25%	408,237	1.25%	0	0.00%
344	Generators and Devices													
	Douglas CT	06-2017	37 - R3	0	555,785	542,840	8,925	9.7	920	0.17%	920	0.17%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	37 - R3	0	8,401,044	3,500,409	2,901,635	13.6	213,356	3.33%	213,356	3.33%	0	0.00%
	Saguaro CT	06-2017	37 - R3	0	4,185,247	2,504,957	1,660,290	13.0	129,253	3.09%	129,253	3.09%	0	0.00%
	Solar Unit 1		12 - SQ	0	8,933,081	3,289,918	3,643,163	7.8	487,072	5.74%	487,072	5.74%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	37 - R3	0	4,115,901	3,202,560	913,341	12.3	74,255	1.80%	74,255	1.80%	0	0.00%
	West Phoenix Combined Cy	06-2031	37 - R3	(2)	81,920,222	11,983,119	71,575,507	26.2	2,731,890	3.33%	2,731,890	3.33%	0	0.00%
	Yucca CT 1 - 4	06-2016	37 - R3	0	5,395,818	4,370,148	1,025,670	11.6	88,420	1.64%	88,420	1.64%	0	0.00%
	Total Account 344				109,504,078	29,393,951	81,748,531		3,705,166	3.38%	3,705,166	3.38%	0	0.00%
345	Accessory Electric Equipment													
	Douglas CT	06-2017	50 - S2	0	353,277	313,549	39,728	13.1	3,033	0.86%	3,033	0.86%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	50 - S2	0	1,494,836	1,281,843	212,793	13.2	16,121	1.08%	16,121	1.08%	0	0.00%
	Saguaro CT	06-2017	50 - S2	0	1,715,774	1,389,500	326,274	13.4	24,349	1.42%	24,349	1.42%	0	0.00%
	Solar Unit 1		12 - SQ	0	169,527	40,179	129,348	9.9	13,065	7.71%	13,065	7.71%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	50 - S2	0	1,557,744	1,315,426	242,318	13.2	18,357	1.18%	18,357	1.18%	0	0.00%
	West Phoenix Combined Cy	06-2031	50 - S2	0	11,925,645	2,562,942	9,362,703	27.8	336,788	2.82%	336,788	2.82%	0	0.00%
	Yucca CT 1 - 4	06-2016	50 - S2	0	2,166,526	1,817,969	348,557	13.0	26,812	1.24%	26,812	1.24%	0	0.00%
	Total Account 345				19,382,329	8,721,408	10,661,721		438,525	2.26%	438,525	2.26%	0	0.00%
346	Miscellaneous Power Plant Equipment													
	Douglas CT	06-2017	70 - L1	0	40,913	30,160	10,753	13.8	779	1.90%	779	1.90%	0	0.00%
	Ocotillo CT 1 - 2	06-2017	70 - L1	0	553,173	418,696	134,477	14.0	9,606	1.74%	9,606	1.74%	0	0.00%
	Saguaro CT	06-2017	70 - L1	0	790,906	410,357	380,549	14.1	26,989	3.41%	26,989	3.41%	0	0.00%
	West Phoenix CT 1 - 2	06-2017	70 - L1	0	957,431	508,533	448,898	14.1	31,837	3.33%	31,837	3.33%	0	0.00%
	West Phoenix Combined Cy	06-2031	70 - L1	0	2,608,877	895,856	1,713,021	26.6	64,399	2.47%	64,399	2.47%	0	0.00%
	Yucca CT 1 - 4	06-2016	70 - L1	0	427,175	357,633	69,542	13.2	5,268	1.23%	5,268	1.23%	0	0.00%
	Total Account 346				5,378,475	2,621,235	2,757,240		138,878	2.58%	138,878	2.58%	0	0.00%
	TOTAL OTHER PRODUCTION PLANT				202,716,436	80,031,011	128,097,259		5,703,052		5,654,849		48,202	

(1) Staff's reallocation of reserves caused account to have a remaining Net Book Value. APS selected the longest life of other plant in that FERC account to calculate remaining life.

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

TRANSMISSION PLANT														
352	Structures and Improvements	50 - R4	(5)	27,618,299	12,484,016	16,515,198	35.2	469,182	1.70%	446,840	1.62%	22,342	0.08%
352.5	Structures and Improvements - SCE 500 KV Line			409,725	424,897	(16,172)		13,316	3.25% (a)	13,316	3.25%	0	0.00%
353	Station Equipment	57 - R1.5	0	428,736,305	130,140,054	298,596,251	45.7	6,538,127	1.52%	6,538,127	1.52%	0	0.00%
353.5	Station Equipment - SCE 500 I			7,747,282	7,349,383	397,919		251,787	3.25% (a)	251,787	3.25%	0	0.00%
354	Towers and Fixtures	60 - R3	(35)	83,464,531	46,097,366	66,579,751	38.3	1,738,375	2.08%	1,287,685	1.54%	450,690	0.54%
354.5	Towers and Fixtures - SCE 50			13,752,584	17,477,965	(3,725,381)		446,959	3.25% (a)	446,959	3.25%	0	0.00%
355	Poles and Fixtures - Wood	48 - R1.5	(35)	91,120,939	27,541,958	95,479,410	38.5	2,479,985	2.72%	1,837,026	2.02%	642,959	0.71%
355.1	Poles and Fixtures - Steel	55 - R3	(15)	83,067,888	22,833,440	72,694,631	45.1	1,611,854	1.94%	1,401,612	1.69%	210,242	0.25%
355.5	Poles and Fixtures - SCE 500			930,308	692,575	237,733		30,235	3.25% (a)	30,235	3.25%	0	0.00%
356	Overhead Conductors and De	55 - R3	(35)	205,771,417	94,269,668	183,521,747	38.5	4,768,799	2.32%	3,530,962	1.72%	1,235,837	0.60%
356.5	Overhead Conductors and Devices - SCE 500 KV Line			22,653,515	28,947,611	(6,294,096)		736,239	3.25% (a)	736,239	3.25%	0	0.00%
357	Underground Conduit	48 - S1.5	(10)	10,444,382	4,087,064	7,401,734	35.7	207,331	1.99%	188,483	1.80%	18,848	0.18%
358	Underground Conductors and	40 - R3	(10)	18,551,254	9,702,854	10,703,525	26.3	406,978	2.19%	369,980	1.99%	36,998	0.20%
	TOTAL TRANSMISSION PLANT			994,274,409	402,048,829	742,093,250		19,697,167		17,079,251		2,617,916	

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
DISTRIBUTION PLANT														
361	Structures and Improvements		45 - R2.5	(10)	25,815,042	10,429,908	17,988,838	33.1	542,799	2.10%	493,453	1.91%	49,345	0.19%
362	Station Equipment		44 - L0.5	0	212,357,577	52,722,295	159,635,282	38.9	4,332,029	2.04%	4,332,029	2.04%	0	0.00%
364	Poles, Towers and Fixtures - V		38 - R0.5	(10)	284,200,711	81,128,434	231,492,348	30.9	7,491,662	2.64%	6,810,602	2.40%	681,060	0.24%
364.1	Poles, Towers and Fixtures - S		50 - R3	(5)	53,919,651	5,601,820	51,013,814	46.6	1,094,717	2.03%	1,042,588	1.93%	52,129	0.10%
365	Overhead Conductors and De		53 - O1	(10)	218,656,780	33,437,453	207,305,005	47.7	4,348,017	1.99%	3,950,924	1.81%	395,092	0.18%
366	Underground Conduit		86 - O1	(5)	425,723,116	26,924,767	420,084,505	82.4	5,098,113	1.20%	4,855,348	1.14%	242,767	0.06%
367	Underground Conductors and		29 - L1	(5)	805,505,783	258,865,205	586,915,867	22.9	25,629,514	3.18%	24,409,061	3.03%	1,220,453	0.15%
368	Line Transformers		36 - R3	(5)	488,837,053	235,537,009	275,641,897	24.6	11,204,955	2.30%	10,671,388	2.19%	533,569	0.11%
369	Services		37 - S2	(10)	242,404,812	91,086,515	175,558,778	27.9	6,292,429	2.60%	5,720,390	2.36%	572,039	0.24%
370	Meters		29 - L0	0	91,330,710	34,836,184	56,494,526	21.8	2,598,256	2.84%	2,598,256	2.84%	0	0.00%
370.1	Electronic Meters		26 - R1.5	0	54,691,249	8,612,961	46,078,288	23.3	1,975,913	3.61%	1,975,913	3.61%	0	0.00%
371	Installations On Customers Pr		50 - O2	(20)	25,335,831	3,863,126	26,539,871	45.0	589,775	2.33%	491,479	1.94%	98,296	0.39%
373	Street Lighting and Signal Sys		35 - R2	(20)	57,185,737	22,716,125	45,906,759	25.9	1,772,462	3.10%	1,477,051	2.58%	295,410	0.52%
TOTAL DISTRIBUTION PLANT					2,984,164,052	865,761,802	2,300,833,578		72,966,640		68,826,478		4,140,162	
GENERAL PLANT														
390	Structures and Improvements		39 - R1	(15)	96,687,435	24,085,116	87,082,434	30.7	2,836,561	2.93%	2,466,575	2.55%	369,986	0.38%
391	Office Furniture and Equipmer		20 - SQ	0	19,919,640	11,543,613	8,376,027	10.1	829,310	4.16%	829,310	4.16%	0	0.00%
391.1	Office Furniture and Equipmer		8 - R3	0	38,654,946	15,103,632	23,551,314	5.3	4,418,633	11.43%	4,418,633	11.43%	0	0.00%
391.2	Office Furniture and Equipmer		22 - R4	0	7,652,923	2,932,191	4,720,732	14.8	318,968	4.17%	318,968	4.17%	0	0.00%
393	Stores Equipment		20 - SQ	0	1,227,371	1,235,746	(8,375)	2.8	0	0.00% (2)	0	0.00%	0	0.00%
394	Tools, Shop and Garage Equi		20 - SQ	0	12,873,031	4,873,542	7,999,489	13.7	583,904	4.61%	583,904	4.61%	0	0.00%
395	Laboratory Equipment		20 - L1	0	1,350,583	531,270	819,313	12.0	68,504	5.07%	68,504	5.07%	0	0.00%
397	Communication Equipment		19 - S1.5	0	94,309,691	40,677,647	53,632,044	12.0	4,469,337	4.74%	4,469,337	4.74%	0	0.00%
398	Miscellaneous Equipment		24 - S1.5	0	1,338,404	481,755	854,649	16.6	51,454	3.85%	51,454	3.85%	0	0.00%

(2) Account is fully depreciated and, therefore, should have zero depreciation, not negative depreciation.

TOTAL GENERAL PLANT					273,782,024	101,264,512	187,027,827		13,576,672		13,206,685		369,986	
TOTAL DEPRECIABLE PLANT STUDIED					3,082,632,804	3,166,573,978	5,562,511,188		228,709,123		212,395,824		16,313,299	

(a) Assets related to the 500 KV SCE Transmission Line are Depreciated at a rate of 3.2[illegible]%.

STEAM PRODUCTION PLANT NOT STUDIED														
311	Structures and Improvements - West Phoenix				0	80,895								
312	Boiler Plant Equipment - West Phoenix Units				0	300,097								
312	Boiler Plant Equipment - Yucca Unit 1				425,323	441,994								
314	Turbogenerator Units - West Phoenix Units 4				0	314,512								
314	Turbogenerator Units - Yucca Unit 1				184,918	188,319								
316	Accessory Electric Equipment - West Phoenix				33,968	83,336								
315	Accessory Electric Equipment - Yucca Unit 1				182,084	185,435								
316	Misc. Power Plant Equipment-West Phoenix U				17,267	0								
TOTAL STEAM PRODUCTION PLANT NOT STUDIED					843,558	1,594,590								
GENERAL PLANT NOT STUDIED														
392	Vehicles				28,410,886	20,605,998								
396	Power Operated Equipment				27,947,651	18,603,989								
TOTAL GENERAL PLANT NOT STUDIED					56,358,537	39,209,987								
OTHER PROPERTY NOT STUDIED														
Intangible Plant														
301	Organization				73,639									

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ARIZONA PUBLIC SERVICE COMPANY

Schedule 1. Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals

Related to Electric Plant at December 31, 2002

The Calculated annual accrual (9) is made up of two depreciation components - service life and net salvage

	Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	Book Accumulated Depreciation	Future Accruals	Composite Remaining Life	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Annual Accrual Service Life Amount	Annual Accrual Service Life Rate	Annual Accrual Net Salvage Amount	Annual Accrual Net Salvage Rate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)=(9)/(5)	(11) =	(12)=(11)/(5)	(13) =	(14)=(13)/(5)
302	Franchises and Consents				883,584									
303	Miscellaneous Intangible Plant				201,550,375									
Leased Property														
321	Structures and Improvements				1,833,193									
322	Reactor Plant Equipment				9,870,223									
323	Turbogenerator Units				2,705,885									
324	Accessory Electric Equipment				944,788									
325	Miscellaneous Power Plant Equipment				563,135									
361	Structures and Improvements				195,612									
368	Line Transformers				179,394									
371	Installations On Customers Premises				80,388									
390	Structures and Improvements				11,180,324									
397	Communication Equipment				246,938									
TOTAL OTHER PROPERTY NOT STUDIED					229,866,377	120,727,768								
TOTAL DEPRECIABLE PLANT IN SERVICE					8,369,701,276	3,348,106,323								
NONDEPRECIABLE PLANT														
310	Land and Land Rights				3,295,268									
320	Land and Land Rights				3,399,728									
330	Land and Land Rights				84,500									
340	Land and Land Rights				26,192									
350	Land and Land Rights				50,806,274									
360	Land and Land Rights				26,755,119									
389	Land and Land Rights				7,327,438									
TOTAL NONDEPRECIABLE					91,694,517									
TOTAL PLANT IN SERVICE					8,461,372,793									

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DOCKET NO. E-01345A-03-0437

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

Depreciable Group	Probable Retirement Year	Estimated Survivor Curve	Net Salvage Percent	Original Cost at 12/31/02	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									
341 Structures and Improvements									
West Phoenix CC 4	6-2056	80 - S1	(5)	3,768,898	69,749	3,887,594	49.71	78,205	2.08%
342 Fuel Holders, Products and Accessories									
West Phoenix CC 4	6-2056	70 - S1	(5)	4,135,109	62,598	4,279,266	48.32	88,561	2.14%
343 Prime Movers									
West Phoenix CC 4	6-2056	70 - L1.5	(2)	57,116,985	919,686	57,339,639	46.94	1,221,552	2.14%
344 Generators and Devices									
Redhawk CC Units 1 & 2	6-2057	70 - O4	(3)	546,899,426	13,736,086	549,570,323	34.03	16,149,583	2.95%
West Phoenix CC 4	6-2056	37 - R3	(2)	14,296,553	28,896	14,553,588	35.47	410,307	2.87%
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	13,840,103	601,707,966		17,618,894	2.94%
TOTAL OTHER PRODUCTION PLANT				663,876,147	14,892,136	667,214,465		19,007,213	
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	(15)	1,500,000	23,458	1,701,542	54.50	31,221	2.08%
356 Overhead Conductors and Devices									
Redhawk CC Units 1 & 2		55 - R3	(35)	1,500,000	23,458	2,001,542	54.50	36,726	2.45%
TOTAL TRANSMISSION PLANT				50,953,105	688,611	51,014,494		904,473	
Depreciate Property Totals				714,829,252	15,580,747	718,228,959		19,911,686	
NONDEPRECIABLE PLANT									
340 Land									
Redhawk CC Common				2,246,597					
West Phoenix CC 4				32,909	70				
TOTAL NONDEPRECIABLE PLANT				2,279,507	70				
TOTAL PWE PLANT IN SERVICE				717,108,759	15,580,817				

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DOCKET NO. E-01345A-03-0437

PINNACLE WEST ENERGY CORPORTATION

Summary of Service Life and Net Salvage Estimates and Calculated Remaining Life Annual Accruals
Related to Electric Plant at December 31, 2002

The Calculated Annual Accrual (9) is made up of two depreciation components - service life and net salvage

Depreciable Group (1)	Probable Retirement Year (2)	Estimated Survivor Curve (3)	Net Salvage Percent (4)	Original Cost at 12/31/02 (5)	Book Accumulated Depreciation (6)	Future Accruals (7)	Composite Remaining Life (8)	Calculated Annual Accrual Amount (9)	Calculated Annual Accrual Rate (10)=(9)/(5)	Annual Accrual Service Life Amount (11) = (9) * 100/100+(-4))	Annual Accrual Service Life Rate (12)=(11)/(5)	Annual Accrual Net Salvage Amount (13) = (9) * (-4)/100+(-4))	Annual Accrual Net Salvage Rate (14)=(13)/(5)
OTHER PRODUCTION													
341 Structures and Improvements													
West Phoenix CC 4	6-2056	80 - S1	(5)	$3,768,898	$69,749	$3,887,594	49.71	$78,205	2.08%	$74,481	1.98%	$3,724	0.10%
342 Fuel Holders, Products and Accessories													
West Phoenix CC 4	6-2056	70 - S1	(5)	4,135,109	62,598	4,279,266	48.32	88,561	2.14%	$84,344	2.04%	$4,217	0.10%
343 Prime Movers													
West Phoenix CC 4	6-2056	70 - L1.5	(2)	57,116,985	919,886	57,339,839	46.94	1,221,552	2.14%	$1,197,600	2.10%	$23,952	0.04%
344 Generators and Devices													
Redhawk CC Units 1 & 2	6-2057	70 - O4	(3)	548,899,428	13,736,086	549,570,323	34.03	16,149,583	2.95%	$15,679,207	2.87%	$470,376	0.09%
West Phoenix CC 4	6-2056	37 - R3	(2)	14,296,553	28,896	14,553,588	35.47	410,307	2.87%	$402,262	2.81%	$8,045	0.06%
Saguaro CT 3	6-2047	37 - R3	0	37,659,176	75,121	37,584,055	35.49	1,059,004	2.81%	$1,059,004	2.81%	$0	0.00%
Total Account 344				598,855,155	13,840,103	601,707,966		17,618,894	2.94%	$17,140,473	2.86%	$478,421	0.08%
TOTAL OTHER PRODUCTION PLANT				663,876,147	14,892,136	667,214,465		19,007,213		18,496,898		510,315	
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%	$802,806	1.75%	$0	0.00%
West Phoenix CC 4		57 - R1.5	0	1,953,105	72,502	1,880,603	55.77	33,721	1.73%	$33,721	1.73%	$0	0.00%
Total Account 353				47,953,105	641,695	47,311,410		836,527	1.74%	$836,527	1.74%	$0	
355 Poles and Fixtures- Steel													
Redhawk CC Units 1 & 2		55 - R3	(15)	1,500,000	23,458	1,701,542	54.50	31,221	2.08%	$27,149	1.81%	$4,072	0.27%
356 Overhead Conductors and Devices													
Redhawk CC Units 1 & 2		55 - R3	(35)	1,500,000	23,458	2,001,542	54.50	36,728	2.45%	$27,204	1.81%	$9,521	0.63%
TOTAL TRANSMISSION PLANT				50,953,105	688,611	51,014,494		904,473		890,880		13,594	
Depreciate Property Totals				$714,829,252	$15,580,747	$718,228,959		$19,911,686		$19,387,778		$523,908	
NONDEPRECIABLE PLANT													
340 Land													
Redhawk CC Common				2,246,597									
West Phoenix CC 4				32,909	70								
TOTAL NONDEPRECIABLE PLANT				2,279,507	70								
TOTAL PWE PLANT IN SERVICE				$717,108,759	$15,580,817								

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DOCKET NO. E-01345A-03-0437

Preliminary Energy Efficiency DSM Plan Arizona Public Service Company		
Programs Organized by Market or Customer Segment	Program Descriptions: Elements/Concepts/Strategies/Tactics	Budget [1] (millions)
C&I New Construction	• Energy efficient schools • New construction, renovation, remodeling, equipment replacement • Early project identification • Design assistance • Education and training for designers • High efficiency HVAC, lighting and lighting design, motors/drives, systems and processes, cool roofs/materials (prescriptive and custom measures) • Commissioning[2] • Promotion of high performance buildings, including LEED certification • Building code support	$2.7
C&I Retrofit of Existing Facilities	• Energy efficient schools retrofit, including financial incentives • Large/medium C&I customers • High efficiency HVAC, lighting, motors/drives, O&M, systems and processes, cool roofs/materials (prescriptive and custom measures) • Building operator training and certification • Retro-commissioning[3] • Vendor and contractor training • National accounts/franchises • Municipal financial incentives • Education and information	$2.5
Small Business	• Lighting, HVAC, refrigeration • Technical assistance • Vendors market directly to customers in a one-stop, turnkey approach • Financial incentives	$1.7
C&I Subtotal		$6.9

[1] Includes incremental labor

[2] Commissioning uses a systematic process to optimize a new building's operations, and to ensure that new buildings operate and perform as intended by their designers, supported with documentation and training.

[3] Retro-commissioning uses a systematic process to improve and optimize an existing building's operations and to support those improvements with enhanced documentation and training.

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DOCKET NO. E-01345A-03-0437

Preliminary Energy Efficiency DSM Plan
Arizona Public Service Company

Programs Organized by Market or Customer Segment	Program Descriptions: Elements/Concepts/Strategies/Tactics	Budget (millions)
Residential New Construction	• Energy Star Plus equivalent (high performance) homes for leading builders • Energy Star equivalent promotion for the mainstream builders • Builder/contractor/realtor training • Guaranteed heating/cooling • Home performance testing • Lighting and appliances packages • Building code support	$2.4
Residential Existing Homes and HVAC	• HVAC contractor training and certification, systems approach • High efficiency HVAC systems • Duct testing and sealing • Home performance testing • Other cost-effective measures, including insulation and trees • Consumer education	$1.4
Residential Consumer Products	• Energy Star consumer products (lighting, appliances, windows) • Point of purchase displays/education • Cooperative advertising/marketing • Industry partnerships and buy downs • Retailing training • Federal efficiency standards support	$1.4
Residential Low Income	• Expand existing low income weatherization program • Lighting and appliance measures • Bill assistance	$1.0
Residential Subtotal		$6.2

DOCKET NO. E-01345A-03-0437

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Preliminary Energy Efficiency DSM Plan Arizona Public Service Company		
Programs Organized by Market or Customer Segment	Program Description: Elements/Concepts/Strategies/Tactics	Budget (millions)
Residential and C&I Programs Subtotal		$13.1
Measurement, Evaluation, and Research	MER plan will be developed for each DSM program. As a general rule, MER costs should be about 3% to 8% of total DSM budget. MER budget includes funding for some baseline studies to determine current practices, stock, and efficiency levels.	$1.3
Performance Incentive	Share (%) of DSM net economic benefits (benefits minus costs), capped at 10% of total DSM expenditures, inclusive of the performance incentive.	$1.6
TOTAL		$16.0

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

APPENDIX C

SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

1. General

1.1 Services will be supplied in accordance with these Terms and Conditions and any changes required by law, and such applicable rate or rates as may from time to time be authorized by law. However, in the case of the customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required.

1.2 These Terms and Conditions shall be considered a part of all rate schedules, except where specifically changed by a written agreement.

1.3 In case of a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule shall apply.

1.4 Company will supply electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and is responsible for distribution services, emergency system conditions, outages and safety situations related to Company's distribution system.

2. Establishment of Service

2.1 Application for Service - Customers requesting service may be required to appear at Company's place of business to produce proof of identity and sign Company's standard form of application for service or a contract before service is supplied by Company.

2.1.1 In the absence of a signed application or contract for service, the supplying of Standard Offer and/or Direct Access services by Company and acceptance thereof by the customer shall be deemed to constitute a service agreement by and between Company and the customer for delivery of, acceptance of, and payment for service, subject to Company's applicable rates and rules and regulations.

2.1.2 Where service is requested by two or more individuals, Company shall have the right to collect the full amount owed Company from any one of the applicants.

2.1.3 In mobile home parks identified by Company as being seasonal parks, Company may install or connect a meter as its scheduling permits; however, the customer will only be responsible for energy and demand recorded on and after their requested service turn on date.

2.2 Service Establishment Charge - A service establishment charge of $25.00 for residential and $35.00 non-residential plus any applicable tax adjustment will be assessed each time Company is requested to establish, reconnect or re-establish electric service to the customer's delivery point, or to make a special read without a disconnect and calculate a bill for a partial month. Billing for the service charge will be rendered as part of the service bill, but not later than the second service bill.

The service establishment charges above may be assessed when a customer changes their rate selection from Direct Access to Standard Offer.

2.2.1 The customer may additionally be required to pay a trip charge of $16.00 when an authorized Company representative travels to the customer's site and is unable to complete the customer's requested services due to lack of access to meter panel.

2.2.2 The customer may additionally be required to pay an after-hour charge of $75.00 should the customer request service, as defined in A.A.C. R14-2-203.D.3, be established, reconnected, or re-established during a period other than regular working hours, or on the same day of their request, regardless of the time the order may be worked by Company.

2.2.3 The charge for Company work, requested by the customer to be worked after hours or on a Company holiday that does not meet the definition of A.A.C. R14-2-203.D.3 will be $75.00 per hour.

2.3 Direct Access Service Request (DASR) - A Direct Access Service Request charge of $10.00 plus any applicable tax adjustment will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in the Company's Schedule 10, Terms and Conditions for Direct Access.

2.4 Grounds for Refusal of Service - Company may refuse to connect or reconnect Standard Offer or Direct Access service if any of the following conditions exist:

2.4.1 The applicant has an outstanding amount due with Company for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.

2.4.2 A condition exists which in Company's judgment is unsafe or hazardous.

2.4.3 The applicant has failed to meet the security deposit requirements set forth by Company as specified under Section 2.6 hereof.

2.4.4 The applicant is known to be in violation of Company's tariff.

2.4.5 The applicant fails to furnish such funds, service, equipment, and/or rights-of-way or easements required to serve the applicant and which have been specified by Company as a condition for providing service.

2.4.6 The applicant falsifies his or her identity for the purpose of obtaining service.

2.4.7 Service is already being provided at the address for which the applicant is requesting service.

2.4.8 Service is requested by an applicant and a prior customer living with the applicant owes a delinquent bill.

2.4.9 The applicant is acting as an agent for a prior customer who is deriving benefits of the service and who owes a delinquent bill.

2.4.10 The applicant has failed to obtain all required permits and/or inspections indicating that the applicant's facilities comply with local construction and safety codes.

2.5 Establishment of Credit or Security Deposit

2.5.1 Residential Establishment of Credit - Company shall not require a security deposit from a new applicant for residential service if the applicant is able to meet any of the following requirements:

2.5.1.1 The applicant has had service of a comparable nature with Company within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months or disconnected for nonpayment.

2.5.1.2 Company receives an acceptable credit rating, as determined by Company, for the applicant from a credit rating agency utilized by Company.

2.5.1.3 The applicant can produce a letter regarding credit or verification from an electric utility where service of a comparable nature was last received which states that the applicant had a timely payment history at the time of service discontinuation.

2.5.1.4 In lieu of a security deposit, Company receives deposit guarantee notification from a social or governmental agency acceptable to Company or a surety bond as security for Company in a sum equal to the required deposit.

2.5.2 Residential Establishment of Security Deposit - When credit cannot be established as provided for in Section 2.5.1 hereof or when it is determined that the applicant left an unpaid final bill owing to another utility company, the applicant will be required to:

2.5.2.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.2.2 Provide a surety bond acceptable to Company in an amount equal to the required security deposit.

2.5.3 Nonresidential Establishment of Security Deposit - All nonresidential customers may be required to:

2.5.3.1 Place a cash deposit to secure payment of bills for service as prescribed herein, or

2.5.3.2 Provide a non-cash security deposit in the form of a Surety Bond, Irrevocable Letter of Credit, or Assignment of Monies in an amount equal to the required security deposit.

2.6 Reestablishment of Security Deposit

2.6.1 Residential - Company may require a residential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a twelve (12) consecutive month period or has been disconnected for non-payment during the last twelve (12) months.

2.6.2 Nonresidential - Company may require a nonresidential customer to establish or re-establish a security deposit if the customer becomes delinquent in the payment of two (2) or more bills within a six (6) consecutive month period or if the customer has been disconnected for non-payment during the last twelve (12) months, or when the customer's

financial condition may jeopardize the payment of their bill, as determined by Company based on the results of using a credit scoring worksheet. Company will inform all customers of the Arizona Corporation Commission's complaint process should the customer dispute the deposit based on the financial data.

2.7 Security Deposits

2.7.1 Company reserves the right to increase or decrease security deposit amounts applicable to the services being provided by the Company:

2.7.1.1 If the customer's average consumption increases by more than ten (10) percent for residential accounts within a twelve (12) consecutive month period and five (5) percent for nonresidential accounts within a twelve (12) consecutive month period; or,

2.7.1.2 If the customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount which reflects that portion of the customer's service being provided by a Load Serving ESP. However if the Load Serving ESP is providing ESP Consolidated Billing pursuant to Company's Schedule 10 Section 7, the entire deposit will be credited to the customer's account; or,

2.7.1.3 If the customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount pursuant to Section 2.5, which reflects that APS is providing bundled electric service.

2.7.2 Separate security deposits may be required for each service location.

2.7.3 Customer security deposits shall not preclude Company from terminating an agreement for service or suspending service for any failure in the performance of customer obligation under the agreement for service.

2.7.4 Cash deposits held by Company six (6) months/183 days or longer shall earn interest at the established one year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website. Deposits on inactive accounts are applied to the final bill when all service options become inactive, and the balance, if any, is refunded to the customer of record within thirty (30) days. For refunds resulting from the customer changing from Standard Offer to Direct Access, the difference in the deposit amounts will be applied to the customer's account.

2.7.5 If the customer terminates all service with Company, the security deposit may be credited to the customer's final bill.

2.7.6 Residential security deposits shall not exceed two (2) times the customer's average monthly bill as estimated by Company for the services being provided by the Company.

2.7.6.1 Deposits or other instruments of credit will automatically expire or be returned or credited to the customers account after twelve (12) consecutive months of service, provided the customer has not been delinquent more than twice, unless Customer has filed bankruptcy in the last 12 months.

2.7.7 Nonresidential security deposits shall not exceed two and one-half (2-1/2) times the customer's maximum monthly billing as estimated by Company for the service being provided by the Company.

2.7.7.1 Deposits and non-cash deposits on file with Company will be reviewed after twenty-four (24) months of service and will be returned provided the customer has not been delinquent more than twice in the payment of bills or disconnected for non-payment during the previous twelve (12) consecutive months unless the customer's financial condition warrants extension of the security deposit.

2.8 Line Extensions - Installations requiring Company to extend its facilities in order to establish service will be made in accordance with Company's Schedule #3, Conditions Governing Extensions of Electric Distribution Lines and Services filed with the Arizona Corporation Commission.

3. Rates

3.1 Rate Information - Company shall provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to that customer for the requested type of service. In addition, Company shall notify its customers of any changes in Company tariffs affecting those customers.

3.2 Rate Selection – The customer's service characteristics and service requirements determine the selection of applicable rate schedule. If the customer is being served on a Standard Offer rate, Company will use reasonable care in initially establishing service to the customer under the most advantageous Standard Offer rate schedule applicable to the customer. However, because of varying customer usage patterns and other reasons beyond its reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. Company will not make any refunds in any instances where it is determined that the customer would have paid less for service had the customer been billed on an alternate applicable rate or provision of that rate.

3.3 Standard Offer Optional Rates – Certain optional Standard Offer rate schedules applicable to certain classes of service allow the customer the option to select the rate schedule to be effective initially or after service has been established. A customer desiring service under an alternate rate schedule after service has been established must make such request in writing to Company. Billing under the alternate rate will become effective from the next meter reading, or when the appropriate metering equipment is installed. No further rate schedule changes, however, may be made within the succeeding twelve-month period. Where the rate schedule or contract pursuant to which the customer is provided service specifies a term, the customer may not exercise its option to select an alternate rate schedule until expiration of that term.

3.4 Direct Access rate selection will be effective upon the next meter read date if DASR is processed fifteen (15) calendar days prior to that read date and the appropriate metering equipment is in place. If a DASR is made less than fifteen (15) days prior to the next regular read date the effective date will be at the next meter read date thereafter. The above timeframes are applicable for customers changing their selection of Electric Service Providers or for customers returning to Standard Offer service.

3.5 Any customer making a Direct Access rate selection may return to Standard Offer service in accordance with the rules, regulations, and orders of the Commission. However, such customer will not be eligible for Direct Access for the succeeding twelve (12) month period. If a customer

returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services then the above provision will only apply if the customer fails to select another ESP within sixty (60) days of returning to Standard Offer.

4. Billing and Collection

4.1 Customer Service Installation and Billing - Service billing periods normally consist of approximately 30 days unless designated otherwise under rate schedules, through contractual agreement, or at Company option.

4.1.1 Company normally meters and bills each site separately; however, adjacent and contiguous sites not separated by private or public property or right of way and operated as one integral unit under the same name and as a part of the same business, will be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

4.1.2 The customer's service installation will normally be arranged to accept only one type of service at one point of delivery to enable service measurement through one meter. If the customer requires more than one type of service, or total service cannot be measured through one meter according to Company's regular practice, separate meters will be used and separate billing rendered for the service measured by each meter.

4.2 Collection Policy - The following collection policy shall apply to all customer accounts:

4.2.1 All bills rendered by 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 bills for which payment has not been received shall be subject to the provisions of Company's termination procedure. Company reserves the right to suspend or terminate the customer's service for non-payment of any Arizona Corporation Commission approved services. All delinquent charges will be subject to a late charge at the rate of eighteen percent (18%) per annum.

4.2.2 If the customer, as defined in A.A.C. R 14-2-201.9, has two or more services with Company and one or more of such services is terminated for any reason leaving an outstanding bill and the customer is unwilling to make payment arrangements that are acceptable to Company, Company shall be entitled to transfer the balance due on the terminated service to any other active account of the customer for the same class of service. The failure of the customer to pay the active account shall result in the suspension or termination of service thereunder.

4.2.3 Unpaid charges incurred prior to the customer selecting Direct Access will not delay the customer's request for Direct Access. These charges remain the responsibility of the customer to pay. Normal collection activity, including discontinuing service, may be followed for failure to pay.

4.3 Responsibility for Payment of Bills

4.3.1 The customer is responsible for the payment of bills until service is ordered discontinued and Company has had reasonable time to secure a final meter reading for those services involving energy usage, or if non-metered services are involved until the Company has had reasonable time to process the disconnect request.

4.3.2 When an error is found to exist in the billing rendered to the customer, Company will correct such an error to recover or refund the difference between the original billing and the correct billing. Such adjusted billings will not be rendered for periods in excess of the applicable statute of limitations from the date the error is discovered. Any refunds to customers resulting from overbillings will be made promptly upon discovery by Company. Underbillings by Company shall be billed to the customer who shall be given an equal length of time such as number of months underbilled to pay the backbill without late payment penalties, unless there is evidence of meter tampering or energy diversion. Except in situations where the account is billed on a special contract or non-metered rate, where service has been established but no bills have been rendered, or where there is evidence of meter tampering or energy diversion, underbillings for residential accounts shall be limited to three (3) months and non-residential accounts shall be limited to six (6) months.

4.3.3 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of up to $10.00 per customer to customers who elect to pay their bills using Company's electronically transmitted payment options.

4.3.4 Where Company is responsible for rendering the customer's bill, Company may provide a one time incentive of $5.00 per customer for a customer electing to forego the presentation of a paper bill.

4.4 Dishonored Payments - If Company is notified by the customer's financial institution that they will not honor a payment tendered by the customer for payment of any bill, Company may require the customer to make payment in cash, by money order, certified check, or other means which guarantee the customer's payment to Company.

4.4.1 The customer shall be charged a fee of $15.00 for each instance where the customer tenders payment of a bill with a payment that is not honored by the customer's financial institution.

4.4.2 The tender of a dishonored payment shall in no way (i) relieve the customer of the obligation to render payment to Company under the original terms of the bill, or (ii) defer Company's right to terminate service for nonpayment of bills.

4.4.3 Where the customer has tendered two (2) or more dishonored payments in the past twelve (12) consecutive months, Company may require the customer to make payment in cash, money order or cashier's check for the next twelve (12) consecutive months.

4.5 Field Call Charge - Company may require payment of a Field Call Charge of $15.00 when an authorized Company representative travels to the customer's site to accept payment of a delinquent account, notify of service termination, make payment arrangements or terminate the service. This charge will only be applied for field calls resulting from the termination process.

4.5.1 If a termination is required at the pole, a reconnection charge of $96.50 will be required; if the termination is in underground equipment, the reconnection charge will be $115.00.

4.5.2 To avoid termination of service, the customer may make payment in full, including any necessary deposit in accordance with Section 2.5 hereof or make payment arrangements satisfactory to Company.

4.6 On-site Evaluation – Company may require payment of an On-site Evaluation Charge of $82.00 when an authorized Company field investigator performs an on-site visit to evaluate how the customer may reduce their energy usage. This charge may be assessed regardless of if the customer actually implements Company suggestions.

5. Service Responsibilities of Company and Customer

5.1 Service Voltage –Company will deliver electric service at the standard voltages specified in the Electric Service Requirements Manual published by Company and as specified in A.A.C. R14-2-208.F.

5.2 Responsibility: Use of Service or Apparatus

5.2.1 The customer shall save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or the use thereof on the customer's side of the point of delivery. Company shall have the right to suspend or terminate service in the event Company should learn of service use by the customer under hazardous conditions.

5.2.2 The customer shall exercise all reasonable care to prevent loss or damage to Company property installed on the customer's site for the purpose of supplying service to the customer.

5.2.3 The customer shall be responsible for payment for loss or damage to Company property on the customer's site arising from neglect, carelessness or misuse and shall reimburse Company for the cost of necessary repairs or replacements.

5.2.4 The customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the meter.

5.2.5 The customer shall be responsible for notifying Company of any failure in Company's equipment.

5.3 Service Interruptions: Limitations on Liability of Company

5.3.1 Company shall not be liable to the customer for any damages occasioned by Load Serving ESP's equipment or failure to perform, fluctuations, interruptions or curtailment of electric service except where due to Company's willful misconduct or gross negligence. Company may, without incurring any liability therefore, suspend the customer's electric service for periods reasonably required to permit Company to accomplish repairs to or changes in any of Company's facilities. The customer needs to protect their own sensitive equipment from harm caused by variations or interruptions in power supply.

5.3.2 In the event of a national emergency or local disaster resulting in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers

or Company, interrupt service to other customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

5.4 Company Access to Customer Sites - Company's authorized agents shall have unassisted access to the customer's sites at all reasonable hours to install, inspect, read, repair or remove its meters or to install, operate or maintain other Company property, or to inspect and determine the connected electrical load. If, after six (6) months (not necessarily consecutive) of good faith efforts by Company to deal with the customer, Company in its opinion does not have unassisted access to the meter, then Company shall have sufficient cause for termination of service or denial of any existing rate options where access is required. The remedy for unassisted access will be at Company discretion and may include the installation by Company of a specialized meter. If such specialized meter is installed, the customer will be billed the difference between the otherwise applicable meter for their rate and the specialized meter. If service is terminated as a result of failure to provide unassisted access, Company verification of unassisted access may be required before service is restored. Written termination notice is required prior to disconnecting service under this schedule.

5.5 Easements

5.5.1 All suitable easements or rights-of-way required by Company for any portion of the extension which is on sites owned, leased or otherwise controlled by the customer shall be furnished in Company's name by the customer without cost to Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

5.5.2 When Company discovers that the customer or the customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow adjacent to or within an easement or right-of-way or Company-owned equipment, and such work, construction, vegetation or facility poses a hazard or is in violation of federal, state, or local laws, ordinances, statutes, rules or regulations, or significantly interferes with Company's safe use, operation or maintenance of, or access to, equipment or facilities, Company shall notify the customer or the customer's agent and shall take whatever actions are necessary to eliminate the hazard, obstruction, interference or violation at the customer's expense. Company will notify the customer in writing of the violations.

5.6 Load Characteristics – The customer shall exercise reasonable care to assure that the electrical characteristics of its load, such as deviation from sine wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in demand, shall not impair service to other customers or interfere with operation of telephone, television, or other communication facilities. The deviation from phase balance shall not be greater than ten percent (10%) at any time. Customers receiving service at voltage levels below 69 kV shall maintain a power factor of 90% lagging but in no event leading unless agreed to by Company. In situations where Company suspects that a customer's load has a non-conforming power factor, Company may install at its cost the appropriate metering to monitor such loads. If the customer's power factor is found to be non-conforming, the customer will be required to pay the cost of installation and removal of VAR metering and recording equipment.

Customers found to have a power factor of less than 90%, or leading, or other detrimental conditions shall be required to remedy problems in order to achieve a power factor in conformance with above standards, or pay for facilities/equipment that Company must install on its system to

correct for problems caused by the customer's load. Until such time as the customer remedies the problem, kVa may be substituted for kW in determining the applicable charge for billing purposes for each month in which such failure occurs.

6. Metering and Metering Equipment

6.1 Customer Equipment - The customer shall install and maintain all wiring and equipment beyond the point of delivery. Except for Company's meters and special equipment, the customer's entire installation must conform to all applicable construction standards and safety codes and the customer must furnish an inspection or permit if required by law or by Company.

6.1.1 The customer shall provide, in accordance with Company's current service standards and/or Electric Service Requirements Manual, at no expense to Company, and close to the point of delivery, a sufficient and suitable space acceptable to Company's agent for the installation, accessibility and maintenance of Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line at http://esp.apsc.com/resource/metering.

6.1.2 If telephone lines or any other devices are required to read the customer's meter, the customer is responsible for the installation, maintenance, and usage fees at no cost to Company.

6.1.3 Where a customer requests, and Company approves, a special meter reading device to accommodate the customer's needs, the cost for such additional equipment shall be the responsibility of the customer.

6.2 Company Equipment

6.2.1 A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment pursuant to Company's Schedule 10. Meters not returned to Company or returned damaged will be charged the replacement costs less five (5) years depreciation plus an administration fee of fifteen percent (15%).

6.2.2 Company will lease lock ring keys to MSP's and/or their agents authorized to remove Company meters pursuant to the terms and conditions of Company's Schedule 10 at a refundable charge of $70.00 per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace ten percent (10%) of the issued keys within any twelve (12) month period due to loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint meeting. All lock ring keys must be returned to Company within five (5) working days if the MSP and/or its authorized agents are:

1) No longer permitted to remove Company meters pursuant to conditions of the Company's Schedule 10;
2) No longer authorized by the Arizona Corporation Commission to provide services; or
3) The ESP Agreement has been terminated.

6.2.3 If the MSP, the customer, and/or its' agent request a joint site meeting for removal of Company metering and associated equipment and/or lock ring, a base charge will be assessed of $62.00 per site. Company may assess an additional charge of $53.00 per hour for joint site meetings that exceed thirty (30) minutes. In the event Company must

temporarily replace the MSP's meter and/or associated metering equipment as necessary during emergency situations or to restore power to a customer, the above charges may apply.

6.3 Service Connections - Company is not required to install and maintain any lines and equipment on the customer's side of the point of delivery except its meter. For overhead service, the point of delivery shall be where Company's service conductors terminate at the customer's weatherhead or bus rider. For underground service, the point of delivery shall be where Company's service conductors terminate in the customer's service equipment. The customer shall furnish, install and maintain any risers, raceways and/or termination cabinet necessary for the installation of Company's underground service conductors. For the mutual protection of the customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the customer's service entrance conductors. Such employees carry credentials which they will show on request.

6.4 Measuring Customer Service - All the energy sold to the customer will be measured by commercially acceptable measuring devices by Company or the Meter Reading Service Provider (MRSP) pursuant to the terms and conditions of Company's Schedule 10. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company.

6.4.1 For Standard Offer customers, or where Company is the MRSP, the readings of the meter will be conclusive as to the amount of electric power supplied to the customer unless there is evidence of meter tampering or energy diversion, or unless a test reveals the meter is in error by more than plus or minus three percent (3%).

6.4.2 If there is evidence of meter tampering or energy diversion, the customer will be billed for the estimated energy consumption that would have registered had all energy usage been properly metered. Additionally, where there is evidence of meter tampering, energy diversion, or by-passing the meter, the customer may also be charged the cost of the investigation as determined by Company.

6.4.3 If after testing, a meter is found to be more than three percent (3%) in error, either fast or slow, proper correction shall be made of previous readings and adjusted bills shall be rendered or adjusted billing information will be provided to the MRSP.

6.4.4 Customer will be billed for the estimated energy and demand that would have registered had the meter been operating properly. Where Company is the MRSP, Company shall, at the request of the customer or the ESP, reread the customer's meter within ten (10) working days after such request by the customer. The cost of such rereads is $16.50 and may be charged to the customer or the ESP, provided that the original reading was not in error.

6.4.5 Where the ESP is the MSP or MRSP, and the ESP and/or its' agent fails to provide the meter data to Company pursuant to Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may obtain the data, or may estimate the billing determinants. The charge for such reread is $16.50 and may be charged to the ESP.

6.5 Meter Testing - Company tests its meters regularly in accordance with a meter testing and maintenance program as approved by the Arizona Corporation Commission. Company will,

however, individually test a Company owned/maintained meter upon customer or ESP request. If the meter is found to be within the plus or minus three percent (3%) limit, Company may charge the customer or the ESP $30.00 for the meter test if the meter is removed from the site and tested in the meter shop, and $50.00 if the meter remains on site and is tested in the field.

6.6 Master Metering

6.6.1 Mobile Home Parks - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by Company.

6.6.2 Residential Apartment Complexes, Condominiums and Other Multiunit Residential Buildings - Company shall refuse service to all new construction of apartment complexes and condominiums which are master metered unless the building(s) will be served by a centralized heating, ventilation and/or air conditioning system and the contractor can provide to Company an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in A.A.C. R14-2-205.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A customer violation of any of the applicable rules of the Arizona Corporation Commission or Company tariffs.

7.1.2 Failure of the customer to pay a delinquent bill for services provided by Company.

7.1.3 The customer's breach of a written contract for service.

7.1.4 Failure of the customer to comply with Company's deposit requirements.

7.1.5 Failure of the customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.

7.1.7 Failure of a prior customer to pay a delinquent bill for utility services where the prior customer continues to reside on the premises.

7.1.8 Failure to provide or retain rights-of-way or easements necessary to serve the customer.

7.2 Without Notice - Company may without liability for injury or damage disconnect service to any customer without advance notice under any of the following conditions:

7.2.1 The existence of an obvious hazard to the health or safety of persons or property.

7.2.2 Company has evidence of meter tampering or fraud.

7.2.3 Company has evidence of unauthorized resale or use of electric service.

7.2.4 Failure of the customer to comply with the curtailment procedures imposed by Company during a supply shortage.

7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.

8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the customer, and Company shall be under no further obligation to serve the customer. If, however, Company has not removed its facilities within one (1) year after the termination of service, Company shall thereafter give the customer thirty (30) days written notice before removing its facilities, or else waive any reestablishment charge within the next year for the same service to the same customer at the same location.

For purposes of this Section notice to the customer shall be deemed given at the time such notice is deposited in the U.S. Postal Service, first class mail, postage prepaid, to the customer at his/her last known address.

9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the customer and Company, but no assignments by the customer shall be effective until the customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.

10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.

APS

APPENDIX D SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF ELECTRIC DISTRIBUTION LINES AND SERVICES

Provision of electric service from Arizona Public Service Company (Company) may require construction of new facilities or upgrades to existing facilities. Costs for construction depend on the customer's location, load size, and load characteristics. This schedule establishes the terms and conditions under which Company will extend its facilities to provide new or upgraded facilities.

All extensions are made on the basis of economic feasibility. Construction allowance and revenue basis methodologies are offered below for use in circumstances where feasibility is generally accepted because of the number of extensions made within the construction allowance and dollar limits.

All extensions shall be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and company facilities at the beginning point of an extension also as determined by Company.

The following policy governs the extension of overhead and underground electric facilities, and underground facilities as specified in Section 6, to customers whose requirements are deemed by Company to be usual and reasonable in nature.

1. FOOTAGE BASIS - RESIDENTIAL ONLY

1.1 GENERAL POLICY - Footage basis extensions may be made only if all of the following conditions exist:

1.1.1 The applicant is a new permanent residential customer or group of new permanent residential customers. Customers specified in Section 4 below are not eligible for this allowance.

1.1.2 The total extension does not exceed 2,000 feet per customer and under no circumstances can the total allowable distance exceed 10,000 feet.

1.1.3 The total extension does not exceed a total construction cost of $25,000.

1.1.4 No construction allowance will be permitted beyond the shortest practical route to the nearest practical point of delivery on each customer's site as determined by Company.

1.2 FREE EXTENSIONS - May be made if the conditions specified in Section 1.1 are met and:

1.2.1 The free extension will be limited to a maximum of 1,000 feet per new permanent residential customer.

1.2.2 Free allowance for the total extension will be 1,000 feet per customer regardless of the customer's location along the route of the extension.

1.3 EXTENSIONS OVER THE FREE DISTANCE

For extensions which meet the conditions specified in Section 1.1 above, and which exceed the free distance specified in Section 1.2.1, Company may extend its facilities up to the maximum allowed in Section 1.1.2 provided the customer or customers will sign an extension agreement and advance the cost of such additional footage. Advances are subject to refund as specified in Section 5.

2. REVENUE BASIS - NON-RESIDENTIAL

2.1 GENERAL POLICY - Revenue basis extensions may be made only if all of the following conditions exist:

2.1.1 Applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

2.1.2 Such extension does not exceed a total construction cost of $25,000.

2.2 FREE EXTENSIONS

Such extension shall be free to the customer where the conditions specified in Section 2.1 herein are met and the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) multiplied by six (6.0) is equal to or greater than the total construction cost less nonrefundable customer contributions.

2.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 2.1, above, and which exceed the free limits specified in Section 2.1.2, Company may extend its facilities up to a cost limitation of $25,000, provided the customer or customers will sign an extension agreement and advance a sufficient portion of the construction cost so that the remainder satisfies the requirements of Section 2.2. Advances are subject to refund as specified in Section 5.

3. ECONOMIC FEASIBILITY BASIS

3.1 GENERAL POLICY - Extensions may be made on the basis of economic feasibility only if all of the following conditions exist:

3.1.1 The applicant is or will be a permanent customer or group of permanent customers. Customers specified in Sections 4.1, 4.2, or 4.3 are not eligible for this basis.

3.1.2 The total construction cost exceeds $25,000 except for extensions specified in Sections 4.4 or 7.7.

3.2 FREE EXTENSIONS

Such extensions shall be free to the customer where the conditions specified in Section 3.1 are met and the extension is determined to be economically feasible. "Economic feasibility", as used in this policy, shall mean a determination by Company that the estimated annual revenue based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the customer.

3.3 EXTENSIONS OVER THE FREE LIMITS

For extensions which meet the conditions specified in Section 3.1, above, Company, after special study and at its option, may extend its facilities to customers who do not satisfy the definition of economic feasibility as specified in Section 3.2, provided such customers sign an extension agreement and advance as much of the construction cost and/or agree to pay such higher special rate (facilities

charge) as is required to make the extension economically feasible. Advances are subject to refund as specified in Section 5.

4. OTHER CONDITIONS

4.1 IRRIGATION CUSTOMERS

Customers requiring construction of electric facilities for service to agricultural irrigation pumping will advance the total construction cost. Advances are subject to refund as specified in Section 5.2. Non-agricultural irrigation pumping will be extended as specified in Section 2 or 3.

4.2 TEMPORARY CUSTOMERS

Where a temporary meter or construction is required to provide service to the customer, then the customer, in advance of installation or construction, shall make a non-refundable contribution equal to the cost of installing and removing the facilities required to furnish service, less the salvage value of such facilities. When the use of service is discontinued or agreement for service is terminated, Company may dismantle its facilities and the materials and equipment provided by Company will be salvaged and remain Company property.

4.3 DOUBTFUL PERMANENCY CUSTOMERS

When, in the opinion of Company, permanency of the customer's residence or operation is doubtful, the customer will be required to advance the total construction cost. Advances are subject to refund as specified in Section 5.3.

4.4 REAL ESTATE DEVELOPMENT

Extensions of electric facilities within real estate developments including residential sub divisions, industrial parks, mobile home parks, apartment complexes, planned area developments, etc., may be made in advance of application for service by permanent customers, as specified in Section 3. Anticipated revenue for Residential Real Estate extensions shall be calculated from information provided by the developer.

4.4.1 MOBILE HOME PARKS - Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion is individually metered by the utility.

4.4.2 RESIDENTIAL APARTMENT COMPLEXES, CONDOMINIUMS AND OTHER MULTI UNIT RESIDENTIAL BUILDINGS - Company shall refuse service to all new construction and/or expansion of apartment complexes and condominiums unless the construction and/or expansion is individually metered by the utility. Master metering will only be allowed for buildings utilizing centralized heating, ventilation and/or air conditioning system where the contractor can provide an analysis demonstrating that the central unit will result in a favorable cost/benefit relationship as stated in R14-2-205 of Corporation Commission's Administrative Rules and Regulations.

5. REFUNDS

5.1 REVENUE AND ECONOMIC FEASIBILITY BASIS REFUNDS

5.1.1 Customer advances over $50.00 are subject to full or partial refund, provided that a survey based on conditions of the extension, not including laterals or extensions from the extension being surveyed as specified in Section 5.1.2 existing at the time of survey, results in an advance lower than the amount actually advanced. Except as provided for in Section 5.3, such surveys shall not be made for customers extended to under the basis specified in Section 4.1, 4.2, or 4.3. A survey will be conducted by Company five (5) years after signing the extension agreement under the extension policy in force at the time of the extension . Upon request, the customer will be entitled to intermediate surveys within the five (5) year period after the end of six (6) months following the date of signing the extension agreement and subsequent surveys at intervals of not less than one (1) year thereafter. Company will refund the difference between the amount advanced and the amount that would have been advanced had the advance been calculated at the time of survey. In no event shall the amount of any refund exceed the amount originally advanced.

5.1.2 Laterals or extensions from an extension being surveyed shall not be considered in the survey when the lateral or extension was extended on the basis "extensions over the free limits" of Sections 2.2 or 3.2, or is not connected directly to the extension being surveyed. In real estate developments extended to under the basis specified in Section 4.4, the survey may include laterals and extensions to serve permanent customers located within the real estate development described in the extension agreement for the extension being surveyed.

5.1.3 In lieu of surveys, Company will determine the refund based on the number of permanent connections to the extension for residential real estate development. In such event, Company shall specify in the extension agreement the amount of refund per permanent customer connection.

5.2 REFUNDS FOR EXTENSIONS TO IRRIGATION CUSTOMERS

Customer advances over $50.00 are subject to refund of twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill, for service to the irrigation pump specified in the agreement for the extension being surveyed, commencing with the date of signing the agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.3 REFUNDS TO CUSTOMERS OF DOUBTFUL PERMANENCY

Customer advances over $50.00 are subject to full or partial refund pursuant to surveys based on the Revenue or Economic Feasibility Basis as specified in Section 5.1.1. In no event shall the refund exceed twenty-five (25) percent of the annual accumulation of twelve (12) monthly bills based on Company's then currently effective rate for distribution service (excluding taxes, regulatory assessment and other adjustments) in excess of the annual minimum bill for the customer specified in the extension agreement. In no event shall the amount of any refund exceed the amount originally advanced.

5.4. GENERAL REFUND CONDITIONS

5.4.1 Customer advances of $50.00 or less are not subject to refund.

5.4.2 No refund will be made to any customer for an amount more than the unrefunded balance of the customer's advance.

5.4.3 Any unrefunded balance of the customer's advance shall become nonrefundable five (5) years from the date of Company's receipt of the advance.

5.4.4 Company reserves the right to withhold refunds to any customer whose account is delinquent and apply these refund amounts to past due bills.

6. UNDERGROUND CONSTRUCTION

6.1 GENERAL UNDERGROUND CONSTRUCTION POLICY - With respect to all underground installations, Company may install underground facilities only if all of the following conditions are met:

6.1.1 The extension meets feasibility requirements as specified in Sections 1, 2, 3, or 4.

6.1.2 The customer or developer provides all earthwork including, but not limited to, trench, boring or punching, conduits, backfill, compaction, and surface restoration in accordance with Company specifications.

(Company may provide all earthwork and the customer or developer will make a nonrefundable contribution equal to the cost of such work provided by Company.)

6.2 THREE-PHASE UNDERGROUND CONSTRUCTION - Where it is determined that three phase is required to serve the customer, Company may install three-phase facilities if the conditions specified in Section 6.1 are met, and the customer provides the following:

6.2.1 Installation of equipment pads, pull-boxes, manholes, and conduits as required in accordance with Company specifications. In lieu of providing conduits, the customer may provide a nonrefundable contribution equal to the estimated difference in cost between overhead and underground facilities.

6.2.2 A nonrefundable contribution for excess service footage required by the customer equal to the increased estimated cost of installed service lines over what would be required with a maximum 40-foot service at 480 volts and 20-foot service at 120/208 or 240 volts.

6.2.3 Transformer pad and secondary conduits in accordance with Company specifications. (Company may provide pad and conduits, and the customer or developer will make a non-refundable contribution equal to the cost of such work provided by Company.)

7. GENERAL CONDITIONS

7.1 VOLTAGE

The extension will be designed and constructed for operation at standard voltages used by Company in the area in which the extension is located.

7.2 THREE PHASE

Extensions for three phase service can be made under this extension policy where the customer has installed major three phase equipment. Motors with a name-plate rating of 7-1/2 HP or more or single air conditioning units of 6 tons or more or where total horsepower of all connected three phase motors exceeds 12 HP or total load exceeding 100 kVa demand shall qualify for three phase. If the estimated

load is less than the above horsepower or connected kVa specifications, Company may, at its option and when requested by the customer, serve three phase and require a nonrefundable contribution equal to the difference in cost between single phase and three phase construction, but in no case less than $100.

7.3 EASEMENTS

All suitable easements or rights-of-way required by Company for any portion of the extension which is either on premises owned, leased or otherwise controlled by the customer or developer, or other property required for the extension, shall be furnished in Company's name by the customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All easements or rights-of-way obtained on behalf of Company shall contain such terms and conditions as are acceptable to Company.

7.4 GRADE MODIFICATIONS

If subsequent to construction of electric distribution lines and services, the final grade established by the customer or developer is changed in such a way as to require relocation of Company facilities or the customer's actions or those of his contractor results in damage to such facilities, the cost of relocation and/or resulting repairs shall be borne by Customer or developer.

7.5 OWNERSHIP

Except for customer-owned facilities, all construction, including that for which customers have made advances and/or contributions, will be owned, operated and maintained by Company.

7.6 MEASUREMENT AND LOCATION

7.6.1 Measurement must be along the proposed route of construction.

7.6.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.

7.6.3 The extension must be a branch from, the continuation of, or an addition to, one of Company's existing distribution lines.

7.7 UNUSUAL CIRCUMSTANCES

In unusual circumstances as determined by Company, when the application and provisions of this policy appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when Customer's estimated load will exceed 3,000 kW, Company will make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in Section 1.1 of Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.

7.8 NON-STANDARD CONSTRUCTION

Company's construction practices employ contemporary methods and equipment and meet current industry standards. Where extensions of electric facilities require construction that is in any way nonstandard, as determined by Company, or if unusual obstructions are encountered, the customer

will make a non- refundable contribution equal to the difference in cost between standard and non-standard construction, in addition to other applicable costs involved.

7.9 ABNORMAL LOADS

Company, at its option, may make extensions to serve certain abnormal loads (such as: transformer-type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics), provided the customer makes a nonrefundable contribution equal to the total cost of such extension, including transformers.

7.10 RELOCATIONS AND/OR CONVERSIONS

7.10.1 Company will relocate or convert its facilities for the customer's convenience or aesthetics, providing the customer makes a nonrefundable contribution equal to the total cost of relocation or conversion.

7.10.2 When the relocation or conversion is in conjunction with added revenue, as determined by Company and is not for the customer's convenience or aesthetics, then the relocation or conversion costs plus the costs to serve will be used to determine the customers advance on the basis specified in Section 2 or 3.

7.11 CHANGING OF MASTER METER TO INDIVIDUAL METER

Company will convert its facilities from master metered system to a permanent individually metered system at the customer's request provided the customer makes a nonrefundable contribution equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the individual meters will be extended on basis specified in Section 2 or 3.

7.12 CHANGE IN CUSTOMER'S SERVICE REQUIREMENTS

Company will rebuild or revamp existing facilities to meet the customer's added load or change in service requirements on the basis specified in Section 2 or 3.

7.13 DESIGN DEPOSIT

Any applicant requesting Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with Company an amount equal to the estimated cost of preparation. Where the applicant authorizes Company to proceed with construction of the extension, the deposit shall be credited to the cost of construction; otherwise the deposit shall be nonrefundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the customer for a line extension upon request.

7.14 CUSTOMER CONSTRUCTION OF COMPANY DISTRIBUTION FACILITIES

The customer may provide construction related services, e.g. engineering, survey, materials and/or labor, associated with new distribution facilities to serve the customer's new or added load, provided the customer meets all of the requirements set forth by Company. All work and/or materials provided by the customer shall comply with Company standards in effect at the time of construction. The customer shall receive written approval from Company prior to performing any construction related services. Company will perform an Economic Feasibility Analysis prior to the approval of any

proposed customer provided construction to ensure the proposed scope of work results in mutual benefits to the customer and Company.

7.15 SETTLEMENT OF DISPUTES

Any dispute between the customer or prospective customer and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may, by either party, be referred to the Arizona Corporation Commission or a designated representative or employee thereof for determination.

7.16 INTEREST

All advances made by the customer to Company in aid of construction shall be non-interest bearing.

7.16 EXTENSION AGREEMENTS

All line extensions requiring payment by the customer shall be in writing and signed by both the customer and Company.

7.17 ADDITIONAL PRIMARY FEED

Company will provide an additional primary (alternate) feed as requested by the customer provided the customer pays the added cost for the additional feed as a nonrefundable contribution in aid of construction and pays the applicable rate for the additional feed requested.

APPENDIX E

SCHEDULE 7

ELECTRIC METER TESTING AND MAINTENANCE PLAN

General Plan

This schedule establishes a meter maintenance and testing program for electric meters in order to ensure an acceptable degree of performance in the registration of the energy consumption of Arizona Public Service Company (Company) customers. Company will file an annual report with the Arizona Corporation Commission summarizing the results of the meter maintenance and testing program.

Specific Plan

1. Single-Phase Self Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

   1.1 Meters shall be separated into groups having common physical attributes and the average performance of each group will be determined based on the weighted average of the meter's percentage registration at light load (LL) and at full load (FL) giving the full load registration a weight factor of four (4).

   1.2 Analysis of the test results for each group evaluated shall be done in accordance with the statistical formulas outlined in ANSI/ASQC Z1.9 – 1995 Formulas B-3, Tables A-1, A-2 and B-5. The minimum sample size shall be 100 meters when possible.

2. Single Phase Self Contained Meters – Solid State

   Company will monitor performance of these types of meters through the Company Metering and Billing systems.

3. Three Phase Self-Contained Meters - Non-Solid State Hybrids and Electro-Mechanical

   Company shall monitor installations with the following types of meters for accuracy and recalibrate as necessary according to the following schedule:

   3.1 Three-phase meters with surge-proof magnets and without demand registers or pulse initiators: 16 years.

   3.2 Three phase block-interval demand-register-equipped kWh meters with surge-proof magnets: 12 years.

   3.3 Three phase lagged-demand meters: 8 years.

4. Three Phase Self-Contained Meters – Solid State

   Company will monitor performance for these types of meters through the Company Metering and Billing systems.

5. Three Phase Transformer-Rated Meter Installations – Solid State Hybrids and Electro-Mechanical

   Company will conduct a periodic testing program whereby three phase transformer-rated meter installations along with their associated equipment shall be inspected and tested for accuracy according to the following schedule:

5.1 Installations with 500 to 1,000 kW load: 4 years.

5.2 Installations with 1001 kW to 2000 kW load: 2 years.

5.3 Installations over 2000 kW load: 1 year.

APPENDIX F

SCHEDULE 10

TERMS AND CONDITIONS FOR DIRECT ACCESS

The following terms and conditions and any changes authorized by law will apply to Arizona Public Service Company (Company), Energy Service Providers (ESPs), and their agents that participate in Direct Access under the Arizona Corporation Commission's (ACC) rules for retail electric competition (A.A.C. R14-2-1601, et seq., referred to herein as the "Rules"). "Direct Access customer" refers to any Company retail customer electing to procure its electricity and any other ACC authorized Competitive Services directly from ESPs as defined in the Rules.

Customer Selections

All Company retail customers shall obtain service under one of two options:

1. Standard Offer Service. With this election, retail customers will receive all services from Company, including metering, meter reading, billing, collection and other consumer information services, at regulated rates authorized by the ACC. Any customer who is eligible for Direct Access who does not elect to procure Competitive Services shall remain on Standard Offer Service. Direct Access customers may also choose to return to Standard Offer Service after having elected Direct Access.

2. Competitive Services (Direct Access). This service election allows customers who are eligible for Direct Access to purchase electric generation and other Competitive services from an ACC certificated ESP. Direct Access customers with single premise demands greater than 20 kW or usage of 100,000 kWh annually will be required to have Interval Metering, as specified in Section 3.6.1. Pursuant to the Rules, and any restrictions herein, the ESP serving these customers will have options available for choosing to offer Meter Services, Meter Reading Services and/or Billing Services on their own behalf (or through a qualified third party), or to have Company provide those services (when permitted by the Rules) as specified within.

1. General Terms

1.1. Definitions. The definitions of principal terms used in this Schedule shall have the same meaning as ascribed to them in the Rules, unless otherwise expressly stated in this Schedule.

1.1.1. Customer - Unless otherwise stated, all references to Customer in this agreement refer to Company customers who are eligible for and have elected Direct Access.

1.1.2. Service Account - Unless otherwise stated, all references to "Service Account" in this agreement shall refer to an installed service, identified by a Universal Node Identifier (UNI).

1.1.3. Local Arizona Time – All time references in this Schedule are in Local Arizona Time, which is Mountain Standard Time (MST).

2. General Obligations of Company

2.1. Non-Discrimination

2.1.1. Company shall discharge its responsibilities under the Rules in a non-discriminatory manner as to providers of all Competitive Services. Unless otherwise authorized by the ACC, the Federal Energy Regulatory Commission ("FERC") or applicable affiliate transactions rules, Company shall not:

2.1.1.1. Represent that its affiliates or customers of its affiliates will receive any different treatment with regard to the provision of Company services than other, unaffiliated services providers as a result of affiliation with Company; or

2.1.1.2. Provide its affiliates, or customers of its affiliates, any preference based on the affiliation including but not limited to terms and conditions of service, information, pricing or timing over non-affiliated suppliers or their customers in the provision of Company services.

2.2. Transmission and Distribution Service

Company will offer transmission and distribution services under applicable tariffs, schedules and contracts for delivery of electric generation to Direct Access customers under the provisions of State law, the terms of the ACC's Rules and Regulations, this Schedule, the ESP Service Acquisition Agreement, applicable tariffs and applicable FERC rules.

3. General Obligations of ESPs

3.1. Timeliness, Due Diligence and Security Requirements

3.1.1. ESPs shall exercise due diligence in meeting their obligations and deadlines under the Rules to facilitate customer choice. ESPs shall make all payments owed to Company in a timely manner.

3.1.2. ESPs shall adhere to all credit, deposit and security requirements specified in the ESP Service Acquisition Agreement and Company tariffs and schedules.

3.2. Arrangements with ESP Customers

ESPs shall be solely responsible for having appropriate contractual or other arrangements with their customers necessary to implement Direct Access. Company shall not be responsible for monitoring, reviewing or enforcing such contracts or arrangements.

3.3. Responsibility for Electric Purchases

ESPs will be responsible for the purchase of their Direct Access customers' electric generation needs and the delivery of such purchases to designated receipt points as set forth on schedules given to the Scheduling Coordinators ("SCs").

3.4. Company Not Liable for ESP Services

To the extent the customer elects to procure services from an ESP, Company has no obligations to the customer with respect to the services provided by the ESP.

3.5. Load Aggregation for Procuring Electric Generation/Split Loads

3.5.1. ESPs may aggregate individually-metered electric loads for procuring competitive electric generation only. Load aggregation shall not be used to compute Company charges or for tariff applicability.

3.5.2. Customers requesting Direct Access Services may not partition the electric loads of a Service Account among electric service options or providers. The entire load of a Service Account must be provided by only one (1) ESP. This provision shall not restrict the use of separate parties for metering and billing services.

3.6. Interval Metering

3.6.1. "Interval Metering" refers to the purchase, installation and maintenance of electricity metering equipment capable of measuring and recording minimum data requirements, including hourly interval data required for Direct Access settlement processes and distribution billing. Interval Metering is required for all customers that elect Direct Access and reach a single site maximum demand in excess of 20 kW one or more times or annual usage of 100,000 kWh or more. Interval Metering is provided by the ESP, at no cost to Company. Interval Metering is optional for those customers with single site maximum demands that are 20 kW or less or annual usage of less than 100,000 kWh.

3.6.2. Company shall determine if Customer meets the requirements for Interval Metering based on historical data, or an estimated calculation of the demand and/or usage for new customers.

3.7. Meter Data Requirements

Minimum meter data requirements consist of data required to bill Company distribution tariffs and determine transmission settlement. Company shall have access to meter data necessary for regulatory purposes or rate-setting purposes pursuant to mutually agreed upon terms with the ESP for such data access.

3.8. Statistical Load Profiles

Company will offer statistical load profiles in place of Interval Metering, for qualifying Customers to estimate hourly consumption for settlement and scheduling purposes. Statistical load profiles will be applied as authorized by FERC.

3.9 Fees and Other Charges

Direct Access customers shall pay all applicable fees, surcharges, impositions, assessments and taxes on the sale of energy or the provisions of other services as authorized by law. The ESP and Company will each be respectively responsible for paying such fees to the taxing or regulatory agency to the extent it is their obligation to do so. Both the ESP and Company will be responsible for providing the authorized billing agent the information necessary to bill these charges to the customer.

3.10. Liability In Connection With ESP Services

3.10.1. "Damages" shall include all losses, harm, costs and detriment, both direct and indirect, and consequential, suffered by Customer or third parties.

3.10.2. Company shall not be liable for any damages caused by Company conduct in compliance with, or as permitted by, Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service, or as otherwise set forth in Company's Schedule #1.

3.10.3. Company shall not be liable for any damages caused to Customer by any ESP, including failure to comply with Company's electric rules and tariffs, the ESP Service Acquisition Agreement, the Rules, and associated legal and regulatory requirements related to Direct Access service.

3.10.4. Company shall not be liable for any damages caused by the ESP's failure to perform any commitment to Customer.

3.10.5. An ESP is not a Company agent for any purpose. Company shall not be liable for any damages resulting from acts, omissions, or representations made by an ESP in connection with soliciting customers for Direct Access or rendering Competitive Services.

3.10.6 Under no circumstances shall Company be liable to Customer, ESP (including any entity retained by it to provide competitive services to the customer) or third parties for lost revenues or profits, indirect or consequential damages or punitive or exemplary damages in connection with Direct Access Services. This provision shall not limit remedies otherwise available to customers under Company's schedules and tariffs and applicable laws and regulations.

4. Customer Inquiries and Data Accessibility

4.1 Customer Inquiries – For customers requesting information on Direct Access, Company shall make available the following information:

4.1.1 Materials to consumers about competition and consumer choices.

4.1.2 A list of ESPs that have been issued a Certificate of Convenience and Necessity to offer Competitive Services within Company's service territory. Company will provide the list maintained by the ACC, but Company is under no obligation to assure the accuracy of this list. Reference to any particular ESP or group of ESPs on the list shall not be considered an endorsement or other form of recommendation by Company.

4.2. Access to Customer Usage Data. For Company customers on Standard Offer Service, Company shall provide customer specific usage data to ESP or to Customer, subject to the following provisions:

4.2.1. ESPs may request Customer usage data prior to submission of a Direct Access Service Request ("DASR") by obtaining and submitting to Company the Customer's written authorization on a Customer Information Service Request ("CISR") form. Company may charge for customer usage data at rates approved by the ACC.

4.2.2. Company will provide the most recent twelve (12) months of customer usage data or the amount of data available for that Customer if there is less than twelve (12) months of usage history.

4.3 Customer Inquires Concerning Billing Related Issues

4.3.1 Customer inquiries concerning Company charges or services shall be directed to Company.

4.3.2 Customer inquiries concerning ESP charges or services shall be directed to the ESP.

4.4. Customer Inquiries Related to Emergency Situations and Outages

4.4.1. Company shall be responsible for responding to all Standard Offer Service or, in the case of Direct Access customers, distribution service emergency system conditions, outages and safety situation inquiries related to Company's distribution system. Customers contacting an ESP with such inquiries are to be referred directly to Company for resolution. ESPs performing consolidated billing must show Company's emergency telephone number on their bills.

4.4.2. Company may shed or curtail customer load as provided by its ACC-approved tariffs and schedules, or by other ACC rules and regulations.

5. ESP Service Establishment

5.1. Before the ESP or its agents can offer Direct Access services in Company's distribution service territory they must meet the applicable provisions as listed:

5.1.1. All ESPs must obtain a Certificate of Convenience and Necessity from the ACC which authorizes the ESP to offer Competitive Services in Company's distribution service territory.

5.1.2. All ESPs must register to do business in the State of Arizona and obtain all other licenses and registrations needed as a legal predicate to the ESP's ability to offer Competitive Services in Company's distribution service territory.

5.1.3. Load Serving ESPs must satisfy creditworthiness requirements as specified in the ESP Service Acquisition Agreement if the ESP chooses the ESP Consolidated Billing option. If the ESP chooses Company UDC Consolidated Billing, they must enter into a Customized Billing Services Agreement.

5.1.4 Load Serving ESPs must enter into an ESP Service Acquisition Agreement with Company.

5.1.5. All ESPs must satisfy any applicable ACC electronic data exchange requirements including:

5.1.5.1. The ESP and/or its designated agents must complete to Company's satisfaction all necessary electronic interfaces between the ESP and Company to exchange DASRs and general communications.

5.1.5.2. The ESP or its agent must complete to Company's satisfaction all electronic interfaces between the ESP and Company to exchange meter reading and usage data. This includes communication to and from the Meter Reading Service Provider's (MRSP) server for sharing of meter reading and usage data.

5.1.5.3. The ESP must have the capability to electronically exchange data with Company. Alternative arrangements may be acceptable at Company's option.

5.1.5.4. The ESP and its agents must use Electronic Data Interchange (EDI) using Arizona Standard Formats to exchange billing and remittance data with Company when offering ESP Consolidated Billing or Company UDC Consolidated Billing. The ESP and its agents must use the Arizona Standard Format to exchange meter reading data with Company when providing meter reading services. Alternative arrangements may be allowed at Company's option.

5.1.6. For Company UDC Consolidated Billing or ESP Consolidated Billing options, compliance testing is required. Both parties must demonstrate the ability to perform data exchange functions required by the ACC and the ESP Service Acquisition Agreement. Any change of the billing agent will require a revalidation of the applicable compliance testing. Provided the ESP is acting diligently and in good faith, its failure to complete such compliance testing shall not affect its ability to offer electric generation to Direct Access customers. Dual Company/ESP Billing will be performed until the compliance testing is completed to Company's satisfaction.

5.1.7. Compliance testing will be required for a MRSP when providing meter reading services to ensure that meter data can be delivered successfully. Any change of the MRSP's system, or any change to the Arizona Standard 867 EDI format, will require a revalidation of the applicable compliance testing.

6. Direct Access Service Request (DASR)

6.1 A DASR is submitted pursuant to the terms and conditions of the Arizona DASR Handbook, the ESP Service Acquisition Agreement and this section, and shall also be used to define the Competitive Services that the ESP will provide the customer.

6.2 ESPs shall have a CC&N from the ACC; shall have entered into an ESP Service Acquisition Agreement with Company, if required, and shall have successfully completed data exchange compliance testing before submitting DASRs.

6.3 The customer's authorized ESP must submit a completed DASR to Company before Customer can be switched from Standard Offer Service or Competitive Service provided by another ESP. The DASR process described herein shall be used for customer Direct Access elections, updates, cancellations, customer-initiated returns to Company Standard Offer Service, or requests for physical disconnection of service and ESP- or customer-initiated termination of an ESP/customer service agreement.

6.4. A separate DASR must be submitted for each service delivery point. Each of the five (5) DASR operation types [Request (RQ), Termination of Service Agreement (TS), Physical Disconnect (PD), Cancel (CL) and Update/Change (UC)] has specific field requirements that must be fully completed before the DASR is submitted to Company. A DASR that does not contain the required field information or is otherwise incomplete may be rejected. In accordance with the provisions of the applicable Service Acquisition Agreement, Company may deny the ESP or customer request for service if the information provided in the DASR is false, incomplete, or inaccurate in any material respect. ESPs filing DASRs are thereby representing that they have their customer's authorization for such transaction.

6.5. Company requires that DASRs be submitted electronically using Electronic Data Interchange (EDI) or Comma Separated Value (CSV) formats through the Company's web site (http://esp.apsc.com).

6.6. DASRs will be handled on a first-come, first-served basis. Each request shall be time and date stamped when received by Company.

6.7. Once the DASR is submitted, the following timeframes will apply:

6.7.1. Company will respond to RQ, TS, CL and UC DASRs within two (2) working days of the time and date stamp. Company will exercise best efforts (no later than five (5) working days) to provide the ESP with a DASR status notification informing them whether the DASR has been accepted, rejected or placed in a pending status awaiting further information. If accepted, the effective switch date will be determined in accordance with Sections 6.8, 6.9, and 6.12 and will be confirmed in the response to the ESP and the former ESP if applicable. If a DASR is rejected, Company shall provide the reasons for the rejection. If a DASR is held pending further information, it shall be rejected if the DASR is not completed with the required information within thirty (30) working days, or a mutually agreed upon date, following the status notification. Company will send written notification to the customer once the RQ DASR has been processed.

6.7.2. When a customer requests electric services to be disconnected, the ESP is responsible for submitting a PD DASR to Company on behalf of the customer, regardless of the Meter Service Provider (MSP).

6.7.2.1. When Company is acting as the MSP, Company shall perform the physical disconnect of the service. The PD DASR must be received by Company at least three (3) working days prior to the requested disconnect date. Company will acknowledge the PD DASR status within two (2) working days of the time and date stamp.

6.7.2.2 When Company is not acting as the MSP, the ESP is responsible for performing the physical disconnect. The ESP shall notify Company by DASR of the date of the physical disconnect. Disconnect reads must be posted to the server within three (3) working days following the disconnection.

6.8. DASRs that do not require a meter exchange must be received by Company at least fifteen (15) calendar days prior to the next scheduled meter read date. The actual meter read date would be the effective switch date. DASRs received less than fifteen (15) calendar days prior to the next scheduled meter read date will be scheduled for switch to Direct Access on the following month's read date.

6.9 DASRs that require a meter exchange will have an effective change date to Direct Access as of the meter exchange date. Notification of meter exchange dates shall be coordinated between the ESP, MSP and Company's Meter Activity Coordinator ("MAC").

6.10. If more than one (1) RQ DASR is received for a service delivery point within a Customer's billing cycle, only the first valid DASR received shall be processed in that period. All subsequent DASRs shall be rejected.

6.11. Upon acceptance of an RQ DASR, a maximum of twelve (12) months of customer usage data, or the available usage for that customer switching from Standard Offer, shall be provided to the ESP. If there is an existing ESP currently serving that customer, that ESP shall be responsible for submitting the customer usage data to the new ESP. In both cases, the customer usage data will be submitted to the appropriate ESP no later than five (5) working days before the scheduled switch date.

6.12. Customers returning to Company Standard Offer service must contact their ESP. The ESP shall be responsible for submitting the DASR on behalf of the customer.

6.13. ESPs requesting to return a Direct Access customer to Company Standard Offer service shall submit a TS DASR and shall be responsible for the continued provision of the customer's electric supply service, metering, and billing services until the effective change date.

6.14. Customers requesting to return to Company Standard Offer service are subject to the same timing requirements as used to establish Direct Access service. Direct Access customers returning to Company Standard Offer service may be subject to the RCDAC-1.

6.15. Company may assess a fee for processing DASRs. All fees are payable to Company within fifteen (15) calendar days after the invoice date. All unpaid fees received after this date will be assessed applicable late fees pursuant to Schedule 1. If an ESP fails to pay these fees within thirty (30) days after the due date, Company may suspend accepting DASRs from the ESP unless a deposit sufficient to cover the fees due is currently available or until such time as the fees are paid. If an ESP is late in paying fees, a deposit or an additional deposit may be required from the ESP.

6.16. A customer moving to new premises may retain or start Direct Access immediately. The customer must first contact Company to establish a Service Account. The customer will be provided the necessary information that will enable its ESP to submit a DASR. The same timing requirements apply as set forth in Section 6.8 and 6.9.

6.17. Billing and metering option changes are requested through a UC DASR and cannot be changed more than once per billing cycle.

6.18. Company shall not hold the ESP responsible for any customer unpaid billing charges prior to the customer's switch to Direct Access. Unpaid billing charges shall not delay the processing of DASRs and shall remain the customer's responsibility to pay Company. Company's Schedule 1 applies in the event of customer non-payment, which includes the possible disconnection of distribution services. Company shall not accept any DASRs submitted for customers who have been terminated for nonpayment and have not yet been reinstated. Disconnection by Company of a delinquent customer shall not make Company liable to the ESP or third-parties for the customer's disconnection.

6.19 Company shall not accept DASRs that specify a switch date of more than sixty (60) calendar days from the date the DASR is submitted.

7. Billing Service Options and Obligations

7.1 Subject to availability, and pursuant to the terms in the ESP Service Acquisition Agreement, this Schedule 10, and applicable tariffs and the restrictions therein, ESPs may select among the following billing options:

7.1.1 COMPANY UDC CONSOLIDATED BILLING

7.1.2 ESP CONSOLIDATED BILLING

7.1.3 DUAL COMPANY/ESP BILLING

7.2 COMPANY UDC CONSOLIDATED BILLING

7.2.1 The customer's authorized ESP sends its bill-ready data to Company, and Company sends a consolidated bill containing both Company and ESP charges to the Customer.

7.2.2 Company Obligations:

7.2.2.1 Company shall bill the ESP charges and send the bill either by mail or electronic means to the customer. Company is not responsible for computing or determining the accuracy of the ESP charges. Company is not required to estimate ESP charges if the expected bill ready data is not received nor is Company required to delay Company billing. Billing rendered on behalf of the ESP by Company shall comply with A.A.C. R14-2-1612.

7.2.2.2 Company bills shall include in Customer's bill a detailed total of ESP charges and applicable taxes, assessments and billed fees, the ESP's name and telephone number, and other information provided by the ESP.

7.2.2.3 If Company processes Customer payments on behalf of the ESP, the ESP shall receive payment for its charges as specified in Section 7.7.

7.2.3 ESP Obligations

7.2.3.1 Once a billing election is in place as specified in the ESP Service Acquisition Agreement, the ESP may offer Company UDC Consolidated Billing services to Direct Access customers pursuant to the terms and conditions of the applicable ACC approved tariff.

7.2.3.2. The ESP shall submit the necessary billing information to facilitate billing services under this billing option by Service Account, according to Company's meter reading schedule,

and pursuant to the applicable tariff. Timing of billing submittals is provided for in Section 7.2.4 below.

7.2.4 Timing Requirements

7.2.4.1. Bills under this option will be rendered once a month. Nothing contained in this Schedule shall limit Company's ability to render bills more frequently consistent with Company's existing practices. However, if Company renders bills more frequently than once a month, ESP charges need only to be calculated based on monthly billing periods.

7.2.4.2. Except as provided in Section 7.2.4.1, Company shall require that all ESP and Company charges be based on the same billing period data.

7.2.4.3. ESP charges for normal monthly customer billing and any adjustments for prior months' metering or billing errors must be received by Company in EDI "810" format no later than 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date. If billing charges have not been received from the ESP by this deadline, Company will render a bill for Company charges only. The ESP must wait until the next billing cycle, unless there is a mutual agreement for Company to send an interim bill. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. An interim bill issued pursuant to this Section may also include a message that Company charges were previously billed.

7.2.4.4. ESP charges for a Physical Disconnect Final Bill must be received by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If final billing charges have not been received from the ESP by this date, Company will render the customer's final bill for Company charges only, without the ESP's final charges. If Company renders the bill for Company charges only, Company will include a note on the bill stating that ESP charges will be forthcoming. The ESP must send the final charges to Company. Company will produce and send a separate bill for the final billing charges.

7.2.5. Restrictions

Company UDC Consolidated Billing shall be an option for individual customer bills only, not an aggregated group of customers. Nothing in this Section precludes each individual customer in an aggregated group, however, from receiving the customer's individual bills under Company UDC Consolidated Billing.

7.3. ESP CONSOLIDATED BILLING

7.3.1 Company calculates and sends its bill-ready data to the ESP. The ESP in turn sends a consolidated bill to its customer. The ESP shall be obligated to provide the customer detailed Company charges to the extent that the ESP receives such detail from Company. The ESP is not responsible for the accuracy of Company charges.

7.3.2 Company Obligations:

7.3.2.1 Company shall calculate all its charges once per month based on existing Company billing cycles and provide these to the ESP to be included on the ESP consolidated bill or as otherwise specified. Company and the ESP may mutually agree to alternative options for the calculation of Company charges.

7.3.2.2 Company shall provide the ESP with sufficient detail of its charges, including any adjustments for prior months' metering and billing error, by EDI "810" format. Company charges that are not transmitted to the ESP by 4:00 p.m. Local Arizona Time on the third working day following the Last Meter Read/First Bill Date need not be included in the ESP's bill. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges unless there is a mutual agreement to have the ESP send an interim bill to the customer including Company charges. The ESP will include a message on the bill stating that Company charges are forthcoming.

7.3.2.3 For a Physical Disconnect Final Bill, Company will provide the ESP with Company's final bill charges by 4:00 p.m. Local Arizona Time on the sixth working day following the actual disconnect date. If Company's billing charges have not been received by such date, the ESP may render the bill without Company charges. The ESP shall include a message on the bill stating that Company charges are forthcoming. Company will send the final bill charges to the ESP, and the ESP will produce and deliver a separate bill for Company charges.

7.3.3 ESP Obligations:

7.3.3.1 Once an ESP Service Acquisition Agreement is entered into, including an appropriate billing election, and all other applicable prerequisites are met, the ESP may offer consolidated billing services to Direct Access customers they serve.

7.3.3.2 The ESP bill shall include any billing-related details of Company charges. Company charges may be printed with the ESP bill or electronically transmitted. Billing rendered on behalf of Company by the ESP shall comply with A.A.C. R14-2-1612.

7.3.3.3 Other than including the billing data provided by Company on the customer's bill, the ESP has no obligations regarding the accuracy of Company charges or for disputes related to these charges. Disputed charges shall be handled according to ACC procedures.

7.3.3.4 The ESP shall process customer payments and handle collection responsibilities. Under this billing option, the ESP must pay all charges due to Company and not disputed by the customer as specified in Section 7.7.2.1.

7.3.3.5 Subject to the limitations of this Section and with the written consent of the Customer, the ESP may offer customers customized billing cycles or payment plans which permit the Customer to pay the ESP for Company charges in different amounts than Company charges to the ESP for any given billing period. Such plans shall not, however, affect in any manner the obligation of the ESP to pay all Company charges in full. Should Customer select an optional payment plan, all Company charges must be billed in accordance with A.A.C. R14-2-210(G).

7.3.4 Timing Requirements

ESPs may render bills more or less frequently than once a month. However, Company shall continue to bill the ESP each billing cycle period for the amounts due by the customer for that billing month.

7.4 DUAL COMPANY/ESP BILLING

Company and the ESP each separately bill the customer directly for services provided by them. The billing method is the sole responsibility of Company and the ESP. Company and the ESP shall process only the customer payments relating to their respective charges.

7.5 Billing Information and Inserts

7.5.1 All customers, including Direct Access customers, shall receive mandated legal, safety and other notices equally in accordance with A.A.C. R14-2-204 (B). If the ESP is providing consolidated billing, Company shall make available one (1) copy of these notices to the ESP for distribution to customers or, at the ESP's request, in electronic format to the ESP for production and communication to electronically billed Customers. If Company is providing Consolidated billing services, Company shall continue to provide these notices.

7.5.2 Under Company UDC Consolidated Billing, ESP bill inserts may be included pursuant to the applicable Company tariff.

7.6 Billing Adjustments for Meter and Billing Error

7.6.1 Meter and Billing Error

7.6.1.1 The MSP (including the ESP or Company if providing such services) shall resolve any meter errors and must notify the ESP and Company, as applicable, so any billing adjustments can be made. All other affected parties, including the appropriate Scheduling Coordinator, shall be notified by the ESP.

7.6.1.2 A billing error is the incorrect billing of Customer's energy or demand. If the MSP, MRSP, ESP or Company becomes aware of a potential billing error, the party discovering the billing error shall contact the ESP and Company, as applicable, to investigate the error. If it is determined that there is in fact a billing error, the ESP and Company will make any necessary adjustments and notify all other affected parties in a timely manner.

7.6.1.3 Company UDC Consolidated Billing

7.6.1.3.1 Company shall be responsible for notifying Customer and adjusting the bill for its charges to the extent those charges were affected by the meter or billing error.

7.6.1.3.2 The ESP shall be responsible for any recalculation of the ESP charges. Following the receipt of the recalculated charges from the ESP, the charges or credits will be applied to Customer's next normal monthly bill, unless there is mutual agreement to have Company send an interim bill to the Customer including the ESP's charges.

7.6.1.4 ESP Consolidated Billing

7.6.1.4.1 The ESP shall be responsible for notifying the Customer and adjusting the bill for ESP charges to the extent those charges were affected by the meter or billing error. The Customer shall be solely responsible for obtaining refunds of ESP electric generation overcharges from its current and prior ESPs, as appropriate.

7.6.1.4.2 Company shall transmit its adjusted charges and any refunds to the ESP with Customer's next normal monthly bill. The ESP shall apply the charges to Customer's

next normal monthly bill, unless there is a mutual agreement to have the ESP send an interim bill to Customer including Company charges.

7.6.1.5 Dual Company/ESP Billing

7.6.1.5.1 Company and the ESP shall be separately responsible for notifying Customer and adjusting its respective bill for their charges.

7.7 Payment and Collection Terms

7.7.1 Company UDC Consolidated Billing

7.7.1.1 Company shall remit payments to the ESP for the total ESP charges collected from Customer within three (3) working days after Customer's payment is received. Company is not required to pay amounts owed to the ESP for ESP charges billed but not received by Company.

7.7.1.2 Customer is obligated to pay Company for all undisputed Company and ESP charges consistent with existing tariffs and other contractual arrangements for service between the ESP and the customer.

7.7.1.3 The ESP is responsible for all collections related to the ESP services on the Customer's bill, including, but not limited to, security deposits and late charges unless otherwise agreed upon in the customized billing services agreement between ESP and Company.

7.7.1.4 Payment for any Company charges for Consolidated Billing is due in full from the ESP within fifteen (15) calendar days of the date Company charges are rendered to the ESP. Any payment not received within this time frame will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2 ESP Consolidated Billing

7.7.2.1 Payment is due in full from the ESP within fifteen (15) calendar days after the date Company's charges are rendered to the ESP. The ESP shall pay all undisputed Company charges regardless of whether Customer has paid the ESP. All payments received after fifteen (15) calendar days will be assessed applicable late charges pursuant to Schedule 1. If an ESP fails to pay these charges prior to the next billing cycle, Company may revert the billing option for that ESP's customers to Dual Billing pursuant to Section 7.10.4. If an ESP is late in paying charges a deposit or additional deposit as provided for in Section 7.11 may be required.

7.7.2.2 Company shall be responsible for any follow-up inquiries with the ESP if there is question concerning the payment amount.

7.7.2.3 Company has no payment obligations to the ESP for Customer payments under ESP Consolidated Billing services.

7.7.3 Dual Company/ESP Billing

Company and the ESP are separately responsible for collection of Customer payment for their respective charges.

7.8 Late or Partial Payments and Unpaid Bills

7.8.1 Company UDC Consolidated Billing

7.8.1.1 Company shall not be responsible for ESP's Customer collections, collecting the unpaid balance of ESP charges from Customers, sending notices informing Customers of unpaid ESP balances, or taking any action to recover the unpaid amounts owed the ESP. The ESP shall assume any collection obligations and/or late charge assessments for late or unpaid balances related to ESP charges under this billing option.

7.8.1.2 All Customer payments shall be applied first to unpaid balances identified as Company charges until such balances are paid in full, then applied to ESP charges. A Customer may dispute charges as provided by A.A.C. R14-2-212, but a Customer will not otherwise have the right to direct partial payments between Company and the ESP.

7.8.1.3 ACC rules shall apply to late or non-payment of all Company customer charges. Undisputed Company delinquent balances owed on a customer account shall be considered late and subject to Company late payment procedures.

7.8.2 ESP Consolidated Billing

The ESP shall be responsible for collecting both unpaid ESP and Company charges, sending notices informing Customers of unpaid ESP and Company balances, and taking appropriate actions to recover the amounts owed. Company shall not assume any collection obligations under this billing option and ESP is liable to Company for all undisputed payments owed Company.

7.8.3 Dual Company/ESP Billing

Company and the ESP are responsible for collecting their respective unpaid balances, sending notices to Customers informing them of the unpaid balance, and taking appropriate actions to recover their respective unpaid balances. Customer disputes with ESP charges must be directed to the ESP and Customer disputes with Company charges must be directed to Company.

7.9 Service Disconnects and Reconnects

In accordance with ACC rules, Company has the right to disconnect electric service to the Customer for a variety of reasons, including, but not limited to, the non-payment of Company's final bills or any past due charges by Customer, or evidence of safety violations, energy theft, or fraud, by Customer. The following provides for service disconnects and reconnects.

7.9.1 Company shall notify Customer and Customer's ESP of Company's intent to disconnect electric service for the non-payment of Company charges prior to disconnecting electric service to the Customer. Company shall further notify the ESP at the time Customer has been disconnected. To

the extent authorized by the ACC, a service charge shall be imposed on Customer if a field call is performed to disconnect electric service.

7.9.2 Company shall reconnect electric service for a fee when the criteria for reconnection have been met to Company's satisfaction. Company shall notify the ESP of a Customer's reconnection.

7.9.3 Company shall not disconnect electric service to Customer for the non-payment of ESP charges by Customer. In the event of non-payment of ESP charges by Customer, the ESP may submit a DASR requesting termination of the service agreement and request return to Company Standard Offer Service. Company will then advise the Customer that they will be placed on Company Standard Offer Service unless a DASR is received from another ESP on their behalf.

7.10. Involuntary Service Changes

7.10.1. A Customer may have its service of electricity, billing, or metering from an ESP changed to another provider, including Company, involuntarily in the following circumstances:

7.10.1.1. The ACC has decertified the ESP or the ESP otherwise receives an ACC order that prohibits the ESP from serving the customer.

7.10.1.2 The ESP, including its agents, has materially failed to meet its obligations under the terms of its ESP Service Acquisition Agreement with Company (including applicable tariffs and schedules) so as to constitute an Event of Default under the terms of the ESP Service Acquisition Agreement, and Company exercises its contractual right to terminate the ESP Service Acquisition Agreement.

7.10.1.3 The ESP has materially failed to meet its obligations under the terms of the ESP Service Acquisition Agreement (including applicable tariffs and schedules) so as to constitute an Event of Default and Company exercises a contractual right to change billing options.

7.10.1.4 The ESP ceases to perform by failing to provide schedules through a Scheduling Coordinator whenever such schedules are required, or the ESP fails to have a Service Acquisition Agreement in place with a Scheduling Coordinator.

7.10.1.5. The Customer fails to meet its Direct Access requirements and obligations under the ACC rules and Company tariffs and schedules.

7.10.2. Change of Service Election in Exigent Circumstances

In the event Company finds that an ESP or the Customer has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company elects to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3) and the failure constitutes an emergency (defined as posing a substantial threat to the reliability of the electric system or to public health and safety), or the failure relates to ESP's sale of unscheduled energy, Company may initiate a change in the Customer's service election, or terminate an ESP's ability to offer certain services under Direct Access. In such case, Company shall initiate the change or termination by preparing a DASR, but the change or termination may be made immediately notwithstanding the applicable DASR processing times set forth in this Schedule. Company shall provide such notice and opportunity to remedy the problem if there are reasonable circumstances prevailing. Additionally, Company shall notify the ACC of the circumstances that required the change or the termination and the

resulting action taken by Company. The ESP and/or Customer shall have the right to seek an order from the ACC restoring the customer's service election and/or the ESP's ability to offer services. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to Customer other than as provided in Section 4.4.2 .

7.10.3. Change in Service Election Absent Exigent Circumstances

7.10.3.1. In the event Company finds that an ESP has materially failed to meet its obligations under this Schedule or the ESP Service Acquisition Agreement such that Company seeks to invoke its remedies under Section 7.10 (other than termination of ESP Consolidated Billing under Section 7.10.1.3), and the failure does not constitute an emergency (as defined in Section 7.10.2) or involve an ESP's unauthorized energy use, Company shall notify the ESP and the ACC of such finding in writing stating the following:

7.10.3.1.1. The nature of the alleged failure;

7.10.3.1.2. The actions necessary to remedy the failure;

7.10.3.1.3. The name, address and telephone number of a contact person at the Company authorized to discuss resolution of the failure.

7.10.3.2. The ESP shall have thirty (30) calendar days from receipt of such notice to remedy the alleged failure or reach an agreement with Company regarding the alleged failure. If the failure is not remedied and no agreement is reached between Company and the ESP following this thirty (30) day period, Company may initiate the DASR process set forth in this Schedule to accomplish its remedy and shall notify the customers of such remedy. Unless expressly ordered by the ACC, the provisions of this section shall not disconnect electric service provided to the customer other than as provided in Section 4.4.2.

7.10.4. Termination of ESP Consolidated Billing

7.10.4.1. Company may terminate ESP Consolidated Billing under the following circumstances:

7.10.4.1.1. The Company shall notify affected Customers that ESP Consolidated Billing services will be terminated, and the Company may switch affected Customers to Dual Company/ESP billing as promptly as possible if any of the following occur:

7.10.4.1.1.1 Company finds that the information provided by the ESP in the ESP Service Acquisition Agreement is materially false, incomplete, or inaccurate.

7.10.4.1.1.2 The ESP attempts to avoid payment of Company charges.

7.10.4.1.1.3 The ESP files for bankruptcy.

7.10.4.1.1.4 The ESP fails to have an involuntary bankruptcy proceeding filed against the ESP dismissed within sixty (60) calendar days.

7.10.4.1.1.5 The ESP admits insolvency.

7.10.4.1.1.6 The ESP makes a general assignment for the benefit of creditors.

7.10.4.1.1.7 The ESP is unable to pay its debts as they mature.

7.10.4.1.1.8 The ESP has a trustee or receiver appointed over all, or a substantial portion, of its assets.

7.10.4.1.2. If the ESP fails to pay Company (or dispute payment pursuant to the procedures set forth in this Schedule) the full amount of all Company charges and fees by the applicable due date, Company shall notify the ESP of the past due amount within two (2) working days of the applicable past due date. If the ESP incurs late charges on more than two (2) occasions or fails to pay overdue amounts including late charges within five (5) working days of the receipt of notice by Company, Company may notify the ESP's customers and the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.1.3. If the ESP fails to comply within thirty (30) calendar days of the receipt of notice from Company of any additional credit, security or deposit requirements set forth in Sections 5.1.3 and 7.11, Company may notify the ESP that ESP Consolidated Billing services will be terminated, and that Customers shall be switched to Dual Billing.

7.10.4.2. Upon termination of ESP Consolidated Billing pursuant to Section 7.10.4, Company may deliver a separate bill for all Company charges which were not previously billed by the ESP.

7.10.4.3 Company may reinstate the ESP's eligibility to engage in ESP Consolidated Billing upon a reasonable showing by the ESP that the problems causing the revocation of ESP Consolidated Billing have been cured, including payment of any late charges, reestablishing credit requirements in compliance with Sections 5.1.4 and 7.11, and payment to Company of all costs associated with changing ESP customers' billing elections to and from dual billing.

7.10.4.4 In the event Company terminates ESP Consolidated Billing, Company will return any security posted by the ESP pursuant to the ESP Service Acquisition Agreement.

7.10.5. Termination of Company UDC Consolidated Billing

7.10.5.1. Company may terminate Company UDC Consolidated Billing and revert to Dual Billing upon providing thirty (30) calendar days notice to an ESP if ESP fails to pay Company charges in connection with Company UDC Consolidated Billing or otherwise fails to comply with its obligations under Section 7.2.

7.10.5.2 Company may terminate Consolidated Billing upon providing thirty (30) days notice to an ESP if Company cancels or changes the tariff governing Company UDC Consolidated Billing.

7.10.6. Upon termination of ESP Direct Access services pursuant to Section 7.10, the provision of the affected service(s) shall be assumed by another eligible ESP from which the Customer elects to obtain the affected service(s). Absent an election by Customer, Company shall provide such services, until such time that Customer makes an election.

7.10.7. Company shall not use involuntary service changes in an anticompetitive or discriminatory manner.

7.11. ESP Security Deposits

7.11.1. Company may, at its discretion, require cash security deposits from any ESP that has on more than one occasion failed to pay Company charges or ACC-approved Direct Access charges within the established time frame, such as DASR fees, meter or billing error or service fees, and other fees applicable to an ESP through Schedule 10 and Company's other tariffs and schedules.

7.11.2. The amount of the security deposit required shall not exceed two and one-half times the estimated maximum monthly bill to the ESP for such charges, and a separate security deposit may be required for separate categories of ESP or Direct Access charges.

7.11.3. Security deposits required pursuant to Section 7.11 shall be in the form of a cash deposit accruing interest as specified in Section 2.7.4 of Company Schedule 1. Company shall issue the ESP a nonnegotiable receipt for the amount of the deposit.

7.11.4. Company may refuse to accept DASRs from, or provide other Company services to, an ESP that fails to comply within thirty (30) calendar days to a demand that the ESP establish a security deposit pursuant to Section 7.11.

8. Meter Services

8.1 Under Direct Access, ESPs may offer certain metering services for Direct Access implementation, including meter ownership, MSP and MRSP services.

8.2 Company has the right to offer the following meter services:

8.2.1 Metering and Meter Reading for Residential Load-Profiled Customers

8.2.2 Services as authorized by the ACC.

8.2.3 Company reserves the right to perform meter disconnects, regardless of meter ownership, in cases of potential safety hazards or non-payment for Company charges.

8.3 A Load Serving ESP may sub-contract Metering or Meter Reading Services to a certificated third party. If the ESP sub-contracts any of the components of these services to a third party, the ESP shall, for the purposes of this Schedule, remain responsible for the services.

8.4 Load Serving ESPs providing Metering or Meter Reading Services to Direct Access customers either on their own or through a third party assume full responsibility for meeting the applicable meter and communication standards, as well as assuming responsibility for the safe installation and operation of the meter and any personal injuries and damage caused to customer or Company property by the meter or its installation. This liability will lie with the ESP regardless of whether the ESP or its subcontractors perform the work.

8.5 Meter Specifications

8.5.1 The Director of Utilities Division of the ACC has determined the following specifications and standards shall apply to competitive metering where applicable (see Performance Metering Specifications and Standards document):

8.5.2 Metering standards (American National Standards Institute):

ANSI C12.1	Code for Electricity Metering
ANSI C12.6	Marketing & Arrangement of Terminals for Phase Shifting Devices used in Metering
ANSI C12.7	Watt-hour Meter Socket
ANSI C12.10	Electromechanical Watt-hour Meters
ANSI C12.13	Electronic TOU Registers for Electricity Meters
ANSI C12.18	Type 2 Optical Port
ANSI C12.20	0.2% & 0.5% Accuracy Class Meters
ANSI C37.90	Surge Withstand Test
ANSI 57.13	Instrument Transformers (All CTs & PTs)
ANSI Z1.4	Sampling Procedures and Tables for Inspection
ANSI Z1.9	Sampling Procedures and Tables for Inspection

8.5.3 EEI Electricity Metering Handbook

8.5.4 Electric Utilities Service Equipment Requirements Committee (EUSERC)

8.5.5 NEC & Local Requirements by jurisdictions

8.5.6 Company's Electric Service Requirements Manual (ESRM)

8.5.7 National Electrical Safety Code (NESC)

8.5.8 ESPs or their contractors providing competitive metering services shall also comply with such other specifications or standards determined to be applicable or appropriate by the ACC's Director of Utilities Division.

8.6 Meter Conformity

8.6.1 All Direct Access meters shall have a visual kWh display and must have a physical interface to enable on-site interrogation of all stored meter data. All meters installed must support the Company's rate schedules.

8.6.2 If Company is providing MRSP functions for the ESP, pursuant to the Rules, meters must be compatible with Company's meter reading system.

8.6.3 No meter or associated metering equipment shall be set or allowed to remain in service if it is determined that the meter or its associated equipment did not meet approved specifications, as set forth in Company's ESRM, or is in violation of any code listed in Section 8.5.

8.7 Meter Testing

8.7.1 If a manufacturer's sealed meter has not previously been set and the meter was tested within the last twelve (12) months, the meter shall be deemed in compliance with ACC standards without additional testing.

8.7.2 Any meter removed from service shall be processed according to the following table prior to its re-installation:

METER TYPE	REMOVAL REASON	ACTION REQUIRED
1 Ph kWh Electro-Mechanical	Routine	Meter Inspection
1 Ph kWh Electro-Mechanical	Trouble	Meter Test
1 Ph kWh Hybrid or Solid State	Routine	Meter Test
1 Ph TOU (all)	Trouble	Meter Test
3 Ph Meters (all)	All	Meter Test
1 Ph or 3 Ph IDR Meters	All	Meter Test

8.7.3 Meter tests are to be conducted in accordance with ANSI C12.1 recommended testing standards.

8.7.4 Records on meter testing shall be maintained by the MSP and provided to the requesting parties within three (3) working days of such a request for such records. The latest meter test record shall be kept as long as the meter is in service.

8.8 Meter Test Requests

Pursuant to A.A.C. R14-209(F), either party may request that the other party perform a meter test, in which instance the requesting party is entitled to witness the test if it so chooses. The requesting party shall be notified of the test date and written test results from the testing party. If the meter is found to be within ACC-approved standards, the requesting party shall reimburse the other party for all costs incurred in the process of testing the meter (per ACC approved tariffs). The MSP shall take reasonable measures to detect meter error. The MSP shall notify Company as soon as it becomes aware of any meter that is not operating in compliance with ACC performance specifications. The MSP shall make any repairs or changes required to correct the error. ESPs and Company shall use a form approved by the ACC Process Standardization Working Group (PSWG) to initiate and respond to such action.

8.9 Meter Identification

8.9.1 The ESP or its agent shall install a Company provided unique number on each meter. Company will provide the unique numbers printed on stickers in blocks of up to 1,000 numbers. These stickers must be readily visible from the front of the meter. The number assigned to that meter shall remain solely with that meter while in use in Company's service territory.

8.9.2 When an ESP installs either its own meter or a customer owned meter, the ring or lock ring must be secured with a blue seal that is imprinted with the name and/or logo of the ESP or their agent.

8.10 Installation of metering equipment

8.10.1 All metering equipment shall be installed according to all applicable ACC requirements and Company's Electric Service Requirements Manual.

8.10.2 An ESP or its agent must be authorized by Company to remove a Company owned meter. The Existing Meter Information (EMI) form will be sent to the ESP and MSP within five (5) working days within receiving the DASR acceptance notification indicating a pending meter exchange. When the MSP intends to remove a Company meter, Company must receive a Meter Data Communication Request (MDCR) format at least five (5) working days prior to the exchange.

Upon completion of the meter exchange, the MSP will return the Meter Installation/Removal Notification (MIRN) form to Company by the end of business, three (3) working days from the day of the exchange.

8.10.3 The ESP or its agent shall inform Company of all meter activity, such as meter installations or exchanges, via the Meter Activity Coordination (MAC) Form within the time frames specified above. If final meter reads are not provided to Company, are inaccurate, or otherwise result in Company not being able to render accurate final bills to customers pursuant to ACC Rules and Regulations, the ESP shall be responsible for any unbilled, disputed, or unrecoverable amounts and applicable late charges.

8.10.4 The ESP or its agent shall return the existing meter to Company at one of Company's designated locations identified in the meter drop off list within fifteen (15) working days after its removal, or be charged the cost of the meter and metering equipment and /or any other charges per the applicable ACC-approved tariff. The ESP or its agent shall be responsible for damage to the meter occurring during shipment.

8.11 On-Site Inspections/Site Meets

8.11.1 Company may perform on-site inspections of meter installations. The ESP shall be notified if the inspections uncover any material non-compliance by the MSP with the approved specifications and standards.

8.11.2 For new construction, the party installing the meter shall ensure that the owner/builder has met the construction standards outlined in Company's ESRM, and Company's Transmission and Distribution construction manual, as well as local municipal agency requirements, and any updates, supplements, amendments and other changes that may be made to these manuals and requirements. Company shall perform a preinstallation inspection on all new construction. Local city/county clearances may also be required prior to energizing any new construction.

8.11.3 Company may require a site meet for: the exchange or removal of an IDR meter which requires an optical device to retrieve interval data; the exchange or removal of equipment at an existing totalized metering installation; a restricted access location for which Company forbids key access; cogeneration sites, bi-directional or detented metering sites; or upon request of an ESP or MSP. The ESP and Company's MAC shall coordinate the time of the site meet. If the ESP or MSP miss two (2) site meets, Company may cancel the applicable DASR. Company may charge for a site meet requested by the ESP or MSP, or if the ESP or MSP fails to arrive within thirty (30) minutes of the appointment time, or if the ESP fails to cancel a site meet at least one (1) working day in advance of the appointment time.

8.12 Meter Service Options and Obligations

8.12.1 Meter Ownership shall be limited to Company, an ESP, or the customer. The customer must obtain the meter through Company or an ESP. Although a customer may own the electric meter, maintenance and servicing of the metering equipment shall be limited to Company, the ESP, or the ESP's qualified representative (MSP).

8.12.2 If the ESP or customer owns the meter, the ESP must own the CTs, PTs, and associated equipment, except as provided in Section 8.12.3. The ESP may purchase existing CTs and PTs and associated metering equipment from Company.

8.12.3 The following provisions apply to the ownership of CTs and PTs.

8.12.3.1 For distribution voltages up to 25kV, the ESP or Company shall own the CTs and PTs. For transmission primary voltages (over 25kV), the CTs and PTs shall be owned by Company. ESP owned CTs and PTs must meet Company specifications. No CTs and PTs or associated metering equipment shall be set or allowed to remain in service if it is determined that the CTs and PTs or their associated equipment does not meet Company's approved specifications, as set forth in Company's Electric Service Requirements Manual in place at the time of installation.

8.12.4 All CT-rated meter installations shall utilize safety test switches, and all self-contained commercial metering shall utilize safety-test blocks as provided in Company's ESRM. During meter exchanges, the ESP or its agent's employees who are certificated to perform the related MSP activities may install, replace or operate Company test switches and operate Company-sealed customer-owned test blocks.

8.13 Installation Options

8.13.1 The ESP is responsible for Direct Access customer meter installation. Company may optionally provide meter installation pursuant to the Rules.

8.13.2 ESPs or their agents must be certificated by the ACC in order to offer MSP services. The policies and procedures described in this Section 8.13 assume that the MSP and their meter installers have ACC certification. ESPs may elect to offer metering services by:

8.13.2.1 Becoming a certificated MSP.

8.13.2.2 Subcontracting with a third party that is a certificated MSP.

8.13.2.3 Subcontracting with Company under the circumstances described in Section 8.2.

8.14 As part of providing metering services, ESPs or their agents shall:

8.14.1 Obtain lock ring keys for meters originally installed by Company or request site meets with Company. Company will issue lock ring keys to certified MSPs upon receipt of a refundable deposit. The deposit will not be refunded if a key is either lost or stolen, and a fee will be applied to replace lost or damaged keys. For more information about the cost of lock rings, standard rings, or lock ring keys, please consult the Company MAC.

8.14.2 If lock rings are used they shall meet Company requirements. If a meter is installed and the readings are obtained from a source other than a physical inspection, a lock ring must be utilized. Lock rings may be purchased from Company.

8.14.3 Provide information to Company on the specifications and other specifics on meters not purchased from or installed by Company.

8.14.4 Allow Company to remove the customer's meter, or schedule a site meet to remove the meter transferring from Direct Access to Standard Offer service. If the ESP allows Company to remove meters, ESP shall coordinate with Company regarding the return of the meters.

8.14.5 Be responsible for obtaining and providing reads from any meter that it installs from the time it is installed to the time it is removed or until meter reading responsibilities are assumed by another ESP or the customer returns to Standard Offer service.

8.14.6 Ensure that ESP and MSP employees working in Company's territory follow ACC and other applicable safety standards.

8.14.7 Company shall notify the ESP immediately and the ESP shall notify Company immediately of any suspected unauthorized energy use when a safety hazard exists. In instances where there is not a safety hazard, each party will notify each other within twenty-four (24) hours. The ESP shall ensure that a lock ring is installed to secure any meter that does not require a monthly local (i.e., manual) meter read. The Parties agree to preserve any evidence of unauthorized energy use. Once unauthorized energy use is suspected, Company, in its sole discretion, may take any or all of the actions permitted under Company's tariffs and schedules and shall notify the ACC of any such action taken.

8.14.8 Take no action to impede Company's safe and unrestricted access to a customer's service entrance.

8.14.9 Glass over any socket when a meter is removed and a new meter is not installed.

8.15 MSRP Services provided as a responsibility of an ESP

Only certificated MRSP's acting on the ESP's behalf in accordance with ACC regulations shall perform MRSP functions. The MRSP for each Direct Access customer will be specified on the DASR received from the ESP. Any changes to Customers MRSP will be updated by the ESP with a "UC" DASR at least ten (10) days prior to the next scheduled read date. MRSP obligations and responsibilities are stated in the ACC's Rules and Regulations and include:

8.15.1 Meter data for Direct Access Customers shall be read, validated, edited, and transferred pursuant to Arizona's Validation, Editing, and Estimation Process (VEE). It is the responsibility of the MRSP to comply with this process. In cases where validated data is unavailable for transfer by the posting deadline, it is the responsibility of the MRSP to provide an estimated data file for the entire read cycle until actual meter data is available. At such time as actual data becomes available, a corrected data file shall be posted immediately.

8.15.2 Both Company and the ESP shall have 24-hour/7 days per week access to the MRSP server.

8.15.3 Meter read data shall include beginning and ending reads as well as the validated usage for load-profiled customers. Validated interval data shall be provided for all interval metering customers. Data must be posted to the MRSP server using the Arizona Standard EDI "867" format. Estimated data shall contain applicable reason codes pursuant to the 867 guidelines.

8.15.4 The MRSP shall provide Company with access to meter data at the MRSP server as required to allow the proper performance of billing and settlement.

8.15.5 MRSPs must have a CC&N from the ACC authorizing it to offer MSRP services, and must be certified in Company territory.

8.15.6 MRSPs shall read Customer's meter based on the scheduled read date per Company's Yearly Meter Read Schedule. The billing cycle for each meter shall contain the full period from read date to the following read date. Interval data cycles shall be considered from 00:15 on the read date to 00:00 on the following read date (i.e. 9/1/00 00:15 through 10/1/00 00:00). The first complete interval timestamp shall begin at 00:15 in each cycle. For meter exchanges to Direct Access, the first complete interval through the first read date at 00:00 shall constitute the billing cycle. For meter exchanges back to Standard Offer, every interval shall be included up to the last full interval prior to the exchange. It is the responsibility of the MRSP to provide estimation of any intervals that are necessary to constitute the full billing cycle.

8.15.7 The MRSP shall provide re-reads or read verifies within ten (10) working days of a request by Company or Customer. The requesting party may be charged per the applicable ACC tariff if the original read was not in error.

8.16 Meter Reading Data Obligations

8.16.1 Accuracy for all meters.

8.16.1.1 Meter clocks shall be maintained according to Arizona time within +/- three (3) minutes of the National Time Standard.

8.16.1.2 Meter read date and time shall be accurate.

8.16.1.3 All meter reading data shall be validated pursuant to the approved Arizona VEE guidelines.

8.16.2 Timeliness for Validated Meter Reading Data

Pursuant to guidelines established by the Utilities Division Director, one hundred percent (100%) of the validated meter data shall be available by 3:00 p.m. Local Arizona Time (MST) on the third working day after the scheduled read date. If the meter data is not posted, is unavailable, or clearly contains errors by this deadline, the billing determinants including usage (kWh) and demand (kW) may be estimated by Company and the ESP shall be charged an approved charge for this service.

8.16.3 Proof of Operational Ability

Prior to performing MRSP services in Company's distribution service territory, or prior to making any significant change in MRSP service methodology, each MRSP will perform compliance testing to demonstrate its ability to read meters, validate data, edit data, estimate missing data and post validated data in Company-compatible EDI format to the MRSP server. In addition, upon installation of the initial meter on Direct Access accounts in Company's distribution service territory, each MRSP shall prove its ability to read its meters and post validated data in Company-compatible EDI format to the MRSP server. If the MRSP is unsuccessful in its attempts to meet these requirements, all subsequent requests for meter exchanges will be postponed until the MRSP successfully demonstrates its operational ability.

8.16.4 Retention and Format for Meter Reading Data

8.16.4.1 All meter reading data for a Customer shall remain posted on the MRSP server for five (5) working days and will be recoverable for at least three (3) years.

8.16.4.2 Meter reading data posted to the MRSP server shall be stored in Company-compatible EDI format.

8.17 Company performing MSP and MRSP functions:

If Company is eligible to perform Direct Access related MSP and MRSP functions as defined in section 8.2, the following restriction applies:

The validated meter read will be posted in EDI format no later than 6 working days following the scheduled read date.

8.18 Non-Conforming Meters, Meter Errors and Meter Reading Errors

8.18.1 Whenever Company, the ESP or its agents becomes aware of any non-conforming meters, erroneous meter services and/or meter reading services that impact billing, it shall promptly notify the other parties and the affected Customer. Bills found to be in error due to non-conforming meters or errors in meter services or meter reading services will be corrected by the appropriate parties.

8.18.2 In cases of meter failure or non-compliance, the ESP or its agents shall have five (5) working days to correct the non-compliance. If the non-compliance is not remedied within five (5) working days, the following actions may apply:

8.18.2.1 A site meeting may be required when services are being performed. The non-compliant party may be charged an ACC-approved tariff for the meeting.

8.18.2.2 Company may repair the defect, and the other party shall be responsible for all related expenses.

8.18.2.3 Company shall adhere to the approved Performance Monitoring Standards and follow the steps outlined to address non-compliance by an MRSP.

8.18.3 Company may refuse to enter into a new ESP Service Acquisition Agreement, or cancel an existing ESP Service Acquisition Agreement pursuant to section 7.10.1.2, with any ESP or its agents that has a demonstrated pattern of uncorrected non-compliance as established above. This provision shall not apply if the alleged demonstrated pattern of non-compliance or correction thereof is disputed and is pending before any agency or entity with jurisdiction to resolve the dispute.

APPENDIX G SCHEDULE 4
TOTALIZED METERING OF MULTIPLE SERVICE ENTRANCE SECTIONS AT A SINGLE SITE FOR STANDARD OFFER AND DIRECT ACCESS SERVICE

Arizona Public Service Company (Company) customers at a single site whose load requires multiple points of delivery through multiple service entrance sections (SESs) may be metered and billed from a single meter through Adjacent Totalized Metering or Remote Totalized Metering as specified in this schedule.

Totalized Metering (Adjacent or Remote) is the measurement for billing purposes on the appropriate rate, through one meter, of the simultaneous demands and energy of a customer who receives electric service at more than one SES at a single site.

A. Totalized metering will either be Adjacent or Remote and shall be permitted only if conditions 1 through 7 are all satisfied.

1. The customer's facilities must be located on adjacent and contiguous sites not separated by private or public property or right-of-way and must be operated as one integral unit under the same name and as a part of the same business or residence (these conditions must be met to be considered a single site, as specified in Company's Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service, Section 4.1.1) ; and

2. Power will generally be delivered at no less than 277/480 volt (nominal), three phase, four wire or 120/240 volt (nominal) single phase three wire; and

3. Three phase and single phase service entrance sections can not be combined for totalizing purposes; and

4. For Standard Offer customers, totalized metering must be accomplished by a physical wire interconnection of metering information with the customer providing conduit between the SESs; for Direct Access customers the customer's Electric Service Provider may provide electronically totalized demand and energy reads in compliance with Company's Schedule 10, Terms and Conditions for Direct Access; and

5. The customer shall provide vault or transformer space, which meets Company specifications, on the customer's property at no cost to Company; and

6. If the customer operates an electric generation unit on the premise, totalized metering will be permitted when the customer complies with all of Company's requirements for interconnection, pays all costs for any additional special metering required to accommodate such service from totalized service sections, and takes service on an applicable rate schedule for interconnected customer-owned generation; and

7. Written approval by Company's authorized representative is required before totalized metering may be implemented.

B. Adjacent Totalized Metering will apply when conditions A.1-A.7 and the following conditions are met:

1. The customer's <u>total</u> load to be totalized requires a National Electrical Code (NEC) service entrance size of over 3,000 amps three phase or 800 amps single phase; and

2. Company requires that load be split and served from multiple SESs; and

3. The customer must locate SESs to be totalized within 10 feet of each other.

There will be no additional charge to the customer's monthly bill for Adjacent Totalized Metering.

C. Remote Totalized Metering will apply when conditions A.1-A.7 are met, multiple SESs are separated from one another by more than 10 feet, and the following conditions are met:

1. Each of the customer's service entrance sections to be totalized requires an NEC section size of 3,000 amps three phase or 800 amps single phase or greater; and

2. The customer's total load to be totalized has a minimum demand of 2,000 kVa or 1,500 kW three phase or 100 kVa or 80 kW single phase; and

3. The customer has made a non-refundable contribution for the net additional cost to Company of the meter totalizing connection and equipment.

When the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is equal to or less than the cost to serve a single point of delivery, then no additional monthly charge shall be made to the customer receiving Remote Totalized Metering. However, lower capital investment which results from the customer's contribution, other than the meter costs in C.3 above, shall not be considered.

For customers where the total capital investment by Company to provide service at multiple points of delivery, as computed by Company, is greater than the cost to serve at a single point of delivery, then there shall be an additional charge. The additional monthly charge for each delivery point above one shall consist of 1% of the totalized bill, plus $500.00, plus all applicable taxes and adjustments.

D. Removal of Totalized Metering Configuration

In some cases, it may be to the customer's benefit to remove all totalized metering equipment, or remove selected totalized metering equipment from the totalized account. This will be permitted under the following conditions:

1. The customer must submit a written request to Company stating the reason for the removal and the specific equipment to be removed.

2. After removal of the equipment, the customer may not ask for services to be totalized for one (1) year from the removal date. At the end of one (1) year, if the customer does request services to be totalized, the applicable conditions listed above must be met.

3. The customer will be required to make a nonrefundable contribution for the costs associated with the removal of the meter totalizing connection and equipment.

APS

APPENDIX H SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION OF SPECIALIZED METERING

Arizona Public Service Company (Company) will provide specialized metering upon customer request, provided the customer agrees to the following conditions:

1. The customer must contact their Company Account Representative to request and coordinate the purchase and installation of specialized metering such as KYZ pulse meters, IDR meters, or IDR and KYZ pulse meters. The customer must specify whether a modem will be required.

2. If the customer requests a meter with a modem option, the customer will be required to install communication equipment and connections which shall include a RJ11 or RJ12 jack. A coil of communication cable with either an RJ11 or RJ12 jack is to be provided within five to ten feet of the meter panel location and in such a manner that will provide for ease of attachment of the jack to the meter panel by Company. The phone line must be installed prior to the installation of the meter. The customer must provide Company with a phone number and any other communication access information to the meter(s) prior to Company installation of the meter(s).

3. If a customer requests kWh pulses, Company shall furnish an isolation relay and maintain the output wire and connections from this relay to an approved terminal block to be furnished by the customer. The terminal block shall be located in a lockable junction box mounted adjacent to (but not within) the Company metering compartment and not on the face of the Company metering panel.

4. The customer will be required to make a non-refundable contribution in aid of construction to Company for the requested meter(s) installation. The non-refundable contribution amount will be determined at the time of the request as follows:

   4.1 If a meter currently exists on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less the equipment cost of Company's existing meter.

   4.2 If a meter has not been installed on the customer site, the charge is based on Company's total equipment and installation costs for the requested specialized metering less 100% of the AUC cost of a Company standard meter.

   4.3 If a specialized meter is existing on a customer's site and the customer requests an upgrade to a different type of meter, the customer will be responsible for 100% of the cost (installation and equipment) associated with the requested meter.

Company will not place an order for a requested meter(s) until payment has been received from the customer. The typical lead time for procurement of meters is six (6) to eight (8) weeks. Once the requested meter(s) have been received, Company will schedule the installation of the meter(s) with the customer or a designated representative.

Company will retain ownership of all meters and Company installed metering equipment.

If a customer makes a nonrefundable contribution for the installation of a specialized meter and then terminates service or requests Company to remove and/or replace the specialized meter, the customer will not be eligible for a refund.

APS

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

Company will provide general maintenance of the specialized meter; however, in the event the meter should become damaged, obsolete or inoperable, the customer will be responsible for 100% of the replacement cost (installation and equipment) associated with the specialized meter.

Company will not be responsible for the installation, maintenance, or usage fees associated with any phone lines or related communication equipment.

5. Under no circumstances shall the customer stop the operation or in any way affect or interfere with the operation of the isolation relay and the related output wiring. The integrity of Company's billing metering equipment within the sealed metering compartment shall be maintained.

6. Company reserves the right to interrupt the specialized metering circuit for emergencies or to perform routine or special tests or maintenance on its billing metering equipment, and in so doing assumes no responsibility for affecting the operation of the customer's demand control or other equipment. However, Company will make a good faith effort to notify the customer prior to any interruption of the specialized metering circuit.

7. The possible failure or malfunction of an isolation relay and subsequent loss of kWh contact closures to the customer's control equipment shall in no way be deemed to invalidate or in any way impair the accuracy and readings of Company's meters in establishing the kWh and demand record for billing purposes.

8. The accuracy of the customer's equipment is entirely the responsibility of the customer. Should the customer's equipment malfunction, Company will reasonably cooperate with the customer to the extent of assuring that no malfunction exists in Company's equipment. Work of this nature will be billed to the customer, unless the actual source of the malfunction is found within Company's equipment.

9. If Company provides pulse values in kWh, customer's equipment must be capable of readjustment or recalibration to adjust to new contact closure values and rates should it become necessary for Company to adjust the pulse values due to changes in Company's equipment.

10. No circuit for use by the customer shall be installed from Company's billing metering potential or current transformer secondaries.

11. Company reserves the right, without assuming any liability or responsibility, to disconnect and/or remove the pulse delivery equipment at any time upon 30 days written notice to the customer.

12. Upon request by Company, the customer shall make available to Company monthly load analysis information.

13. References to electric kWh pulses above shall mean isolation relay contact closures only; the customer is required to furnish operating voltage service. Isolation relay contacts are rated 5 amps, 28 volts DC or 120 volts AC.

14. The customer assumes all responsibility for, and agrees to indemnify and save Company harmless against, all liability, damages, judgments, fines, penalties, claims, charges, costs and fees incurred by Company resulting from the furnishing of specialized metering.

15. A waiver at any time by either party, or any default of or breach by the other party or any matter arising in connection with this service, shall not be considered a waiver of any subsequent default or matter.

APS

SCHEDULE 15
CONDITIONS GOVERNING THE PROVISION
OF SPECIALIZED METERING

16. Prior written approval by an authorized Company representative is required before electric kWh pulses service may be implemented.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT I
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 125	$ 107	$ 4,077	$ 4,309	$ 4,246
2	2005	251	214	5,122	5,587	5,505
3	2006	251	214	5,122	5,587	5,505
4	2007	251	214	5,122	5,587	5,505
5	2008	251	214	5,122	5,587	5,505
6	2009	605	214	5,122	5,941	5,854
7	2010	960	214	5,122	6,296	6,204
8	2011	960	214	5,122	6,296	6,204
9	2012	960	214	5,122	6,296	6,204
10	2013	960	214	5,122	6,296	6,204
11	2014	960	214	5,122	6,296	6,204
12	2015	960	214	5,122	6,296	6,204
13	2016	960	214	5,122	6,296	6,204
14	2017	960	214	5,122	6,296	6,204
15	2018	960	214	5,122	6,296	6,204
16	2019	960	214	5,122	6,296	6,204
17	2020	960	214	5,122	6,296	6,204
18	2021	960	214	5,122	6,296	6,204
19	2022	960	214	5,122	6,296	6,204
20	2023	960	214	5,122	6,296	6,204
21	2024	960	214	5,122	6,296	6,204
22	2025	-	-	-	-	-
23	2026	-	-	-	-	-
		$ 16,134	$ 4,387	$ 106,517	$ 127,038	$ 125,183

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT II
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 126	$ 194	$ 6,153	$ 6,473	$ 6,378
2	2005	250	388	8,072	8,710	8,583
3	2006	250	388	8,072	8,710	8,583
4	2007	250	388	8,072	8,710	8,583
5	2008	250	388	8,072	8,710	8,583
6	2009	606	388	8,072	9,066	8,934
7	2010	2,561	388	8,072	11,021	10,860
8	2011	2,561	388	8,072	11,021	10,860
9	2012	2,561	388	8,072	11,021	10,860
10	2013	2,561	388	8,072	11,021	10,860
11	2014	2,561	388	8,072	11,021	10,860
12	2015	2,561	388	8,072	11,021	10,860
13	2016	-	-	-	-	-
14	2017	-	-	-	-	-
15	2018	-	-	-	-	-
16	2019	-	-	-	-	-
17	2020	-	-	-	-	-
18	2021	-	-	-	-	-
19	2022	-	-	-	-	-
20	2023	-	-	-	-	-
21	2024	-	-	-	-	-
22	2025	-	-	-	-	-
23	2026	-	-	-	-	-
		$ 17,098	$ 4,462	$ 94,945	$ 116,505	$ 114,804

/1/ ACC Jurisdictional share is approximately 98.54%.

ARIZONA PUBLIC SERVICE COMPANY
SCHEDULE OF AMOUNTS TO BE DEPOSITED IN THE
DECOMMISSIONING TRUSTS INCLUDED IN COST-OF-SERVICE
PALO VERDE UNIT III
(Thousands of Dollars)
(APS Share)

Line	Year	Post Shutdown On-Going ISFSI Annual Contribution Required	Post Shutdown ISFSI Regulatory Asset Amortization Annual Contribution Required	Decommissioning Annual Contribution Required	Total Annual Contribution Required	ACC Jurisdictional Amount /1/
1	2004	$ 125	$ 95	$ 5,098	$ 5,318	$ 5,240
2	2005	251	190	6,017	6,458	6,364
3	2006	251	190	6,017	6,458	6,364
4	2007	251	190	6,017	6,458	6,364
5	2008	251	190	6,017	6,458	6,364
6	2009	605	190	6,017	6,812	6,713
7	2010	960	190	6,017	7,167	7,062
8	2011	960	190	6,017	7,167	7,062
9	2012	960	190	6,017	7,167	7,062
10	2013	960	190	6,017	7,167	7,062
11	2014	960	190	6,017	7,167	7,062
12	2015	960	190	6,017	7,167	7,062
13	2016	960	190	6,017	7,167	7,062
14	2017	960	190	6,017	7,167	7,062
15	2018	960	190	6,017	7,167	7,062
16	2019	960	190	6,017	7,167	7,062
17	2020	960	190	6,017	7,167	7,062
18	2021	960	190	6,017	7,167	7,062
19	2022	960	190	6,017	7,167	7,062
20	2023	960	190	6,017	7,167	7,062
21	2024	960	190	6,017	7,167	7,062
22	2025	960	190	6,017	7,167	7,062
23	2026	1,004	238	6,017	7,259	7,153
		$ 18,098	$ 4,323	$ 137,472	$ 159,893	$ 157,559

/1/ ACC Jurisdictional share is approximately 98.54%.

Settlement Rates for Residential Customers

Schedule E-10

Bundled Rate:	
Summer	
BSC (per day)	$ 0.253
1st 400 kWh	0.06929
Next 400 kWh	0.09490
additional kWh	0.09760
Winter	
BSC (per day)	$ 0.253
All kWh	0.07601
Generation:	
Summer	
1st 400 kWh	0.03518
Next 400 kWh	0.06079
additional kWh	0.06349
Winter	
All kWh	0.04190
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.253
All kWh	0.02722
Winter	
BSC (per day)	$ 0.253
All kWh	0.02722
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.063
Metering	$ 0.073
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.253

Schedule E-12

Bundled Rate:	
Summer	
BSC (per day)	$ 0.253
1st 400 kWh	0.07570
Next 400 kWh	0.10556
additional kWh	0.12314
Winter	
BSC (per day)	$ 0.253
All kWh	0.07361
Generation:	
Summer	
1st 400 kWh	0.04007
Next 400 kWh	0.06993
additional kWh	0.08751
Winter	
All kWh	0.03798
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.253
All kWh	0.02874
Winter	
BSC (per day)	$ 0.253
All kWh	0.02874
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.056
Metering	$ 0.081
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.253

Schedule EC-1

Bundled Rate:	
Summer	
BSC (per day)	$ 0.329
All kWh	0.03943
per kW	$ 10.00
Winter	
BSC (per day)	$ 0.329
All kWh	0.02978
kW	$ 7.10
Generation:	
Summer	
All kWh	0.01821
per kW	$ 7.66
Winter	
All kWh	0.00995
per kW	$ 5.08
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.329
All kWh	0.01433
per kW	$ 2.34
Winter	
BSC (per day)	$ 0.329
All kWh	0.01294
per kW	$ 2.02
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.049
Metering	$ 0.163
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.329

Schedule ECT-1R

Bundled Rate:	
Summer	
BSC (per day)	$ 0.493
On-peak kWh	0.04765
Off-peak kWh	0.02672
On-peak - kW	$ 11.81
Winter	
BSC (per day)	$ 0.493
On-peak kWh	0.0364[illegible]
Off-peak kWh	0.02570
On-peak - kW	$ 8.11
Generation:	
Summer	
On-peak kWh	0.03113
Off-peak kWh	0.01020
On-peak - kW	$ 8.43
Winter	
On-peak kWh	0.01608
Off-peak kWh	0.00537
On-peak - kW	$ 6.26
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.493
All kWh	0.00963
On-peak - kW	$ 3.38
Winter	
BSC (per day)	$ 0.493
All kWh	0.01344
On-peak - kW	$ 1.85
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.208
Metering	$ 0.168
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.493

Schedule ET-1

Bundled Rate:	
Summer	
BSC (per day)	$ 0.493
On-peak kWh	0.13310
Off-peak kWh	0.04299
Winter	
BSC (per day)	$ 0.493
On-peak kWh	0.10918
Off-peak kWh	0.04167
Generation:	
Summer	
On-peak kWh	0.10527
Off-peak kWh	0.01516
Winter	
On-peak kWh	0.08135
Off-peak kWh	0.01384
Transmission:	
Summer	
All kWh	0.00476
Winter	
All kWh	0.00476
Distribution:	
Summer	
BSC (per day)	$ 0.493
All kWh	0.02094
Winter	
BSC (per day)	$ 0.493
All kWh	0.02094
System Benefits:	
Summer	
All kWh	0.00213
Winter	
All kWh	0.00213
BSC: (per day)	
Customer Accts	$ 0.211
Metering	$ 0.166
Billing	$ 0.062
Meter Reading	$ 0.055
BSC Total	$ 0.493

DECISION NO. 67744

DOCKET NO. E-01345A-03-0437

APPENDIX J

August 10, 2004

Settlement Rate for Schedule E-32

E-32 Rate (20 kW or Less)		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
Summer		
kWh (1st 5000 / mo.) (Secondary)	$	0.09892
kWh (over 5000 / mo.) (Secondary)	$	0.04711
kWh (1st 5000 / mo.) (Primary)	$	0.09610
kWh (over 5000 / mo.) (Primary)	$	0.04429
Winter		
kWh (1st 5000 / mo.) (Secondary)	$	0.08892
kWh (over 5000 / mo.) (Secondary)	$	0.03711
kWh (1st 5000 / mo.) (Primary)	$	0.08610
kWh (over 5000 / mo.) (Primary)	$	0.03429
Primary Discount (per kWh)	$	0.00282
Generation		
Summer		
kWh (1st 5000 / mo.)	$	0.05894
kWh (over 5000 / mo.)	$	0.03163
Winter		
kWh (1st 5000 / mo.)	$	0.04901
kWh (over 5000 / mo.)	$	0.02170
Transmission		
per kWh	$	0.00476
Delivery		
Summer		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03309
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00859
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03027
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00577
Winter		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03302
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00852
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03020
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00570
System Benefits		
per kWh	$	0.00213
BSC (per day)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

E-32 Rate (over 20 kW)		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
kW		
1st 100 kW (Secondary)	$	7.722
Next 400 kW (Secondary)	$	3.497
Over 500 kW (Secondary)	$	3.497
1st 100 kW (Primary)	$	7.102
Next 400 kW (Primary)	$	2.877
Over 500 kW (Primary)	$	2.877
Summer		
1 st 200 kWh/kW	$	0.07938
over 200 kWh/kW	$	0.04175
Winter		
1 st 200 kWh/kW	$	0.06945
over 200 kWh/kW	$	0.03182
Primary Discount (per kW)	$	0.620
Transmission Discount (per kW)	$	3.490
Generation		
Summer		
1 st 200 kWh/kW	$	0.07239
over 200 kWh/kW	$	0.03476
Winter		
1 st 200 kWh/kW	$	0.06246
over 200 kWh/kW	$	0.02483
Transmission		
per kWh	$	0.00476
Delivery		
Delivery 1st 100 kW (Secondary)	$	7.722
Delivery next 400 kW (Secondary)	$	3.497
Delivery kW over 500 (Secondary)	$	3.497
Delivery 1st 100 kW (Primary)	$	7.102
Delivery next 400 kW (Primary)	$	2.877
Delivery kW over 500 (Primary)	$	2.877
Delivery - All kWh	$	0.00010
System Benefits		
in $/kWh	$	0.00213
BSC (per day)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

Settlement Rate for Schedule E-32 TOU

E-32TOU (20 kW or Less)		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
Summer		
kWh (1st 5000 / mo.) (Secondary) On-Pk	$	0.11172
kWh (over 5000 / mo.) (Secondary) On-Pk	$	0.05991
kWh (1st 5000 / mo.) (Secondary) Off-Pk	$	0.09172
kWh (over 5000 / mo.) (Secondary) Off-Pk	$	0.03991
kWh (1st 5000 / mo.) (Primary) On-Pk	$	0.10890
kWh (over 5000 / mo.) (Primary) On-Pk	$	0.05709
kWh (1st 5000 / mo.) (Primary) Off-Pk	$	0.08890
kWh (over 5000 / mo.) (Primary) Off-Pk	$	0.03709
Winter		
kWh (1st 5000 / mo.) (Secondary) On-Pk	$	0.10172
kWh (over 5000 / mo.) (Secondary) On-Pk	$	0.04991
kWh (1st 5000 / mo.) (Secondary) Off-Pk	$	0.08172
kWh (over 5000 / mo.) (Secondary) Off-Pk	$	0.02991
kWh (1st 5000 / mo.) (Primary) On-Pk	$	0.09890
kWh (over 5000 / mo.) (Primary) On-Pk	$	0.04709
kWh (1st 5000 / mo.) (Primary) Off-Pk	$	0.07890
kWh (over 5000 / mo.) (Primary) Off-Pk	$	0.02709
Primary Discount (per kWh)	$	0.00282
Generation		
Summer		
kWh (1st 5000 / mo.) On-Peak	$	0.07174
kWh (over 5000 / mo.) On-Peak	$	0.04443
kWh (1st 5000 / mo.) Off-Peak	$	0.05174
kWh (over 5000 / mo.) Off-Peak	$	0.02443
Winter		
kWh (1st 5000 / mo.) On-Peak	$	0.06181
kWh (over 5000 / mo.) On-Peak	$	0.03450
kWh (1st 5000 / mo.) Off-Peak	$	0.04181
kWh (over 5000 / mo.) Off-Peak	$	0.01450
Transmission		
per kWh	$	0.00476
Delivery		
Summer		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03309
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00859
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03027
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00577
Winter		
Delivery (1st 5000 kWh per mo.) (Secondary)	$	0.03302
Delivery (over 5000 kWh per mo.) (Secondary)	$	0.00852
Delivery (1st 5000 kWh per mo.) (Primary)	$	0.03020
Delivery (over 5000 kWh per mo.) (Primary)	$	0.00570
System Benefits		
per kWh	$	0.00213
BSC (per day charges)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

E-32 TOU (Over 20 kW)		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
kW		
1st 100 kW (Secondary) On-Peak	$	15.112
Next 400 kW (Secondary) On-Peak	$	10.887
Over 500 kW (Secondary) On-Peak	$	10.887
Residual kW (Secondary) Off-Peak	$	7.972
1st 100 kW (Primary) On-Peak	$	14.492
Next 400 kW (Primary) On-Peak	$	10.267
Over 500 kW (Primary) On-Peak	$	10.267
Residual kW (Primary) Off-Peak	$	7.352
Summer		
kWh On-Peak	$	0.04815
kWh Off-Peak	$	0.03815
Winter		
kWh On-Peak	$	0.03822
kWh Off-Peak	$	0.02822
Primary Discount (per kW)	$	0.620
Transmission Discount (per kW)	$	3.490
Generation		
1st 100 kW On-Peak	$	7.390
Next 400 kW On-Peak	$	7.390
Over 500 kW On-Peak	$	7.390
Residual kW Off-Peak	$	0.250
Summer		
kWh On-Peak	$	0.04116
kWh Off-Peak	$	0.03116
Winter		
kWh On-Peak	$	0.03123
kWh Off-Peak	$	0.02123
Transmission		
per kWh	$	0.00476
Delivery		
Delivery 1st 100 kW (Secondary)	$	7.722
Delivery next 400 kW (Secondary)	$	3.497
Delivery kW over 500 (Secondary)	$	[illegible]
Delivery - Residual kW Off-Peak	$	7.722
Delivery 1st 100 kW (Primary)	$	7.102
Delivery next 400 kW (Primary)	$	2.877
Delivery kW over 500 (Primary)	$	2.877
Delivery - Residual kW Off-Peak	$	7.102
Delivery - All kWh	$	0.00010
System Benefits		
in $/kWh	$	0.00213
BSC (per day charges)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

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DECISION NO. _____

Settlement Rate for Schedules E-34 and E-35

Schedule E-34		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
All kW		
All kW (Secondary)	$	12.343
All kW (Primary)	$	11.683
All kW (Transmission)	$	8.043
All kWh	$	0.03183
The numbers above reflect:		
Primary Discount (per kW)	$	0.660
Transmission Discount (per kW)	$	4.300
Generation		
Generation per kWh	$	0.02494
Generation per kW	$	7.740
Transmission		
per kWh	$	0.00476
Delivery		
Delivery per kWh	$	-
Delivery per kW (Secondary)	$	4.603
Delivery per kW (Primary)	$	3.943
Delivery per kW (Transmission)	$	0.303
System Benefits		
System Benefits per kWh	$	0.00213
BSC (per day)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

Schedule E-35		
Bundled Rate:		
BSC - Self-Contained Meter (per day)	$	0.575
BSC - Instrument-Rated Meter	$	1.134
BSC - Primary	$	2.926
BSC - Transmission	$	22.422
All kW		
On-Peak kW (Secondary)	$	12.869
On-Peak kW (Primary)	$	12.209
On-Peak kW (Transmission)	$	8.569
Off-Peak Excess kW (Secondary)	$	6.388
Off-Peak Excess kW (Primary)	$	5.728
Off-Peak Excess kW (Transmission)	$	2.088
On-Peak kWh	$	0.03529
Off-Peak kWh	$	0.02792
Primary Discount (per kW)	$	0.660
Transmission Discount (per kW)	$	4.300
Generation		
Generation per kWh - Peak	$	0.02840
Generation per kWh - Off-Peak	$	0.02103
Generation per kW - Peak	$	8.266
Generation per kW - Off Peak Excess	$	1.785
Transmission		
per kWh	$	0.00476
Delivery		
Delivery per kWh	$	-
Delivery per kW (Secondary)	$	4.603
Delivery per kW (Primary)	$	3.943
Delivery per kW (Transmission)	$	0.303
System Benefits		
per kWh	$	0.00213
BSC (per day charges)		
BSC self-contained (per day)	$	0.108
BSC instrument-rated	$	0.108
BSC primary	$	0.108
BSC transmission	$	0.108
Revenue Cycle (per day charges)		
Metering (self contained)	$	0.345
Metering (instrument-rated)	$	0.904
Metering (primary)	$	2.696
Metering (transmission)	$	22.192
Billing	$	0.064
Mtr Reading	$	0.058

Note:
On-peak period is 11AM-9PM

KPMG

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Consolidated Financial Statements

December 31, 2003 and 2002

(With Independent Auditors' Report Thereon)

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EXHIBIT
S-18
ADMITTED

Company credit card program: The Cooperative also maintains a line of credit agreement with the CFC of $250,000 as part of its company credit card program. The term of the agreement is for 12 months from July 23, 2003. The agreement automatically renews for subsequent periods of 12 months. Interest rates on all advances under the line of credit will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2003 was 4.00 percent. No amounts were drawn under the line of credit for the year ended December 31, 2003.

12. Patronage Capital:

	2003	2002
January 1	**$ 13,904,668**	$ 4,606,612
Patronage capital allocation	**3,898,570**	9,298,056
Patronage capital retirement	-	-
December 31	**$ 17,803,238**	$ 13,904,668

Patronage capital allocation: In accordance with the Cooperative's by-laws, net margins are accounted for on a patronage basis in the following sequence:

1. Offset prior year's unallocated accumulated losses.
2. Assign to Members' accounts as credits based on specific excesses of revenues over operating costs and expenses.

Patronage capital retirement: RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative.

13. Income Tax Status:

For the years ended December 31, 2003 and 2002, the Cooperative qualified for tax-exempt status under Internal Revenue code section 501(c)(12), which requires that 85 percent or more of income consist of amounts collected from Members for the sole purpose of meeting losses and expenses.

14. Employee Benefit Plans:

Pension Plans - The Cooperative has a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service, age, retirement interest rate, and the employee's highest five years of compensation during the last ten years of employment. The Cooperative's policy has been to fund retirement costs annually as they accrue.

KPMG

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

Financial Statements

December 31, 2003 and 2002

(With Independent Auditors' Report Thereon)

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S-19
ADMITTED

5. Accounts Receivable:

Accounts receivable at December 31, consist of the following:

	2003	2002
Electric transmission sales	**$ 2,743,061**	$ 2,655,734
Telecommunication/line maintenance services	**40,320**	31,747
Other	**158,157**	76,390
Total accounts receivable	**$ 2,941,538**	$ 2,763,871

Electric transmission sales – Electric transmission sales consist of sales to Members and non-members under transmission service agreements (See Note 11) and are generally not collateralized.

6. Deferred Debits:

Deferred debits at December 31, consist of the following:

	2003	2002
Regulatory asset	**$11,487,485**	$14,194,633
Unamortized debt costs	**2,334,497**	2,594,622
Other	**878,478**	925,276
Total deferred debits	**$14,700,460**	$17,714,531

Regulatory asset - The ACC authorized the recovery of the regulatory asset through the imposition of a specific charge. The regulatory asset, pursuant to an order from the ACC, is being amortized as revenues related to the regulatory asset are collected.

7. Patronage Capital:

	2003	2002
January 1	**$ 1,520,795**	$ 1,520,795
Patronage capital allocation	**696,540**	0
December 31	**$ 2,217,335**	$ 1,520,795

In accordance with the Cooperative's bylaws, the Cooperative is obligated to account on a patronage basis, to all its members for all amounts received and receivable from the furnishing of electric energy and other services to members in excess of the sum of:

- operating costs and expenses, including interest on debt services, properly chargeable against the furnishing of electric energy and other services; and
- amounts required to offset any losses incurred during the current or any prior fiscal year; and
- maintenance of reserves, if any.

All such amounts in excess of operating costs, expenses and prior losses at the moment of receipt by the Cooperative are received with the understanding that they are furnished by the members as capital. The Cooperative is obligated to pay by credits or account for losses to a capital account for each member all such amounts for credits or losses in proportion to the value or quantity of the Cooperative's service used, received or purchased by each member during the applicable fiscal year in excess of operating costs and expenses and prior losses.

RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative.

8. Long-Term Debt:

Federal Financing Bank (FFB) –This debt is payable at interest rates based on long-term obligations of the United States Government as determined on the date of advance. Interest rates on individual FFB notes ranged from 4.3 percent to 9.1 percent for 2003 and 5.0 percent to 9.1 percent for 2002. Interest rates on the debt averaged 6.2 percent in 2003 and 2002. Equal quarterly principal and interest installments on these obligations extend through 2021. The obligations are guaranteed by the RUS. The Cooperative may prepay all outstanding notes by paying the principal amount plus the lesser of: 1) the difference between the outstanding principal balance of the loan being refinanced or the present value of the loan discounted at a rate equal to the current cost of funds to the Department of the Treasury for obligations of comparable maturity; 2) 100 percent of the amount of interest for one year on the outstanding principal balance of the loan being refinanced; or 3) present value of 100 percent of the amount of interest for one year on the outstanding principal balance of the loan.

Cooperative Utility Trust -The Cooperative issued a note, underlying a Certificate of Beneficial Interests (the Certificate), to a Cooperative Utility Trust. Principal payments on the note are due annually in installments ranging from $398,092 to $1,572,497 from 2004 to 2018. The interest rate on the note is 7.7 percent. Interest is paid semi-annually. The note is guaranteed by the RUS. The Certificate is callable, only in whole, at any time on or after September 1, 2006, at redemption prices declining from an initial redemption price of 103.50 percent of par to 100 percent of par from and after September 1, 2013. The Certificate is also subject to prepayment at par at any time on or after September 1, 2006.

Pollution Control Revenue Refunding Bonds - Principal payments on the Series 1997 Pollution Control Revenue Refunding Bonds are payable semi-annually through mandatory sinking fund payments ranging from $830,716 to $959,396 from 2004 through 2007. The interest rates in effect at December 31, 2003, ranged from 4.7 percent to 5.0 percent. The interest rate on the bonds averaged 5.0 percent in 2003 and 2002. Interest is paid semi-annually. These bonds are guaranteed by the CFC. The bonds are not subject to optional redemption prior to maturity.

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S-21
Official Notice Taken

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
APR 11 2005
DOCKETED BY NR

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF GRAHAM COUNTY UTILITIES, INC. FOR A RATE INCREASE.

DOCKET NO. G-02527A-04-0301

DECISION NO. 67748

OPINION AND ORDER

DATE OF HEARING: February 3, 2005

PLACE OF HEARING: Tucson, Arizona

ADMINISTRATIVE LAW JUDGE: Jane L. Rodda

APPEARANCES: Russ Barney, Finance Manager, Graham County Utilities; and

David Ronald, Staff Attorney Legal Division, on behalf of the Utilities Division.

BY THE COMMISSION:

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Arizona Corporation Commission ("Commission") finds, concludes, and orders that:

FINDINGS OF FACT

1. Graham County Utilities, Inc. ("GCU" or "Cooperative") is a certificated Arizona based non-profit rural cooperative formed by Graham County Electric Cooperative, Inc. in Graham County, Arizona.

2. GCU provides natural gas and water services to approximately 4,691 gas and 950 water customers.

3. On April 20, 2004, GCU filed an application with the Commission for a rate increase for its gas division.

4. On May 20, 2004, Commission Utilities Division Staff ("Staff") docketed notification to the Cooperative that its application met the sufficiency requirements of the Arizona Administrative

Code and classified the Cooperative as a Class B utility.

5. By Procedural Order dated June 1, 2004, procedural guidelines were established and the matter set for hearing on February 3, 2005.

6. GCU mailed notice of the hearing to its customers as required by the June 1, 2004 Procedural Order.

7. By letter dated October 7, 2004, GCU requested that the refinancing of its National Rural Utilities Cooperative Finance Corporation ("CFC") loans be consolidated with its rate application.

8. In comments filed November 4, 2004, Staff concurred with the request to consolidate the rate application and the financing request.

9. On November 16, 2004, Staff filed its Direct Testimony that recommended a 14.26 percent increase in revenues, which was higher than the 13.7 percent increase requested by GCU in its application. Staff recommended that the Commission retroactively approve the Cooperative's refinancing of its CFC loan.

10. On November 17, 2004, Staff filed a Request to Re-notice. Staff recommended that GCU provide additional notice to its customers because Staff's recommended rates were higher than those GCU requested in the application.

11. Following a teleconference on December 9, 2004, during which Staff and GCU agreed that under the circumstances, publication of an additional notice was appropriate, GCU was ordered to publish notice of Staff's recommended revenue increase by Procedural Order of the same date.

12. GCU published the additional notice required in the December 9, 2004, Procedural Order on December 22, and December 29, 2004, in the *Eastern Arizona Courier*, a newspaper of general circulation within its service area.

13. GCU's current rates and charges were authorized in Decision No. 63850 (June 28, 2001).

Revenue Requirement

14. During the test year ended December 31, 2003, GCU's gas division experienced an adjusted negative operating margin of $99,489, on total revenues of $2,472,613.

15. GCU proposed an increase in revenue of $338,846, or 13.70 percent over test year revenues. As filed, GCU's proposed revenue level would result in a positive operating margin of $123,606, a Times Interest Earned Ratio ("TIER") of 1.9987, a Debt Service Ratio ("DSC") of 1.5741 and a return on Original Cost Rate Base ("OCRB") of 14.7 percent.

16. Staff recommends an increase in revenue of $352,598, or 14.26 percent, over test year revenue. Staff's recommended increase is greater than that requested by the Cooperative in order to produce a TIER of 2.0 and to help the Cooperative move toward a positive equity position. Staff's recommended revenue yields a DSC of 1.6344 and a return on OCRB of 15.5 percent.

17. GCU's lender, the CFC, requires GCU to maintain a TIER of 1.0 and a minimum DSC of 1.15.

Rate Base

18. Staff recommended an adjustment of $2,789 to remove Construction Work in Progress from rate base, reducing OCRB from $1,627,996 to $1,625,207. The Cooperative did not object to Staff's adjustment, nor did the Cooperative file any Reconstruction Cost New Less Rate Base ("RCND") schedules. Thus, GCU waived its right to a RCND finding. Staff's adjustment is reasonable. Consequently, we determine GCU's Fair Value Rate Base ("FVRB") to be the same as its OCRB, or $1,625,207.

Operating Expenses

19. Staff made no adjustments to GCU's test year revenues. Staff's adjustments increased the Cooperative's proposed Operating Expenses by $998, from $2,571,516 to $2,572,514. Staff adjusted Property Tax Expense to reflect the actual amount collected in the test year and the amount billed for 2004.

20. Staff's adjustments to Operating Expenses are reasonable and should be adopted.

Refinancing Request

21. In Decision No. 56660 (October 25, 1989), the Commission authorized GCU to acquire the water system of Cities Utilities Company and the gas system of General Utilities, Inc. In the same Decision, the Commission authorized GCU to borrow up to $2,243,711 from the CFC to finance the purchase. This CFC loan had a term of 25 years and an embedded cost of 10.25 percent

per annum. On May 1, 1998, GCU refinanced the loan for a term of 15 years at a rate of 7.1 percent per annum. GCU did not seek Commission approval to refinance the debt. The refinanced loan has the same maturity date (2014) as the original loan.

22. Staff's analysis shows that by refinancing the loan, GCU reduced its cost of debt by 315 basis points, resulting in total savings over the term of the loan of $230,357.

23. Staff recommends that the Commission retroactively approve GCU's refinancing.

Equity Plan

24. GCU had negative equity of (-) $168,874, (-) $107,060, and (-) $112,458 for the years ended 2001, 2002 and 2003, respectively. At the end of the test year, GCU's capital structure was composed of 108.8 percent debt and negative (-) 8.8 percent equity.

25. The average capital structure of distribution cooperatives that operate in Arizona is comprised of 55.2 percent debt and 44.8 percent equity.

26. Staff is concerned that GCU's negative equity position will result in higher debt costs, hinder its ability to incur new debt and finance capital improvements, and that it places upward pressure on rates to cover debt service obligations.

27. Staff believes that GCU's revenue requirement should improve its negative equity position and provide an adequate operating margin, TIER and DSC. Staff concludes that a TIER of 2.0 would provide GCU with sufficient revenues to meet its debt service and to improve its equity position with minimal impact on ratepayers.

28. Staff recommends that the Commission approve an equity plan for GCU with the objective to achieve a capital structure of at least 30 percent equity. Staff recommends that by the end of 2006, GCU increase its percentage of equity by 4 percent over its year-end 2004 equity. Each year thereafter, Staff recommends that the Cooperative increase its equity by 3 percent over year-end 2004 equity, until its capital structure is composed of at least 30 percent equity. Staff further recommends that GCU file a rate application within 180 days of the end of any calendar year that GCU is not able to meet the cumulative equity level specified in Staff's plan. Staff believes that GCU should be able to request a waiver from filing a rate application if it can demonstrate to Staff's satisfaction that it is likely that it would achieve Staff's recommended capital levels within a

reasonable timeframe without any rate adjustments. Staff states that such demonstration should be provided within 90 days after the end of the calendar year. Staff further believes that under no instance should GCU fail to meet Staff's recommended cumulative increase in equity for three consecutive years without filing a rate application. Staff also recommends that the Commission prohibit distribution of patronage dividends until GCU has achieved a capital structure composed of at least 30 percent.[1]

29. It is in the public interest that GCU improve the equity in its capital structure.

Base Cost of Gas and Rate Design

30. The base cost of gas is used as an estimate of the typical cost of natural gas to GCU and is included in GCU's base rates. The base cost of gas accounts for both the commodity cost and the cost of transporting the natural gas from its source to GCU's distribution system. GCU uses a purchased gas adjustor ("PGA") mechanism to account for the changing cost of natural gas. Currently, GCU uses a 12 month rolling average PGA mechanism, whereby a new PGA is calculated each month. The PGA is banded such that each new month when the PGA rate is set it cannot change by more that $0.10 per therm from the rate that was in place in any of the previous 12 months.

31. GCU's Gas Division's current rates and the rates and charges proposed by the Cooperative and Staff are set forth in Exhibit A attached hereto and incorporated herein by reference.

32. GCU's current rate schedule for residential gas service contains a monthly service charge of $10.00 and a commodity charge of $0.60477 per therm. GCU's current rate schedule for irrigation gas service contains a monthly service charge of $16.00 and a commodity charge of $0.47576 per therm. GCU's current rate schedule for commercial gas service contains a monthly service charge of $17.00 and a commodity charge of $0.60651 per therm. The per therm commodity charge consists of two components, the base cost of gas and the margin rate.

33. GCU proposed that the monthly service charge for residential service be increased to $11.00 and the commodity charge increased to $0.81433 per therm; that the irrigation monthly charge be increased to $18.00 and the commodity charge increased to $0.72532 per therm; and that the

[1] GCU testified that it does not make, and has never made, distributions of patronage dividends.

monthly service charge for commercial service be increased to $19.00 and the commodity charge increased to $0.79607 per therm. The proposed commodity charges include GCU's newly proposed base cost of gas of $0.59056 per therm. (See Exhibit A)

34. GCU's current base cost of gas is $0.4210 per therm, which was set in GCU's last rate proceeding (Decision No. 63850, June 28, 2001).

35. Staff believes that given the information available at this time concerning GCU's cost of gas, GCU's proposed base cost of gas is reasonable.

36. The proposed increase in the base cost of gas is $0.16944 per therm. Staff recommends that to minimize the impact on ratepayers given the size of the change in the base cost of gas, that the $0.10 per therm limitation on PGA increases only apply to the upward movement of the monthly PGA rate for the first 12 months that the new rates are in effect.

37. Staff further recommends that a GCU officer certify under oath through an affidavit attached to each adjustor report that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

38. GCU proposed an increase in the monthly service charge for all three classes in a generally proportional manner. GCU's proposed per therm commodity charge rates contain a larger increase for irrigation customers on both a percentage and $/therm basis because GCU's cost of service study showed that the rate of return from irrigation customers was less than the return from other customer classes.

39. Staff considered the effect of GCU's and its own cost of service study on the allocation of the proposed revenue increase, but also considered other factors such as the minimization of rate shock. Staff's proposed rate design reflects less emphasis in recovering revenues through monthly service charges and contains a more moderate increase for irrigation customers while still increasing the irrigation margin rate more than for the other customer classes on both a percentage and $/therm basis. To achieve Staff's proposed revenue requirement, Staff recommends a monthly service charge of $10.50 and a tariffed rate of $0.82500 per therm for residential customers; a monthly service charge of $17.00 and a tariffed rate of $0.69000 per therm for irrigation customers; and a monthly service charge of $18.00 and a tariffed rate of $0.83100 per

therm for commercial customers. (See Exhibit A)

40. Under Staff's proposed rates, and holding the total cost of gas constant at $0.59056 per therm, the average residential customer using 37 therms per month would experience an increase of 6.14 percent, from $38.65 to $41.03. The average irrigation customer using 323 therms per month would experience an increase of 6.88 percent, from $224.44 to $239.87. An average commercial customer using 257 therms per month would see an increase of 6.98 percent, from $216.45 to $231.57. During the peak heating season, based on January 2004 usage, an average residential customer using 99 therms would experience a 6.37 percent increase, from $86.66 to $92.18. Based on an average consumption of 615 therms, the average commercial customers would experience an increase of 7.04 percent, from $494.28 to $529.07. Irrigation customers using the average January 2004 consumption of 209 therms, would see an increase of 6.85 percent, from $150.87 to $163.30.

41. GCU had no objection to Staff's proposed revenue requirement or rate design.

42. GCU proposed changes to two of its service charges. It proposed eliminating its charge for "field collection charge – delinquent accounts", which was $20.00, because the Cooperative no longer wants to have its employees in the field collecting on delinquent accounts due to liability and other concerns. In addition, GCU proposes increasing the insufficient funds check charge from $20.00 to $25.00 due to higher costs being incurred by the Cooperative.

43. Staff concurs with GCU's proposed service charges.

44. Staff's recommended revenue requirement and its proposed rates and charges are fair and reasonable and should be adopted.

45. GCU's Rules and Regulations contain a short discussion of curtailment procedures in essence indicting that proportionate curtailments will be made, and if such proportionate curtailments are not sufficient, first priority will be given to customer classes where health, safety and welfare would be adversely affected. Staff believes GCU's gas curtailment plan does not contain the level of detail necessary to clearly define issues such as the priority of customer/classes in the curtailment process.

46. Staff recommends that within 60 days of the final Decision in this proceeding, GCU be required to file an updated, more detailed gas curtailment plan with Docket Control for the review

and approval of Staff.

Cost of Service

47. Staff reviewed GCU's Cost of Service Study ("COSS") and found it to be generally consistent with the methodology accepted in the industry. Staff recommends two changes in allocation factors. Specifically, Staff recommends that Distribution Mains be allocated based on demand and that Operating Expenses for Distribution Mains and Services be allocated based on 70 percent demand and 30 percent according to weighted customers (as opposed to GCU's 50 percent allocation factors). The result of Staff's modification to GCU's COSS shifts rate base and operating expenses from residential and irrigation customers to commercial customers, and increases the rate of return attributed to residential and irrigation customers and decreases the rate of return from commercial customers.

48. Staff recommends that GCU continue to utilize the current COSS model including the revised allocation factors in future rate cases.

49. GCU did not oppose Staff's modifications to its COSS.

50. GCU is in compliance with Commission Rules, Regulations and Orders.

51. GCU is current with its property and sales taxes.

CONCLUSIONS OF LAW

1. GCU is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250 and 40-251.

2. The Commission has jurisdiction over GCU and of the subject matter of the application.

3. Notice of the application was provided in the manner prescribed by law.

4. The rates and charges approved herein are just and reasonable and should be adopted.

5. Staff's recommendations set forth in Findings of Fact Nos. 23, 28, 36, 37, 46 and 48 are reasonable and should be adopted.

6. The financing approved herein is for lawful purposes within the Cooperative's corporate powers, is compatible with the public interest, with sound financial practices, and with the

proper performance by GCU of service as a public service corporation, and will not impair GCU's ability to perform the service.

7. The financing approved herein is for the purposes stated in the application, is reasonably necessary for those purposes, and such purposes are not, wholly or in part, reasonably chargeable to operating expenses or to income.

ORDER

IT IS THEREFORE ORDERED that Graham County Utilities, Inc. shall file with the Commission on or before April 29, 2005, revised schedules of rates and charges consistent with the rates approved hereinbelow:

Base Cost of Gas	$0.59056
Residential	
Monthly Service Charge	$10.50
Commodity Charge	$0.82500 per therm
Irrigation	
Monthly Service Charge	$17.00
Commodity Charge	$0.69000 per therm
Commercial	
Monthly Service Charge	$18.00
Commodity Charge	$0.83100 per therm
Miscellaneous Service Charges:	
Establishment of Service – Regular Hours	$20.00
Establishment of Service – After Hours	$35.00
Reestablishment of Service – Regular hours	$30.00
Reestablishment of Service – After Hours	$45.00
Reconnection of Service – Regular Hours	$30.00
Reconnection of Service – After Hours	$50.00
After Hours Service Calls – Customer caused	$50.00
Meter Re-read Charge (if correct)	$10.00
Meter Test Fee	$10.00
NSF Charge	$25.00
Interest Rate on Customer Deposits	6.0%
Late Payment (per month)	1.5%

. . .

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after May 1, 2005.

IT IS FURTHER ORDERED that Graham County Utilities, Inc. shall notify its customers of the revised schedules of rates and charges authorized herein by an insert in its next customer newsletter or by separate mailing in a form approved by Staff.

IT IS FURTHER ORDERED that GCU's refinancing of its acquisition debt from the CFC in 1998 is hereby approved.

IT IS FURTHER ORDERED that approval of the financing set forth hereinabove does not constitute or imply approval or disapproval by the Commission of any particular expenditure of the proceeds derived thereby for purposes of establishing just and reasonable rates.

IT IS FURTHER ORDERED THAT Graham County Utilities, Inc. shall comply with Staff's recommended equity enhancement plan as set forth in Findings of Fact No. 28.

IT IS FURTHER ORDERED that for the first twelve months after the effective date of this Decision the $0.10 per therm limitation on PGA increases shall only apply to the upward movement of the PGA rate.

IT IS FURTHER ORDERED that an officer of Graham County Utilities, Inc. shall certify under oath through an affidavit attached to each adjustor report that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

IT IS FURTHER ORDERED that Graham County Utilities, Inc. shall file within 60 days of the effective date of this Decision a detailed curtailment plan for the review and approval of Staff.

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IT IS FURTHER ORDERED that in its next rate case GCU shall utilize its current Cost of Service Study model as modified by Staff's recommendations herein.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER COMMISSIONER

COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 11th day of April, 2005.

BRIAN C. McNEIL
EXECUTIVE SECRETARY

DISSENT _____

DISSENT _____

JR:mj

SERVICE LIST FOR: GRAHAM COUNTY UTILITIES, INC.

DOCKET NO.: G-02527A-04-0301

Mr. Russ Barney
Graham County Utilities, Inc.
Post Office Drawer B
Pima, Arizona 85543

Christopher Kempley, Chief Counsel
LEGAL DIVISION
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Ernest Johnson, Director
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Miscellaneous Service Charges

Service Charge	Current	Proposed
Establishment of Service - Regular Hours	$20.00	$20.00
Establishment of Service - After Hours	$35.00	$35.00
Reestablishment of Service - Regular Hours	$30.00	$30.00
Reestablishment of Service - After Hours	$45.00	$45.00
Reconnection of Service - Regular Hours	$30.00	$30.00
Reconnection of Service - After Hours	$50.00	$50.00
Field Collection Charge - Delinquent Accounts	$20.00	-
After Hourse Service Calls - Consumer Caused	$50.00	$50.00
Meter Reread Charge (No Charge for Read Error)	$10.00	$10.00
Mete rTest Fee	$10.00	$10.00
Insufficient Funds Check	$20.00	$25.00
Interest Rate on Customer Deposits	6.00%	6.00%
Late Payment (Per Month)	1.50%	1.50%

DOCKET NO. G-02527A-04-0301

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RGG-3

RATE DESIGN COMPARISON

GRAHAM COUNTY UTILITES GAS DIVISION
DOCKET NO. G-02527A-04-0301

	PRESENT RATES	PROPOSED RATES					
		COMPANY	$ CHANGE	% CHANGE	STAFF RECOMMENDED	$ CHANGE	% CHANGE
BASE COST OF GAS	$0.42100	$0.59056	$0.16956	40.28%	$0.59056	$0.16956	40.28%
PURCHASED GAS ADJUSTOR	$0.16956	$0.00000	-$0.16956	-100.00%	$0.00000	-$0.16956	-100.00%

RATE SCHEDULES	PRESENT RATES	PROPOSED RATES					
		COMPANY	$ CHANGE	% CHANGE	STAFF RECOMMENDED	$ CHANGE	% CHANGE
RESIDENTIAL							
TARRIFED RATE	0.60477	0.81433	0.20956	0.34651	0.82500	$0.22023	36.42%
SERVICE AVAILABILITY	10.00	11.00	1.00000	0.10000	10.50000	$0.50000	5.00%
IRRIGATION							
TARIFFED RATE	0.47576	0.72532	0.24956	0.52455	0.69000	$0.21424	45.03%
SERVICE AVAILABILITY	16.00	18.00	2.00000	0.12500	17.00000	$1.00000	6.25%
COMMERCIAL							
TARIFFED RATE	0.60651	0.79607	0.18956	0.31254	0.83100	$0.22449	37.01%
SERVICE AVAILABILITY	17.00	19.00	2.00000	0.11765	18.00000	$1.00000	5.88%

RATE SCHEDULES	PRESENT RATES INCLUDING MONTHLY PGA	PROPOSED RATES					
		COMPANY	$ CHANGE	% CHANGE	STAFF RECOMMENDED	$ CHANGE	% CHANGE
RESIDENTIAL							
TOTAL RATE	0.77433	0.81433	0.04000	0.05166	0.82500	$0.05067	6.54%
SERVICE AVAILABILITY	10.00	11.00	1.00000	0.10000	10.50000	$0.50000	5.00%
IRRIGATION							
TOTAL RATE	0.64532	0.72532	0.08000	0.12397	0.69000	$0.04468	6.92%
SERVICE AVAILABILITY	16.00	18.00	2.00000	0.12500	17.00000	$1.00000	6.25%
COMMERCIAL							
TOTAL RATE	0.77607	0.79607	0.02000	0.02577	0.83100	$0.05493	7.08%
SERVICE AVAILABILITY	17.00	19.00	2.00000	0.11765	18.00000	$1.00000	5.88%

EXHIBIT A

67748

DOCKET NO. G-02527A-04-0301

EXHIBIT
S-22
ADMITTED
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Memorandum

RECEIVED
APR 01 2005
LEGAL DIV.
ARIZ. CORPORATION COMMISSION

Date: March 31, 2005
To: Staff Team for AEPCO Rate Application
From: Jerry D. Smith, Electric Utility Engineer
Subject: AEPCO Power Plant Depreciation and Overhaul Costs
Docket No. E-01773A-04-0528

Arizona Electric Power Cooperative ("AEPCO") submitted and utilized a revised depreciation rate for its Apache Generating Station Units 2 and 3 in its pending rate case application. Dirk Minson offered the attached Exhibit DCM-1 in his direct testimony. It shows the depreciation rate for Unit 2 being reduced from 2.09% to 1.34% and Unit 3 from 1.81% to 1.413%. The revised depreciation rates are based upon an engineering assessment that the two AEPCO generating units have thirty two (32) years of remaining useful life. This extends the normal assumed useful life of the units by fifteen (15) years.

I have read the August, 2003 "Major Power Generation and Plant Electrical Equipment Condition Assessment" report prepared for AEPCO by Burns & McDonnell. The assessment is technically sound and justifies an extended useful life for the units by recommending a variety of refurbishment, improvements and replacement of components over time. I concur with Burns & McDonnell's findings provided the recommended normal and customary refurbishments, improvements and replacements are timely performed during minor and major overhaul of the units.

The detailed cycle of refurbishment, improvements and replacement of components recommended by Burns & McDonnell may influence the scope and timing of future minor and major overhauls of Apache Generating Station Units 2 and 3. This implies that the historical frequency and cost of overhauls of the two generating units may not be good predictors of the frequency and costs of future overhauls. Furthermore, there is no historical data on the cost of overhauls for the new Gas Turbine #4 that was placed in service in 2002. Accrual of overhaul costs assumed for future years should take in to account these two factors.

AEPCO offered an engineering estimate of $1.6 million for the major overhaul cost for Gas Turbine #4 in Gary Pierson's rebuttal testimony. Mr. Pierson projected this overhaul will be required by 2010. The major overhaul frequency and cost magnitude projected by AEPCO for Gas Turbine #4 are both comparable to the major overhaul frequency and cost commonly found in the industry for a unit of this size, type and vintage. Therefore, it would be appropriate to adjust Staff's schedule of overhaul accrual expenses to include this expenditure in accordance with AEPCO's Exhibit GEP-8.

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JDS/js
Attachments: Exhibit DCM-1
Exhibit GEP-8
cc: Ernest Johnson, Utilities Director
Steve Olea, Assistant Utilities Director
Del Smith, Engineering Supervisor
Staff Team - Barbara Keene, Erin Casper, Gordon Fox, Alejandro Rameriz, Crystal Brown, Tim Sabo, and Diane Targovnik
~~~

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Exhibit DCM-1

Analysis of effect of change in depreciation rates for ST2 and ST3 (life change to 2035)

	(a)	(b)	(c)	(d)	(e)	(f)
	Estimated Book Value 12/31/03	Estimated Accum. Prov. Depreciation 12/31/03	Estimated Net Book Value 12/31/03	Current Depreciation Rates **	Years Remaining 12/31/03 to 12/31/2035***	Calculated Proposed Depreciation Rates
Steam 2*	$134,034,371	$76,577,621	$57,456,750	2.09%	32	1.340%
Steam 3*	$127,122,671	$69,630,377	$57,492,294	1.81%	32	1.413%
	$261,157,041	$146,207,998	$114,949,043			

*: Includes common facilities allocated to each unit (excludes fully depreciated rail cars)
Also excludes furniture & equipment, rolling stock, etc, and general plant.

**: RUS approved these rates July 1995

***: Burns & McDonnell August 2003 Condition Assessment Report states "through 2035"

Arizona Electric Power Cooperative, Inc.
Docket No. E-01773A-04-0528
Test Year Ended December 31, 2003

Exhibit GEP-8

REBUTTAL ADJUSTMENT NO. 3 - OVERHAUL ACCRUAL EXPENSE

LINE NO.	DESCRIPTION	[A] STAFF AS ADJUSTED	[B] COMPANY REBUTTAL ADJUSTMENTS	[C] COMPANY REBUTTAL AS ADJUSTED
1	Overhaul Accrual Expense	$4,129,720	$ 193,569	$ 4,323,289

		ST1	ST2	ST3	GT1	GT2*	GT3	GT4**	Total
3	1996	$ -	$ -	$ 5,180,041	$ -	$ -	$ -	$ -	$ 5,180,041
4	1997	$ -	$ 2,671,333	$ 489,239	$ -	$ -	$ -	$ -	$ 3,160,572
5	1998	$ -	$ -	$ 1,775,453	$ -	$ -	$ -	$ -	$ 1,775,453
6	1999	$ -	$ 3,828,921	$ -	$ -	$ -	$ 2,347,954	$ -	$ 6,176,875
7	2000	$ 94,116	$ 381,564	$ 1,181,848	$ -	$ -	$ -	$ -	$ 1,657,528
8	2001	$ 3,100,357	$ 2,740,233	$ -	$ 3,172,225	$ -	$ -	$ -	$ 9,012,815
9	2002	$ -	$ -	$ 2,868,220	$ -	$ -	$ -	$ -	$ 2,868,220
10	2003	$ -	$ 3,148,905	$ -	$ -	$ -	$ -	$ 57,354	$ 3,206,259
11		$ 3,194,473	$ 12,770,956	$ 11,494,801	$ 3,172,225	$ -	$ 2,347,954	$ 57,354	$ 33,037,763
12								Divided by	8
13									$ 4,129,720

13	ADJUSTMENT TO ANNUALIZE GT4 OVERHAUL ACCRUALS	
14	ANNUAL GT4 MAJOR OVERHAUL ACCRUAL - $1,605,900 / 8 YEARS =	$ 200,738
15	LESS: AMOUNT INCLUDED IN TOTAL, LINE 10 - $57,354 / 8 YEARS=	7,169
16	ADDITIONAL GT4 ACCRUAL	193,569
17		$ 4,323,289

18

19 • Per response to CSB 1-38, there has been no actual overhaul expense
20 for generating GT2 for the period 1990 to 2004.

21 ** Per response to CSB 1-37, unit GT4 was placed in service in 2002.

22 References:

23 Column A: Staff Exhibit CSB -17, Column C
24 Column B: Gary Pierson Rebuttal Testimony
25 Column C: Column [A] + Column [B]

SOUTHWEST TRANSMISSION COOPERATIVE, INC.
RESPONSE TO FIRST SET OF DATA REQUESTS FROM
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-04100A-04-0527
September 15, 2004

AR 1-1 In general, what are the minimum TIER, DSC and Equity ratios that the National Rural Utilities Cooperative Finance Corporation ("CFC") and the Rural Utilities Service ("RUS") require for new loans?

Respondent: Gary E. Pierson, Manager of Financial Services

Response: RUS requirements for new loans are set forth in 7 CFR Part 1710 – General and Pre-Loan Policies and Procedures Common to Loans and Guarantees. Subpart C – Loan Purposes and Basic Policies §1710.114(2) states, "The minimum coverage ratios required of power supply borrowers, whether applied on an annual or average basis, are a TIER of 1.05 and a DSC of 1.00." Section 1710.114(3) also allows the Administrator of RUS to increase these minimum coverage ratios, on a case-by-case basis, if the Administrator determines that the higher ratios are necessary to ensure reasonable security for and/or the repayment of new loans made or guaranteed by RUS. CFC and other Note holders secured by a lien accommodation under the terms of SWTC's Consolidated Mortgage and Security Agreement, dated July 2, 2001 adhere to the same minimum TIER and DSC coverage ratios.

Although the policies and procedures mentioned in 7 CFR Part 1710 don't mention specific minimum equity ratios, equity levels are part of the reasonable security analysis that RUS requires for new loans. 7 CFR Part 1717 - Post-Loan Policies and Procedures Common to Loans and Guarantees §1717.617 require prior approval by RUS of patronage capital refunds until the borrower's equity level is greater than or equal to 30%. After the borrower reaches that equity level, RUS approval of patronage capital refunds is not needed, subject to certain conditions set forth in §1717.617. In addition, CFC is concerned with development and maintenance of an adequate equity level and makes recommendations on managing equity levels. See the prepared testimony of William K. Edwards for additional detail.

Also, in Decision No. 64991, Staff expressed concerns about SWTC's equity position and recommended it file a capital plan similar to the plan the Commission ordered AEPCO to file in Commission Decision No. 64227. The Commission ordered that SWTC file a capital plan discussing an increase in its membership capital (equity) position to the Staff-recommended levels of 10% by the end of 2006, 15% by the end of 2010 and 30% by the end of 2015. SWTCO filed the Capital Plan on December 23, 2002.

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SOUTHWEST TRANSMISSION COOPERATIVE, INC.
RESPONSE TO FIRST SET OF DATA REQUESTS FROM
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-04100A-04-0527
September 15, 2004

Please refer to page 9 of Dirk C. Minson's testimony which discusses that Capital Plan and reiterates that the plan did not anticipate the large MW&E revenue losses.

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSE TO SECOND SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-04-0528
September 15, 2004

AR 2-1: In general, what are the minimum TIER, DSC and Equity ratios that the National Rural Utilities Cooperative Finance Corporation ("CFC") and the Rural Utilities Service ("RUS") require for new loans?

Respondent: Gary E. Pierson, Manager of Financial Services

Response: RUS requirements for new loans are set forth in 7 CFR Part 1710 – General and Pre-Loan Policies and Procedures Common to Loans and Guarantees. Subpart C – Loan Purposes and Basic Policies §1710.114(2) states, "The minimum coverage ratios required of power supply borrowers, whether applied on an annual or average basis, are a TIER of 1.05 and a DSC of 1.00." Section 1710.114(3) also allows the Administrator of RUS to increase these minimum coverage ratios, on a case-by-case basis, if the Administrator determines that the higher ratios are necessary to ensure reasonable security for and/or the repayment of new loans made or guaranteed by RUS. CFC and other Noteholders secured by a lien accommodation under the terms of AEPCO's Consolidated Mortgage and Security Agreement, dated June 14, 1989 (a copy of which was furnished in response to Staff Data Request CSB 1-7) adhere to the same minimum TIER and DSC coverage ratios.

Although the policies and procedures in 7 CFR Part 1710 don't mention specific minimum equity ratios, equity levels are part of the reasonable security analysis that RUS requires for new loans. 7 CFR Part 1717 - Post-Loan Policies and Procedures Common to Loans and Guarantees §1717.617 requires prior approval by RUS of patronage capital refunds until the borrower's equity level is greater than or equal to 30%. After the borrower reaches that equity level, RUS approval of patronage capital refunds is not needed, subject to certain conditions set forth in §1717.617. In addition, CFC is concerned with development and maintenance of an adequate equity level and makes recommendations on managing equity levels. See the prepared testimony of William K. Edwards for more detail.

Further, in Decision Nos. 64227 and 65210, Staff expressed concerns about AEPCO's marginal equity position and, on Staff's recommendation, the Commission ordered AEPCO to file a capital plan discussing an increase in its membership capital (equity) position to the Staff-recommended levels of 10% by the end of 2006, 15% by the end of 2010 and 30% by the end of 2015. AEPCO filed the capital plan with the Commission on December 23, 2002. The prepared testimony of Dirk C. Minson, page 10, addresses the subject.

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ADMITTED

ARIZONA ELECTRIC POWER COOPERATIVE, INC.
RESPONSE TO FIFTH SET OF DATA REQUESTS OF
ARIZONA CORPORATION COMMISSION STAFF
Docket No. E-01773A-04-0528
October 20, 2004

BEK 5-6 Did AEPCO engage in any demand-side management activities during the test year or after the test year?

Respondent: Dennis T. Criswell, Vice President – Marketing & Strategic Ventures

Response: No. AEPCO currently does not administer or coordinate member distribution cooperative DSM programs. Following suspension of most of the Integrated Resource Planning Rules in late 1997, the institution of various approved DSM programs by its member distribution cooperatives and the cancellation of its PPFAC which included a DSM cost recovery component in 2002, AEPCO gradually phased out its involvement in retail-level DSM programs.

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EXHIBIT
S-26
ADMITTED

Garkane Power Association, Inc.
Operating Expesnes
Year Ending December 31, 1996

Description	G/L#	Amount	Arizona	Utah	Allocation Method
Dist.-Exp - Maintenance					
Supervision	590	$ 2,230	$ 309	$ 1,921	13.86% Az Dist Plant to Total
Station Equipment	592	$ 43,229	$ 5,992	$ 37,237	13.86% Az Dist Plant to Total
Overhead Lines	593	$ 313,438	$ 43,443	$ 269,995	13.86% Az Dist Plant to Total
Underground Lines	594	$ 57,464	$ 7,965	$ 49,499	13.86% Az Dist Plant to Total
Line Transformers	595	$ 22,155	$ 3,072	$ 19,083	13.86% Az Dist Plant to Total
Street Lights	596	$ 6,167	$ 855	$ 5,312	13.86% Az Dist Plant to Total
Meters	597	$ 32,788	$ 4,544	$ 28,244	13.86% Az Dist Plant to Total
Misc Dist Plant	598	$ 6,515	$ 903	$ 5,612	13.86% Az Dist Plant to Total
Total		$ 483,996	$ 67,083	$ 416,913	
Cons Accts Expense					
Customer Accts - Sup	901	$ 11,770	$ 683	$ 11,087	5.80% Az Customers to Total
Meter Reading Expense	902	$ 101,694	$ 5,898	$ 95,796	5.80% Az Customers to Total
Collection Expense	903	$ 181,283	$ 10,514	$ 170,769	5.80% Az Customers to Total
Uncollectible Expense	904	$ -	$ -	$ -	5.80% Az Customers to Total
Misc Cons Expense	905	$ -	$ -	$ -	5.80% Az Customers to Total
Total		$ 294,747	$ 17,095	$ 277,652	
Customer Service Exp					
Supervision Expense	907	$ 24,836	$ 1,440	$ 23,396	5.80% Az Customers to Total
Cust Assistance Exp	908	$ -	$ -	$ -	5.80% Az Customers to Total
Info & Instruct Expense	909	$ 31,595	$ 1,833	$ 29,762	5.80% Az Customers to Total
Misc Cust Expense	910	$ 11,371	$ 660	$ 10,711	5.80% Az Customers to Total
Total		$ 67,802	$ ~~23,396~~ 3,933	$ ~~44,406~~ 63,869	
Sales Expense					
Demo & Selling Expense	912	$ 13,432	$ 874	$ 12,458	7.25% Az kwh Sales to Total
Advert Expense	913	$ 1,446	$ 105	$ 1,341	7.25% Az kwh Sales to Total
Total		$ 14,878	$ 1,079	$ 13,799	
Adm & Gen Expense					
Adm & Gen Salaries	920	$ 370,384	$ 21,482	$ 348,902	5.80% Az Customers to Total
Office Supplies	921	$ 133,395	$ 7,737	$ 125,658	5.80% Az Customers to Total
Outsideservice	923	$ 103,843	$ 6,023	$ 97,820	5.80% Az Customers to Total
Property Insurance	924	$ 95,398	$ 10,208	$ 85,190	10.70% Based on All Other Plant
Injuries & Damages	925	$ 27,344	$ 1,586	$ 25,758	5.80% Az Customers to Total
Employee Benefits	926	$ 399,983	$ 23,199	$ 376,784	5.80% Az Customers to Total
Regulatory Expense	928	$ 23,852	$ 1,383	$ 22,469	5.80% Az Customers to Total ?
Gen Misc	930	$ 306,598	$ 17,783	$ 288,815	5.80% Az Customers to Total
Rents	931	$ 3,000	$ 321	$ 2,679	10.70% Based on all Other Plant
Maint General Plant	932	$ 39,931	$ 2,316	$ 37,615	5.80% Az Customers to Total
Total		$1,503,728	$ 92,038	$1,411,690	

correct

1997 Property Taxes

Garkane Power Association, Inc.
Opertating Expesnes
Year Ending December 31, 1996

Description	G/L#	Amount	Arizona	Utah	Allocation Method
Depreciation Expense					
Other Production	403.2	$ 7,885	$ 559	$ 7,326	7.09% to AZ - Avg T.Y. Load
Hydraulic Plant	403.3	$ 89,711	$ 6,361	$ 83,350	7.09% to AZ - Avg T.Y. Load
Transmission Plant	403.5	$ 247,078	$ 14,948	$ 232,130	6.5% to AZ - 12/96 Peak Load
Distribution Plant	403.6	$ 541,528	$ 74,784	$ 466,744	Actual
General Plant	403.7	$ 225,135	$ 13,058	$ 212,077	5.80% Az Customers to Total
Total		$1,111,337	$ 109,710	$1,001,627	
Property Tax Expense	408.1	$ 249,881	$ 50,644	$ 199,237	actual
Other Tax Expense					
FUTA	408.2	$ 2,485	$ 180	$ 2,305	7.25% Az kwh Sales to Total
FICA	408.3	$ 110,536	$ 8,014	$ 102,522	7.25% Az kwh Sales to Total
SUTA	408.4	$ 1,969	$ 143	$ 1,826	7.25% Az kwh Sales to Total
State Sales	408.5	$ 620	$ 45	$ 575	7.25% Az kwh Sales to Total
Other	408.6	$ 8,779	$ 636	$ 8,143	7.25% Az kwh Sales to Total
Total		$ 124,389	$ 9,018	$ 115,371	
Interest Expense					
Interest Exp - LTD Debt	427	$ 914,670	$ 97,870	$ 816,800	10.7% Based on All Other Plant
Interest Exp Other	431	$ 10,069	$ 584	$ 9,485	5.80% Az Customers to Total
Total		$ 924,739	$ 98,454	$ 826,285	
Other Deductions					
Other Dedcutions	426	$ 16,232	$ 1,177	$ 15,055	7.25% Az kwh Sales to Total
Amort Reaquired Debt	428	$ 18,201	$ 1,948	$ 16,253	10.70% Based on All Other Plant
Total		$ 34,433	$ ~~2,496~~ 3,124	$ 31,308	
Other Non-operating items					
Interest & Divident Income	419	$ 139,377	$ 8,976	$ 130,401	6.44% Az kwh Revenue to Total
		see the schedule of Long Term Debt under Tab II.			
Nonoperating Margins					
Income from O&M Cont	415-416	$ 68,860	$ 30,471	$ 38,389	Fredonia
Gain/loss sale of plant	421	$ 97,737	$ -	$ 97,737	All to Utah
Capital Credit Allocations	424	$ 30,331	$ 1,953	$ 28,378	6.44% Az Electric Revenue to Total
Total		$ 196,928	$ ~~14,277~~ 32,424	$ ~~182,651~~ 164,504	
Other Electric Revenue					
Forfeited Disc & penalties (Late Charges)	450	$ 16,291	$ 1,049	$ 15,242	6.44% Az Electric Revenue to Total
Connect Fees	451	$ 25,953	$ 1,740	$ 24,213	Actual
Rent ← Pole Attachments	454	$ 5,185	$ 555	$ 4,630	10.70% Based on All Other Plant
Misc Electric Revenue	456	$ 548,790	$ 58,771	$ 490,069	10.70% Based on All Other Plant
Total		$ 596,219	$ ~~147,742~~ 62,065	$ 534,154	

Wheeling revenue

EXHIBIT
SWTC-1
ADMITTED

DIRECT TESTIMONY OF DIRK MINSON

BEFORE THE

ARIZONA CORPORATION COMMISSION

ON BEHALF OF

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Dirk Minson and my business address is 1000 South Highway 80, Benson, Arizona, 85602.

Q. Mr. Minson, by whom are you employed and in what capacity?

A. As the Chief Financial Officer of Southwest Transmission Cooperative, Inc. ("Southwest"), I serve as part of the Executive Management Team and report directly to the Chief Executive Officer. My specific responsibilities and duties include the accounting functions of the Cooperative, including establishing fiscal policy and procedure development and implementation of appropriate financial controls. Additional responsibilities include financial and corporate planning, rate design, development and implementation in addition to corporate treasury functions, as well as cash and working capital management, inventory control and risk management.

Q. Please briefly describe your educational background and work related experience.

A. I hold a B.S. Degree in Business Administration from Kansas State University and an M.B.A. from the University of Missouri. My entire 29-year career has been spent either working directly or indirectly for electric cooperative utilities. I began my employment with Arizona Electric Power Cooperative, Inc. in 1982 and was promoted to the position of Chief Financial Officer in May 1990.

Q. Mr. Minson, what is the purpose of your testimony?

A. I will provide the Commission information on Southwest, its members and its Board and member review and approval process for this rate filing. I'll also describe generally the rate request. Gary Pierson, our Manager of Financial Services, will testify more specifically concerning the A-H rate filing schedules. Bill Edwards of the National Rural Utilities Cooperative Finance Corporation will provide information in support of Southwest's Times Interest Earned Ratio ("TIER") and Debt Service Coverage Ratio ("DSCR") requirements.

BACKGROUND

Q. Mr. Minson, please describe Southwest.

A. Southwest is a non-profit, transmission cooperative which was formed in 1999 in anticipation of the restructuring of the Arizona Electric Power Cooperative, Inc. ("AEPCO"). The Commission approved the restructuring in Decision No. 63868 and, on August 1, 2001, AEPCO's transmission assets were transferred to Southwest and it commenced operations. Southwest primarily provides wholesale transmission services to AEPCO on behalf of its five all requirements Class A Member distribution cooperatives and to Mohave Electric Cooperative, Inc. ("Mohave") (the

"distribution cooperatives"). These six Class A Members of AEPCO are also Class A Members of Southwest. One distribution cooperative, Anza Electric Cooperative, Inc., is located in south-central California. The other five Arizona distribution cooperatives are the Duncan Valley Electric Cooperative, Inc. ("Duncan"), Graham County Electric Cooperative, Inc. ("Graham"), Mohave, Sulphur Springs Valley Electric Cooperative ("SSVEC") and Trico Electric Cooperative, Inc. ("Trico"). The Arizona distribution cooperatives are regulated by this Commission. Southwest also provides transmission services to AEPCO for certain of its other sales.

Q. Does Southwest have Class B Members?

A. Yes. AEPCO is a Class B Member of Southwest, as is Sierra Southwest Cooperative Services, Inc. ("Sierra"), which was the third cooperative created as part of AEPCO's restructuring. Southwest's other Class B Member is the Morenci Water & Electric Company ("MW&E"), a wholly-owned subsidiary of the Phelps Dodge Corporation which has a certificated service territory in and around the Phelps Dodge Morenci mine in Greenlee County. As I'll explain later, MW&E is completing transmission facilities that allow it to bypass Southwest's transmission system and has given notice of the cancellation of its firm transmission service agreement with Southwest. When the firm transmission service agreement terminates, MW&E will no longer be eligible for Class B membership.

Q. Does Southwest have transmission agreements with other entities?

A. A few. Southwest provides OATT-based wholesale transmission service to the City of Safford and the Town of Thatcher and has pre-OATT transmission agreements with the Avra Valley Irrigation and Drainage

District and the Silverbell Irrigation and Drainage District. Southwest also has umbrella service agreements under its Open Access Transmission Tariff ("OATT") to enable entities to conduct real time transactions on the Southwest Open Access Same Time Information System. To date, only AEPCO, Tucson Electric Power Company ("TEP") and Mohave have requested any transmission services from Southwest under an umbrella service agreement.

Q. Is Southwest regulated by agencies other than the Commission?

A. Yes. Southwest is a borrower from the Rural Utilities Service ("RUS") which is a division of the United States Department of Agriculture. As an RUS borrower, Southwest is subject to its regulation--both by virtue of its mortgage and also pursuant to federal regulations promulgated by the RUS. Southwest is also a "transmitting utility" under Section 211 of the Federal Power Act. As a transmitting utility, Southwest is subject to certain jurisdiction of the Federal Energy Regulatory Commission ("FERC") and in order to meet the requirements for reciprocity under FERC Order No. 888, it maintains a FERC-approved OATT.

Q. Please briefly describe Southwest's transmission facilities.

A. Southwest owns approximately 603 miles of transmission lines and 20 substations. Some of those transmission facilities are jointly owned with the Salt River Project and TEP. We also have contracts to receive transmission service from those companies, as well as Arizona Public Service, the Western Area Power Administration and Southern California Edison.

1 Q. How is Southwest governed?

2 A. Southwest's Board of Directors oversees all aspects of its operations. The
3 Board is comprised of seven directors. Six of them (one for each Class A
4 Member distribution cooperative) are designated as their representatives to
5 our Board by the distribution cooperatives, whose Board members are
6 elected by their retail customer/owners. The remaining Southwest director
7 is designated by our Class B Members.

8

9 Q. Did Southwest's Board approve this rate filing?

10 A. Yes, it did. Between November 2003 and July 2004, several meetings were
11 held with the Board of Directors discussing the need for and the elements
12 of Southwest's rate filing. In addition, during May and June 2004,
13 meetings were also held with Southwest's Class A Member Boards of
14 Directors and their respective staffs to review the revenue requirement
15 increase request. These meetings culminated in the Southwest Board of
16 Directors approving the filing of this rate case and associated revenue
17 requirement increase during a July 2004 meeting.

18

19 **OVERVIEW OF FILING**

20 Q. Please summarize Southwest's rate request.

21 A. Mr. Pierson will testify in greater detail concerning the requested rate
22 increase. Overall, Southwest requests that the Commission approve revised
23 rates which increase revenues by 13.7%. The revised rates are designed to
24 produce a TIER of 1.15 and a DSCR of 1.11 which, if achieved, will keep
25 Southwest in compliance with the standards required by its RUS mortgage
26 and RUS rules and also provide modest margins and working capital

coverage. The direct testimony of Mr. Edwards provides additional support for Southwest's TIER and DSCR requirements.

Q. Can you estimate the impact that this increase would have on the retail member/owner's bill?

A. That is difficult to estimate with any precision, because each distribution cooperative has different rates and varying rate structures. Generally, however, transmission service costs account for about 10% of the total delivered rate at retail. If you assume a residential rate of $.10 per kwh, on average one cent of that rate is attributable to Southwest's transmission service. Therefore, a residential consumer of Southwest's Class A Members using 750 kwh per month would see about a $1.45 increase in the monthly bill as a result of this rate request.

Q. Mr. Minson, why is this rate increase needed?

A. One of the reasons for this request is to make allowance for necessary maintenance and upgrades of the Southwest transmission system. The Winchester Interconnect Project is chief among these. As discussed with the Siting Committee and Commission in the CEC process which led to issuance of Decision No. 65934, it was completed to enhance system reliability and provide for improved performance of the entire bulk power system serving Southwest's members. It was placed in service in May of 2004. The Winchester Interconnect Project has a significant impact on Southwest's debt and total transmission plant. The $15.7 million cost is about 20% of Southwest's total depreciated transmission plant.

However, the major reason for the request is MW&E's bypass of the Southwest transmission system and the significant reduction in use of its

transmission service with Southwest. As a result, Southwest is losing approximately $2.8 million in annual revenues this year. These revenues had been used to reduce the overall costs which the distribution cooperatives and others had to pay for their use of the system. To place the significance of that revenue loss in context, $2.8 million represents nearly 9% of Southwest's total 2003 operating revenues and is more than five times as great as the roughly $500,000 in annual operating margins which are requested in this rate filing. By January 1, 2006, all firm and non-firm revenues totaling $5.1 million annually will be lost.

Q. Please explain further.

A. MW&E, a wholly-owned subsidiary of the Phelps Dodge Corporation ("PD"), provides the electricity which PD requires to operate its copper mining and processing facilities at Morenci, Arizona. MW&E purchases Morenci's electricity requirements from others and historically has used Southwest's transmission system to deliver approximately 190 MW to the mine site under its firm and non-firm transmission arrangements with Southwest. MW&E is completing a new transmission line and a 345/230 kV substation which instead connect its existing facilities directly to the system of TEP and enable MW&E to bypass Southwest's transmission system. The Commission approved the revised MW&E/PD electric service agreement, which reflected the costs of these new connection facilities to TEP, in April of this year--finding in that Decision that: "Usage of the new transmission line will reduce and eventually replace usage of Southwest Transmission Cooperative's line." (Docket No. E-01049A-04-0135.) MW&E has advised us that the new line will initially serve up to 100 MW of the PD load at Morenci radially from TEP's Phil Young switchyard. By

the end of September, MW&E and Southwest expect to complete the modifications at Southwest's Morenci substation to enable the systems to operate as a closed loop. As the non-firm service agreement between MW&E and Southwest obligates MW&E to pay for only that non-firm wheeling service it requests, once MW&E has a closed loop, Southwest expects to lose the remaining 30 MW of non-firm wheeling service for the PD Morenci load. This 130 MW of non-firm service represents the $2.8 million in lost revenues I mentioned previously. Then, on January 1, 2006, with the termination of the MW&E firm service, Southwest will lose the additional $2.3 million of revenue associated with the MW&E firm wheeling.

Q. Mr. Minson, how does Southwest propose to deal with this large loss of revenues?

A. In two stages. First, we have made an adjustment in the schedules to account for the loss of the $2.8 million in non-firm transmission service to MW&E. In 2003, MW&E took approximately 130 MW of transmission service from Southwest under its non-firm transmission service agreement. Second, we ask that the Commission authorize a procedure to allow Southwest to adjust its rates, without the need for another general rate case, on January 1, 2006 to account for the remaining $2.3 million revenue loss which will occur on the termination of the firm transmission service agreement.

Q. Please describe the details of this procedure.

A. We will work with Staff to refine the procedure during the processing of this application. But, in concept, we would file with the Commission in

October 2005 schedules reflecting financial information concerning Southwest's achieved and expected results for the 2005 calendar year together with TIER, DSCR, rate base and rate of return information. The results would be adjusted to account for the loss of the firm transmission service revenues from MW&E. Revised rate schedules would also be submitted showing the rates necessary to return Southwest to the rate of return, TIER and DSCR levels authorized in the rate decision issued in this case. The Staff would have 60 days to review the filing, ask questions concerning it and submit its recommendation. The Commission would then enter its order in December 2005 authorizing revised rates, effective as of January 1, 2006. I can't stress strongly enough the importance of having a timely and efficient way of handling this extraordinary revenue loss on the Southwest system. The procedure which I have outlined accomplishes both objectives and also provides the Commission sufficient, reliable information to assure just and reasonable rates.

Q. In Decision No. 64991, the Commission instructed Southwest to file a Capital Plan by the end of 2002. Did Southwest comply with that instruction?

A. Yes, we did. The Capital Plan described generally how Southwest might achieve the Staff-recommended equity positions of 10% by 2006, 15% by 2010 and 30% by 2015. The forecasts did not, however, factor in the large MW&E revenue losses I have just described. As Southwest's Chief Financial Officer, I agree with the Commission that it's important for the Cooperative to continue to build equity, although that goal must be balanced against the need to moderate rates to the distribution cooperatives and their customer/owners. If Southwest can get rapid relief in this rate

case as well as authorization of the procedure to further adjust rates on January 1, 2006, we will make significant progress in accomplishing both objectives.

CONCLUSION

Q. Mr. Minson, please summarize Southwest's requests.

A. We would ask that the Commission enter its Order authorizing the revised rates as described in Mr. Pierson's testimony. Further, we would ask that the Commission authorize a one-time rate adjustment procedure to account for the additional loss in the next 18 months of the additional MW&E transmission service revenues as I've described previously.

Q. Does this conclude your testimony?

A. Yes, it does.

15169-6/1192305

EXHIBIT
SWTC-2
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-04100A-04-0527

REBUTTAL TESTIMONY OF

DIRK MINSON

ON BEHALF OF

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

MARCH 16, 2005

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INTRODUCTION

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

A. My name is Dirk Minson. I am the Chief Financial Officer of the Southwest Transmission Cooperative, Inc. ("SWTC") and my business address is 1000 South Highway 80, Benson, Arizona 85602. I previously filed direct testimony in this matter.

Q. What is the purpose of this testimony?

A. I will summarize AEPCO's rebuttal position as well as respond to a few issues covered in the Staff's testimony. I'll also recommend a different procedure than the one discussed in my direct testimony for dealing with the large loss of revenues resulting from MW&E's cancellation of its 60 MW Firm Service Agreement as of December 31, 2005.

SUMMARY REBUTTAL POSITION

Q. Please summarize AEPCO's reaction to the Staff's testimony.

A. While we don't necessarily agree with all of the Staff's adjustments, its basic recommendation that the Commission authorize an increase in operating revenues of approximately $3.67 million is sufficient. As Mr. Pierson explains in his testimony, that level of revenues produces a TIER of 1.17 and a DSCR of 1.02 after taking into account his reclassification of expenses adjustment associated with the Regulatory Asset Charge ("RAC") revenues adjustment recommended by Ms. Brown. Therefore, to reduce disputed issues and hopefully expedite the issuance of a final rate order, we are accepting all of Ms. Brown's rate base adjustments and, on operating income issues, are suggesting only the one companion expense change to her reclassification adjustment on the RAC as discussed in Mr. Pierson's testimony.

1 Q. Can you estimate the impact of this rate increase on the average residential customer of
2 the Class A member distribution cooperatives?
3 A. As I explained in my direct testimony, that is somewhat difficult to do because each
4 distribution cooperative has different rates and varying rate structures. However, we
5 estimate that a residential consumer of SWTC's Class A members using 750 kWh per
6 month would see about a $1.45 increase in the monthly bill as a result of this transmission
7 rate adjustment.

8 **COMMENTS ON SPECIFIC STAFF TESTIMONY**

9 **Ms. Brown's Testimony**

10 Q. At pages 19-20 of her testimony, Ms. Brown discusses a small disallowance of expenses
11 relating to Board of Directors minutes and attorney invoice redactions and at pages 21-22
12 she discusses an adjustment for food and similar expenses. Please respond.
13 A. Again, in an effort to narrow issues in dispute, we are not contesting the adjustments.
14 However, at pages 5-7 of my AEPCO rebuttal testimony I discuss and provide further
15 context for those adjustments which were also proposed in that case. To avoid repetition,
16 I'll simply incorporate that discussion by reference here.
17 Q. Please comment on Ms. Brown's recommendation at pages 23-24 of her testimony that
18 SWTC be required to separate the revenues and expenses for Anza in future rate filings.
19 A. We do not support the recommendation. As I mention in my AEPCO rebuttal testimony,
20 the Commission has never required such a separate cost of service study for Anza before
21 and its transmission service requirements are small. We don't believe the expense of an
22 Anza cost of service study is justified, nor the Staff and Commission effort required to
23 evaluate it.

1 **Mr. Ramirez' Testimony**

2 Q. Please comment on Mr. Ramirez' expressed concerns at pages 7-8 of his testimony that
3 the rates requested in this proceeding will "barely allow the Applicant to cover its debt
4 service."

5 A. I think that our revised rebuttal case as discussed in Mr. Pierson's testimony and exhibits
6 should address these concerns. Our rebuttal position produces a TIER of 1.17, which is
7 .12 above the RUS mortgage minimum. Again, we are trying to walk what is sometimes
8 a fine line between controlling rates and assuring financial stability for the cooperative.
9 We think our recommendations here accomplish that.

10 Q. As was the case with AEPCO, Mr. Ramirez also recommends that SWTC improve its
11 equity position to 30% of its capital structure in a reasonable time frame. Please respond.

12 A. Again, I want to stress that we do not disagree with Mr. Ramirez about the importance of
13 building equity. In the short time that SWTC has been in existence, we've demonstrated
14 that commitment with, among other things, timely rate requests to maintain financial
15 integrity. The rates which we propose here would generate about $890,000 in net
16 margins on an annual basis. Absent other changes, this level of margins would build
17 SWTC's equity ratio to 15% in about ten years. However, for the reasons I stated at
18 pages 8-9 of my AEPCO rebuttal testimony, I would encourage the Commission <u>not</u> to
19 adopt a fixed equity target of 30% over a particular time frame and also feel that the
20 equity goal of 30% for a transmission cooperative like SWTC is unnecessarily high.

21 Q. Finally, please comment on Mr. Ramirez' suggestion that the Commission restrict future
22 patronage distributions until it has achieved a 30% capital structure.

1 A. SWTC has no plans in the foreseeable future to make any patronage distributions. We
2 don't see a need for Commission restrictions because we are already subject to RUS and
3 CFC mortgage controls on that subject. If, however, the Commission wants to impose a
4 restriction, we would suggest that it simply order SWTC to comply with its mortgage
5 restrictions.

6 **MW&E 60 MW FIRM REVENUE LOSS**

7 Q. Mr. Minson, at pages 6-10 of your direct testimony, you described the fact that the loss of
8 both firm and non-firm transmission revenues, as a result of the Morenci Water &
9 Electric Company ("MW&E") bypass of SWTC's transmission system, was a major
10 reason for this rate increase request. Please update the Commission on what has
11 happened on that subject since you filed your testimony last July.

12 A. Effective November 1, 2004, MW&E stopped taking any non-firm transmission service
13 from SWTC following completion of its direct intertie to the Tucson Electric Power
14 transmission system. We had anticipated that would happen and made an adjustment to
15 test year revenues for the approximately $2.8 million dollars in lost non-firm revenues.
16 So, that non-firm revenue loss is adequately covered by Staff and our recommendations
17 here. However, the second large loss of approximately $2.37 million in firm revenues
18 will occur on December 31 of this year when MW&E's cancellation of its firm
19 Transmission Service Agreement takes effect. The financial impact on SWTC of this
20 revenue loss only a few months after the rate order is entered cannot be overstated. It is
21 more than double SWTC's requested, test year adjusted net margin. In order to address
22 this loss, without the necessity of another full rate case, I have an alternate procedure to
23 suggest than the one outlined in my direct testimony.

1 Q. Please describe it.

2 A. As explained in Mr. Pierson's testimony, we ask that the Commission authorize rates for
3 the balance of this year which are set forth in column C of his Exhibit GEP-11. We also
4 request that the Commission authorize in this decision new rates, set forth in column D of
5 Exhibit GEP-11, to take effect on January 1, 2006—the day after the MW&E cancellation
6 of its 60 MW firm agreement takes effect. These revised rates have been designed based
7 upon the adjusted 2003 test year and take into account only the loss of the revenues from
8 MW&E's 60 MW firm agreement. They are designed simply to return SWTC to the
9 TIER, DSCR and rate of return levels we request be authorized in this decision. On
10 December 1 of this year, we propose to file with the Commission a statement verifying
11 that MW&E's cancellation of the Firm Service Agreement remains in effect and no new
12 MW&E Service Agreement has been entered into together with revised tariff pages
13 reflecting the rates set forth in column D of Exhibit GEP-11. Unless the Commission
14 takes action to suspend the filing, the revised rates would then take effect on January 1,
15 2006. This procedure provides assurances that the new rates are just and reasonable
16 based upon the test year data and also provides a timely, cost effective solution to a large
17 rate and revenue issue for SWTC.

18 **CONCLUSION**

19 Q. Please summarize SWTC's requests.

20 A. We request that the Commission authorize (1) the rates set forth in column C of Exhibit
21 GEP-11 through December 31, 2005 and (2) the rates set forth in column D of Exhibit
22 GEP-11 on the procedures I have described effective January 1, 2006. We also ask that a
23 rate order be issued as promptly as possible.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

15169-6/1257396

EXHIBIT
SWTC-3
ADMITTED

DIRECT TESTIMONY OF

GARY E. PIERSON

BEFORE THE

ARIZONA CORPORATION COMMISSION

ON BEHALF OF

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

Q. Please state your name and address for the record.

A. My name is Gary E. Pierson. My business address is Sierra Southwest Cooperative Services, Inc., P.O. Box 2165, 1000 South Highway 80, Benson, Arizona, 85602.

Q. By whom are you employed and in what capacity?

A. I am employed by Sierra Southwest Cooperative Services, Inc. ("Sierra Southwest") as the Manager of Financial Services. As Manager of Financial Services, I am responsible for directing and administrating the treasury, cash management and risk management functions for Sierra Southwest. In addition, as a result of staffing agreements that Sierra Southwest has with Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative, Inc. ("Southwest"), I am responsible for directing and administrating the treasury, cash management, risk management and rate design/implementation functions for these two cooperatives as well.

1

2 Q. Please briefly summarize your educational and professional background.

3 A. I graduated in 1974 from Western State College, Gunnison, Colorado, with a
4 Bachelor of Arts Degree specializing in Accounting and Business Administration.
5 In June 1974, I was employed by Colorado-Ute Electric Association, Inc. and
6 worked there for seventeen years in various positions in the areas of ratemaking,
7 budgeting, financial forecasting and power requirements studies. In May 1992, I
8 was employed by AEPCO as a Rates Administrator in the Financial Services
9 Division where my principal responsibilities and duties included the preparation of
10 rate filings, the design of rate structures and rate analysis studies. In 1993, I was
11 promoted to the position of Manager of Financial Services and in August 2001, as a
12 result of the restructuring of AEPCO into three separate cooperatives, I was
13 employed in that same position by Sierra Southwest. I have testified as an expert
14 witness before the Public Utilities Commission of the State of Colorado, the United
15 States Bankruptcy Court in Denver, Colorado and the Arizona Corporation
16 Commission in connection with various proceedings involving rate cases.

17

18 Q. What is the purpose of your testimony in this proceeding?

A. I will testify in support of the application for a general rate filing for Southwest. My testimony is primarily directed to the financial schedules prepared pursuant to the requirements of A.A.C. R14-2-103 (the "Schedules").

Q. Please describe the Schedules.

A. They are a multi-page exhibit containing the Schedules A-H and are divided into the following categories:

Schedule Category	Section Tab
Summary Schedules	A
Rate Base Schedules	B
Test Year Income Statements	C
Cost of Capital Schedules	D
Financial Statements and Statistical Schedules	E
Projections and Forecast Schedules	F
Cost of Service Analysis Schedules	G
Effect of Proposed Tariff Schedules	H

Q. Please describe Section A of the Schedules.

A. Section A contains the summary schedules that explain the rate filing. Schedule A-1 shows the computation of the increase in gross revenue requirements that result from

the development of the financial schedules. An increase in revenues from Southwest Network and Point-to-Point service customers in the amount of $3,666,668 results from the proposal that (1) the existing Network Services Rate for transmission service be changed from a monthly Network revenue requirement of $1,092,016 to $1,418,473, (2) the existing Point-to-Point Services Rate be changed from $2.805 per kW month to $3.032 per kW month and (3) the existing System Control & Load Dispatching Rate be changed from $0.422 per kW month to $0.289 per kW month. The coverage ratios produced by this proposal are a Times Interest Earned Ratio ("TIER") of 1.15 and a Debt Service Coverage Ratio ("DSCR") of 1.11, consistent with the levels discussed in the testimony of Mr. Minson and Mr. Edwards of the National Rural Utilities Cooperative Finance Corporation ("CFC"). The $3,666,668 represents an increase of 13.70% over the revenues that would be generated by present rates and, based upon a test period adjusted rate base of $79,392,886, generates a rate of return of 7.42%.

Schedule A-2 provides summary results of operations for the calendar years 2001, 2002 and 2003 and the adjusted test year. On an adjusted test year basis, column 5 shows that Southwest had a net margin loss of $2,894,762, a TIER of 0.44 and a DSCR of 0.79. On an adjusted test year basis with proposed rates, Column 6 shows that Southwest would have a net margin of $771,906 and, as mentioned above, a TIER of 1.15 and a DSCR of 1.11. Schedule A-3 provides a summary of the

Southwest capital structure and capitalization ratios for various years and Schedule A-4 provides construction expenditures, net plant additions and gross utility plant in service data. Finally, Schedule A-5 summarizes Southwest changes in financial position.

Q. Please describe Section B of the Schedules.

A. Section B contains supporting rate base schedules that are used in the Southwest rate filing. Schedule B-1 summarizes the components of original cost rate base of $79,392,886, as of December 31, 2003. They include gross utility plant in service of $131,520,683, accumulated depreciation and amortization of $55,772,833, allowances for working capital of $3,122,116, plant held for future use of $377,214 and deferred debits of $145,705. Schedule B-2 reflects pro forma adjustments to the original cost rate base for the inclusion of the capital costs for the Winchester Project that will be discussed later in my testimony. Schedules B-3 and B-4 concerning reconstructed cost net of depreciation ("RCND") rate base have not been completed. As a non-profit cooperative, Southwest stipulates to the use of its original cost rate base as its fair value rate base.

Schedule B-5, page 1 of 5, provides the computation of working capital by components, which add up to total working capital of $3,122,116. Schedule B-5, page 2 of 5 which reflects the calculation of cash working capital has not been

completed. Southwest has not performed a lead/lag study and stipulates to the use of a zero value for its cash working capital.

Q. Please describe Section C of the Schedules.

A. Section C contains the adjusted test year income statements and supporting schedules to the income statement. Schedule C-1, pages 1 through 4, provides the adjusted test year income statement and the pro forma as-adjusted test year income statement for the test year 2003. As noted on Schedule C-1, page 2, Southwest had net margins of $2,021,945 during the test year ending December 31, 2003. The second column represents reclassification adjustments made to the test period, which have a zero effect on the net margins of Southwest, and Column 3 of Schedule C-1, pages 1 and 2, shows the income statement with these reclassifications. Schedule C-1, pages 3 and 4, sets forth the Southwest reclassified income statement and the effects of pro forma adjustments to that income statement. Its first column shows the reclassified test year income statement with net margins of $2,021,945. The second column displays adjustments to reflect changes in revenues and/or expenses so as to normalize or annualize revenues and expenses in the test period. The third column shows, pro forma as adjusted, the net margin loss of $2,894,762.

Schedule C-2, pages 1-10, provides the detail on the reclassification and pro forma adjustments to revenues and expenses. They are as follows:

Reclassification Adjustments – Schedule C-2, Pages 1 and 2:

1. Southwest Revenue Reclassification – This adjustment reclassifies the ancillary services revenues that Southwest collects from various Point-to-Point Customers as credits against the operating expenses that Southwest pays to AEPCO for the services during the test period. In essence, these revenues and charges are a pass-through, at cost, of ancillary services provided by AEPCO to the various Point-to-Point Customers. Therefore, Southwest has removed them from its cost of service. The net effect of this reclassification on net margins is zero.

2. Property Tax Reclassification – This adjustment reclassifies property taxes that are recorded in various operation and maintenance expense categories according to Rural Utilities Service ("RUS") accounting procedures to Taxes so that these expenses can be shown separately for ratemaking purposes. The net effect of this reclassification on net margins also is zero.

Pro Forma Adjustments – Schedule C-2, Pages 1 through 6:

1. City of Mesa Contract Adjustment – This adjustment annualizes the effect of the termination of the 17.5 MW sales contract to the City of Mesa from AEPCO that occurred on May 31, 2003. As a result of the termination of that contract, AEPCO is no longer purchasing from Southwest Point-to-Point transmission service charges to wheel the power associated with this contract. Therefore, these

revenues have been removed from the test period. The effect of this adjustment is to reduce net margins by $282,363.

2. City of Thatcher Sales Adjustment – This adjustment annualizes contractual changes to the City of Thatcher Point-to-Point service that became effective January 1, 2004. The effect is to reduce net margins by $13,790.

3. Mohave Electric Cooperative – This adjustment annualizes revenues to reflect certain contractual amendments that have been made to the transmission agreement between Southwest and Mohave Electric Cooperative. This adjustment increases net margins by $19,870.

4. DAF Revenue Adjustment – This adjustment annualizes the Direct Assignment Facilities charges that are billed to Trico Electric Cooperative, Inc by Southwest. The effect of this adjustment is to increase net margins by $5,487.

5. Morenci Water & Electric ("MW&E") Non-Firm Wheeling Revenue Adjustment – This adjustment removes the revenues associated with MW&E non-firm Point-to-Point transmission service provided by Southwest during the test period because of MW&E's bypass of the transmission system. Mr. Minson provides the background for this adjustment in his testimony. This adjustment decreases net margins by $2,823,017.

6. City of Safford Sales Adjustment – This adjustment annualizes the change in transmission service for the City of Safford from a special contract entered into

before the advent of FERC Order 888 to Network service. The effect of this adjustment reduces net margins by $184,628.

7. Labor Expense Adjustment – This adjustment annualizes labor expense and associated payroll taxes and benefits to reflect wage increases that occurred during the test period and is based upon actual staffing as of the end of the test period. This adjustment decreases net margins by $224,438.

8. Winchester Project Fixed Cost Adjustment – This adjustment annualizes the depreciation, insurance and property taxes associated with the Winchester Project which is discussed in Mr. Minson's testimony. This adjustment decreases net margins by $810,065.

9. Depreciation Adjustment – This adjustment annualizes depreciation expense based upon plant in service as of the end of the test period. The effect is to reduce net margins by $30,146.

10. Winchester Interest Expense Adjustment – This adjustment annualizes the interest expense associated with the Winchester Project discussed in Mr. Minson's testimony. This adjustment decreases net margins by $750,270.

11. A-8 Loan Draw FFB Interest Expense Adjustment – This adjustment annualizes interest expense to reflect the second A-8 FFB loan draw that was made in February 2004 to reimburse Southwest for general funds expended in the

construction of transmission plant that is in service in the test year. The effect of this adjustment decreases net margins by $242,682.

12. Interest Expense Adjustment – This adjustment annualizes interest expense based upon debt balances and interest rates as of the end of the test year and increases interest expense by $19,790. The effect decreases net margins by $19,790.

13. Other Deductions Adjustment – This adjustment removes charges to other deductions that should not be reflected in the test year. The effect of this adjustment increases net margins by $439,125.

As indicated on page 6 of Schedule C-2, these pro forma adjustments in expenses and revenues result in a decrease in net margins of $4,916,707. Finally, Schedule C-3, concerning the computation of the gross revenue conversion factor, is not applicable because Southwest is a non-profit cooperative and does not pay income taxes.

Q. Please describe Section D of the Schedules.

A. Section D contains information on Southwest's cost of capital for the calendar years 2001, 2002 and 2003. Schedule D-1 sets forth the computed cost of capital as of December 31, 2003 for the actual and projected test year. Invested debt capital, as of December 31, 2003, amounted to $87,591,547 with a composite cost rate of 5.67%. Schedule D-2 shows long-term and short-term debt balances by lender that comprise

the total, the interest rates associated with the debt balances and the computation of the composite cost rate. Schedules D-3 and D-4 are not applicable to Southwest because it is a member owned, non-profit cooperative and has no stock.

Q. Please describe Section E of the Schedules.

A. Section E provides financial statements and statistical schedules for the calendar years 2003, 2002 and 2001. Schedule E-1 provides comparative balance sheets and Schedule E-2 shows comparative income statements. Schedule E-3 provides a comparative statement of changes in financial position and Schedule E-4 reflects changes in equity. Schedule E-5 details utility plant additions during 2003 and the balances as of December 31, 2002 and 2003. Schedule E-6 is not applicable to Southwest. Schedule E-7 provides Southwest operating statistics while Schedule E-8 lists taxes charged to operations. I have attached to my testimony as Exhibit GEP-1 the Southwest Audited Financial Statements, December 31, 2003 and 2002, which contains the Independent Auditors' Report to the Southwest Board dated March 25, 2004. It provides the information specified in Schedule E-9.

Q. Please describe Section F of the Schedules.

A. Section F contains projections and forecast schedules. Schedule F-4 discusses certain assumptions that were used in developing the projections contained in these schedules.

Q. Please describe Section G of the Schedules.

A. Section G contains schedules that present cost of service information. Schedule G-1 provides a cost of service summary for the pro forma adjusted test year based upon present rates, while Schedule G-2 provides a cost of service summary for the pro forma adjusted test year based upon developed rates. Schedule G-2A sets forth the computation of the proposed rates for transmission services. These rates are consistent with Federal Energy Regulatory Commission ("FERC") Order 888, which provides for open transmission services and comparable interconnections by transmitting utilities. FERC Order 888 requires that a transmitting utility offer firm or non-firm Point-to-Point and firm Network service transmission on a non-discriminatory open access basis. Under Section 211 of the Federal Power Act, customers can seek transmission services from transmitting utilities like Southwest and FERC requires these utilities to provide comparable access to the national grid. Southwest has made a "safe harbor" filing with FERC based on the methodology used to develop these rates and has obtained a ruling that the methodology is comparable and meets the non-discriminatory open access requirements.

Schedule G-2A, page 1, sets forth the derivation of the annual transmission revenue requirement, which equals total operating expenses less other revenues plus margin requirements. Schedule G-2A, page 2, provides a summary of the proposed transmission service rates for the firm Point-to-Point and Network services offered by Southwest. In addition, the schedule lists the proposed rates for mandatory and optional ancillary services. Southwest provides the Schedule 1 System Control and Load Dispatch Ancillary Service and the calculation of the proposed rate is provided on subsequent pages. Schedules 2-6 detail Ancillary Services that are provided or offered by AEPCO and the calculation of these proposed rates are listed on subsequent pages. Schedule G-2A, page 3, shows the calculation of the firm Point-to-Point rate, which results from dividing the annual transmission revenue requirement by the product of the coincidental peak demand multiplied by 12. The Network services revenue requirement is calculated by subtracting the Point-to-Point revenues from the annual transmission revenue requirement. The Network service proposed rate set forth on Schedule G-2A, page 2, is then obtained by dividing the Network services revenue requirement by twelve months and each Network services customer is billed each month by multiplying the Network service proposed rate by their respective load ratio share percentage. The load ratio share percentage is obtained by dividing the Network services rolling twelve-month average

transmission demand by the total of all Network service customers' rolling twelve-month average transmission demand.

Schedule G-2A, page 4, shows the calculation of the mandatory Schedule 1 system control and load dispatch proposed ancillary service rate. Schedule G-2A, page 5, sets forth the calculation of the mandatory Schedule 2 var support/voltage control proposed ancillary service rate and is based upon costs provided by AEPCO. Schedule G-2A, page 6, sets forth the AEPCO cost information that is used to calculate the proposed rates for the optional Schedule 3, 5 and 6 ancillary services. Schedule G-2A, page 9, shows the derivation of the proposed rate for the optional Schedule 4 ancillary service and is based upon AEPCO cost information.

Q. Please describe Section H of the Schedules.

A. Section H shows the effect of the proposed rate tariff schedules on the revenues generated by sales to the Network and Point-to-Point customers. Schedule H-1 summarizes the revenues generated by present rates and the proposed rates for the pro forma test year 2003. This schedule shows that present rates would generate revenues from sales of transmission to Network services and Point-to-Point customers of $26,768,658 and that proposed rates would generate revenues of $30,435,326. Thus the proposed rates would generate additional revenues of $3,666,668 over present rates. Schedule H-2, page 1, compares revenues generated

by present and proposed rates for each of the Class A Members as well as the other Network services customers. Schedule H-2, pages 2-12, displays an analysis of revenues generated on a monthly basis for each of the Network services customers. Page 13 shows the average monthly costs in $/kW month to each of the Class A Members based upon present and proposed rates. Schedule H-2, pages 14-16, displays an analysis of revenues generated on a monthly basis for each of the Point-to-Point customers. Schedules H-4 and H-5 are not applicable to Southwest.

Q. Does this conclude your direct testimony?

A. Yes it does.

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KPMG

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

Financial Statements

December 31, 2003 and 2002

(With Independent Auditors' Report Thereon)

KPMG LLP
Suite 700, Two Park Square
6565 Americas Parkway NE
PO Box 3990
Albuquerque, NM 87190

Independent Auditors' Report

The Board of Directors
Southwest Transmission Cooperative, Inc.

We have audited the accompanying balance sheets of Southwest Transmission Cooperative, Inc. (the Cooperative) as of December 31, 2003 and 2002, and the related statements of revenues and expenses and unallocated accumulated margins, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Southwest Transmission Cooperative, Inc. as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards*, we also issued a report dated March 25, 2004 on our consideration of the Cooperative's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grants. That report is an integral part of the audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

KPMG LLP

March 25, 2004

KPMG LLP, a U.S. limited liability partnership, is the U.S. member firm of KPMG International, a Swiss cooperative.

Southwest Transmission Cooperative, Inc.
Balance Sheets
December 31, 2003 and 2002

Assets	**2003**	2002
Utility Plant:		
Plant in service	**$ 117,847,897**	$ 115,279,214
Construction work in progress	**6,321,507**	2,822,389
Total utility plant	**124,169,404**	118,101,603
Less - Accumulated depreciation	**(55,772,833)**	(52,463,708)
Utility plant, net	**68,396,571**	65,637,895
Investments and Other Property:		
Restricted held to maturity investments	**1,355,652**	1,350,375
Other	**1,199,968**	1,191,490
Total investments and other property	**2,555,620**	2,541,865
Current Assets:		
Cash and cash equivalents	**7,820,883**	3,202,174
Restricted cash and cash equivalents	**825,966**	-
Accounts receivable	**2,941,538**	2,763,871
Materials and supplies inventory	**931,106**	839,883
Prepayments and other current assets	**266,196**	149,053
Total current assets	**12,785,689**	6,954,981
Deferred Debits	**14,700,460**	17,714,531
Total Assets	**$ 98,438,340**	$ 92,849,272

See accompanying notes to the financial statements.

Southwest Transmission Cooperative, Inc.
Balance Sheets
December 31, 2003 and 2002

Membership Capital and Liabilities	**2003**	2002
Membership Capital:		
Membership fees	**$ 900**	$ 900
Patronage capital	**2,217,335**	1,520,795
Unallocated accumulated margins	**2,021,945**	696,540
Total membership capital	**4,240,180**	2,218,235
Long-Term Debt:		
Federal Financing Bank	**54,277,391**	52,802,815
Cooperative utility trusts	**12,733,423**	13,193,086
Solid waste disposal revenue bonds	**8,404,900**	8,632,939
Pollution control revenue bonds	**2,741,366**	3,572,083
Rural Utilities Service	**1,940,685**	2,343,382
Cooperative Finance Corporation	**806,515**	886,512
Total long-term debt	**80,904,280**	81,430,817
Current Liabilities:		
Member advances	**184,193**	56,105
Current maturities of long-term debt	**6,687,267**	6,065,813
Accounts payable	**4,371,492**	1,402,371
Accrued property taxes	**934,643**	796,406
Accrued interest	**423,221**	444,789
Other	**622,244**	389,516
Total current liabilities	**13,223,060**	9,155,000
Deferred Credits	**70,820**	45,220
Total Membership Capital And Liabilities	**$ 98,438,340**	$ 92,849,272

See accompanying notes to the financial statements.

Southwest Transmission Cooperative, Inc.
Statements of Revenues and Expenses and Unallocated Accumulated Margins
For the Years Ended December 31, 2003 and 2002

	2003	2002
Operating Revenues:		
Sales of electric transmission-		
Members-		
Class A - Firm	$ 13,421,164	$ 12,574,474
Class B - Firm	8,079,847	8,951,863
Class B - Non-firm	2,153,622	1,358,952
Non-members	164,625	137,583
Regulatory asset charge	2,707,122	2,622,363
Sales of ancillary services-		
Members-		
Class A	2,412,904	1,167,830
Class B	4,980,297	3,169,659
Non-members	94,940	120,481
Total operating revenues	34,014,521	30,103,205
Operating Expenses:		
Transmission operation	9,650,415	8,591,869
Depreciation and amortization	6,435,586	6,265,707
Administration and general	3,742,292	3,863,439
Property and other taxes	2,176,869	1,808,659
Transmission wheeling charges	3,028,246	2,906,024
Transmission maintenance	2,386,913	1,978,193
Total operating expenses	27,420,321	25,413,891
Operating Margin	6,594,200	4,689,314
Interest Expense	4,401,910	4,509,494
Other Income (Loss), net	(170,345)	225,751
Net Margin	2,021,945	405,571
Unallocated Accumulated Margins, January 1	696,540	290,969
Patronage Capital Allocation	(696,540)	-
Unallocated Accumulated Margins, December 31	$ 2,021,945	$ 696,540

See accompanying notes to the financial statements.

Southwest Transmission Cooperative, Inc.
Statements of Cash Flows
For the Years Ended December 31, 2003 and 2002

	2003	2002
Cash Flows from Operating Activities:		
Net margin	$ 2,021,945	$ 405,571
Adjustments to reconcile net margin to net cash flows provided by operating activities-		
Depreciation and amortization	3,728,439	3,643,330
Amortization of deferred charges	3,014,651	3,350,747
Changes in assets and liabilities-		
Restricted cash and cash equivalents	(825,966)	-
Accounts receivable	(177,667)	819,177
Materials and supplies inventory	(91,223)	69,603
Deferred debits	(580)	(2,472)
Accrued property taxes	138,237	(148,893)
Accounts payable	2,969,121	738,945
Accrued interest	(21,568)	(73,358)
Deferred credits	25,600	(390,390)
Other, net	111,735	(157,648)
Net cash provided by operating activities	10,892,724	8,254,612
Cash Flows from Investing Activities:		
Construction expenditures	(6,483,265)	(3,994,608)
Maturities of investments	0	6,396
Purchases of investments	(13,755)	(317,785)
Net cash used in investing activities	(6,497,020)	(4,305,997)
Cash Flows from Financing Activities:		
Member advances, net	128,088	(7,817)
Retirement of long-term debt	(6,065,083)	(5,716,144)
Issuance of long-term debt	6,160,000	-
Net cash provided by (used) in financing activities	223,005	(5,723,961)
Net Decrease in Cash and Cash Equivalents	4,618,709	(1,775,346)
Cash and Cash Equivalents, January 1	3,202,174	4,977,520
Cash and Cash Equivalents, December 31	$ 7,820,883	$ 3,202,174
Supplemental Disclosures:		
Cash paid for interest, net of amount capitalized	$ 4,423,478	$ 4,582,852

See accompanying notes to the financial statements.

Notes to Financial Statements

Southwest Transmission Cooperative, Inc.
For the Year Ended December 31, 2003 and 2002

1. Organization:

The Cooperative is organized under Arizona law as a non-profit Arizona rural electric transmission cooperative, which provides electric transmission and ancillary services to its customers. The Cooperative was organized with two classes of Members. Class A Members consist of non-profit electric cooperative or non-profit membership corporations which are electric utilities that are or have been beneficiaries of the Rural Electrification Act of 1936 and have or will have agreements wherein their power and associated energy are delivered using transmission and related facilities owned by the Cooperative and/or transmission rights in third party systems controlled by the Cooperative; and that have each joined with the other Class A members in the Cooperative's operations in order to share the benefits and costs of ownership of an entity engaged in providing transmission services for the benefit of its members. There are currently six Class A Members. Class B members consist of generation and transmission electric cooperatives organized under Arizona law and other electric utilities which currently have, or will have, agreements with the Cooperative whereby transmission services are purchased from the Cooperative. There are currently three Class B Members.

2. Summary of Significant Accounting Policies:

System of Accounts – The Cooperative maintains its accounts in accordance with policies and procedures as prescribed by the Rural Utilities Service (RUS) in conformity with the Uniform System of Accounts. The Cooperative's accounting policies conform to accounting principles generally accepted in the United States as applied in the case of regulated public utilities and are in accordance with the accounting requirements and rate-making practices of the RUS and the Arizona Corporation Commission (ACC).

Accounting for the Effects of Regulation - The Cooperative prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires cost-based, rate-regulated enterprises to reflect the impact of regulatory decisions in their financial statements. It is the Cooperative's policy to assess the recoverability of costs, which have been recognized as regulatory assets, and the Cooperative's ability to continue to account for its activities in accordance with SFAS No. 71, and the criteria set forth in SFAS No. 71.

Certain costs, which have been approved by ACC order, or those costs from which management expects to benefit or recover in future periods through rates, are deferred and amortized over the expected period of benefit (See Note 6).

Utility Plant - Utility Plant is stated at historical cost and includes the costs of outside contractors, direct labor and materials, allocable overhead, and interest charged to construction.

In accordance with the Uniform System of Accounts, the Cooperative capitalizes the interest costs associated with the borrowing of funds used to finance construction work in progress (CWIP). Interest income from construction funds held in trust, if any, are credited to CWIP. Interest costs capitalized on construction projects were approximately $23,000 and $30,000 in 2003 and 2002, respectively.

Depreciation is computed on a straight-line basis over the estimated useful lives of depreciable property in accordance with rates prescribed by the RUS, averaging 3.2 percent and 3.1 percent for 2003 and 2002, respectively. Depreciation expense was approximately $3,676,000 and $3,591,000 for the years ended December 31, 2003 and 2002, respectively. Minor replacements and repairs are charged to expense as incurred. Retirements of utility plant, together with the cost of removal, less salvage, are charged to accumulated depreciation.

The Cooperative assesses its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the fair value is less than the carrying amount of the asset, a loss is recognized for the difference. The Cooperative has not recorded losses resulting from impairment of its long-lived assets.

Investments – The Cooperative reports its investments in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." SFAS provides that the Cooperative classify investments in securities as either trading securities, held to maturity securities, or available-for-sale securities. At December 31, 2002 and 2001, the total investment balances were classified as held to maturity investments (See Note 3).

Cash and Cash Equivalents – For purposes of reporting cash flows, the Cooperative considers all marketable securities with an original maturity of 90 days or less to be cash equivalents. The Cooperative maintains its cash in bank accounts, which, at times, may exceed federally insured limits. The Cooperative has not experienced any losses in such accounts.

Receivables – The Cooperative records its receivables at net realizable value. A bad debt reserve is established for those accounts that management believes are probable of not being collectible in their entirety.

Inventories - Inventories, consisting of materials and supplies, are carried at average cost and are valued at the lower of cost or market.

Unamortized Debt Costs – Costs incurred for the issuance or repricing of long-term debt are deferred and amortized over the life of the related debt (See Note 6).

Deferred Debits – Deferred debits are recorded at cost and either: 1) amortized over their expected period of benefit or alternate period of time as may be mandated by any applicable regulatory order, if different, or 2) eliminated upon determination of their ultimate disposition.

Deferred Credits – Deferred credits are recorded at cost and either: 1) amortized over their expected period of benefit or alternate period of time as may be mandated by any applicable regulatory order, if different, or 2) eliminated upon determination of their ultimate disposition.

Revenues - Revenues are accrued as electric transmission or other services are provided.

Use of Estimates – The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

3. Investments and Other Property:

Investments and other property at December 31, consist of the following:

	2003	2002
Term certificates	**$ 1,355,652**	$ 1,350,375
Investment in associated organization (See Note 17)	**1,000,000**	1,000,000
Other	**199,968**	191,490
Total investments and other property	**$ 2,555,620**	$ 2,541,865

Term certificates - The Cooperative is a member the National Rural Utilities Cooperative Finance Corporation (CFC), a not-for-profit cooperative financing institution, owned and controlled by more than 1,000 rural electric member systems and their affiliates. As a condition of membership, the Cooperative is required to possess Subscription Capital Term Certificates (SCTCs), which bear interest at 5 percent per annum and have maturity dates ranging from 2070 to 2080. The Cooperative also assumed a portion of a Zero Term Certificate (ZTC), which was originally purchased as a condition of the long-term debt due to the CFC. The ZTC purchased in connection with the long-term debt due to the CFC is non-interest bearing and matures in 2013 upon final repayment of the related debt. The SCTCs and ZTC are un-rated, un-collateralized debt securities of the CFC. Fair value equals cost for these investments.

4. Restricted Cash and Cash Equivalents:

RUS has established a Cushion of Credit Payment Program, whereby borrowers may make advance payments on their RUS and Federal Financing Bank (FFB) notes (Notes). These advance payments earn interest at the rate of 5 percent per annum. The advance payments, plus any accrued interest, can only be used for the payment of principal and interest on the Notes. The Cooperative's participation in the Cushion of Credit Payment Program totaled $825,966 and $0 at December 31, 2003 and 2002, respectively.

5. Accounts Receivable:

Accounts receivable at December 31, consist of the following:

	2003	2002
Electric transmission sales	**$ 2,743,061**	$ 2,655,734
Telecommunication/line maintenance services	**40,320**	31,747
Other	**158,157**	76,390
Total accounts receivable	**$ 2,941,538**	$ 2,763,871

Electric transmission sales – Electric transmission sales consist of sales to Members and non-members under transmission service agreements (See Note 11) and are generally not collateralized.

6. Deferred Debits:

Deferred debits at December 31, consist of the following:

	2003	2002
Regulatory asset	**$11,487,485**	$14,194,633
Unamortized debt costs	**2,334,497**	2,594,622
Other	**878,478**	925,276
Total deferred debits	**$14,700,460**	$17,714,531

Regulatory asset - The ACC authorized the recovery of the regulatory asset through the imposition of a specific charge. The regulatory asset, pursuant to an order from the ACC, is being amortized as revenues related to the regulatory asset are collected.

7. Patronage Capital:

	2003	2002
January 1	**$ 1,520,795**	$ 1,520,795
Patronage capital allocation	**696,540**	0
December 31	**$ 2,217,335**	$ 1,520,795

In accordance with the Cooperative's bylaws, the Cooperative is obligated to account on a patronage basis, to all its members for all amounts received and receivable from the furnishing of electric energy and other services to members in excess of the sum of:

- operating costs and expenses, including interest on debt services, properly chargeable against the furnishing of electric energy and other services; and
- amounts required to offset any losses incurred during the current or any prior fiscal year; and
- maintenance of reserves, if any.

All such amounts in excess of operating costs, expenses and prior losses at the moment of receipt by the Cooperative are received with the understanding that they are furnished by the members as capital. The Cooperative is obligated to pay by credits or account for losses to a capital account for each member all such amounts for credits or losses in proportion to the value or quantity of the Cooperative's service used, received or purchased by each member during the applicable fiscal year in excess of operating costs and expenses and prior losses.

RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative.

8. Long-Term Debt:

Federal Financing Bank (FFB) –This debt is payable at interest rates based on long-term obligations of the United States Government as determined on the date of advance. Interest rates on individual FFB notes ranged from 4.3 percent to 9.1 percent for 2003 and 5.0 percent to 9.1 percent for 2002. Interest rates on the debt averaged 6.2 percent in 2003 and 2002. Equal quarterly principal and interest installments on these obligations extend through 2021. The obligations are guaranteed by the RUS. The Cooperative may prepay all outstanding notes by paying the principal amount plus the lesser of: 1) the difference between the outstanding principal balance of the loan being refinanced or the present value of the loan discounted at a rate equal to the current cost of funds to the Department of the Treasury for obligations of comparable maturity; 2) 100 percent of the amount of interest for one year on the outstanding principal balance of the loan being refinanced; or 3) present value of 100 percent of the amount of interest for one year on the outstanding principal balance of the loan.

Cooperative Utility Trust -The Cooperative issued a note, underlying a Certificate of Beneficial Interests (the Certificate), to a Cooperative Utility Trust. Principal payments on the note are due annually in installments ranging from $398,092 to $1,572,497 from 2004 to 2018. The interest rate on the note is 7.7 percent. Interest is paid semi-annually. The note is guaranteed by the RUS. The Certificate is callable, only in whole, at any time on or after September 1, 2006, at redemption prices declining from an initial redemption price of 103.50 percent of par to 100 percent of par from and after September 1, 2013. The Certificate is also subject to prepayment at par at any time on or after September 1, 2006.

Pollution Control Revenue Refunding Bonds - Principal payments on the Series 1997 Pollution Control Revenue Refunding Bonds are payable semi-annually through mandatory sinking fund payments ranging from $830,716 to $959,396 from 2004 through 2007. The interest rates in effect at December 31, 2003, ranged from 4.7 percent to 5.0 percent. The interest rate on the bonds averaged 5.0 percent in 2003 and 2002. Interest is paid semi-annually. These bonds are guaranteed by the CFC. The bonds are not subject to optional redemption prior to maturity.

Solid Waste Disposal Revenue Bonds - Principal on these bonds is due in annual installments ranging from $228,040 to $716,692 from 2004 to 2024. Interest rates on the bonds are variable and are subject to revision semi-annually. The interest rate in effect at December 31, 2003, was 1.1 percent. The interest rate on the bonds averaged 1.2 percent and 1.9 percent in 2003 and 2002, respectively. Interest is paid semi-annually. These bonds are guaranteed by the CFC. The Cooperative may redeem the bonds in whole or in part, subject to a premium of one-eighth of 1 percent of the principal amount.

Rural Utilities Service – This long-term debt consists of notes at interest rates of 2 percent and 5 percent. The interest rate on such borrowings averaged 4.5 percent and 4.4 percent for 2003 and 2002, respectively. Quarterly principal and interest payments on this obligation extend through 2015. The Cooperative may prepay the notes at the lesser of the outstanding principal balance of the loan or the discounted present value. The discount rate is the rate specified in the *Treasury Constant Maturities* section of the weekly publication of the *Federal Reserve Statistical Release.*

Cooperative Finance Corporation –This long-term debt is payable at a variable interest rate that is established monthly and effective on the first day of each month. The interest rate in effect at December 31, 2003, was 2.6 percent. The interest rate on such borrowings averaged 3.0 percent and 4.0 percent for 2003 and 2002, respectively. Quarterly principal and interest payments on this obligation extend through 2013. This obligation is guaranteed by the RUS. The variable interest rate on the debt is convertible to a fixed rate. The fixed rate would be equal to the rate of interest offered by the CFC at the time of the conversion request. The Cooperative may prepay fixed rate notes in whole or in part, subject to a prepayment premium prescribed by the CFC.

Maturities of long-term debt for the next five years are as follows:

2004	$ 6,687,267
2005	7,119,020
2006	7,557,504
2007	8,030,813
2008	7,494,096
Thereafter	50,702,847
Total	$87,591,547

Under covenants of the mortgage held by RUS and the RUS general and pre-loan policies and procedures, the Cooperative, must, among other things, obtain approvals from both the RUS and the CFC for certain transactions and contracts and design rates with a view to maintaining, on an annual basis, certain coverage ratios. These coverage ratios, calculated retrospectively using the highest ratios from two of the three most recent calendar years, must not be less than 1.05 for the times interest earned ratio and 1.0 for the debt service coverage ratio. The average times interest earned and average debt service coverage ratios for 2003, calculated retrospectively using the highest ratios from two of the three most recent calendar years, is 1.29 and 1.17, respectively.

Long-term debt is collateralized by the pledge of all assets through the mortgage.

Components of interest expense at December 31, consist of the following:

	2003	2002
Total interest costs	**$ 4,424,770**	$ 4,539,859
Interest capitalized	**(22,860)**	(30,365)
Total interest expense	**$ 4,401,910**	$ 4,509,494

9. Accounts Payable:

Accounts payable at December 31, consist of the following:

	2003	2002
Wheeling charges	**$ 1,039,274**	$ 788,161
Other	**3,332,218**	614,210
Total accounts payable	**$ 4,371,492**	$ 1,402,371

10. Member Advances:

The Cooperative offers all Members the ability to invest funds with the Cooperative on a short-term basis for periods of up to nine months. Interest rates offered on the notes (1 to 270 day maturity) are the rates announced by the Cooperative as its note participation program rates as of the date of the note. The Cooperative did not have outstanding liabilities for notes at December 31, 2003 and 2002. The interest rate on the notes averaged 1.4 percent and 1.9 percent in 2003 and 2002, respectively. Interest expense on these notes was approximately $400 and $800 for the years ended December 31, 2003 and 2002, respectively.

The Cooperative also offers a prepayment program for all members whereby the members may make interest-bearing prepayments of their monthly transmission billings. Terms offered on the prepayment program are the same as the note participation program. The prepayment and accrued interest are applied to the members' transmission billings on the date such billings become due. The Cooperative recorded liabilities for prepayments of $184,193 and $56,105 at December 31, 2003 and 2002, respectively. The interest rate on prepayments averaged 1.4 percent and 2.0 percent in 2003 and 2002, respectively. Interest expense on the prepayment program was approximately $2,800 and $4,000 for the years ended December 31, 2003 and 2002, respectively.

Interest rates on the notes and prepayments offered by the Cooperative vary depending on the length of the maturity period selected by the Members. Interest rates offered to Members ranged from 1.0 percent to 1.4 percent and 1.2 percent to 1.6 percent at December 31, 2003 and 2002, respectively.

11. Commitments and Contingencies:

Personnel Staffing Agreement – The Cooperative has a personnel staffing agreement with Sierra Southwest Cooperative Services, Inc. (Sierra) (See Note 17), whereby Sierra provides personnel staffing services for all positions except certain key staff and management positions, who are employees of the Cooperative. The personnel staffing agreement provides that the Cooperative shall pay for the actual and verifiable costs incurred by Sierra for personnel, materials, supplies and all other direct, indirect and overhead costs incurred by Sierra in carrying out its responsibilities under the personnel staffing agreement. The term of the staffing agreement is for five years from the effective date of August 1, 2001. The agreement is automatically extended for five successive years unless terminated by either party no later than two years prior to the conclusion of such fifth contract year.

Approximately 43% percent of the personnel employed by Sierra are subject to a collective bargaining agreement. Sierra entered into a three-year collective bargaining agreement, effective March 1, 2002.

Class A Member Network Service Agreements – The Cooperative holds an agreement with AEPCO, in accordance with the Cooperative's Open Access Transmission Tariff, to provide network integration transmission service to AEPCO to deliver AEPCO's power to AEPCO's five all-requirements Class A distribution cooperative members of AEPCO. The Cooperative entered into a separate agreement, in accordance with the Cooperative's Open Access Transmission Tariff, to directly provide network integration transmission service to AEPCO's partial requirements Class A Member. These agreements will remain in effect as long as any existing wholesale power contract between AEPCO and any of AEPCO's Class A members remains in effect. In 2003, those agreements were extended to December 31, 2035. In the opinion of management, the Cooperative will be able to provide service in accordance with these agreements.

Class B Member Network Service Agreement – The agreement to provide transmission service to AEPCO to deliver power to one of AEPCO's Class B members pursuant to AEPCO's power and energy sale agreement, which provided for transmission service for up to 100 MW, expired on May 31, 2002 in conjunction with the expiration of AEPCO's power and energy sale agreement.

AEPCO Bundled Transmission Service Agreements – The Cooperative also has agreements with AEPCO, in accordance with the Cooperative's Open Access Transmission Tariff, to provide point-to-point or network integration transmission service to AEPCO for AEPCO's bundled power sales agreements. These agreements provide for reserved transmission capacity ranging from 8 MW to 100 MW and will remain in effect in accordance with each respective service agreement. In the opinion of management, the Cooperative will be able provide service in accordance with these agreements.

Other Transmission Service Agreements – The Cooperative holds separate transmission service agreements with other entities in accordance with the Cooperative's Open Access Transmission Tariff or other agreements. The terms of these other transmission service agreements provide for reserved transmission capacity ranging from 5 MW to 60 MW and will remain in effect in accordance with each respective service agreement. In the opinion of management, the Cooperative will be able to provide service in accordance with these agreements.

Transmission Wheeling Agreements – The Cooperative purchases transmission wheeling rights from other entities. There are currently five transmission wheeling agreements under which the Cooperative purchases transmission to provide for deliveries to AEPCO's Class A Members, to the AEPCO bundled transmission service agreements, and to other potential transmission customers. The terms of these transmission wheeling agreements provide for wheeling rights ranging from 4 MW to 200 MW and expire from 2004 to 2021.

Lines of Credit -
Short-term financing: The Cooperative maintains a line of credit for short-term financing with the CFC of $6,000,000. The term of the agreement is for 12 months starting August 19, 2003. Interest rates on all advances under the line of credit will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2003 was 4.00 percent. No amounts were drawn under the line of credit for the year ended December 31, 2003.

Company credit card program: The Cooperative also maintains a line of credit agreement with the CFC of $250,000 as part of its company credit card program. The term of the agreement is for 12 months from August 7, 2003. The agreement automatically renews for subsequent periods of 12 months. Interest rates on all advances under the line of credit will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2003 was 4.00 percent. No amounts were drawn under the line of credit for the year ended December 31, 2003.

12. Income Tax Status:

For the years ended December 31, 2003 and 2002, the Cooperative qualifies for tax-exempt status under Internal Revenue Code section 501 (c) (12), which requires that 85 percent or more of income consist of amounts collected from Members for the sole purpose of meeting losses and expenses.

13. Employee Benefit Plans:

Pension Plans - The Cooperative has a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service, age, retirement interest rate, and the employee's highest five years of compensation during the last ten years of employment. The Cooperative's policy has been to fund retirement costs annually as they accrue.

Pension benefits for substantially all employees are provided through participation in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program. The Cooperative contributes a percentage of employees' earnings to the program, as prescribed by the NRECA. Contributions made to this plan were approximately $190,000 and $185,000 for the years ended December 31, 2003 and 2002, respectively.

The Cooperative also offers participation in the NRECA Selectre Pension Plan to all employees meeting certain minimum service requirements. This plan has 401(k) salary deferral features. Under this plan, the Cooperative matches a percentage of the employees' contributions to the plan. The Cooperative's contributions to the plan were approximately $51,000 and $48,000 for the years ended December 31, 2003 and 2002, respectively.

Postretirement Benefits - The Cooperative reports its postretirement benefits in accordance with SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." This statement requires that the Cooperative calculate and record the liability and related expense associated with providing postretirement benefits other than pensions.

The Cooperative has a contributory health care plan covering active employees and retirees under which retirees pay 100 percent of the average cost of benefits determined based on the combined experience of active employees and retirees. The incremental cost of heath care premiums, resulting from the inclusion of retirees' health care experience ratings with active employees' experience ratings, is viewed as a benefit earned through employment service, subject to accrual during the years an employee is working.

	2003	2002
Benefit obligation at January 1 and August 1, respectively	**$ (140,220)**	$ (108,300)
Recognition of current year expense	**(25,600)**	(31,920)
Benefit obligation at December 31	**(165,820)**	$ (140,220)
Fair value of plan assets at December 31	**0**	0
Funded status	**$ (165,820)**	$ (140,220)

Assumptions: The accumulated postretirement benefit obligation was determined using a 7 percent discount rate. A health care cost trend rate of 9 percent was assumed for 2001, decreasing to 5 percent by 2010 and remaining at 5 percent thereafter. A one percent increase in the health care trend cost would result in a $13,400 increase in the accumulated postretirement benefit obligation and a $21,800 increase in the expected postretirement benefit obligation.

14. Concentration of Customers and Credit Risk:

Revenue for the year ended December 31, 2003 included revenue from five customers, whom each individually represented more than 10 percent of the total operating revenue. Revenue from these customers collectively represented approximately 94 percent of total operating revenue for 2003. Accounts receivable at December 31, 2003 included amounts owed from five customers, whom each individually represented 10 percent of the total accounts receivable balance. The amounts owed from these customers collectively represented approximately 92 percent of the total accounts receivable balance at December 31, 2003.

Revenue for the year ended December 31, 2002 included revenue from five customers, whom each individually represented more than 10 percent of the total operating revenue. Revenue from these customers collectively represented approximately 94 percent of total operating revenue for 2002. Accounts receivable at December 31, 2002 included amounts owed from five customers, whom each individually represented 10 percent of the total accounts receivable balance. The amounts owed from these customers collectively represented approximately 94 percent of the total accounts receivable balance at December 31, 2002.

15. Fair Value of Financial Instruments:

Many of the Cooperative's financial instruments lack an available trading market as characterized by a willing buyer and willing seller engaged in an exchange transaction. The Cooperative's general practice and intent is to hold its financial instruments to maturity and not to engage in trading or sales activities. As a result, significant estimations and present value calculations are used by the Cooperative for purposes of disclosure.

Estimated fair values are determined by the Cooperative using the best available data and an estimation methodology suitable for each category of financial instruments. For those financial instruments, which mature or reprice within 90 days, the carrying amounts approximate fair value.

The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value:

a. *Cash and Cash Equivalents* - For cash and cash equivalents, cost is a reasonable estimate of fair value.
b. *Investments* – Investments, which at December 31 consist entirely of capital term certificates, are carried at cost, as fair market value is not readily determinable.
c. *Member Advances* - For Member advances, the carrying value (cost plus accrued interest) of advances with maturities of 90 days or less approximates the fair value. The fair value of advances with maturities greater than 90 days are estimated by recalculating the redemption value at December 31 using the rate, offered by the Cooperative on the original purchase date, for investments that would have a maturity date of December 31.

d. *Long-Term Debt* - The fair value of the Cooperative's long-term debt is estimated by discounting the future cash flows required under the terms of each respective debt agreement by the currently quoted or offered rates for the same or similar issues of debt with similar maturities. The principal amounts of variable rate debt outstanding at December 31, 2003 and 2002, of the Solid Waste Disposal Revenue Bonds and Cooperative Finance Corporation long-term debt are considered reasonable estimates of their fair values, as these are variable interest rate liabilities.

The estimated fair values of the Cooperative's financial instruments at December 31, consist of the following:

	2003	
	Carrying Value	Fair Value
Investments and Other Property:		
Restricted held to maturity investments	**$ 1,355,652**	**$ 1,355,652**
Long-Term Debt:		
(including current maturities):		
Federal Financing Bank	**$58,962,815**	**$58,683,196**
Cooperative utility trust	**13,193,086**	**12,779,883**
Solid waste disposal revenue bonds	**8,632,940**	**8,632,940**
Pollution control revenue bonds	**3,572,079**	**3,810,981**
Rural Utilities Service	**2,443,373**	**4,787,485**
Cooperative Finance Corporation	**886,512**	**886,512**
Current Liabilities:		
Member advances	**$ 184,194**	**$ 184,772**

	2002	
	Carrying Value	Fair Value
Investments and Other Property:		
Restricted held to maturity investments	$ 1,350,375	$ 1,350,375
Long-Term Debt:		
(including current maturities):		
Federal Financing Bank	$57,001,795	$64,442,445
Cooperative utility trust	13,601,929	13,005,555
Solid waste disposal revenue bonds	8,828,402	8,828,402
Pollution control revenue bonds	4,365,335	4,671,741
Rural Utilities Service	2,735,971	2,853,764
Cooperative Finance Corporation	963,198	963,198
Current Liabilities:		
Member advances	$ 56,105	$ 56,137

16. Operating Leases:

Office Facilities and Machinery and Equipment: The Cooperative entered into two separate 60 month lease agreements, effective as of August 1, 2001, for the lease of office facilities and substantially all the machinery and equipment used in the Cooperative's daily operations (See Note 17). Rent expense for the office facilities and machinery and equipment totaled approximately $839,000 for each of the years ended December 31, 2003 and 2002.

The following summarizes the future minimum lease payments under operating leases that have initial or remaining non-cancelable lease terms in excess of one year at December 31, 2003:

Fiscal Year	Leases
2004	$ 838,614
2005	838,614
2006	838,614
2007	489,192
Thereafter	0
Total	$ 3,005,034

17. Related Parties:

The Cooperative is a Class B member of Sierra. Sierra is a member-owned, non-profit Arizona cooperative corporation organized to provide personnel staffing and energy services and products to its members and other customers. Class B members of Sierra are collectively represented by one director seated on Sierra's board of directors. Each director is entitled to one vote on each matter submitted to a vote at a meeting of the directors. The Cooperative's investment in Sierra was $1,000,000 as of December 31, 2003 and 2002. (See Note 3).

AEPCO and Sierra are Class B members of the Cooperative. Class B members of the Cooperative are collectively represented by one director seated on the Cooperative's board. Each director is entitled to one vote on each matter submitted to a vote at a meeting of the directors.

The Cooperative has entered into an agreement with Sierra, whereby Sierra provides personnel staffing services (See Note 11 – *Personnel Staffing Agreement*). The Cooperative recorded expenses for personnel staffing services totaling approximately $5,611,000 and $5,288,000 for the years ended December 31, 2003 and 2002, respectively. The Cooperative has accounts payable to Sierra totaling approximately $15,800 at December 31, 2003. The Cooperative had accounts receivable from Sierra totaling approximately $800 and $32,000, at December 31, 2003 and 2002, respectively.

The Cooperative has entered into an agreement with AEPCO for the lease of Office Facilities and Machinery and Equipment (See Note 16 - *Office Facilities and Machinery and Equipment*). Rents paid to AEPCO totaled approximately $839,000 for each of the years ended December 31, 2003 and 2002.

The Cooperative has also entered into agreements with AEPCO for transmission service (See Note 10 - Class A Member Network Service Agreements, Class B Member Network Service Agreement, and AEPCO Bundled Transmission Service Agreements). The Cooperative recorded revenues from these agreements totaling approximately $16,868,000 and $16,622,000 for the years ended December 31, 2003 and 2002, respectively. The Cooperative had recorded accounts receivable from AEPCO totaling approximately $1,175,000 and $1,124,000 as of December 31, 2003 and 2002, respectively.

18. Asset Retirement Obligations:

In June 2001, FASB Statement No. 143, Accounting for Asset Retirement Obligations, was issued. Statement. 143 requires the Cooperative to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal use of the assets. The Cooperative also would record a corresponding asset that is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation would be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Cooperative was required to adopt Statement 143 on January 1, 2003. After a review of tangible long-lived assets of the Cooperative, it was determined that the transmission facilities have asset retirement obligations. However, as the obligations do not have determinable settlement dates, the Cooperative has not recorded an asset retirement obligation, as the amount cannot be reasonably estimated at this time.

End of Audited Financial Statements.

EXHIBIT
SWTC-4
ADMITTED

DIRECT TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Q. Please state your name and address for the record.

A. My name is Gary E. Pierson. My business address is Sierra Southwest Cooperative Services, Inc., P. O. Box 2165, 1000 S. Highway 80, Benson, Arizona, 85602.

Q. By whom are you employed and in what capacity?

A. I am employed by Sierra Southwest Cooperative Services, Inc. ("Sierra Southwest") as the Manager of Financial Services. As Manager of Financial Services, I am responsible for directing and administrating the treasury, cash management and risk management functions for Sierra Southwest. In addition, as a result of staffing agreements that Sierra Southwest has with Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative, Inc. ("SWTransco"), I am responsible for the same functions as well as rate design/implementation for these two cooperatives as well.

Q. Please briefly summarize your educational and professional background.

A. I graduated in 1974 from Western State College, Gunnison, Colorado, with a Bachelor of Arts Degree specializing in Accounting and Business Administration. In June 1974, I was employed by Colorado-Ute Electric Association, Inc. and worked there for seventeen years

in various positions in the areas of ratemaking, budgeting, financial forecasting and power requirements studies. In May 1992, I was employed by AEPCO as a Rates Administrator in the Financial Services Division where my principal responsibilities and duties included the preparation of rate filings, the design of rate structures and rate analysis studies. In 1993, I was promoted to the position of Manager of Financial Services. In August 2001, as a result of the restructuring of AEPCO into three separate cooperatives, I was employed by Sierra Southwest in the same position. I have testified as an expert witness before the Public Utilities Commission of the State of Colorado, the United States Bankruptcy Court in Denver, Colorado and the Arizona Corporation Commission in connection with various proceedings involving rate cases.

Q. What is the purpose of your testimony in this proceeding?

A. I will testify in support of the application for a general rate filing for AEPCO. My testimony is primarily directed to the financial schedules, which were filed in support of the application (the "Schedules").

Q. Please describe the Schedules.

A. They are a multi-page exhibit containing the Schedules A-H that are described in A.A.C. R14-2-103 and are divided into the following categories:

Schedule Category	Section Tab
Summary Schedules	A
Rate Base Schedules	B
Test Year Income Statements	C
Cost of Capital Schedules	D
Financial Statements and Statistical Schedules	E
Projections and Forecast Schedules	F
Cost of Service Analysis Schedules	G
Effect of Proposed Tariff Schedules	H

Q. Please describe Section A of the Schedules.

A. Section A contains the summary schedules that pertain to the rate filing. Schedule A-1 shows the computation of the increase in gross revenue requirements that results from the development of the financial schedules. An increase in revenues from AEPCO's Class A Member Distribution Cooperatives ("Class A Members") of $8,450,016 results from the change in the existing all-requirements Class A member rates from a Demand Rate of $12.44/kW to $13.79/kW and the Energy Rate from $0.01989/kWh to $0.02071/kWh. Also, the partial-requirement contract rates for Mohave Electric Cooperative, Inc. increase from a Fixed Charge of $688,556 per month to $705,795 per month; the O&M Rate moves from $4.76/kW month to $7.25/kW month; and the Energy Rate adjusts from $0.01989/kWh to $0.02071/kWh. The coverage ratios produced by this proposal are a

Times Interest Earned Ratio ("TIER") of 1.29 and a Debt Service Coverage Ratio ("DSCR") of 1.05, as discussed in the testimony of Mr. Minson of AEPCO and Mr. Edwards of the National Rural Utilities Cooperative Finance Corporation ("CFC"). The $8,450,016 represents an increase of 9.86% over the revenues generated by present rates. Current rates produced an approximately $4.5 million loss in the 2003 test year, as adjusted. Based upon a test period adjusted rate base of $222,147,011, the revenue requirements generate a rate of return of 7.39%.

Schedule A-2 sets forth summary results of operations for the calendar years 2001, 2002 and 2003 and the adjusted test year with present rates and with proposed rates. As I mentioned, on an adjusted test year basis, column 5 shows that AEPCO had a net margin loss of $4,527,610, a TIER of 0.67 and a DSCR of 0.70 in 2003. Schedule A-3 summarizes AEPCO's capital structure and capitalization ratios for calendar years 2001 and 2002 as well as the test year 2003. Schedule A-4 provides data concerning construction expenditures, net plant additions and gross utility plant in service and Schedule A-5 summarizes AEPCO's changes in financial position.

Q. Please describe Section B of the Schedules.

A. Section B contains supporting rate base schedules that are used in the AEPCO rate filing. Schedule B-1 summarizes the components of the original cost rate base of $222,147,011 as of December 31, 2003. That includes gross utility plant in service of $389,603,749, accumulated depreciation and amortization of $186,190,519, allowances for working capital

of $16,778,408 and deferred debits of $1,955,373. Schedule B-2 reflects that adjustments were made to the original cost rate base for the inclusion of the coal blending facility at Apache Station that will be discussed later in my testimony. Schedules B-3 and B-4 concerning reconstructed cost net of depreciation ("RCND") rate base have not been completed. AEPCO, as a non-profit cooperative, stipulates to the use of its original cost rate base as its fair value rate base.

Schedule B-5, page 1 of 5, provides the computation of working capital by components, which add up to total working capital of $16,778,408 and the remaining pages show the calculation of the different components. Schedule B-5, page 2 of 5, concerning the calculation of cash working capital, has not been completed. In Docket U-1773-92-214, AEPCO was directed, in future rate cases, to provide a lead/lag study if AEPCO desired to include cash working capital as a part of its total working capital. In consultation with senior management, it was decided not to incur the considerable time and expense of the lead/lag study and AEPCO stipulates to the use of a zero value for its cash working capital.

Q. Please describe Section C of the Schedules.

A. Section C contains adjusted test year income statements and supporting schedules to the income statement. Schedule C-1, pages 1 through 4, provides the adjusted test year income statement for the test year 2003 and the as-adjusted test year income statement for the test year 2003. Pages 1 and 2 of Schedule C-1 provide per books and reclassified test year income statements for 2003. The first column represents the revenues and expenses of

AEPCO during the test year, which is the twelve months ended December 31, 2003. As noted on Schedule C-1, page 2, AEPCO had an operating margin loss last year of $5,202,265, non-operating margins of $1,963,753 and an extraordinary loss of $3,810,335 that together produced a net margin loss of just over $7 million. The second column represents reclassification adjustments that are made to the test period which have a zero effect on the net margins of AEPCO.

Schedule C-2, pages 1 through 10, provides detail on the reclassification and pro forma adjustments to revenues and expenses. They are as follows:

Reclassification Adjustments – Schedule C-2, Pages 1 and 2:

1. SWTransco Revenue Reclassification – This adjustment reclassifies the network service, system control and load dispatching and regulatory asset charge revenues that AEPCO collects from its all-requirements members and then pays to SWTransco. These revenues and charges are a pass-through at cost of network services provided by SWTransco to AEPCO's all-requirements Class A Members. Therefore, AEPCO has removed them from its cost of service. The net effect of this reclassification on net margins is zero.
2. Property Tax Reclassification – This adjustment reclassifies property taxes, which are recorded in various operation and maintenance expense categories according to Rural Utilities Service ("RUS") accounting procedures to taxes so that these expenses can be shown separately for ratemaking purposes. The net effect of this reclassification on net margins also is zero.

3. Mohave Schedule B Reclassification – This adjustment reclassifies certain extraordinary revenues billed and collected from Mohave Electric Cooperative, Inc. ("Mohave") during the test period pursuant to Schedule B of the Partial Requirements Agreement between AEPCO and Mohave. These Schedule B charges are reclassified from Class A Member revenue to the non-Class A, non-firm and non-member revenue category. These Schedule B Revenues should be stated as non-member revenues since their pricing is not directly tied to Class A Member rates. Again, the net effect of this reclassification on net margins is zero.

Pro Forma Adjustments – Schedule C-2, Pages 3 through 10:

1. Mohave Schedule A Adjustment – This adjustment removes revenues and expenses associated with certain sales to third parties made by Mohave during the extended outage of Steam Turbine Unit 3, using energy from AEPCO resources at the AEPCO tariff rate. Under the Partial Requirements Agreement between AEPCO and Mohave, Mohave may make sales to third parties whenever available power and energy under Schedule A exceeds its native load. However, these sales during the extended outage of Steam Turbine 3 actually resulted in AEPCO generating from higher cost resources and purchasing more expensive replacement power to supply Mohave, but selling that power to Mohave at the lower contract energy rate. AEPCO is in the process of negotiating an amendment to the Partial Requirements Agreement to address this issue and, accordingly, has made an adjustment to the test year to remove its effect. AEPCO has removed $382,774 of revenues and $884,010 of expenses associated with these

sales during the extended outage. The effect of this adjustment is to increase net margins by $501,236.

2. City of Mesa Contract Adjustment – This adjustment annualizes the test year effect of the termination of the 17.5 MW sales contract to the City of Mesa that occurred on May 31, 2003. AEPCO has reviewed the hourly generation and purchased power that was dispatched in connection with this contract and made assumptions as to sales to other sources or decreased generation and purchased power expenses that would have occurred if this contract had not been in effect for the first five months of the test year. In addition, AEPCO has reduced the associated charges that were paid to SWTransco to wheel the power associated with this contract. The effect of this adjustment also results in an increase in net margins of $356,072.

3. Ancillary Services Revenue Adjustment – This adjustment removes $76,586 of ancillary services revenue that AEPCO collected from SWTransco during the test period in connection with 100 MW of non-firm transmission service to Morenci Water & Electric ("MW&E"). Having completed its tap line to the Greenlee substation, MW&E will be wheeling this power over the Tucson Electric Power, not SWTransco system and, therefore, AEPCO will not be collecting this ancillary services revenue. This adjustment reduces net margins by $76,586.

4. Labor Expense Adjustment – This adjustment annualizes labor expense and associated payroll taxes and benefits to reflect wage increases that occurred during the test period. The net effect of this adjustment decreases net margins by $520,342.

5. Fuel Expense Adjustment – This adjustment reduces the test year coal expense to $1.45 per MMBtu which AEPCO expects to achieve as a result of the new coal blending facility installed at Apache Station. The adjustment reduces production fuel expenses by $1,534,274 but is offset by reductions in revenues of $551,934. The revenue reductions result from the pass-through of these coal cost reductions in the charges to Salt River Project, City of Mesa and Electrical District 2 by AEPCO under sales agreements which are tied to cost formulas. The net effect of this adjustment is to increase net margins by $982,340.

6. SO2 Allowance Adjustment – This adjustment also reduces production expenses by $167,069 to reflect the decreased requirement for purchases of SO2 Allowances that is expected to occur as a result of the new coal blending facility at Apache Station. The net effect of this adjustment is to increase net margins by $167,069.

7. Ash Sales Credit Adjustment – This adjustment increases production expense to reflect the reduced levels and price of sales of ash from Apache Station. The coal blending facility will not produce an ash quality sufficient to provide the same volume of sales achieved during the test period. In addition, due to the decreased volume of ash, the price will be lower as well. This adjustment reduces net margins by $820,611.

8. Coal Blender Adjustment – This adjustment reflects the fixed charges such as long-term interest expense, depreciation and taxes associated with the addition of the coal blending facility at Apache Station. This adjustment decreases net margins by $1,005,214.

9. GT4 FFB Financing Adjustment – This adjustment annualizes the increased interest expense of $1,190,178 associated with Gas Turbine 4 to reflect the drawing of $28.9 million of RUS guaranteed FFB financing in order to repay the $23.7 million of CFC interim financing and to reimburse AEPCO for $5.2 million of general funds expended during construction. The effect of this adjustment is to decrease net margins by $1,190,178.

10. Depreciation Adjustment – This adjustment annualizes the depreciation expense associated with plant placed in service during the test year and also reflects the proposed lower deprecation rates for Steam Turbines 2 and 3 which are discussed in Mr. Minson's testimony. This adjustment increases net margins by $1,473,878.

11. Purchased Power Adjustment – This adjustment annualizes the purchase of power from TECO Panda Gila River at a rate of $4.84/kW month and replacement power purchases for the PacifiCorp purchased power contract that terminated during the test period. The effect is to decrease net margins by $88,139.

12. Wheeling Expense Adjustment – This adjustment annualizes transmission expense for (a) wheeling expenses associated with the Western Area Power Administration ("WAPA") West Wing – Marana Transmission Agreement that became effective on January 1, 2004, (b) the El Paso Palo Verde – West Wing Transmission Agreement that became effective on July 1, 2003 and (c) the proposed increase in point-to-point transmission rates that SWTransco charges AEPCO for wheeling associated with contractual sales to Salt River Project, City of Mesa and Electrical District 2 as well as

point-to-point service from Apache – Mead. This adjustment decreases net margins by $1,329,483.

13. Interest Expense Adjustment – This adjustment annualizes interest expense based upon debt balances and interest rates at the end of the test year and decreases interest expense by $375,891. Net margins are increased by the same amount.

14. Other Deductions Adjustment – $266,003 of write-offs of preliminary survey and investigation charges and prior period adjustments should not be reflected in the test year. This adjustment increases net margins by $266,003.

15. Asset Retirement Obligation Adjustment – This adjustment removes the extraordinary loss item of $3,810,335 resulting from the required recognition of an Asset Retirement Obligation to close the combustion waste disposal ponds at Apache. AEPCO proposes to recover this expense over a ten-year period and therefore has included $381,034 in other deductions expense. The ten-year amortization period matches the ten-year unsecured financing that AEPCO will obtain from CFC to finance the cost of the closure. The effect of this adjustment is to increase net margins by $3,429,301.

As indicated on page 10 of Schedule C-2, these pro forma adjustments in expenses and revenues resulted in an increase in net margins of $2,521,237. Finally, Schedule C-3 lists the computation of the gross revenue conversion factor.

1 Q. Please describe Section D of the Schedules.

2 A. Section D contains information on AEPCO's cost of capital for the calendar years 2001,
3 2002 and 2003. Schedule D-1 sets forth the computed cost of capital as of December 31,
4 2003 for the actual and projected test year. Invested debt capital amounted to $213,294,620
5 with a composite cost rate of 5.60%. Schedule D-2 shows long-term and short-term debt
6 balances by lender that comprise the total, the interest rates associated with the debt
7 balances and the computation of the composite cost rate for three years. Schedules D-3 and
8 D-4 on preferred stock and common equity are obviously not applicable to AEPCO since it
9 is a member-owned, non-profit cooperative.

10

11 Q. Please describe Section E of the Schedules.

12 A. Section E sets forth financial statements and statistical schedules for the calendar years
13 2003, 2002 and 2001. Schedule E-1 provides comparative balance sheets and Schedule E-2
14 shows comparative income statements. Schedule E-3 provides a comparative statement of
15 changes in financial position and Schedule E-4 reflects changes in equity. Schedule E-5
16 provides detail of utility plant additions during the test year and balances as of
17 December 31, 2002 and 2003. Schedule E-6 is not applicable to AEPCO. Schedule E-7
18 provides AEPCO operating statistics while Schedule E-8 lists taxes charged to operations.
19 Attached to my testimony as Exhibit GEP-1 are the Consolidated Financial Statements
20 which include the Independent Auditor's Report to the AEPCO Board of Directors, dated
21 March 25, 2004. It contains the information that is referenced in Schedule E-9.

Q. Please describe Section F of the Schedules.

A. Section F contains various projections and forecast schedules. Schedule F-4 discusses certain assumptions used in developing the projections contained in the previous F schedules.

Q. Please describe Section G of the Schedules.

A. Section G contains schedules presenting cost of service information. Schedule G-1 provides a cost of service summary for the pro forma adjusted test year based upon present rates, while Schedule G-2 provides a cost of service summary for the pro forma adjusted test year based upon developed rates. Schedule G-2A, page 1, shows the derivation of revenue requirements and proposed rates, which have been developed based upon the recommended 12 CP methodology discussed in Mr. Daniel's testimony. Lines 17 through 20 of Schedule G-2A, page 1, show the development of the proposed energy rate of $0.02071/kWh. Lines 21 through 39 of Schedule G-2A, page 1, show the development of the proposed Mohave O&M rate of $7.25/kW month and the O&M component of the all-requirements demand rate of $7.29/kW month. Lines 8 though 16 of Schedule G2-A, page 1, show the development of the proposed Mohave Fixed Charge of $705,795 and the fixed component of the all-requirements demand rate of $6.50/kW month. Schedule G-2A, page 2, compares the present rates and proposed rates. Schedules G-3 and G-4 are not applicable to AEPCO. Schedule G-5 provides a distribution of rate base by function.

Schedule G-6 provides a distribution of expenses and revenue credits by function for the test period. Schedule G-7 is not applicable to AEPCO. Schedule G-8 information is shown on Schedule H-2A.

Q. Please describe Section H of the Schedules.

A. Section H shows the effect of the proposed rate tariff schedules on the revenues generated by sales to the Class A Members. Schedule H-1 summarizes the revenues generated by present rates and the proposed rates for the pro forma test year 2003. Schedule H-2, page 1, compares revenues generated by present and proposed rates for each of the Class A Members. Schedule H-2, pages 2 through 7, analyzes revenues on a monthly basis from each Class A Member and pages 8 and 9 analyze revenues from all Class A Members. Page 10 shows the average costs in $/kWh to each of the Class A Members based upon present and proposed rates. Schedule H-2A is a schedule displaying the derivation of the proposed pro forma member fuel cost adjustor base factor. Schedules H-4 and H-5 are not applicable to AEPCO because it does not have retail customers.

Q. What is the member fuel cost adjustor that AEPCO is proposing in this proceeding?

A. AEPCO requests that the Commission approve an adjustor mechanism that would be formula-based and would enable the recovery of increases in the fuel and purchased energy costs over which AEPCO has little control. Conversely, the adjustor mechanism would also allow AEPCO to refund any decreases in fuel and purchased energy costs to the Class A

Members. The adjustor would allow a pass-through of fuel and purchased energy cost changes without the time and expense of a rate case and would provide greater margin stability to AEPCO.

Q. How would the proposed member fuel cost adjustor work?

A. We will work with Staff to refine the details of the procedure. But, in concept, we would suggest that the adjustor base shown on Schedule H-2A be established in this rate order as the clause base. Changes from that adjustor base would be tracked monthly and recouped as a positive or negative charge in the next quarter's billing to the Class A Members. Regular reporting would be performed to keep the Commission timely apprised of the status of the clause.

Q. Why is AEPCO requesting the member fuel cost adjustor clause?

A. As shown on Schedule G-6, page 1, AEPCO's fuel and purchased power expenses amounted to almost one-half of AEPCO's total expenses for the adjusted 2003 test year. In recent years, AEPCO has experienced price increases for natural gas that have been very volatile and beyond AEPCO's control. For example, in 2002, the average price of natural gas burned in AEPCO plants was $3.65/MMBtu versus the average price of $5.17/MMBtu in the 2003 test year. That represents a 41% increase in price during only one year. In his testimony, Mr. Minson discusses the fact that this volatility was one of the primary reasons AEPCO suffered a margin loss in the test year. As a non-profit cooperative, AEPCO has no

other way to recoup or refund volatile changes in fuel and purchased power other than through the rate making process. Given the time, expense and length of a general rate filing, an adjustor mechanism is appropriate to provide financial stability to AEPCO and reduce costs for both our members and the Commission.

Q. Does this conclude your prepared direct testimony?

A. Yes it does.

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KPMG

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Consolidated Financial Statements

December 31, 2003 and 2002

(With Independent Auditors' Report Thereon)

KPMG LLP
Suite 700, Two Park Square
6565 Americas Parkway NE
PO Box 3990
Albuquerque, NM 87190

Independent Auditors' Report

The Board of Directors
Arizona Electric Power Cooperative, Inc.

We have audited the accompanying consolidated balance sheets of Arizona Electric Power Cooperative and subsidiary (the Cooperative) as of December 31, 2003 and 2002, and the related consolidated statements of revenues and expenses and unallocated accumulated margins, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Arizona Electric Power Cooperative and subsidiary as of December 31, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 18 to the consolidated financial statements, the Cooperative adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* effective January 1, 2003.

In accordance with *Government Auditing Standards*, we also issued a report dated March 25, 2004 on our consideration of the Cooperative's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grants. That report is an integral part of the audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

KPMG LLP

March 25, 2004

KPMG LLP, a U.S. limited liability partnership, is the U.S. member firm of KPMG International, a Swiss cooperative.

Arizona Electric Power Cooperative, Inc.
Consolidated Balance Sheets
December 31, 2003 and 2002

Assets	**2003**	2002
Utility Plant:		
Plant in service	**$ 379,651,130**	$ 377,308,895
Construction work in progress	**9,795,448**	2,334,254
Total utility plant	**389,446,578**	379,643,149
Less - Accumulated depreciation	**(185,881,988)**	(179,550,283)
Utility plant, net	**203,564,590**	200,092,866
Investments and Other Property:		
Restricted held to maturity investments	**9,601,463**	7,831,350
Other	**4,002,042**	3,387,182
Total investments and other property	**13,603,505**	11,218,532
Current Assets:		
Cash and cash equivalents-		
General unrestricted	**7,420,590**	7,690,546
Restricted	**4,576,885**	3,995,094
Accounts receivable, less allowance for uncollectible accounts of $1,900,000 for 2003 and 2002	**15,742,346**	19,047,152
Inventories, at average cost:		
Coal	**3,382,266**	12,593,707
Materials and supplies	**5,798,889**	5,199,650
Prepayments and other current assets	**1,246,971**	1,238,923
Notes receivable	**300,465**	348,122
Total current assets	**38,468,412**	50,113,194
Deferred Debits	**5,607,305**	6,309,633
Total Assets	**$ 261,243,812**	$ 267,734,225

See accompanying notes to consolidated financial statements.

Arizona Electric Power Cooperative, Inc.
Consolidated Balance Sheets
December 31, 2003 and 2002

Membership Capital and Liabilities	2003	2002
Membership Capital:		
Membership fees	$ 330	$ 330
Patronage capital	17,803,238	13,904,668
Unallocated accumulated (loss) margins	(7,048,846)	3,898,570
Total membership capital	10,754,722	17,803,568
Long-Term Debt:		
Federal Financing Bank	105,461,962	114,914,607
Cooperative utility trust	26,353,577	27,304,914
Solid waste disposal revenue bonds	17,395,100	17,867,061
Cooperative Finance Corporation	40,798,343	25,534,758
Pollution control revenue bonds	5,673,635	7,392,918
Rural Utilities Service	4,018,036	4,850,508
Total long-term debt	199,700,653	197,864,766
Current Liabilities:		
Member advances	2,529,176	15,278,804
Current maturities of long-term debt	15,801,553	12,553,239
Accounts payable	11,032,390	7,733,171
California power sales refund liability	4,107,752	4,107,752
Accrued property taxes	1,727,253	2,119,162
Accrued interest	854,965	931,190
Other	940,767	622,360
Total current liabilities	36,993,856	43,345,678
Asset Retirement Obligation	3,917,790	-
Deferred Credits	9,876,791	8,720,213
Total Membership Capital And Liabilities	$ 261,243,812	$ 267,734,225

See accompanying notes to consolidated financial statements.

Arizona Electric Power Cooperative, Inc.
Consolidated Statements of Revenues and Expenses and Unallocated Accumulated Margins
For the Years Ended December 31, 2003 and 2002

	2003	2002
Operating Revenues:		
Sales of electric energy-		
Members-		
Class A - Firm	$ 87,642,606	$ 81,886,781
Class A - Non-firm	656,736	2,715,363
Class B	7,411,125	24,078,851
Class C	29,941,937	27,162,485
Non-members	11,916,025	7,381,722
Other, net	13,610,967	12,153,414
Total operating revenues	151,179,396	155,378,616
Operating Expenses:		
Power generation-		
Fuel	62,295,417	56,992,331
Operation	12,615,443	10,671,436
Maintenance	12,714,072	9,694,627
Purchased power and interchange	18,554,563	24,394,795
Administration and general	9,289,462	9,660,298
Depreciation and amortization	8,774,081	7,808,510
Transmission-		
Operation	15,341,229	15,949,082
Maintenance	28,046	15,442
Property and other taxes	3,959,957	4,237,863
Total operating expenses	143,572,270	139,424,384
Operating Margin	7,607,126	15,954,232
Interest Expense	12,226,803	12,584,729
Other Income, net	1,381,166	529,067
Net (Loss) Margin Before Cumulative Effect of Change in Accounting Principle for Asset Retirement Obligation	(3,238,511)	3,898,570
Cumulative Effect of Change in Accounting Principle for Asset Retirement Obligations	(3,810,335)	-
Net (Loss) Margin	(7,048,846)	3,898,570
Unallocated Accumulated Margins, January 1	3,898,570	9,298,056
Patronage Capital Allocation	(3,898,570)	(9,298,056)
Unallocated Accumulated Margins, December 31	$ (7,048,846)	$ 3,898,570

See accompanying notes to consolidated financial statements.

rizona Electric Power Cooperative, Inc.
Consolidated Statements of Cash Flows
For the Years Ended December 31, 2003 and 2002

	2003	2002
Cash Flows from Operating Activities:		
Net (loss) margin	$ (7,048,846)	$ 3,898,570
Adjustments to reconcile net (loss) margin to net cash flows provided by operating activities-		
Depreciation and amortization	8,692,283	7,726,667
Amortization of deferred charges	94,391	94,334
Amortization of other deferred credits	(337,278)	(337,280)
Cumulative effect of change in accounting principle	3,810,335	-
Changes in assets and liabilities-		
Restricted cash and cash equivalents	(581,791)	1,954,400
Accounts receivable	3,352,463	4,822,758
Inventories	8,612,202	(4,807,128)
Deferred debits	(47,035)	543,392
Accounts payable	3,299,219	(2,299,311)
Accrued interest	(76,225)	(681,892)
Accrued overhaul	1,606,156	(69,618)
Other, net	(349,102)	263,527
Net cash provided by operating activities	21,026,772	11,108,419
Cash Flows from Investing Activities:		
Construction expenditures, net	(11,928,062)	(23,155,056)
Maturities of investments	159,037	717,090
Purchase of investments	(1,929,150)	(86,497)
Patronage capital retirement	66,875	36,512
Net cash used in investing activities	(13,631,300)	(22,487,951)
Cash Flows from Financing Activities:		
Member advances, net	(12,749,628)	1,335,418
Issuance of long-term debt	15,429,150	19,587,886
Retirement of long-term debt	(10,344,950)	(12,505,358)
Net cash (used in) provided by financing activities	(7,665,428)	8,417,946
Net Decrease in Cash and Cash Equivalents	(269,956)	(2,961,586)
Cash and Cash Equivalents, January 1	7,690,546	10,652,132
Cash and Cash Equivalents, December 31	$ 7,420,590	$ 7,690,546
Supplemental Disclosures:		
Cash paid for interest, net of amount capitalized	$ 12,303,028	$ 13,266,621

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Arizona Electric Power Cooperative, Inc.
For The Years Ended December 31, 2003 and 2002

1. Organization:

Arizona Electric Power Cooperative, Inc. is a member owned, non-profit Arizona rural electric generation cooperative organized in 1961 to provide wholesale electric power to its member distribution cooperatives, municipalities, and other customers. Carbon Coal, Inc. ("Carbon"), its wholly owned subsidiary, was organized for the purpose of coal mining. These entities are hereinafter referred to as the Cooperative.

Membership of the Cooperative is restricted to electric utilities. The Cooperative has three classes of Members. Class A Members consist of five distribution cooperatives with all requirements contracts and one distribution cooperative with a partial requirements contract. Class B and Class C Members consist of three electrical utilities with partial requirements contracts. Class A, Class B, and Class C Members are collectively referred to herein as Members.

2. Summary of Significant Accounting Policies:

System of Accounts - The Cooperative maintains its accounts in accordance with policies and procedures as prescribed by the Rural Utilities Service (RUS) in conformity with the Uniform System of Accounts. The Cooperative's accounting policies conform to accounting principles generally accepted in the United States as applied in the case of regulated public utilities and are in accordance with the accounting requirements and rate-making practices of the RUS and the Arizona Corporation Commission (ACC), the regulatory authorities having jurisdiction.

Principles of Consolidation - The accompanying consolidated financial statements include the accounts of Arizona Electric Power Cooperative, Inc. and Carbon, its wholly owned subsidiary. All significant inter-company accounts and transactions have been eliminated in consolidation.

Accounting for the Effects of Regulation - The Cooperative prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, regulated enterprise to reflect the impact of regulatory decisions in its financial statements. It is the Cooperative's policy to assess the recoverability of costs recognized as regulatory assets and the Cooperative's ability to continue to account for its activities in accordance with SFAS No. 71, based on each regulatory action and the criteria set forth in SFAS No. 71.

Utility Plant - Utility Plant is stated at historical cost and includes the costs of outside contractors, direct labor and materials, allocable overhead, and interest charged to construction.

In accordance with the Uniform System of Accounts, the Cooperative capitalizes the interest costs associated with the borrowing of funds used to finance construction work in progress (CWIP). Interest income from construction funds held in trust, if any, are credited to CWIP. Interest costs capitalized on construction projects approximated $69,000 and $335,000 for 2003 and 2002, respectively.

Depreciation is computed on a straight-line basis over the estimated useful lives of depreciable property in accordance with rates prescribed by the RUS, averaging 2.3 percent and 2.2 percent in 2003 and 2002, respectively. Depreciation expense approximated $ 8,692,000 and $7,727,000 for 2003 and 2002, respectively. Minor replacements and repairs are charged to expense as incurred. Retirements of utility plant, together with the cost of removal, less salvage, are charged to accumulated depreciation.

The Cooperative assesses its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the fair value is less than the carrying amount of the asset, a loss is recognized for the difference. The Cooperative has not recorded losses resulting from impairment of its long-lived assets.

Investments - The Cooperative reports its investments in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." SFAS No. 115 provides that the Cooperative classify investments in securities as either trading securities, held to maturity securities, or available-for-sale securities. At December 31, 2003 and 2002, the total investment balances were classified as held to maturity investments and are therefore recorded at amortized cost. (See Note 3).

Cash and Cash Equivalents - For purposes of reporting cash flows, the Cooperative considers all marketable securities with an original maturity of 90 days or less to be cash equivalents. The Cooperative maintains its cash in bank accounts, which, at times, may exceed federally insured limits. The Cooperative has not experienced any losses in such accounts.

Receivables - The Cooperative records its receivables at net realizable value. A bad debt reserve has been established for those accounts that management believes are probable of not being collectible in their entirety.

Inventories - Inventories, consisting of coal, and materials and supplies, are carried at the lower of cost or market. Unit prices are determined using average cost.

Deferred Debits – Deferred debits are recorded at cost and either: 1) amortized over their expected period of benefit or alternate period of time as may be mandated by ACC order, if different, or 2) eliminated upon determination of their ultimate disposition.

Unamortized Debt Costs – Costs incurred for the issuance or repricing of long-term debt are deferred and amortized over the life of the related debt (See Note 7).

Overhaul Costs - Minor overhaul costs are those costs associated with the maintenance of significant operating components of the generating units not including the turbine and generator and significant operating components related to the turbine and generator. Estimated minor overhaul costs are expensed in the year in which the overhaul occurs. Frequency of the overhauls is based on the operating characteristics and operating profiles of each generating unit. For baseload generating units, minor overhauls occur approximately every 24 months. For non-baseload generating units, minor overhauls occur between 12 and 60 months. (See Note 7).

Accrued Overhaul Expenses - Major overhaul costs are those costs that exceed the average cost of a minor overhaul and include costs that are associated with the maintenance of the turbine and generator and significant operating components related to the turbine and generator. Estimated major overhaul costs are accrued and expensed in advance of the actual maintenance. The amounts are accrued based on the operating hours or the number of starts depending on the operating characteristics and profiles of the generating units. Frequency of the overhauls is also based on the operating characteristics and operating profiles of each generating unit. (See Note 10). For baseload generating units, major overhauls occur approximately every 96 months. For non-baseload generating units, major overhauls occur between 24 and 96 months. Differences between the estimated and actual overhaul costs incurred are adjusted in the year determined.

Deferred Credits – Deferred credits are recorded at cost and either: 1) amortized over their expected period of benefit or alternate period of time as may be mandated by ACC order, if different, or 2) eliminated upon determination of their ultimate disposition.

Revenues - Revenues are recognized as power is delivered.

Fuel Costs - Purchased power and fuel costs are charged to expense as incurred. In the past, the Cooperative has periodically gone before the ACC to request a ruling on the disposition of its calculated under or over recovered fuel and purchased power costs (the "adjustor"), as the case may be. The latest ruling, dated March 27, 2002, authorized the recovery of $8,294,176 of under-collected fuel and purchased power expenses (See Note 5) and at the same time discontinued the adjustor as of July 31, 2001. The discontinuance of the fuel adjustor eliminates the regulatory authorization to record and/or reimburse or collect any over or under collected fuel or purchased power expenses incurred after July 31, 2001.

Use of Estimates - The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

3. Investments:

The Cooperative has a cash management program, which provides for the investment of cash balances in financial instruments. Investments at December 31, consist of the following:

	2003		
	Cost	Unrealized Gains	Fair Value
Restricted – Municipal bonds	**$ 2,808,481**	**$ 137,339**	**$ 2,947,820**
Restricted - Term certificates	**6,792,982**	**-**	**6,792,982**
Total	**$ 9,601,463**	**$ 137,339**	**$ 9,740,802**

	2002		
	Cost	Unrealized Gains/(Losses)	Fair Value
Restricted – Municipal bonds	$ 2,808,481	$ 47,874	$ 2,856,355
Restricted - Term certificates	5,022,869	-	5,022,869
Total	$ 7,831,350	$ 47,874	$ 7,879,224

Contractual maturities of investments at December 31, are as follows:

	2003		2002	
	Cost	Fair Value	Cost	Fair Value
Due in one year or less	$ -	$ -	$ -	$ -
Due from one year to five years	**1,929,150**	**1,929,150**		
Due from five years to ten years	**1,276,250**	**1,276,250**	1,276,250	1,276,250
Due after ten years	**6,396,063**	**6,535,402**	6,555,100	6,602,974

As a condition of National Rural Utilities Cooperative Finance Corporation's (CFC) guarantee of the Solid Waste Disposal Revenue Bonds (See Note 8), the Cooperative was required to purchase a non-interest bearing Debt Service Reserve Certificate (the "certificate") totaling $2,808,000 and maturing in 2024 upon final payment of the debt. The proceeds of the certificate, totaling 2,809,606 and $2,808,481 as of December 31, 2003 and 2002, are held by CFC in a Debt Service Reserve Fund (DSRF). The fair market value of the underlying investments in the DSRF totaled $2,947,820 and $2,856,355 as of December 31, 2003 and 2002, respectively. One of the underlying investments, totaling $2,762,250 and maturing in 2022, has a call feature exercisable by the issuer in 2008.

The Cooperative is a member of the CFC, a not-for-profit cooperative financing institution, owned and controlled by more than 1,000 rural electric member systems and their affiliates. As a condition of membership, the Cooperative was required to purchase Subscription Capital Term Certificates (SCTCs). The SCTCs, totaling $2,759,517 at December 31, 2003 and 2002, bear interest at 5 percent per annum and have maturity dates ranging from 2070 to 2080. As a condition of the Pollution Control Revenue Bonds and Solid Waste Disposal Revenue Bonds (See Note 8), which are guaranteed by the CFC, the Cooperative was required to purchase Subordinated Term Certificates (STCs). The STCs purchased in connection with the Solid Waste Disposal Revenue Bonds, totaling $813,000 and $936,000 at December 31, 2003 and 2002, respectively, bear interest at 7.6 percent per annum and mature in full in 2024 upon final repayment of the related debt. The STCs purchased in connection with the Pollution Control Revenue Refunding Bonds, totaling $1,276,000 at December 31, 2003 and 2002, bear interest at 5.9 percent and mature in 2008 upon final maturity of the related debt. As a condition of the long-term debt due to the CFC (See Note 8), the Cooperative was required to purchase Zero Term Certificates (ZTCs) and one STC. One of the ZTCs, totaling $15,065 and $51,352 as of December 31, 2003 and 2002, respectively, is non-interest bearing and matures in 2013. Three of the ZTCs, totaling $1,929,150 and $0 as of December 31, 2003 and 2002, respectively, bear interest at 3.2 percent per annum and mature in 2007. The STC purchased in connection with the debt due to the CFC matured in 2002 upon final payment of the related debt. The SCTCs, STCs, and ZTCs, are unrated, uncollateralized debt securities of the CFC.

4. Restricted Cash and Cash Equivalents:

Restricted cash and cash equivalents at December 31, consist of the following:

	2003	2002
California power sales collateral security (See Note 11)	**$ 2,500,000**	$ 2,500,000
Coal resourcing project (See Note 11)	**1,190,250**	1,190,250
Cushion of credit program	**482,866**	-
Other deposits on account	**403,769**	304,844
Total restricted cash and cash equivalents	**$ 4,576,885**	$ 3,995,094

Cushion of credit program: RUS has established a Cushion of Credit Payment Program, whereby borrowers may make advance payments on their RUS and Federal Financing Bank (FFB) notes (Notes). These advance payments earn interest at the rate of 5 percent per annum. The advance payments, plus any accrued interest, can only be used for the payment of principal and interest on the Notes.

5. Accounts Receivable:

Accounts receivable at December 31, consist of the following:

	2003	2002
Member energy sales	**$ 10,866,566**	$ 11,105,431
Accumulated net under-recovered fuel costs	**1,368,611**	5,417,107
Non-member energy sales (net of allowance for doubtful accounts of $1.9 million for 2003 and 2002)	**1,203,665**	1,118,503
Other	**2,303,504**	1,406,111
Total accounts receivable	**$ 15,742,346**	$ 19,047,152

Member energy sales: Member energy sales consist of sales to Members under their wholesale power sales contracts (See Note 11 – *Member Wholesale Power Sales Contracts*) and generally are not collateralized. Non-member energy sales consist of non-firm sales to unrelated electric utilities and are also generally not collateralized.

Accumulated net under-recovered fuel costs: In 2001, the ACC approved the recovery of an accumulated net under-recovery of fuel costs (See Note 2 – Fuel Costs). The balance of net under-recovered fuel costs is being collected from the Class A Members through a surcharge. Current estimates anticipate the balance to be recovered by July 2004.

6. Notes Receivable:

In 1998, the Cooperative was awarded a $400,000, Rural Utilities Service Rural Economic Development Grant. In accordance with grant guidelines, the initial loans made to qualifying recipients carry a zero interest rate and are repaid over a ten-year period. Loan repayments are required to be used to establish a revolving loan fund, which in turn, will be for the purpose of providing loans to foster rural economic development. Loans made from repayments of the initial loans may carry an interest rate. Notes receivable from the qualifying recipients totaled $300,465 and $348,122 as of December 31, 2003 and 2002, respectively.

7. Deferred Debits:

Deferred debits at December 31, consist of the following:

	2003	2002
Deferred contract costs	**$ 4,226,488**	$ 4,271,349
Unamortized debt costs	**684,284**	760,531
Redemption premium (See Note 8 - *Cooperative Utility Trusts*)	**266,121**	284,265
Other deferred debits	**430,412**	993,488
Total deferred debits	**$ 5,607,305**	$ 6,309,633

Deferred contract costs: The Cooperative entered into long-term power sales agreements that provide for the billing of certain overhaul costs after such costs have been paid. Deferred contract costs consist of accrued overhaul expenses (see Note 10 – *Accrued Overhaul Expenses*) that are not currently billable under the terms of these long-term power sales agreements.

8. Long-Term Debt:

Federal Financing Bank (FFB) - Long-term debt due the FFB is payable at interest rates based on long-term obligations of the United States Government as determined on the date of advance. Interest rates on existing FFB debt range from 4.7 percent to 9.1 percent and 5.0 percent to 9.1 percent for 2003 and 2002, respectively. Interest rates on the advances averaged 6.2 percent in 2003 and 2002. Equal quarterly principal and interest installments on these obligations extend through 2021. The obligations are guaranteed by the RUS. The Cooperative may prepay all outstanding notes by paying the principal amount plus the lesser of: 1) the difference between the outstanding principal balance of the loan being refinanced or the present value of the loan discounted at a rate equal to the current cost of funds to the Department of the Treasury for obligations of comparable maturity; 2) 100 percent of the amount of interest for one year on the outstanding principal balance of the loan being refinanced; or 3) present value of 100 percent of the amount of interest for one year on the outstanding principal balance of the loan.

Cooperative Utility Trust - The Cooperative issued a note, underlying a Certificate of Beneficial Interests (the Certificate), to a Cooperative Utility Trust. Principal on the note is due annually in installments ranging from $823,908 to $3,254,503 from 2004 to 2018. The interest rate on the note is 7.7 percent. Payments are made semi-annually. The note is guaranteed by the RUS. The Certificate is callable, only in whole, at any time on or after September 1, 2006, at redemption prices declining from an initial redemption price of 103.50 percent of par to 100 percent of par from and after September 1, 2013. The Certificate is also subject to prepayment at par at any time on or after September 1, 2006.

Solid Waste Disposal Revenue Bonds - The Cooperative has issued Guaranteed Solid Waste Disposal Revenue Bonds to finance the cost of solid waste disposal facilities. Principal is due in annual installments ranging from $471,960 to $1,483,304 from 2004 to 2024. Interest rates on the bonds are variable and are subject to revision semi-annually. The interest rate in effect as of December 31, 2003 and 2002 was 1.0 percent. The interest rate on the bonds averaged 1.2 percent and 1.9 percent in 2003 and 2002, respectively. Accrued interest is paid semi-annually. These bonds are guaranteed by the CFC. The Cooperative may redeem the bonds in whole or in part, subject to a premium of one-eighth of 1 percent of the principal amount.

Pollution Control Revenue Refunding Bonds - Principal payments on the Series 1997 Pollution Control Revenue Refunding Bonds are payable semi-annually through mandatory sinking fund payments ranging from $1,719,284 to $1,985,604 from 2004 through 2007. The interest rates in effect at December 31, 2003 ranged from 4.8 percent to 5.1 percent. The interest rate on the bonds averaged 4.9 percent in 2003 and 2002. Interest is paid semi-annually. These bonds are guaranteed by the CFC. The bonds are not subject to optional redemption prior to maturity.

Rural Utilities Service - Long-term debt due to the RUS consists of notes at interest rates of 2 percent and 5 percent for 2003 and 2002. The interest rate on the notes averaged 4.4 percent in 2003 and 2002. Quarterly principal and interest payments on these obligations extend through 2010. The Cooperative may prepay the notes at the lesser of the outstanding principal balance of the loan or the discounted present value. The discount rate is the rate specified in the *Treasury Constant Maturities* section of the weekly publication of the *Federal Reserve Statistical Release*.

Cooperative Finance Corporation - Long-term debt due to the CFC is payable at a variable interest rate that is established monthly and effective on the first day of each month. The interest rate in effect at December 31, 2003 was 2.6 percent. The interest rate on such borrowing averaged 2.7 percent and 4.0 percent in 2003 and 2002, respectively. Quarterly principal and interest payments on this obligation extend through 2013. This obligation is guaranteed by RUS. The variable interest rate on the debt is convertible to a fixed rate. The fixed rate would be equal to the rate of interest offered by CFC at the time of the conversion request. The Cooperative may prepay fixed rate notes in whole or in part, subject to a prepayment premium prescribed by CFC.

Maturities of long-term debt for the next five years are as follows:

2004	$ 15,801,553
2005	14,423,403
2006	15,308,436
2007	16,264,692
2008	15,117,242
Thereafter	138,586,880
Total	$215,502,206

Under covenants of the mortgage held by RUS and RUS general and pre-loan policies and procedures, the Cooperative must, among other things, obtain approvals from both the RUS and the CFC for certain transactions and contracts and design its rates with a view to maintaining, on an annual basis, an average times interest earned ratio of 1.05 and debt service coverage ratio of 1.0 calculated retrospectively using the highest ratios from two of the three most recent years. The average times interest earned ratios, calculated using the highest ratios from two of the three most recent years, were 1.66 for the years ended December 31, 2003 and 2002. The average debt service coverage ratios, calculated using the highest ratios from two of the three most recent years, were 1.25 for the years ended December 31, 2003 and 2002.

Long-term debt is collateralized by the pledge of all assets through the mortgage.

Components of interest expense at December 31, consist of the following:

	2003	2002
Total interest costs	**$ 12,295,388**	$ 12,919,900
Interest capitalized	**(68,585)**	(335,171)
Total interest expense	**$ 12,226,803**	$ 12,584,729

9. Member Advances:

Member investment program: The Cooperative offers all Members the ability to invest funds with the Cooperative on a short-term basis for periods of up to nine months. Interest rates offered on the notes (1 to 270 day maturity) are the rates announced by the Cooperative as its note participation program rates as of the date of the note. The Cooperative had recorded liabilities for notes of $1,834,000 and $4,978,804 at December 31, 2003 and 2002, respectively. The interest rate on these notes averaged 1.3 percent and 2.0 percent in 2003 and 2002, respectively. Interest expense on these notes was approximately $78,000 and $139,000 for the years ended December 31, 2003 and 2002, respectively.

Prepaid power program: The Cooperative also offers a program for all members whereby the members may make interest-bearing prepayments of their monthly power billings. The prepayment and accrued interest are applied to the members' power billings on the date such billings become due. The Cooperative recorded liabilities for prepayments of $695,176 and $10,300,000 at December 31, 2003 and 2002, respectively. The interest rate on these prepayments averaged 1.3 percent and 2.0 percent in 2003 and 2002, respectively. Interest expense on these prepayments was approximately $92,000 and $171,000 for the years ended December 31, 2003 and 2002, respectively.

Interest rates on the notes and prepayments, offered by the member investment program and prepaid power program, vary depending on the length of the maturity period selected by the Members. Interest rates offered to Members ranged from 1.0 percent to 1.4 percent and 1.2 percent to 1.6 percent at December 31, 2003 and 2002, respectively.

10. Deferred Credits:

Deferred credits at December 31, consist of the following:

	2003	2002
Customer advance payments	**$ 2,951,199**	$ 3,288,479
Accrued overhaul expenses	**6,013,325**	4,407,168
Postretirement benefit obligation (See Note 14 - *Postretirement Benefits*)	**323,800**	311,100
Other deferred credits	**588,467**	713,466
Total deferred credits	**$ 9,876,791**	$ 8,720,213

Customer advance payments: In 1987, the Cooperative entered into a long-term power sale agreement with a non-member customer for an initial term of twenty-five years. The customer made advance payments for demand charges under this agreement totaling $8,432,000. The advance payments are being amortized as revenue on a straight-line basis over the term of the agreement.

11. Commitments and Contingencies:

Member Wholesale Power Sales Contracts - The Cooperative holds wholesale power sales contracts with five of its six Class A Member Cooperatives pursuant to which each Class A Member Cooperative agrees to purchase from the Cooperative all of its electric power requirements to the extent that the Cooperative has such power available. In 2003, the expiration of the wholesale power contracts were extended from December 31, 2020 to December 31, 2035 and will remain in effect thereafter until terminated by either party upon six months notice. Management believes the Cooperative will be able to fulfill the requirements of these long-term contracts.

Partial Requirements Capacity and Energy Agreement – The Cooperative holds a wholesale power sales contract, expiring December 31, 2035, with one of its Class A Member Cooperatives pursuant to which the Class A Member has agreed to purchase from the Cooperative electric energy and capacity up to the member's allocated capacity in the Cooperative's total resources existing at the time of execution of the contract.

Wholesale Power Purchase Contracts - The Cooperative's current power supply includes hydroelectric power purchases from Western Area Power Administration ("Western"), a federal power marketing agency. Under the terms of its Salt Lake City Integrated Project (formerly Colorado River Storage Project) contract, which expires September 30, 2004, the Cooperative can receive up to 2.4 MW during October through March and 12.1 MW during April through September for service to its Class A Members. Effective October 1, 2004, the Salt Lake City Integrated Project may reduce the Cooperative's seasonal allocations by 7 percent to be used by Western for its redistribution of the available hydroelectric capacity to new preference customers. Additionally, under the terms of a contract with the Parker Davis Project , which expires September 30, 2008, the Cooperative receives 18.4 MW during October through February and 23.8 MW during March through September. The Cooperative had a summer season power purchase agreement with PacifiCorp, which expired on September 30, 2003, to purchase capacity ranging from 15 MW in 2002 to 25 MW in 2003. Beginning in 2003, the Cooperative has a summer season power purchase agreement with Panda Gila River, expiring on September 30, 2007, to purchase capacity ranging from 30 MW in 2003 to 85 MW in 2007. The Cooperative also has a power purchase agreement with the Public Service Company of New Mexico, expiring on December 31, 2008, to purchase capacity of 15 MW.

Network Service Agreement (Class A) – The Cooperative holds an agreement with SWTransco for network integration transmission service for delivery of its power sales to the Cooperative's five all-requirements Class A Members. This agreement remains in effect as long as any existing wholesale power contract between the Cooperative and any of the five members remains in effect.

AEPCO Bundled Transmission Service Agreements – The Cooperative holds agreements with SWTransco for both point-to-point and network integration transmission service for AEPCO's bundled power sales agreements. These agreements provide for reserved transmission capacity ranging from 8 MW to 100 MW. They remain in effect as determined by each service agreement.

Retail Electric Competition - Retail electric competition in Arizona continues to be stayed by developments from a number of fronts.

The ACC continued the slowdown it began in 2002 when it posed a number of questions on the issue and ordered a review of the ACC's electric competition rules (Rules). The Commission is proceeding on two paths, the first is to develop a viable competitive wholesale market through requiring the state's investor owned utilities to bid out a portion of their resource needs from competing wholesale suppliers. The second is to maintain the electric utilities' obligation to serve while thoroughly reviewing the Rules through an electric competition advisory group formed in 2003 for that purpose.

Although the Rules are still in place, there are no retail competition electric services being offered nor purchased in Arizona in spite of a number of service areas being open since 2001. The service areas of AEPCO's Class A member distribution cooperatives have not been opened to competition by the ACC and will not be until the ACC hears and decides those cooperatives' stranded cost cases.

In addition, the Arizona Court of Appeals, in January 2004, issued its decision on the lower court case brought successfully by the Cooperative and others challenging the jurisdictional, constitutional and statutory bases for the ACC Rules. The Court held a number of the Rules invalid, directed some stayed to be submitted for approval by the Arizona Attorney General, invalidated the Certificates of Convenience & Necessity (CC&Ns) issued by the ACC to all competitive suppliers, and required such suppliers to undergo rate and other regulatory review before doing business as competitive electric service providers in Arizona. It is unknown yet whether any party will appeal that decision. It is unknown what effect the ruling may have on the current Rules' review and the willingness of the Commissioners to go forward with retail electrical competition.

In the interim (and also in the event of such competition), the Cooperative will continue to provide electric power to its all and partial requirements members pursuant to long term contracts (now extended to December 31, 2035) for resale to their Standard Offer customers at regulated rates.

Since the Cooperative cannot currently determine the potential for electric competition and the affects of these various events and is currently recovering its costs of providing electric service from regulated rates charged to its members for power sold to Standard Offer customers, it continues to apply SFAS No. 71 to its operations.

California Power Sales -
Collateral Security – When the Cooperative entered into scheduling coordinator agreements with the California Independent System Operator Corporation (ISO) and California Power Exchange Corporation (CPX) in 2000 for the sale of energy into California, the ISO and CPX required the Cooperative to provide security in the form of irrevocable letters of credit to be drawn against in the event of default by the Cooperative.

The Cooperative continues to maintain two letters of credit, totaling $3,500,000, to the CPX as required by both the CPX bankruptcy court and the Federal Energy Regulatory Commission (FERC) even though the Cooperative as a seller was in the position of creditor to the CPX. The court deferred to FERC's decision on the collateral and FERC has ordered them kept in place until it decides whether and which sellers of energy into the California market must make refunds of monies received for those sales because of the dysfunctionality of the California energy market (California Refunds). The decision from FERC on this matter is not expected before August 2004. One letter of credit, totaling $2,500,000, was extended April 17, 2005. A second letter of credit, totaling $1,000,000, was extended to January 14, 2005. The interest rate on draws, if any were to be made on these letters of credit, will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2002 was 4.00 percent. No amounts were drawn on the letters of credit for the year ended December 31, 2003.

As a condition to issuing the $2,500,000 letter of credit, the Cooperative is required to maintain collateral security in the form of an investment in commercial paper for the duration of the term of the letter of credit. The balance of the investment in commercial paper, totaling $2,500,000 as of December 31, 2003 and 2002, is included in restricted cash and cash equivalents.

The core participants of the CPX were also required to provide an additional level of collateral security in the form of performance bonds executed by a surety on behalf of the core participants. The Cooperative in conjunction with the other core participants entered into an indemnity agreement with a surety for the issuance of performance bonds totaling $20,000,000. The Cooperative's indemnity to the surety is limited to only the amount of loss and expenses caused by the Cooperative's default as provided for in the agreement with the CPX. At this time, the CPX is in bankruptcy and no longer conducts transactions and the Cooperative withdrew as a core participant. The bonds were seized by the State of California in 2001 and the CPX is litigating their return on behalf of its creditor participants including the Cooperative.

Refund Liability – During 2000, the Cooperative was a participant of and sold power to both the CPX and ISO. In December 2000, two California utilities buying from the CPX, Southern California Edison (SCE) and Pacific Gas & Electric (PG&E), defaulted on their payments. The CPX tariff provided that in the event amounts owed to the CPX participants could not be paid due to an insufficiency of funds in the CPX clearing accounts, the CPX would allocate the shortage to the CPX participants using a charge-back methodology proportionate to the sales made by a participant. At the end of 2000, the Cooperative estimated that the potential exposure at that time resulting from the proportional charge-back of the shortfall ranged between the asserted claim of approximately $2,300,000 and $5,300,000, which included the estimated range of potential loss for unasserted claims of an amount up to $3,000,000. As a result, in 2000 the Cooperative accrued its best estimate of the associated obligation, totaling approximately $4,100,000, in its financial statements.

In early 2001, the charge-backs were challenged by a group of participant sellers in two separate proceedings before the Federal Energy Regulatory Commission (FERC) and the United States District Court, Southern District of California, arguing that the charge-backs provided in the tariff were never intended to apply in the instant situation involving the bankruptcy of both the CPX as well as PG&E. The District Court enjoined the CPX from enforcing the charge-back and required the CPX to place any funds paid because of it into escrow pending decision by the FERC. The FERC, in a decision not yet final and appealable, agreed with the participant sellers that the charge-back should not be used in this situation and has consolidated that matter (and requests for reconsideration concerning that decision) with the participant sellers' requests for release of the letters of credit (see above "Collateral Security" and other collateral held by the CPX with the California Refunds issues into one case. The FERC ordered reruns of all transactions in these matters to determine the amount of refunds to be made. The reruns are not expected to be completed until at least August 2004. In the interim, the majority of the sellers into the California market, including AEPCO, have appealed the FERC's early orders to the U.S. Court of Appeals, both in the Ninth and D.C. Circuits. The Cooperative's estimate of the maximum potential refund liability, using the least favorable set of proposed mitigated market clearing prices recently proposed by the ISO, approximates $9,300,000.

In 2001, SCE made payment of the amounts it owed to the CPX, which is holding the monies in escrow pending the FERC overall decision. As well, the PG&E bankruptcy case continues with a plan having been approved by the Court, which provides for repayment of the PG&E default. Any distribution under that plan also awaits the FERC decision.

Although the Cooperative cannot predict the outcome of these proceedings, the Cooperative continues to believe that the $4,100,000 previously accrued related to these matters, less related legal costs of approximately $660,000, is the best estimate of its probable loss associated with all these proceedings. In the event that the Cooperative's exposure to these matters is greater than currently estimated, the resulting refund could be material to the Cooperative's financial position, results of operations and cash flows.

Fuel Procurement Contracts

Coal Supply Agreements: To ensure an adequate fuel supply, the Cooperative enters into various long-term fuel contracts. Deliveries of coal under contracts in effect at December 31, 2003 provide for substantially all the Cooperative's coal requirements in the near term.

Rail Transportation Agreement: AEPCO's rail transportation contracts expired on December 31, 2000. Once it was evident new agreements could not be reached, the Cooperative became a railroad common carrier customer. As such, all the rights and duties of the Cooperative and the railroad are governed by tariffs. Believing the tariff rates unjust, the Cooperative in 2000 filed a complaint with the Surface Transportation Board (STB) seeking the establishment of reasonable rates and other terms for unit train coal transportation service. AEPCO has reached a partial settlement with one of the carriers for unit train coal transportation from some of the coal origins resulting in a contract for that service. AEPCO continues to seek a rate prescription from the STB regarding transportation from the remaining coal origins.

Coal Railcar Lease Agreements: To provide for the shipment of the coal supply, the Cooperative entered into lease agreements for the lease of coal railcar trainsets (See Note 15 – *Coal Railcar Trainsets*).

Coal Railcar Maintenance Agreement: The Cooperative entered into a ten-year railcar maintenance service agreement, effective December 17, 2002, for the maintenance of the coal railcar trainset leased under the twenty-year lease agreement (See Note 15 – *Coal Railcar Trainsets*). The agreement shall continue for successive twelve-month terms unless the agreement is cancelled or the last car covered by the agreement is released. The Cooperative has leased property at its generating station to the company performing the railcar maintenance. The term of the property lease coincides with the railcar maintenance agreement.

Personnel Staffing Agreement – The Cooperative has a personnel staffing agreement with Sierra, whereby Sierra provides personnel staffing services for all positions except certain key staff and management positions, who are employees of the Cooperative (See Note 18). The personnel staffing agreement provides that the Cooperative shall pay for the actual and verifiable costs incurred by Sierra for personnel, materials, supplies and all other direct, indirect and overhead costs incurred by Sierra in carrying out its responsibilities under the personnel staffing agreement. The term of the staffing agreement is for five years from August 1, 2001. The agreement is automatically extended for five successive years unless terminated by either party no later than two years prior to the conclusion of such fifth contract year.

Approximately 42% percent of the personnel employed by Sierra are subject to a collective bargaining agreement. Sierra entered into a three-year collective bargaining agreement, effective March 1, 2002.

Office Facilities and Machinery and Equipment Lease Agreements - The Cooperative entered into two separate 60 month lease agreements with Sierra and SWTransco, effective August 1, 2001, for the lease of the Cooperative's office facilities and substantially all of its non-generating machinery and equipment (See Note 18).

Coal Resourcing Project - In 1987, a coal resourcing project was implemented, whereby a coal mining arrangement with Carbon was terminated and the remaining assets and liabilities of Carbon were acquired by the Cooperative. The Cooperative continues to be responsible for reclamation costs under the coal resourcing project. The reclamation obligation remaining at December 31, 2003, is estimated to be $175,000. Reclamation costs approximated $245,000 and $267,000 for 2003 and 2002, respectively, and are included as a component of fuel expense (See Note 2 – Fuel Costs).

Also as part of the coal resourcing project, the Cooperative provided the State of New Mexico with a surety bond in the amount of $1,587,000 to ensure future reclamation work will be performed. As a condition of the surety bond, the Cooperative is required to provide collateral in the form of a cash deposit in a non-interest bearing escrow account. The cash deposit, totaling $1,190,250 as of December 31, 2003 and 2002, is included in restricted cash and cash equivalents on the consolidated balance sheets. The collateral will be released to the Cooperative after the New Mexico Minerals and Mining Division has fully released the Cooperative from the reclamation liability.

Lines of Credit –
Short-term financing: The Cooperative maintains a line of credit for short-term financing with the CFC of $12,000,000. The term of the agreement is for 12 months from August 20, 2003. The interest rate on all advances will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*" published n the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2003 was 4.00 percent. No amounts were drawn under the line of credit for the year ended December 31, 2003.

Company credit card program: The Cooperative also maintains a line of credit agreement with the CFC of $250,000 as part of its company credit card program. The term of the agreement is for 12 months from July 23, 2003. The agreement automatically renews for subsequent periods of 12 months. Interest rates on all advances under the line of credit will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2003 was 4.00 percent. No amounts were drawn under the line of credit for the year ended December 31, 2003.

12. Patronage Capital:

	2003	2002
January 1	**$ 13,904,668**	$ 4,606,612
Patronage capital allocation	**3,898,570**	9,298,056
Patronage capital retirement	**-**	-
December 31	**$ 17,803,238**	$ 13,904,668

Patronage capital allocation: In accordance with the Cooperative's by-laws, net margins are accounted for on a patronage basis in the following sequence:

1. Offset prior year's unallocated accumulated losses.
2. Assign to Members' accounts as credits based on specific excesses of revenues over operating costs and expenses.

Patronage capital retirement: RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative.

13. Income Tax Status:

For the years ended December 31, 2003 and 2002, the Cooperative qualified for tax-exempt status under Internal Revenue code section 501(c)(12), which requires that 85 percent or more of income consist of amounts collected from Members for the sole purpose of meeting losses and expenses.

14. Employee Benefit Plans:

Pension Plans - The Cooperative has a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service, age, retirement interest rate, and the employee's highest five years of compensation during the last ten years of employment. The Cooperative's policy has been to fund retirement costs annually as they accrue.

Pension benefits for substantially all employees are provided through participation in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program. The Cooperative contributes a percentage of salaried and union employees' earnings to the program, as prescribed by the NRECA. Contributions made to this plan approximated $128,000 and $108,000 for the years ended December 31, 2003 and 2002, respectively.

The Cooperative also offers participation in the NRECA Selectre Pension Plan to all employees meeting certain minimum service requirements. This plan has 401(k) salary deferral features. Under this plan, the Cooperative matches a percentage of the employees' contributions to the plan. The Cooperative's contributions to the plan approximated $41,000 and $36,000 for the years ended December 31, 2003 and 2002, respectively.

Postretirement Benefits - The Cooperative reports its postretirement benefits in accordance with SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." This statement requires that the Cooperative calculate and record the liability and related expense associated with providing postretirement benefits other than pensions.

The Cooperative has a contributory health care plan covering active employees and retirees under which retirees pay 100 percent of the average cost of benefits determined based on the combined experience of active employees and retirees. The incremental cost of heath care premiums, resulting from the inclusion of retirees' health care experience ratings with active employees' experience ratings, is viewed as a benefit earned through employment service, subject to accrual during the years an employee is working.

	2003	2002
Benefit obligation at January 1	**$ (311,100)**	$ (204,200)
Recognition of current year expense	**(12,700)**	(106,900)
Benefit obligation at December 31	**(323,800)**	(311,100)
Fair value of plan assets at December 31	**0**	0
Funded status	**$ (323,800)**	$ (311,100)

Assumptions: The accumulated postretirement benefit obligation was determined using a 7 percent discount rate. A health care cost trend rate of 9 percent was assumed for 2001, decreasing to 5 percent by 2010 and remaining at 5 percent thereafter. A one percent increase in the health care trend cost would result in a $12,400 increase in the accumulated postretirement benefit obligation and a $17,800 increase in the expected postretirement benefit obligation.

15. Operating Leases:

Commercial Office Building: In 1999, the Cooperative entered into a non-cancellable lease agreement for the lease of a commercial office building (office lease). The initial lease term is for a period of ten years and has a renewal option to extend the term of the lease for an additional five years. The Cooperative has sub-leased the building to Sierra and other tenants. The term of the lease with Sierra is for 89.5 months commencing on August 1, 2001. Rental income received from the sublease of the commercial office building was approximately $211,000 and $203,000 for 2003 and 2002, respectively.

The following summarizes the future minimum sub-lease income under leases that had initial or remaining non-cancelable lease terms in excess of one year at December 31, 2003:

Fiscal Year	Leases
2004	$209,810
2005	98,701
2006	91,287
2007	88,691
2008	88,691
Thereafter	0
Total	$577,180

Computer Equipment: The Cooperative entered into a master lease agreement for the lease of substantially all the Cooperative's personal computers and peripheral equipment. Individual certificates of acceptance (COAs), underlying the master lease agreement, were entered into as groups of computers and equipment were delivered. The terms of the COAs are for three years from the first day of the month subsequent to the delivery of equipment under the COA.

Rent expense for the lease of the commercial office building and computer equipment was approximately $702,000 and $785,000 for the years ended December 31, 2003 and 2002, respectively, and is included in administration and general on the statements of revenues and expenses.

Coal Railcar Trainsets: The Cooperative entered into lease agreements for the lease of coal railcar trainsets. Lease payments are included as a component of fuel expense (See Note 2 – *Fuel Costs*). At December 31, 2003, these lease agreements consist of:

- A twenty-year lease agreement, effective December 17, 2002. Lease payments under this agreement totaled approximately $400,000 and $538,000 for 2003 and 2002, respectively. The Cooperative has the option of canceling this agreement effective December 31, 2012 subject to the following: 1) the Cooperative notifies the lessor in writing on or before 180 days prior to the effective date of the termination, and 2) the Cooperative pays an additional amount of $5,971 per car for each car terminated.
- A sixty-month lease agreement, effective January 1, 2004. Lease payments under this agreement totaled approximately $94,800 for 2003.
- A twelve-month lease agreement, effective January 1, 2003. This lease provides for the periodic use of a coal railcar trainset. Lease payments under this agreement totaled approximately $16,000 for 2003.

The following summarizes the future minimum lease payments under operating leases that had initial or remaining non-cancelable lease terms in excess of one year at December 31, 2003:

Fiscal Year	Leases
2004	$ 1,403,520
2005	1,285,315
2006	1,218,453
2007	1,184,600
2008	1,137,200
Thereafter	5,594,400
Total	$11,823,488

16. Concentration of Customers and Credit Risk:

Revenue for the year ended December 31, 2003 included revenue from four customers, whom each individually represented more than 10 percent of the total operating revenue. Revenue from these customers collectively represented approximately 72 percent of total operating revenue for 2003. Accounts receivable at December 31, 2003 included amounts owed from four customers, whom each individually represented 10 percent of the total accounts receivable balance. The amounts owed from these customers collectively represented approximately 64 percent of the total accounts receivable balance at December 31, 2003.

Revenue for the year ended December 31, 2002 included revenue from four customers, whom each individually represented more than 10 percent of the total operating revenue. Revenue from these customers collectively represented approximately 66 percent of total operating revenue for 2002. Accounts receivable at December 31, 2002 included amounts owed from four customers, whom each individually represented 10 percent of the total accounts receivable balance. The amounts owed from these customers collectively represented approximately 51 percent of the total accounts receivable balance at December 31, 2002.

17. Fair Value of Financial Instruments:

Many of the Cooperative's financial instruments lack an available trading market as characterized by a willing buyer and willing seller engaged in an exchange transaction. The Cooperative's general practice and intent is to hold its financial instruments to maturity and not to engage in trading or sales activities. As a result, significant estimations and present value calculations are used by the Cooperative for purposes of disclosure.

Estimated fair values are determined by the Cooperative using the best available data and an estimation methodology suitable for each category of financial instruments. For those financial instruments, which mature or reprice within 90 days, the carrying amounts approximate fair value.

The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value:

a. *Cash and Cash Equivalents* - For cash and cash equivalents, cost is a reasonable estimate of fair value.
b. *Investments* - For all investments, except for capital term certificates, which are carried at cost as fair market value is not readily determinable, fair value is estimated based on quoted or market prices for those similar investments.
c. *Member Advances* - For Member advances, the carrying value (cost plus accrued interest) of advances with maturities of 90 days or less approximates the fair value. The fair value of advances with maturities greater than 90 days are estimated by recalculating the redemption value at December 31 using the rate, offered by the Cooperative on the original purchase date, for investments that would have a maturity date of December 31.
d. *Long-Term Debt* - The fair value of the Cooperative's long-term debt is estimated by discounting the future cash flows required under the terms of each respective debt agreement by the currently quoted or offered rates for the same or similar issues of debt with similar maturities. The principal amounts of variable rate debt outstanding at December 31, 2003 and 2002, of the Solid Waste Disposal Revenue Bonds and Cooperative Finance Corporation long-term debt are considered reasonable estimates of their fair value, as these are variable interest rate liabilities.

The estimated fair values of the Cooperative's financial instruments at December 31, consist of the following:

	2003	
	Carrying Value	**Fair Value**
Investments and Other Property:		
Restricted held to maturity investments	**$ 9,601,463**	**$ 9,740,803**
Long-Term Debt:		
(including current maturities):		
Federal Financing Bank	**117,122,303**	**116,994,000**
Cooperative utility trust	**27,304,914**	**28,437,403**
Pollution control revenue bonds	**7,392,918**	**7,887,363**
Solid waste disposal revenue bonds	**17,867,061**	**17,867,061**
Rural Utilities Service	**4,851,102**	**5,056,538**
Cooperative Finance Corporation	**40,963,908**	**40,963,908**
Current Liabilities:		
Member advances	**2,529,176**	**2,529,582**

	2002	
	Carrying Value	Fair Value
Investments and Other Property:		
Restricted held to maturity investments	$ 7,831,350	$ 7,879,224
Long-Term Debt:		
(including current maturities):		
Federal Financing Bank	123,605,087	138,639,411
Cooperative utility trust	28,151,070	26,916,830
Pollution control revenue bonds	9,034,665	9,668,826
Solid waste disposal revenue bonds	18,271,598	18,271,598
Rural Utilities Service	5,662,114	5,892,430
Cooperative Finance Corporation	25,693,471	25,693,471
Current Liabilities:		
Member advances	15,278,804	15,278,804

18. Related Parties:

The Cooperative is a class B member of Sierra and SWTransco. Class B members of Sierra are collectively represented by one director seated on Sierra's board of directors. Class B members of SWTransco are also collectively represented by one director seated on SWTransco's board of directors. Directors for both SWTransco and Sierra are entitled to one vote on each matter submitted to a vote at a meeting of the members.

The Cooperative has entered into an agreement with Sierra, whereby Sierra provides personnel staffing services (See Note 11 – *Personnel Staffing Agreement*). For 2003 and 2002, the Cooperative recorded expenses for personnel staffing services from Sierra totaling approximately $17,225,000 and $16,923,000, respectively.

The Cooperative has entered into lease agreements with SWTransco and Sierra for the lease of Office Facilities and Machinery and Equipment (See Note 11 - *Office Facilities and Machinery and Equipment Lease Agreements*). For 2003, rents received by the Cooperative from SWTransco and Sierra totaled approximately $839,000 and $1,435,000, respectively. For 2002, rents received by the Cooperative from SWTransco and Sierra totaled approximately $839,000 and $1,431,000, respectively.

The Cooperative has also entered into agreements with SWTransco for transmission service (See Note 11 - *Network Service Agreements (Class A and Class B), and AEPCO Bundled Transmission Service Agreements)*. For 2003 and 2002, the Cooperative recorded transmission expenses from these agreements totaling approximately $16,868,000 and $15,519,000, respectively.

As of December 31, 2003, the Cooperative had recorded accounts payable to SWTransco totaling approximately $1,175,000 and accounts receivable from Sierra totaling approximately $456,000. As of December 31, 2002, the Cooperative had recorded accounts payable to SWTransco totaling approximately $1,124,000 and accounts receivable from Sierra totaling approximately $27,000.

19. Asset Retirement Obligations:

Effective January 1, 2003, the Cooperative adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 sets forth accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. An asset retirement obligation (ARO) associated with long-lived assets included within the scope of SFAS No. 143 is that for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Under the statement, these liabilities are recognized as incurred if a reasonable estimate of fair value can be established and are capitalized as part of the cost of the related tangible long-lived assets. The increase in the ARO due to the passage of time (accretion expense) is an operating expense. Upon adoption of SFAS No. 143, the Cooperative recorded the cumulative effect of the accounting change, totaling $3,810,335, in the consolidated statements of revenues and expenses and unallocated accumulated margins. The Cooperative also recognized the present value of its projected asset retirement costs, totaling $1,962,630, as a component of its capitalized utility plant on the consolidated balance sheets. Subsequently, the Cooperative recognized accretion of the liability, totaling $185,802, as a component of interest expense and depreciation of the asset retirement cost, totaling $69,445, as depreciation expense in the consolidated statements of revenues and expenses and unallocated accumulated margins. The net asset retirement obligation as of January 1, 2003, the date of the adoption, and December 31, 2003, and the changes in the net liability for the twelve months ended December 31, 2003, were as follows:

Liability at January 1, 2003	**$ 4,381,198**
Accretion expense in 2003	**185,802**
Liabilities incurred	**5,762**
Liability at December 31, 2003	**$ 4,572,762**

End of Audited Financial Statements.

PENGAD-Bayonne, N.J.
EXHIBIT
SWTC-5
ADMITTED

DIRECT TESTIMONY OF

WILLIAM K. EDWARDS

BEFORE THE

ARIZONA CORPORATION COMMISSION

ON BEHALF OF

SOUTHWEST TRANSMISSION COOPERATIVE, INC.

Q. What is your name and business address?

A. My name is William K. Edwards. My business address is 2201 Cooperative Way, Herndon, Virginia, 20171.

Q. By whom are you employed, and in what capacity?

A. I am employed by the National Rural Utilities Cooperative Finance Corporation ("CFC") as an economist and Vice President of Regulatory Affairs. In that capacity, I am responsible for testifying about and advising on regulatory issues of cooperatives before the FERC and many state commissions.

Q. What is your educational background and experience?

A. I received my B.S. Degree in Business with a concentration in economics from Christopher Newport College of the College of William & Mary in 1977, and

an M.A. degree in Economics from Old Dominion University in 1979. My major fields of study included mathematical economics, econometrics and microeconomics. I have completed a number of courses toward a Ph.D. in Economics from the Virginia Polytechnic Institute & State University. I have worked for the firm of Ernst & Ernst as a consultant principally in the electric utility industry. From 1982 to 1985, I was employed by Mississippi Power & Light Company (Entergy - Mississippi) as a supervisor responsible for rate research. From January 1986 until early 1995, I was employed by Central Louisiana Electric Company, Inc. as Manager of Rate Research and subsequently as Director of Rates. In that capacity I was responsible for regulatory affairs, regulatory accounting, rate design, cost of service studies, rate administration and the attendant litigation associated with regulatory issues before both the Louisiana Public Service Commission and the Federal Energy Regulatory Commission. Since 1996, I have been employed by CFC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support Southwest Transmission Cooperative, Inc.'s ("SW-Trans") request for a Debt Service Coverage Ratio ("DSCR") of 1.15 and a Times Interest Earned Ratio ("TIER") of 1.11.

THE ROLE OF CFC

Q. What is CFC?

A. CFC was incorporated as a private, not-for-profit cooperative association under the laws of the District of Columbia in April 1969. The principal purpose of CFC is to provide its members with a dependable source of low-cost capital and state-of-the-art financial products and services. CFC provides its members with a source of financing to supplement the loan programs of the Rural Utilities Service ("RUS") of the United States Department of Agriculture, which is the successor agency of the Rural Electrification Administration. CFC is owned by and makes loans primarily to its rural utility system members to enable them to acquire, construct and operate electric distribution, generation, transmission and related facilities. CFC also provides guarantees on debt to its members for tax-exempt financings of pollution control facilities and other properties constructed or acquired by its members, debt in connection with certain leases and various other transactions.

CFC had 1,546 members as of February 29, 2004, including 898 electric utility members, virtually all of whom are consumer-owned cooperatives. The utility members included 827 distribution systems and 71 generation and transmission ("power supply") systems operating in 49 states and four U.S. territories.

Q. How does CFC obtain the funds it lends to cooperative utilities?

A. CFC functions as both a borrower and a lender. As a lender, CFC makes short-, medium- and long-term loans to its member systems. As security for its long-term loans, CFC receives a first mortgage on its borrowers' facilities. These mortgages and related mortgage notes are in turn used as security for CFC collateral trust bonds issued in the public capital market. Through the sale of such bonds, as well as commercial paper and other debt instruments, CFC obtains capital on behalf of its member borrowers. In this role, CFC acts as a borrower.

CFC issues long-, medium- and short-term debt in both the domestic and foreign capital markets. CFC issues long-term secured collateral trust bonds, unsecured medium-term notes, unsecured quarterly income capital securities and unsecured commercial paper. CFC's collateral trust bonds, medium-term notes, quarterly income capital securities and commercial paper all carry investment grade ratings from three rating agencies (Standard & Poors, Moodys and Fitch).

CFC also sells unsecured commercial paper and medium-term notes to its members. In addition, members may invest in the daily liquidity program, which can be withdrawn by the members on demand.

Consequently, CFC has a great interest in rate of return issues, including but not limited to, the appropriate DSCR and TIER ratio, equity management and the associated issue of return on equity.

Q. Is SW-Trans a member of CFC?

A. Yes. SW-Trans is a member of CFC and has long-term loans with CFC as of December 31, 2003 totaling $806,515 concurrent with the RUS.

Q. In what ways does SW-Trans differ from an investor-owned utility?

A. The main difference between an investor-owned utility and an electric cooperative is the form of ownership. In the investor-owned utility, stockholders own the equity of the utility and ratepayers (the customers) are not entitled to the benefits of equity holders. Investor-owned utilities typically have a Board of Directors separate from the customers of the utility. Therefore, there is an implicit conflict associated with investor-owned utilities; the interests of the equity owners are different from the interests of the customers. In the past, vertically integrated electric utilities were regarded as a monopoly whose goal was to maximize profits to the stockholders at the expense of its customers. As such, both State and Federal governments instituted rate regulation to control such behavior.

In a cooperative, the customers own the equity. Hence, the benefits of being an equity holder belong to the customer. There are a number of benefits that accrue to customers of cooperative organizations including a return of excess margins and, all things being equal, lower cost electricity. In a cooperative, the Board of

Directors is comprised of customers that are democratically elected. As such, the conflict present with investor-owned utilities is not present with cooperative structures because the customers, the decision-makers and equity owners are the same people. As Mr. Minson has discussed in his testimony, this rate increase request has already faced the scrutiny of SW-Trans' Board of Directors and its Members who are themselves customers and who represent the interests of other equity owners.

Although aware of the differences, sometimes regulators forget that, as a result of the cooperative structure, there is no incentive to maximize prices or otherwise charge a profit on sales to its members. Additionally, should customers of cooperatives become convinced that a specific rate increase or other action is unnecessary or unwise, they have their remedy of representational rights before the Board of Directors.

Q. In what ways does SW-Trans differ from generation and transmission ("G&T") companies?

A. SW-Trans is a non-profit electric transmission only cooperative, which provides electric transmission and ancillary services to its members. SW-Trans owns and operates transmission assets. Most G&T's as well as many investor-owned utilities operate an integrated generation and transmission system for the benefit of their customers and owners. The effect of the unbundled nature of these

assets on the TIER (and DSCR ratios) is that there is likely a difference in risk associated with the operation of generation assets compared to transmission assets.

Although regulatory policies on competition remain unsettled, transmission is envisioned by most people to remain a monopoly service. Therefore, a transmission company like SW-Trans is anticipated to have somewhat less risk than a comparable generation company may have. The result is that the TIER requirements for a transmission company may be slightly less than a generation company, all other things being equal. On the other hand, SW-Trans was only recently formed, has a small amount of equity and operates with thin margins. This increases risk and makes it particularly vulnerable to even small changes in revenues and operating expenses.

Q. What are some of the specific criteria that creditors like CFC use to evaluate the credit worthiness of cooperative utilities like SW-Trans?

A. With the onset of electric deregulation in the mid-1990s as well as other more subtle changes to the utility industry, CFC has re-evaluated its lending policies in an attempt to better manage its portfolio. The revisiting of lending policies is a continuing process to challenge CFC in its efforts to provide low-cost capital to its members. Although the credit decisions relating to specific

applicants are "fact specific" decisions, there are company specific criteria that are considered by CFC prior to it issuing credit.

In evaluating the credit quality of cooperative utilities like SW-Trans, CFC continues to focus on several key factors: management, rates, generation and distribution facilities, regulation, demographics, financial performance and legal provisions.

With respect to financial evaluations, CFC has devised a list of key financial ratios that are used to supplement its credit decisions. The "G&T Trend Analysis" provides a generalized and quick method for credit analysts to preliminarily evaluate a G&T cooperative.

Table 1 below illustrates the more key parameters for SW-Trans over the past two years.

Table 1
Key Ratios

Year	TIER	DSC	Equity Ratio[1]
2002	1.10	1.10	2.39%
2003	1.49	1.23	4.34%

Although 2003 was a fairly strong actual performance year for SW-Trans, on an adjusted basis its TIER and DSCR fall to only 0.44 and 0.79, respectively. Comparing these results to a pool of 55 G&T's nationwide in 2002 (the last year collective data is available), they are significantly below the 1.29 TIER

[1] Total Equity/Total Assets.

and 0.97 DSCR pool average. Also, SW-Trans' equity of 4.34% is less than one-third of the 13.22% pool average. Obviously, SW-Trans' financial posture is tenuous and that emphasizes the need for prompt and adequate rate relief.

Q. Please explain the importance to a rural electric cooperative of developing and maintaining an adequate equity level.

A. Congress established the Rural Electric Administration in 1936 to provide funding for electric cooperatives to extend their lines and make central station power available in rural areas. Under the original Act, the government provided 100% financing and the need for equity capital was not required.

In 1973, Congress amended the Rural Electrification Act. It established the rural electric revolving fund and required rural electrics to borrow a portion of their long-term capital needs from supplemental sources. Because private capital (like CFC) was now required, it was necessary to establish financial standards in order to access affordable funding from the competitive capital markets.

Q. Is equity an important consideration in securing private source capital?

A. Yes. CFC works closely with all its borrowers to assist them in building an appropriate equity level in order to achieve a capital structure that will allow

them to attract private capital. CFC makes recommendations designed to manage equity in order to continue to have access to reasonably priced private capital.

Q. Does CFC have an interest in the amount of equity that SW-Trans maintains?

A. Yes. CFC is vitally interested in SW-Trans' capitalization as well as every other cooperative that seeks financing from CFC. This interest is on an individual as well as a collective basis since the overall position of the borrowers like SW-Trans as a group is what CFC proffers to the market. The industry's equity ratios affect the attitudes of investors in CFC securities. Should the overall equity position of electric cooperative utilities change, investors can be expected to react toward CFC securities, as they would towards the securities of an investor-owned utility. If the overall equity ratio of electric cooperatives declines, the investors would perceive an increase in risk and would demand a higher risk premium associated with the cost of debt.

Q. How Does SW-Trans' equity ratio compare to other cooperatives?

A. At the end of the 2003 test year, the equity ratio of total capitalization was approximately 4.34%. At December 31, 2002, the equity ratio was 2.39%. By contrast, G&T cooperatives had a median equity ratio at the end of 2002 of 13.22%.

Q. Why is it important for SW-Trans to develop a stronger equity base?

A. The lower the equity ratio, the higher the annual charges for interest expense and the greater the margin requirements to maintain an adequate DSCR and TIER. As the blended cost of long-term debt rises, the requirements to achieve adequate operating ratios will become more difficult unless the equity ratio is increased.

For this reason, I support both SW-Trans and this Commission's efforts to establish long-range goals for SW-Trans equity (Decision No. 64991). Prompt and adequate action on this rate request will help SW-Trans advance toward those goals.

Q. What is your recommendation for appropriate DSCR and TIER ratios at this time for SW-Trans?

A. SW-Trans is requesting a TIER and DSCR ratio of 1.15 and 1.11, respectively. In my opinion, these are minimum ratios to provide some financial stability and modest progress toward equity goals.

Q. Will the requested DSCR and TIER in this case provide SW-Trans with comparable security required by creditors?

A. Both will allow SW-Trans to make progress toward improved financial strength, although it has a long way to go. For example, Table 2 illustrates Standard & Poor's ("S&P's") median equity ratios and operating TIER requirements for utilities by financial rating of senior debt.

Table 2
S&P Median Values of
Utility Financial Ratings

Rating	Equity Ratio	Operating TIER
AA	50.3%	4.2
A	43.5%	3.0
BBB	37.4%	2.1
BB	34.6%	1.2

S&P rates senior debt beginning with the rating "AAA." An AAA rated utility has the highest rating assigned by S&P. The obligor's capacity to meet its financial commitment on its debt is extremely strong. In contrast, ratings of "BB" and below are regarded as having significant speculative characteristics. Presently, the proposed operating TIER of 1.15 places SW-Trans below investment grade, while the present equity ratio, of course, is far below any of the ratings.

Q. Would the proposed 1.15 TIER and 1.11 DSCR ratios allow SW-Trans to borrow money from CFC and RUS?

A. I believe it would qualify for lending by both organizations.

1

2 Q. Does this conclude your testimony?

3 A. Yes, it does.

4

5 1204179/15169-6

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A RATE INCREASE.	DOCKET NO. E-01773A-04-0528
IN THE MATTER OF THE APPLICATION OF SOUTHWEST TRANSMISSION COOPERATIVE, INC. FOR A RATE INCREASE.	DOCKET NO. E-04100A-04-0527 **NOTICE OF FILING REBUTTAL TESTIMONY**

In relation to the Arizona Electric Power Cooperative, Inc. ("AEPCO") rate matter, AEPCO has filed the rebuttal testimony of Messrs. Dirk Minson and Gary E. Pierson.

In relation to the Southwest Transmission Cooperative, Inc. ("SWTC") rate matter, SWTC has filed the rebuttal testimony of Messrs. Dirk Minson and Gary E. Pierson.

RESPECTFULLY SUBMITTED this 16th day of March, 2005.

GALLAGHER & KENNEDY, P.A.

By [signature]
Michael M. Grant
Todd C. Wiley
2575 East Camelback Road
Phoenix, Arizona 85016-9225
Attorneys for AEPCO and SWTC

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Original and fifteen copies filed this 16th day of March, 2005, with:

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Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Copy of the foregoing delivered this 16th day of March, 2005, to:

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Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Two copies of the foregoing delivered this 16th day of March, 2005, to:

Chairman Jeff Hatch-Miller
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Commissioner William A. Mundell
Arizona Corporation Commission
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10421-36/15169-6/1257893

Southwest Transmission Cooperative, Inc.
Docket No. E-04100A-04-0527
Test Year Ended December 31, 2003

Exhibit GEP-12

EXHIBIT
SWTC-6
ADMITTED
PENGAD-Bayonne, N.J.

REVENUE REQUIREMENT - COMPANY REJOINDER POSITION

LINE NO.	DESCRIPTION	[A] STAFF SURREBUTTAL POSITION PHASE 1	[B] STAFF SURREBUTTAL POSITION PHASE 2	[C] COMPANY REJOINDER POSITION PHASE 3	[D] COMPANY REJOINDER POSITION PHASE 4
1	Adjusted Operating Income (Loss)	$ 2,480,064	$ 185,604	$ 185,604	$ 185,604
2	Depreciation and Amortization	$ 4,144,985	$ 4,144,985	$ 4,144,985	$ 4,144,985
3	Income Tax Expense	-	-	-	-
4	Interest Expense on Long-term Debt	$ 5,302,088	$ 5,302,088	$ 5,302,088	$ 5,302,088
5	Principal Repayment	$ 7,358,610	$ 7,358,610	$ 7,358,610	$ 7,358,610
6	Recommended Increase in Operating Revenue	$ 3,666,668	$ 5,961,128	$ 342,806	$ 342,806
7	Percent Increase (Line 6 / Line 10)	14.58%	26.08%	1.50%	1.50%
8	Network Service and Other Revenue	$ 25,148,196	$ 22,853,736	$ 22,853,736	$ 22,853,736
9	Regulatory Asset Charge ("RAC")	$ -	$ -	$ -	$ -
10	Adjusted Test Year Operating Revenue	$ 25,148,196	$ 22,853,736	$ 22,853,736	$ 22,853,736
11	Total Annual Operating Revenue	$ 28,814,864	$ 28,814,864	$ 29,157,670	$ 29,500,476
12	Margins Before Interest on Long Term Debt	$ 6,146,732	$ 6,146,732	$ 6,489,538	$ 6,832,344
13	Net Margin	$ 893,486	$ 893,486	$ 955,420	$ 1,579,098
14a	Regulatory Asset Charges:				
14b	Normalized RAC Revenue	$ 2,559,926	$ 2,559,926	$ 2,559,926	$ 2,559,926
14c	Normalized RAC Expense	$ 2,559,926	$ 2,559,926	$ 2,559,926	$ 2,559,926
14d	Net Normalized RAC Margin	$ -	$ -	$ -	$ -
15	Total Operating Revenue and RAC Margins	$ 6,146,732	$ 6,146,732	$ 6,489,538	$ 6,832,344
16	Staff Operating TIER (L3+L12+L14b) / L4	1.16	1.16	1.22	1.29
17	Staff Operating DSC (L2+L3+L12+14b)/(L4+L5)	1.02	1.02	1.04	1.07
18	Adjusted Rate Base	$ 76,345,655	$ 76,345,655	$ 76,345,655	$ 76,345,655
19	Rate of Return (L12 / L20)	8.05%	8.05%	8.50%	8.95%

References:
Column [A]: Surrebuttal Schedule CSB-1
Column [B]: Crystal Brown Surrebuttal Testimony
Column [C] Gary Pierson Rejoinder Testimony
Column [D] Gary Pierson Rejoinder Testimony

Southwest Transmission Cooperative, Inc.

Docket No. E-01773A-04-0527

Test Year Ended December 31, 2003

Exhibit GEP-13

SUMMARY OF PROPOSED RATES - COMPANY REJOINDER POSITION

Line No.	Description	[A] Staff Surrebuttal Position Phase 1	[B] Staff Surrebuttal Position Phase 2	[C] Company Rejoinder Position Phase 1	[D] Company Rejoinder Position Phase 2	[E] Company Rejoinder Position Phase 3	[F] Company Rejoinder Position Phase 4
	Proposed Effective Dates (1)			July 1, 2005	January 1, 2006	July 1, 2006	July 1, 2007
1	Network Transmission Service:						
2	Transmission Rate - $/Month	$ 1,420,722	$1,566,081	$ 1,420,722	$ 1,566,081	$ 1,587,088	$1,608,258
3	Ancillary Services:						
4	Schedule 1: System Control and Load Dispatch - $/kW Mon.	$ 0.289	$ 0.289	$ 0.289	$ 0.289	$ 0.289	$ 0.289
5	Schedule 2: Cost of Reactive Power (VAR) Production - $/kW Mon.	$ 0.090	$ 0.100	$ 0.095	$ 0.107	$ 0.113	$ 0.120
6	Schedule 3: Regulation and Frequency Response - $/kW Mon.	$ 0.444	$ 0.444	$ 0.452	$ 0.452	$ 0.461	$ 0.471
7	Schedule 4: Energy Imbalance - $/MWh	$ 20.40	$ 20.40	$ 20.40	$ 20.40	$ 20.40	$ 20.40
8	Schedule 5: Operating Reserves - Spinning - $/kW Mon.	$ 0.671	$ 0.671	$ 0.683	$ 0.683	$ 0.697	$ 0.711
9	Schedule 6: Operating Reserves - Supplemental - $/kW Mon.	$ 0.433	$ 0.433	$ 0.441	$ 0.441	$ 0.450	$ 0.459
10							
	Point-to-Point						
11	Firm Point-to-Point Rate - $/ kW Month	$ 3.022	$ 3.334	$ 3.022	$ 3.334	$ 3.379	$ 3.423
12	Non-Firm Point-to-Point Rate - $/ kW Month	$ 3.022	$ 3.334	$ 3.022	$ 3.334	$ 3.379	$ 3.423
13	Ancillary Services:						
14	Schedule 1: System Control and Load Dispatch - $/kW Mon.	$ 0.289	$ 0.289	$ 0.289	$ 0.289	$ 0.289	$ 0.289
15	Schedule 2: Cost of Reactive Power (VAR) Production - $/kW Mon.	$ 0.072	$ 0.078	$ 0.076	$ 0.083	$ 0.089	$ 0.094
16	Schedule 3: Regulation and Frequency Response - $/kW Mon.	$ 0.444	$ 0.444	$ 0.452	$ 0.452	$ 0.461	$ 0.471
17	Schedule 4: Energy Imbalance - $/MWh	$ 20.40	$ 20.40	$ 20.40	$ 20.40	$ 20.40	$ 20.40
18	Schedule 5: Operating Reserves - Spinning - $/kW Mon.	$ 0.671	$ 0.671	$ 0.683	$ 0.683	$ 0.697	$ 0.711
19	Schedule 6: Operating Reserves - Supplemental - $/kW Mon.	$ 0.433	$ 0.433	$ 0.441	$ 0.441	$ 0.450	$ 0.459

(1) Proposed effective dates are based upon the assumption that the Commission will act upon the proposed Order in this proceeding at the June 2005 Open Meeting.

References:

Column [A] - Erin Casper Surrebuttal Testimony

Column [B] - Erin Casper Surrebuttal Testimony

Column [C] - Gary Pierson Rejoinder Testimony

Column [D] - Gary Pierson Rejoinder Testimony

References:

Column [E] - Gary Pierson Rejoinder Testimony

Column [F] - Gary Pierson Rejoinder Testimony