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BEFORE THE ARIZONA CORPORATION COMMISSION

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1 JEFF HATCH-MILLER

Chairman

2 WILLIAM A. MUNDELL

Commissioner

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Commissioner

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Commissioner

5 KRISTIN K. MAYES

Commissioner

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AZ CORP COMMISSION  
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Arizona Corporation Commission  
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FEB 23 2005

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8 IN THE MATTER OF THE APPLICATION  
9 OF ARIZONA ELECTRIC POWER  
10 COOPERATIVE, INC. FOR A RATE  
11 INCREASE

DOCKET NO.E-01773A-04-0528

11 IN THE MATTER OF THE APPLICATION  
12 OF SOUTHWEST TRANSMISSION  
13 COOPERATIVE, INC. FOR A RATE  
14 INCREASE.

DOCKET NO. E-04100A-04-0527

NOTICE OF FILING  
DIRECT TESTIMONY

14 In regard to Arizona Electric Power Cooperative, Inc., the Utilities Division ("Staff") of the  
15 Arizona Corporation Commission hereby files the Direct Testimony of Crystal Brown, Alejandro  
16 Ramirez, Barbara Keene, and Jerry Smith.

17 In regard to Southwest Transmission Cooperative, Inc., the Utilities Division ("Staff") of  
18 the Arizona Corporation Commission hereby files the Direct Testimony of Crystal Brown,  
19 Alejandro Ramirez, Erin Casper, and Jerry Smith.

20 **RESPECTFULLY SUBMITTED** this 23<sup>rd</sup> day of February 2005.

21  
22  
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1 The original and fifteen (15)  
2 copies of the foregoing were  
3 filed this 23<sup>rd</sup> day of February 2005 with:

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**DIRECT  
TESTIMONY  
OF  
CRYSTAL S. BROWN  
ALEJANDRO RAMIREZ  
BARBARA KEENE  
JERRY D. SMITH**

**DOCKET NO. E-01773A-04-0528**

**IN THE MATTER OF THE APPLICATION OF  
ARIZONA ELECTRIC POWER COOPERATIVE,  
INC. FOR A RATE INCREASE**

**FEBRUARY 23, 2005**

**BROWN**

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 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 )

DIRECT TESTIMONY OF  
CRYSTAL S. BROWN  
PUBLIC UTILITIES ANALYST V  
UTILITIES DIVISION  
ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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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<sup>1</sup> 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.

---

<sup>1</sup> As shown on Schedule CSB-16, line 4.

1 **INTRODUCTION**

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

3 A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona  
4 Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff").  
5 My business address is 1200 West Washington Street, Phoenix, Arizona 85007.  
6

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

8 A. I am responsible for the examination and verification of financial and statistical  
9 information included in utility rate applications. In addition, I develop revenue  
10 requirements, prepare written reports, testimonies, and schedules that include Staff  
11 recommendations to the Commission. I am also responsible for testifying at formal  
12 hearings on these matters.  
13

14 **Q. Please describe your educational background and professional experience.**

15 A. I received a Bachelor of Science Degree in Business Administration from the University  
16 of Arizona and a Bachelor of Science Degree in Accounting from Arizona State  
17 University.  
18

19 Since joining the Commission, I have participated in numerous rate cases and other  
20 regulatory proceedings involving large electric, gas, telecommunications, and water  
21 utilities. I have testified on matters involving regulatory accounting and auditing. During  
22 the past six years, I have attended utility-related seminars on regulation, accounting,  
23 finance and income taxes designed to provide continuing and updated education in these  
24 areas. Various professional and industry organizations sponsored these seminars.  
25

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

6  
7 **Q. What is the scope of your testimony in this case?**

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

16  
17 **Q. What is the basis of your recommendations?**

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

24  
25  
26

1 **BACKGROUND**

2 **Q. Please review the background of this application.**

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

9  
10 AEPCO became a generation cooperative. Southwest Transmission became a  
11 transmission cooperative. Sierra Southwest became a cooperative that provides wholesale  
12 marketing and support services, including staffing of non-core positions to AEPCO and  
13 Southwest Transmission.

14  
15 Decision No. 63868 required that the Cooperatives provide the Director of the Utilities  
16 Division with “an informational submission” that was required within “35 months of the  
17 date of closing”<sup>2</sup> for the restructuring. Decision No. 65367, dated November 5, 2002,  
18 modified this requirement to include full Arizona Administrative Code R14-2-103  
19 information and set the rate filing date at July 1, 2004. On July 23, 2004, AEPCO filed an  
20 application for a permanent rate increase. On August 27, 2004, Staff filed a Letter of  
21 Sufficiency.

22  
23 AEPCO is a certificated Arizona-based generation cooperative that provided service to six  
24 Class A, two Class B, and one Class C member during the test year. The rates requested  
25 in this case pertain only to the Class A members.

---

<sup>2</sup> Decision No. 63868, Page 14, Finding of Fact No. 74

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

6  
7 **Q. What are the primary reasons for the Cooperative's requested permanent rate**  
8 **increase?**

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

14  
15 **CONSUMER SERVICE**

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

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

22  
23  
24  

---

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

1 **SUMMARY OF PROPOSED REVENUES**

2 **Q. Please summarize the Company's filing.**

3 A. The Cooperative proposes total annual operating revenue for Class A members of  
4 \$94,135,640. This represents an increase of \$8,450,016, or 9.86 percent, over Test Year  
5 Class A revenue of \$85,685,624.

6  
7 **Q. Please summarize Staff's recommended revenue.**

8 A. Staff recommends a revenue requirement no less than the \$146,061,466 proposed by  
9 AEPCO. This proposed revenue provides a \$6,773,320, or 4.86 percent, revenue increase  
10 over Staff adjusted Test Year revenues of \$139,288,146. Operating revenue of  
11 \$146,061,466 would produce an operating margin of \$17,755,094 for a 9.36 percent rate  
12 of return on a Staff adjusted original cost rate base of \$189,637,810 and produce a 1.33  
13 TIER.

14  
15 **Q. What Test Year did AEPCO use in this filing?**

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

18  
19 **Q. Please summarize the rate base and operating income recommendations and  
20 adjustments addressed in your testimony for AEPCO.**

21 A. My testimony addresses the following issues:

22  
23 Post-Test Year Plant— This adjustment decreases Plant In Service by \$9,952,618 to  
24 remove plant that was not used and useful during the Test Year.

25

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

3  
4           Accumulated Depreciation – This adjustment decreases Accumulated Depreciation by  
5 \$253,883 to remove retirement work in progress and accumulated depreciation directly  
6 related to the Post-Test Year plant.

7  
8           Member Advances – This adjustment decreases rate base by \$11,982,081. This  
9 adjustment recognizes that the interest paid to the Members is recovered through operating  
10 expense, and consequently, the advances which are directly related to the interest expense  
11 should be removed from rate base to prevent double recovery.

12  
13           Working Capital – This adjustment to reflect Staff's different calculation of certain  
14 Working Capital components and to eliminate the Cooperative's selective recognition of  
15 components decreases working capital by \$6,897,144.

16  
17           Deferred Debit – This adjustment to remove items that are not generally included in rate  
18 base decreases it by \$1,955,373.

19  
20           Asset Retirement Obligation ("ARO") – This adjustment to remove amounts recorded for  
21 financial accounting purposes related to future retirement obligations decreases plant in  
22 service by \$1,962,630.

23  
24           Post-Test Year Revenue and Expense – This adjustment to remove expenses is directly  
25 related to the Post-Test Year ("PTY") plant and increases operating margin by \$143,951.  
26

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

3  
4           Asset Retirement Obligation – This adjustment to remove costs recorded for financial  
5           accounting purposes related to future retirement obligations increases operating margin  
6           and net margins by \$69,446 and 642,044, respectively.

7  
8           Base Cost of Power – This adjustment increases operating margin by \$250,000 to reflect  
9           annualization of savings from a new power contract. Staff also made an adjustment to  
10          segregate the revenue associated with the power costs included in the energy charge for  
11          Class A members from other revenues. The latter adjustment has no affect on operating  
12          margin.

13  
14          Overhaul Accrual Expense – This adjustment increases operating margin by \$657,788 to  
15          reflect a normalized level of expense using historical costs.

16  
17          Transportation Expense Annualization – This adjustment increases operating margin by  
18          \$19,560 to reflect the Staff recommended Point to Point rate recommended for Southwest  
19          Transmission Cooperative.

20  
21          Normalized Legal Expense – This adjustment decreases operating margin by \$539,989 to  
22          reflect legal expenses at a normalized level.

23  
24          Fuel Expense – This adjustment increases operating margin by \$1,053,073 to remove legal  
25          costs and interest on long-term debt from fuel expense.

26

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

3  
4            Contributions and Other Expense – This adjustment to remove expenses that are not  
5            needed for safe and reliable service increases operating margin by \$159,891.

6  
7            ACC Assessment – This adjustment to remove revenues and expenses that should be  
8            treated as pass-through items increases operating margin by \$141,606.

9  
10           Interest Expense on Long-term Debt – This non-operating adjustment to reflect Staff's  
11           calculation of interest expense on long-term debt increases net margin by \$234,585.

12  
13        **RATE BASE**

14  
15        **Fair Value Rate Base**

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

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

20  
21        **Rate Base Summary**

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

24        A. Staff's adjustments to AEPCO's rate base resulted in a net decrease of \$32,509,201, from  
25        \$222,147,011 to \$189,637,810. This decrease was primarily due to (1) Staff removing

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

3  
4 **Rate Base Adjustment 1 – Utility Plant In Service, Post-Test Year Plant**

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

6 **A.** AEPCO is proposing \$389,603,749 for Utility Plant In Service. The amount is composed  
7 of \$379,651,131 in actual plant that was used and useful during the Test Year and  
8 \$9,952,618 in Post-Test Year (“PTY”) plant as shown on Schedule CSB-4.

9  
10 **Q. Please describe the Post-Test Year Plant.**

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

13  
14 **Q. What is Staff’s recommended treatment for the Post-Test Year Plant?**

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

17  
18 **Q. What is the effect of AEPCO’s proposal to include Post-Test Year plant in rate base?**

19 **A.** AEPCO’s proposal to include the \$9.9 million of PTY plant in rate base over-states the  
20 revenue requirement, and ultimately, the rates paid by the Class A Member cooperatives’  
21 120,000 customers. The over-stated revenue requirement occurs because the PTY plant  
22 creates a mismatch between the revenues, expenses incurred and the plant used to provide  
23 service in the Test Year and amounts requested for recovery in rates.

24  
25 In the absence of extraordinary circumstances, the costs of the historical test year should  
26 be used in the development of the revenue requirement. These costs are consistent with

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

3  
4 **Q. When is recognition of PTY plant in rate base appropriate?**

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

11  
12 Staff recognizes two such cases:

- 13 1. When the magnitude of the investment relative to the utility's total investment is  
14 such that not including the PTY plant in the cost of service would jeopardize the utility's  
15 financial health; and
- 16 2. When all of the following conditions exist:
- 17 a. the cost of the PTY plant is significant and substantial,
  - 18 b. the net impact on revenue and expenses for the PTY plant is known and  
19 insignificant,
  - 20 c. the PTY plant is prudent and necessary for the provision of service and reflects  
21 appropriate, efficient, effective, and timely decision-making,
  - 22 d. the funding source(s) and amounts for the PTY plant are known and recognized in  
23 the rate application,
  - 24 e. the PTY plant is in service at the time of the rate filing,
  - 25 f. the PTY plant is recorded in a completed plant account(s) in the general ledger and  
26 auditable records are available at the time of the rate filing, and

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

3

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

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

7

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

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

12

13 **Q. What is Staff recommending?**

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

16

17 **Rate Base Adjustment 2 – Plant Acquisition Adjustment**

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

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

21

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

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

1 (Page 4 at line 23). Southwest's acquisition adjustment is directly related to AEPCO's  
2 acquisition adjustment.<sup>4</sup>

3  
4 **Q. Did Staff audit the plant acquisition adjustment in this rate proceeding?**

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

7  
8 **Q. Should the plant acquisition adjustment be included in rate base?**

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

14  
15 **Q. What is Staff recommending?**

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

18  
19 **Rate Base Adjustment 3 –Accumulated Depreciation**

20 **Q. What is AEPCO proposing for Accumulated Depreciation?**

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

25  

---

<sup>4</sup> Per response to data request CSB 3-4.

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

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

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

12  
13 **Q. Did Staff remove the \$308,531 of Accumulated Depreciation directly related to the**  
14 **Post-Test Year plant?**

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

17  
18 **Q. What is Staff recommending?**

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

21  
22  
23

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<sup>5</sup> Page 24 at line 23

<sup>6</sup> Page 24 at line 23

<sup>7</sup> Decision No. 65367, page 4, lines 6 through 9

1 **Rate Base Adjustment 4 – Member Advances**

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

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

8  
9 **Q. How does the Cooperative treat the balance of Member Advances and the interest  
10 paid on those funds in its filing?**

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

17  
18 **Q. What is the effect of the Cooperative's proposed treatment?**

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

24

25

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<sup>8</sup> Per data request response CSB 1-21

<sup>9</sup> Per data request response CSB 3-19

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

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

5  
6 **Q. What is Staff recommending?**

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

9  
10 **Rate Base Adjustment 5 – Working Capital**

11 **Q. What is AEPCO proposing for Working Capital?**

12 A. AEPCO is proposing \$16,778,408 for Working Capital. The amount is composed of  
13 \$5,581,933 for fuel stock, \$5,265,561 for materials and supplies, \$908,046 for  
14 prepayments, and \$5,022,869 for CFC Certificates and Bonds as shown on Schedule CSB-  
15 8.

16  
17 **Q. Did Staff make any adjustments to the Cooperative's Working Capital?**

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

20  
21 Working Capital - Fuel Stock, Coal

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

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

1 **Q. What amount in fuel stock is AEPCO proposing?**

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

3  
4 **Q. How did AEPCO calculate its fuel stock inventory levels during the Test Year?**

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

9  
10 **Q. AEPCO changed the Number of Burn Days calculation in April<sup>11</sup> of the Test Year  
11 which resulted in lower levels of coal inventory. Did AEPCO reflect this lower level  
12 of coal inventory in rate base?**

13 A. No, the Cooperative changed its inventory level from 5,300 tons to 4,100<sup>12</sup> tons in April of  
14 the Test Year and did not reflect the lower level in rate base.

15  
16 **Q. AEPCO's proposed inventory level is based upon a 13-Month average of fuel stock.  
17 Does this calculation over-state the inventory balance included in rate base?**

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

20  
21 **Q. What methodology to calculate the fuel stock balance does Staff recommend using?**

22 A. Staff recommends basing the inventory balance on the number of burn days rather than on  
23 13-Month average. Staff's recommended inventory balance is calculated by multiplying  
24 the number of burn days by the average daily tons per burn day and the average cost per

---

<sup>10</sup> Per data request response CSB 3-15

<sup>11</sup> Per data request response CSB 1-4, April 2003 AEPCO Monthly Financial Board Report, page 7.1

<sup>12</sup> Per data request response CSB 3-15

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

3  
4 **Q. Did Staff remove fuel related legal expenses from the fuel stock balance?**

5 A. Yes, Staff removed \$191,545<sup>15</sup> in fuel related legal costs as shown on Schedule CSB-8.1.  
6 Staff discusses this issue in greater detail in Operating Income Adjustment No. 8, Fuel  
7 Expense.

8  
9 **Q. What is Staff recommending for the fuel stock balance?**

10 A. Staff recommends \$4,635,180 for fuel stock as shown on Schedules CSB-8 and CSB-8.1.  
11

12 Working Capital - Materials and Supplies

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

15 A. AEPCO is proposing \$5,265,561 for Materials and Supplies inventory.  
16

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

19 A. AEPCO calculated the Materials and Supplies balance using a 13-month average. This  
20 method adds together the December 31, 2002, ending Materials and Supplies balance with  
21 the Test Year month-end balances and divides by 13.  
22  
23

---

<sup>13</sup> Per response to data request CSB 3-15, 42.5 days is the average of the 40 to 45 burn days range

<sup>14</sup> Per response to data request CSB 6-9

<sup>15</sup> Per response to data request CSB 15-3

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

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

5  
6 **Q. What method provides a more accurate measurement of the average balance each**  
7 **month?**

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

14  
15 **Q. What does Staff recommend for the Materials and Supplies balance in the Working**  
16 **Capital calculation?**

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

18  
19 Working Capital - Prepayments, CFC Certificates and Bonds  
20

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

23 A. Yes. AEPCO is proposing \$908,046 for prepayments, and \$5,581,933<sup>16</sup> in CFC  
24 Certificates and Bonds.

---

<sup>16</sup> 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.

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

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

9  
10 The Cooperative chose not to conduct a lead-lag study, and accordingly, omitted a major  
11 component of Working Capital. It is inequitable to ignore a major component of the  
12 Working Capital analysis and selectively recognize other components. Had a lead-lag  
13 study been conducted, it might have shown that Working Capital is a negative component  
14 of rate base.

15  
16 **Q. What factors imply that a lead-lag study could result in Working Capital being a**  
17 **negative component of rate base?**

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

25  
26

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

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

6  
7 **Q. Did the Commission remove Prepayments and CFC Certificates and Bonds from**  
8 **rate base in AEPCO's prior rate case?**

9 A. Yes, it did. The Commission removed prepayments in Decision No. 58405<sup>18</sup>. The  
10 Cooperative had not included CFC Certificates and Bonds in the rate base of that  
11 proceeding, therefore, it was not addressed in Decision No. 58405.

12  
13 **Q. What is Staff recommending for Prepayments and CFC Certificates and Bonds?**

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

17  
18 **Q. What is Staff's recommended adjustment to Working Capital?**

19 A. Staff recommends decreasing Working Capital by \$6,897,144 from \$16,778,409 to  
20 \$9,881,264 as shown on Schedules CSB-3 and CSB-8.

21  
22  
23  
24

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<sup>17</sup> 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.

<sup>18</sup> Page 6, at line

1 **Rate Base Adjustment 6 – Deferred Debit**

2  
3 **Q. What amount in Deferred Debits is AEPCO proposing to include in Rate Base?**

4 A. AEPCO is proposing \$1,955,373 for Deferred Debits as shown on Schedule CSB-9. The  
5 amount is composed of \$957,472 for preliminary survey and investigation charges,  
6 \$731,780 for Job Tickets, and \$266,121 for unamortized losses on reacquired debt.<sup>19</sup>

7  
8 **Q. Should these Deferred Debits be included in rate base?**

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

13  
14 Unamortized losses on reacquired debt present no future cash requirements for the  
15 Cooperative. Since Staff recommends a revenue requirement dependent on cash flow  
16 needs, there is no revenue requirement directly related to the carrying balance.

17  
18 Including the unamortized loss on reacquired debt in rate base would be inequitable and  
19 serve only as a selective adjustment to augment rate base in the same manner as  
20 prepayments, CFC Bonds and Certificates.

21  
22 **Q. Did the Commission remove the deferred debit from rate base in AEPCO's prior  
23 rate case?**

24 A. Yes, the Commission, in Decision No. 58405, removed the Deferred Debit from rate base.  
25

---

<sup>19</sup> Per response to CSB 3-1

1 **Q. What is Staff recommending?**

2 A. Consistent with Decision No. 58405, Staff recommends removal of the Deferred Debit  
3 from Rate Base as shown on Schedules CSB-3 and CSB-9.  
4

5 **Rate Base Adjustment 7 –Asset Retirement Obligation (“ARO”)**

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

7 A. AEPCO included a \$1,962,630 ARO in its proposed plant. The Cooperative recorded the  
8 amount to “recognize the present value of its projected retirement cost”<sup>20</sup> associated with  
9 the retirement of an ash pond.  
10

11 **Q. What is an ARO?**

12 A. In 2003, AEPCO adopted Statement of Financial Accounting Standards (“SFAS”) No.  
13 143, *Accounting for Asset Retirement Obligation* for purposes of financial statement  
14 presentation. Adoption of SFAS No. 143 represented a change in accounting principle for  
15 retirement of long-lived tangible assets with a legal obligation for disposal.  
16

17 An asset retirement obligation is a liability recognized on the balance sheet for a legal  
18 obligation associated with the retirement of a long-lived tangible asset used in operations.  
19 Normally upon recognition of an ARO, an ARO asset and an ARO liability are recorded at  
20 the present value of the expected cost of disposal. The ARO liability grows as a cost of  
21 money factor (accretion expense) is applied to the ARO liability balance each period until  
22 the asset is retired. If the initial estimates were correct, the ARO liability will equal the  
23 cost at the time of disposal. The ARO asset is depreciated over the life of the asset. It is  
24 the ARO asset that AEPCO has included in plant.  
25

---

<sup>20</sup> Note 19 of AEPCO’s 2003 audited financial statements

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

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

5  
6 **Q. For what asset did AEPCO recognize an ARO?**

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

10

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

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

16

17 **Q. What is Staff recommending?**

18 A. Staff recommends decreasing plant in service by \$1,962,630 as shown on Schedules CSB-  
19 3 and CSB-10. Staff also recommends no change in the rate-making treatment of  
20 retirements with legal obligations.

21

22 **OPERATING INCOME – AEPCO**

23

24 **Operating Income Summary – AEPCO**

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

1 A. As shown on Schedules CSB-11 and CSB-12 Staff's analysis resulted in Test Year  
2 revenues of \$139,288,146, expenses of \$128,306,372 and operating margin of  
3 \$10,981,774.

4  
5 **Operating Income Adjustment No. 1 – Post-Test Year Revenue and Expenses**

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

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

8

Post-Test Year Revenue and Expense Adjustments For Coal Blending Facility					
	AEPCO Adj. No. 5	AEPCO Adj. No. 6	AEPCO Adj. No. 7	AEPCO Adj. No. 8	Total
	Fuel Expense	SO2 Allowance	Ash Sales Credit	Coal Blender (Depreciation & Prop Taxes)	
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)
<b>Total</b>	<b>\$ 982,340</b>	<b>\$167,069</b>	<b>(\$820,611)</b>	<b>(\$1,005,214)</b>	<b>(\$676,416)</b>

9  
10 **Q. Why did the Cooperative propose a pro forma adjustment for PTY expenses?**

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

13  
14 **Q. When would recognition of expenses related to PTY be appropriate?**

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

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

3  
4 **Q. What treatment does Staff recommend for the Cooperative's pro forma adjustment  
5 for PTY expenses?**

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

8  
9 **Q. What is Staff recommending?**

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

13  
14 **Operating Income Adjustment No. 2 – Revenue and Expense Annualizations**

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

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

22  
23 **Q. Has Staff analyzed growth in the number of customers served by AEPCO's Class A  
24 Members?**

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

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

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

6  
7 To illustrate: At the beginning of the year, Class A Members had a total of 116,074  
8 customers as shown on Schedule CSB-14 line 14. At the end of the year, the actual  
9 number of customers was 119,895 as shown on Schedule CSB-14, line 15. To annualize  
10 the sales based on year-end customers, an adjustment of 1.65 percent  $(((119,895-116,074)/$   
11  $116,074) / 2]$  is necessary.

12  
13 **Q. What is Staff recommending?**

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

16  
17 **Operating Income Adjustment No. 3 – Asset Retirement Obligation**

18  
19 **Q. What effects of adopting SFAS No. 143 is AEPCO proposing as expenses?**

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

25

1 **Q. Does AEPCO have any investment in the ARO asset upon which it recorded \$69,446**  
2 **of depreciation expense?**

3 A. No. As previously discussed, the ARO asset is merely an accounting entry to  
4 accommodate financial reporting requirements. AEPCO has no investment in the ARO  
5 asset it included in plant, and accordingly, there is no asset cost to be recovered through  
6 depreciation.  
7

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

9 A. According to Note 19 of AEPCO's 2003 audited financial statements, AEPCO "recorded  
10 the cumulative effect of the accounting change, totaling \$3,810,335 in the consolidated  
11 statements of revenues and expenses and unallocated accumulated margins. The  
12 Cooperative also recognized the present value of its projected asset retirement costs,  
13 totaling \$1,962,630, as a component of its capitalized utility plant on the consolidated  
14 balance sheets. Subsequently, the Cooperative recognized accretion<sup>21</sup> of the liability,  
15 totaling \$185,802, as a component of interest expense and depreciation of the asset  
16 retirement costs, totaling \$69,445, as depreciation expense<sup>22</sup> . . ."  
17

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

---

<sup>21</sup> Accretion expense is a type of interest expense that is added to the ARO liability annually to account for the time value of money.

<sup>22</sup> The ARO asset is depreciated over the life of the associated tangible asset.

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

2 A. AEPCO proposes to recover the \$3.8 million write-off by including one-tenth, or  
3 \$381,034, in operating expenses over a ten-year period.

4  
5 **Q. Is AEPCO's proposed treatment of the \$3.8 million write-off consistent with rate-**  
6 **making principles?**

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

9  
10 **Q. Did AEPCO experience any cash outlay related to the \$3.8 million write-off during**  
11 **the Test Year?**

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

14  
15 **Q. If implementation of SFAS No. 143 is not recognized how would AEPCO recover the**  
16 **ash pond disposal cost?**

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

20  
21 **Q. Could AEPCO's proposed treatment result in excess recovery of the \$3.8 million**  
22 **write-off?**

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

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

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

6  
7 **Q. Please summarize why the \$381,034 ARO write-off should not be included in**  
8 **calculation of the revenue requirement.**

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

13  
14 **Q. What is Staff recommending?**

15 A. Staff recommends removing all effects of the ARO on the income statement including  
16 \$69,446 from operating expenses and \$572,598 from Interest and Other Deductions as  
17 shown on Schedules CSB-12 and CSB-15.

18  
19 **Operating Income Adjustment No. 4 – Tracker Mechanism (Base Power Cost)**

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

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

24  
25

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

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

7  
8 **Q. Is Staff recommending a different level of base power costs?**

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

11  
12 **Q. What adjustment did Staff make to revenue to recognize the \$7,716,227 difference**  
13 **between Staff and AEPCO's base power costs?**

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

18  
19 **Q. Did Staff disallow any costs from the accounts included in the base cost of power**  
20 **expense?**

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

24  
25

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<sup>23</sup> Cooperative Schedule H 2A, Line 36

<sup>24</sup> Cooperative Schedule H 2A, Line 38

1 **Operating Income Adjustment No. 5 – Overhaul Accrual Expense**  
2

3 **Q. Why are generation unit overhauls needed?**

4 A. A generation unit consists of thousands of separate components that deteriorate at  
5 different rates based on operating conditions. The overhaul of one of these complex units  
6 encompasses a wide range of preventative maintenance, repair, and replacement activities  
7 that are needed to help ensure safe and reliable operation.  
8

9 **Q. What is AEPCO proposing for overhaul accrual expense?**

10 A. AEPCO is proposing \$4,787,507 for overhaul accrual expense<sup>25</sup>.  
11

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

13 A. AEPCO's actual overhaul expense was \$3,148,905<sup>26</sup>.  
14

15 **Q. Why are the actual and accrual expenses different?**

16 A. The actual overhaul expense is not representative of the overhaul expense from year to  
17 year because the nature and scope of overhauls vary from year to year based on operating  
18 conditions. Consequently, the Cooperative estimates and accrues an amount for the  
19 annual overhaul expense. In 2003, AEPCO began using a revised methodology to  
20 calculate its overhaul accruals.  
21

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

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

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<sup>25</sup> Per response to data request CSB 1-38

<sup>26</sup> Per response to data request CSB 1-38

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

4  
5 **Q. What method does Staff recommend for calculating the accrual amount?**

6 A. Staff recommends calculating the accrual expense as the eight year average<sup>27</sup> of the actual  
7 overhaul expense as shown on Schedule CSB-17. Eight years is representative of the  
8 typical overhaul period.

9  
10 **Q. What is Staff recommending?**

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

13  
14 **Operating Income Adjustment No. 6 – Transmission Expense Annualization**

15 **Q. What is the Cooperative proposing for transmission expense?**

16 A. AEPCO is proposing \$8,036,486 for transmission expense. This amount is composed of  
17 \$6,692,293 of actual Test Year transmission expense; a (\$245,438) pro forma adjustment  
18 to reflect termination of the City of Mesa contract and; a \$1,589,631 pro forma adjustment  
19 to reflect the annualization of transmission expense for its (a) wheeling expenses  
20 associated with a Western Area Power Administration agreement and (b) an El Paso Palo  
21 Verde agreement and (c) the proposed increase in point-to-point transmission rates that  
22 Southwest Transmission charges AEPCO.

23  
24  

---

<sup>27</sup> Per response to CSB 1-38, major overhauls occur approximately every 96 months for base load generating units.

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

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

7  
8 **Q. What is Staff recommending?**

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

11  
12 **Operating Income Adjustment No. 7 – Normalized Legal Expense**

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

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

18  
19 **Q. What approach did Staff take for evaluating legal expenses?**

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

---

<sup>28</sup> Per data request response to CSB 13-1.

<sup>29</sup> Per data request response to CSB 13-1.

1 Normalized Railroad Transportation Legal Expense

2 **Q. How did Staff calculate the normalized railroad transportation tariff legal expense?**

3 A. Staff normalized this expense by amortizing the total of the 2002, 2003, and 2004 costs  
4 related to the railroad transportation tariff over the five-year contract term (i.e., expected  
5 benefit period) as shown on Schedule CSB-19.1. The \$1,792,246 expense for 2003  
6 includes the \$1,030,873 reclassified from fuel expense as discussed in Operating Income  
7 Adjustment No. 8, "Fuel Expense." The calculation is presented on Schedule CSB-20,  
8 line 22.

9  
10 **Q. What amount is Staff recommending for the normalized railroad transportation  
11 tariff portion of legal expense?**

12 A. Staff recommends \$620,129 for the normalized railroad transportation tariff portion of  
13 legal expense as shown on Schedule CSB-19, line 6.

14  
15 Normalized Outside Services (Non-Railroad Transportation Tariff) Legal Expenses

16 **Q. Has Staff prepared an explanation for each amount it excluded from the 2003 costs  
17 in its calculation of the normalized non-railroad transportation legal expenses as  
18 shown on Schedule CSB-19.2?**

19 A. Yes. An explanation of each type of cost excluded from Staff's normalization adjustment  
20 is presented below.

21  
22 Natural Gas Related Legal Expenses

23 **Q. How are costs allocated between the three cooperatives (AEPCO, Southwest  
24 Transmission, and Sierra Southwest)?**

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

4  
5 **Q. Did AEPCO receive 80.23 percent of the natural gas-related legal expenses based on  
6 the three-entity allocation factor?**

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

9  
10 **Q. Does Staff agree that virtually all natural gas-related legal expenses should be  
11 directly charged to AEPCO?**

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

20  
21 **Q. What amount of natural gas-related legal costs has Staff excluded from its  
22 calculation of normalized legal expense?**

23 A. Staff allocated the \$354,824 cost by the current three-entity allocation factor (80.23  
24 percent) to calculate \$284,675 as AEPCO's allocation resulting in a \$70,149 (\$354,824-  
25 \$284,675) exclusion from the normalization calculation shown on Schedule CSB-19.2,  
26 line 2.

1 El Paso Electric Company Contract Related Legal Expenses

2 **Q. What is the El Paso Electric Company contract?**

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

7  
8 **Q. Is it appropriate to charge all of the costs of a contract that will benefit multiple  
9 years to the Test Year?**

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

13  
14 **Q. What amount of EPE contract-related legal costs has Staff excluded from its  
15 calculation of normalized legal expense?**

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

18  
19 Public Utilities Holding Company Act ("PUHCA")

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

22 A. Yes.  
23  
24  
25

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

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

8  
9 **Q. How did Staff treat these PUCHA legal costs in its calculation of normalized legal**  
10 **expenses?**

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

13  
14 **Q. Does AEPCO's denial of access to records provide concerns beyond whether these**  
15 **legal costs are related to the provision of utility service and recoverable?**

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

19  
20 **Q. Does Staff have any other recommendations regarding redacted issues?**

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

26

1 Capitalized Expenses

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

3 A. Yes. AEPCO capitalized \$13,605 of legal expenses in 2003.  
4

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

7 A. Staff excluded the \$13,605 capitalized legal cost from its calculation of normalized legal  
8 expense as shown on Schedule CSB-19.2, line 5.  
9

10 Redacted Minutes and Legal Invoices

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

12 A. Yes, AEPCO objected to the release of certain portions of the Minutes of the Executive  
13 Session of the Board of Directors and legal invoices citing the attorney-client privilege.  
14 Therefore, the appropriateness of the costs could not be substantiated.  
15

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

18 A. Yes, in a letter to the Cooperative dated September 29, 2004, Staff indicated that failure to  
19 provide complete legal invoices would result in a disallowance of such costs.  
20

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

23 A. Staff excluded \$68,412<sup>30</sup> from its calculation of normalized legal expense as shown on  
24 Schedule CSB-19.2, line 6.

---

<sup>30</sup> 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.

1 **Q. What is Staff recommending for normalized legal expense?**

2 A. Staff recommends \$620,129 and \$823,372 for railroad and non-railroad transportation  
3 tariff legal expenses, respectively, for a total of \$1,443,501. This amount is \$539,989  
4 greater than the \$903,512 proposed by AEPCO, as shown on Schedules CSB-12 and CSB-  
5 19, line 11.

6  
7 **Operating Income Adjustment No. 8 – Fuel Expense**

8 **Q. What is AEPCO proposing for fuel expense?**

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

12  
13 **Q. Does the \$44,521,523 in fuel expense for coal include legal expenses?**

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

19  
20 **Q. Did the Commission remove legal expense from fuel costs in the Cooperative's prior  
21 rate proceeding?**

22 A. Yes, the Commission removed legal expense from fuel costs in the prior rate proceeding.  
23 AEPCO had included all fuel expenses including legal in its purchased power fuel  
24 adjustor. The Commission removed these costs in the prior rate proceeding indicating that  
25 its inclusion was inappropriate.<sup>31</sup>

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<sup>31</sup> Decision No. 58405, page 28, lines 22 through 26, and page 29, lines 1 through 6.

1 **Q. Did Staff calculate the amount of legal expense included in fuel expense?**

2 A. Yes. Staff calculated that fuel cost includes \$1,030,873 legal expenses as shown on  
3 Schedule CSB-20, line 24.

4

5 **Q. How did Staff treat the legal expenses embedded fuel costs?**

6 A. Staff reclassified these legal expenses and included them in its calculation of normalized  
7 legal expenses as shown on Schedule CSB-19, line 2.

8

9 **Q. Did Staff find any other costs in the Cooperative's proposed fuel expense for which it  
10 recommends alternate treatment?**

11 A. Yes. Included in the fixed costs the Cooperative allocated to coal fuel costs is \$22,200 of  
12 interest on long-term debt. Staff removed this interest expense from fuel costs, as shown  
13 on Schedule CSB-20, line 22, because Staff is recognizing recovery of interest expense  
14 separately.

15

16 **Q. What is Staff recommending?**

17 A. Staff recommends decreasing fuel expense by \$1,053,073 as shown on Schedules CSB-12  
18 and CSB-20.

19

20 **Operating Income Adjustment No. 9 – Advertising**

21 **Q. What is AEPCO proposing for advertising expense?**

22 A. AEPCO is proposing \$46,241 for advertising expense.

23

24 **Q. Are these advertising costs necessary for safe and reliable service?**

25 A. No, these costs are not necessary to provide safe and reliable service. AEPCO is a  
26 regulated electric service provider. Consequently, there is no reason to recover

1 advertising costs incurred primarily for image building that may otherwise make economic  
2 sense for a firm selling services in an open competitive market.

3  
4 **Q. What rate-making treatment does Staff recommend for these advertising costs?**

5 A. Staff recommends that these costs be recognized below-the-line (removed from rates).  
6

7 **Q. What is Staff recommending?**

8 A. Staff recommends decreasing operating expense by \$46,241 as shown on Schedules CSB-  
9 12 and CSB-21.  
10

11 **Operating Income Adjustment No. 10 – Charitable Contributions and Other Expenses**

12 **Q. What is AEPCO proposing for contributions, sponsorships, food, entertainment and  
13 similar expenses?**

14 A. AEPCO is proposing \$159,891 for contributions, sponsorships, food, entertainment, and  
15 similar expenses as shown on Schedule CSB - 22.  
16

17 **Q. What ratemaking treatment does Staff recommend for these types of expenses?**

18 A. Since these costs are not necessary to provide service, Staff recommends that they be  
19 recognized as non-operating expenses and excluded from the revenue requirement.  
20

21 **Q. What is Staff recommending?**

22 A. Staff recommends decreasing operating expense by \$159,891 as shown on Schedules  
23 CSB-12 and CSB-22.  
24  
25

1 **Operating Income Adjustment No. 11 – Arizona Corporation Commission Gross Revenue**  
2 **Assessment**

3 **Q. What is the Cooperative proposing for the ACC assessment?**

4 A. The Cooperative included \$147,146 in operating revenue and \$288,752 in operating  
5 expense for the ACC assessment.

6  
7 **Q. What does Decision No. 58405 state concerning the ACC assessment for AEPCO?**

8 A. On footnote 9 of page 17, the Commission states that “The gross revenue tax will in the  
9 future be recovered through a bill add-on.” Therefore, the assessment should not be  
10 included in the cost of service.

11  
12 **Q. What is Staff recommending?**

13 A. Staff recommends decreasing operating revenue by \$147,146 and operating expense by  
14 \$288,752 to remove the effects of the ACC assessment as shown on Schedules CSB-12  
15 and CSB-23.

16  
17 **Income Adjustment No. 12 (Non-Operating) – Interest Expense on Long-term Debt**

18 **Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?**

19 A. AEPCO is proposing \$13,547,749 for Interest Expense on Long-term Debt as shown on  
20 Schedule CSB-24. The amount is composed of \$12,200,997 in actual interest expense and  
21 proforma adjustments totaling \$1,346,752 (Cooperative adjustment numbers 8, 9, and 13  
22 in the amounts of \$532,465, \$1,190,178, and (\$375,891), respectively).

23  
24  
25

1 **Q. Did Staff make an independent assessment of the Cooperative's Interest Expense on**  
2 **Long-term Debt?**

3 A. Yes. Staff witness Alejandro Ramirez independently calculated \$13,313,164 as the  
4 Cooperative's interest expense on long-term debt and prepared testimony to support his  
5 calculation.

6  
7 **Q. What adjustment did Staff make to Interest Expense on Long-term Debt?**

8 A. Staff decreased Interest Expense on Long-term Debt by \$234,585 as shown on Schedules  
9 CSB-12 and CSB-24.

10

11 **Deferred Fuel-Related Legal and Pension Expense**

12

13 **Q. Staff noted that Decision No. 58405 authorized AEPCO to establish two deferral**  
14 **accounts. Would you please discuss the background of the deferral accounts?**

15 A. Yes. Fuel related legal costs and pension costs were not included in the cost of service in  
16 AEPCO's prior rate proceeding (Decision No. 58405, page 29, beginning at line 2).  
17 Subsequently, the Commission ordered AEPCO to establish two deferral accounts: one for  
18 fuel related legal expenses and a second deferral account for actual pension costs for  
19 possible recovery in a future rate proceeding (Decision No. 58405, Page 37, beginning at  
20 line 5).

21

22 **Q. What were the balances for the fuel-related Legal and Pension expenses as of**  
23 **December 31, 2003?**

24 A. AEPCO had not recorded any amounts related to the deferrals as of December 31, 2003,  
25 because the recovery of the deferrals were uncertain (CSB 3-2). However, the  
26 Cooperative indicated that it had accumulated \$5,839,957 in required NRECA pension

1 fund contributions and \$3,722,948 in legal expenses associated with fuel costs, for a total  
2 of \$9,562,905 (CSB 6-3).  
3

4 **Q. What treatment does Staff recommend for the \$9.5 million unrecorded Legal and**  
5 **Pension deferrals?**

6 A. Staff recommends not including the unrecorded deferrals in rates. The revenue  
7 requirement for the Cooperative is based primarily on cash flow needs, and there are no  
8 cash requirements going forward for these costs from prior periods that were deferred.  
9 Since AEPCO did not record the deferrals, there would be no write-down and associated  
10 negative effect on the Cooperatives patronage equity due to non-recovery.  
11

12 **Q. Does Staff recommend that the deferrals continue?**

13 A. Since the cost of service in the instant case includes costs for fuel related legal expenses  
14 and pension, Staff recommends that the deferrals be discontinued.  
15

### 16 **Jurisdictional Separation**

17 **Q. Did AEPCO maintain separation between Commission jurisdiction and non-**  
18 **jurisdiction revenues and expenses?**

19 A. No, it did not. The Cooperative serves a California member for which separate revenues  
20 and expenses were not maintained.  
21

22 **Q. Is the Cooperative required to maintain separation of the revenues and expenses for**  
23 **the California member?**

24 A. Yes, it is. The Arizona Administrative Code R14-2-103 B4 states the following:  
25

26 Separation of nonjurisdictional properties, revenues and expenses associated  
27 with the rendition of utility service not subject to the jurisdiction of the

1 Commission must be identified and properly segregated in a recognized  
2 manner when appropriate.

3

4 **Q. Can Staff identify some cooperatives that provided jurisdictionally separated**  
5 **information in their rate filings?**

6 A. Yes. Duncan Valley Electric Cooperative, Inc. and Garkane Power Association, Inc.  
7 provide jurisdictionally separated information in compliance with the Administrative  
8 Code. These cooperatives generate much smaller revenues than AEPCO. The  
9 jurisdictionally separated financial information helps to verify that Arizona ratepayers are  
10 not paying more than their fair share of the cost of providing service.

11

12 **Q. What is Staff recommending?**

13 A. Staff recommends that the Cooperative comply with Arizona Administrative Code R14-2-  
14 103 B4 in its next rate filing.

15

16 **Q. Does this conclude your direct testimony?**

17 A. Yes, it does.

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

Schedule CSB-1

**REVENUE REQUIREMENT**

<u>LINE NO.</u>	<u>DESCRIPTION</u>	<u>[A] COMPANY ORIGINAL COST</u>	<u>[B] STAFF ORIGINAL COST</u>
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	<b>Recommended Increase in Operating Revenue</b>	\$ 8,450,016	\$ <b>6,773,320</b>
6b	<b>Percent Increase (Line 6a / Line 7) - Per Staff</b>	N/A	<b>4.86%</b>
6c	<b>Percent Increase (Line 6a / \$85,685,624) - Per Coop</b>	9.86%	N/A
7	Adjusted Test Year Operating Revenue	\$ 137,611,450	\$ 139,288,146
8	<b>Recommended Annual Operating Revenue</b>	\$ 146,061,466	\$ <b>146,061,466</b>
9a	<b>Recommended Operating Margin</b>	\$ 16,422,692	\$ <b>17,755,094</b>
9b	Recommended Net Margin	\$ 3,922,406	\$ 4,099,540
10a	<b>Recommended Operating TIER (L3+L9)/L4 - Per Staff</b>	N/A	<b>1.33</b>
10b	Recommended Net TIER (L4+L9b)/L4 - Per Coop	1.29	N/A
11a	<b>Recommended DSC (L2+L3+L9)/(L4+L5) - Per Staff</b>	N/A	<b>0.91</b>
11b	Recommended DSC (L2+L4+L9b)/(L4+L5) - Per Coop	1.05	N/A
12	<b>Adjusted Rate Base</b>	\$ 222,147,011	\$ <b>189,637,810</b>
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

**RATE BASE - ORIGINAL COST**

LINE NO.	[A] COMPANY AS FILED	[B] STAFF ADJUSTMENTS	[C] STAFF AS ADJUSTED
1	\$ 389,603,749	\$ (11,928,486)	\$ 377,675,263
2	(186,190,519)	253,883	(185,936,636)
3	<u>\$ 203,413,230</u>	<u>\$ (11,674,603)</u>	<u>\$ 191,738,627</u>
<u>LESS:</u>			
4	\$ -	\$ -	\$ -
5	\$ -	\$ -	\$ -
6	-	-	-
7	-	-	-
8	\$ -	\$ -	\$ -
9	\$ -	\$ (11,982,081)	\$ (11,982,081)
<u>ADD:</u>			
10	\$ 16,778,408	\$ (6,897,144)	\$ 9,881,264
11	\$ -	\$ -	\$ -
12	<u>\$ 1,955,373</u>	<u>\$ (1,955,373)</u>	<u>\$ -</u>
13	<u>\$ 222,147,011</u>	<u>\$ (32,509,201)</u>	<u>\$ 189,637,810</u>

References:

Column [A], Company Schedule B-1, Page 1  
Column [B]: Schedule CSB-3  
Column [C]: Column [A] + Column [B]

**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
<b>PLANT IN SERVICE:</b>										
1	Intangible Plant <sup>1</sup>	\$ 18,527	\$ -	\$ (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 <sup>2</sup>	21,531,578	-	-	-	-	-	-	-	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	-	-	-	-	-	-	-	639,270
10	Other Production Plant - Fuel Hldrs Prodcrs & Acces	2,805,026	(9,952,618)	-	-	-	-	-	-	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 <sup>3</sup>	3,361,517	-	-	-	-	-	-	-	3,361,517
14	Transmission Plant - Station Equipment	2,524,442	-	-	-	-	-	-	-	2,524,442
15	Transmission Plant - Poles, Fixtures, Conductors <sup>4</sup>	247,329	-	-	-	-	-	-	-	247,329
16	General Plant <sup>5</sup>	17,278,108	-	-	-	-	-	-	-	17,278,108
17	Unclassified Completed Construction - General Plant	3,943,249	-	-	-	-	-	-	-	3,943,249
18	Unclassified Completed Constr - Steam, Generation	10,027	-	(13,238)	-	-	-	-	(1,962,630)	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
<b>LESS:</b>										
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)
<b>ADD:</b>										
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	Schedule CSB-4
2	Schedule CSB-5
3	Schedule CSB-6
4	Schedule CSB-7
5	Schedule CSB-8
6	Schedule CSB-9
7	Schedule CSB-10

Footnote Explanations  
<sup>1</sup> Includes account nos. 301,114,302, & 303  
<sup>2</sup> Includes account nos. 315 & 316  
<sup>3</sup> Includes account nos. 345 & 346  
<sup>4</sup> Includes account nos. 355 & 356  
<sup>5</sup> Includes account nos. 389 and 390 to 389

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Schedule CSB-4

**RATE BASE ADJUSTMENT NO. 1 - POST-TEST YEAR PLANT, COAL BLENDING FACILITY**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED (Sch E-5)	STAFF ADJUSTMENTS	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)	\$ -
		<b>\$ 389,603,749</b>	<b>\$ (9,952,618)</b>	<b>\$ 379,651,131</b>

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]

**RATE BASE ADJUSTMENT NO. 2 - ACQUISITION ADJUSTMENT**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED (Sch E-5)	STAFF ADJUSTMENTS	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	<u>\$ 18,527</u>	<u>\$ (13,238)</u>	<u>\$ 5,289</u>

3 To remove unauthorized acquisition 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]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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	<b>Total Accumulated Depreciation</b>	<b>\$ (185,972,877)</b>	<b>\$ 253,883</b>	<b>\$ (185,718,994)</b>

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]

**RATE BASE ADJUSTMENT NO. 4 - MEMBER ADVANCES**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Member Advances	\$ -	\$ (11,982,081)	\$ (11,982,081)
2				
3		Member		
4		Advances		Member
5		Ending Balance		Advances
6		(Per CSB 1-21)		Average Balance
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			<u>\$(143,784,971.48)</u>	<u>\$ (134,880,981.40)</u>
21				/ 12
22				<u>\$ (11,982,080.96)</u>

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]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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	<b>Total Working Capital</b>	<b>\$ 16,778,409</b>	<b>\$ (6,897,144)</b>	<b>\$ 9,881,265</b>

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	<b>Less:</b> 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]

**MATERIALS AND SUPPLIES BALANCE CALCULATION**

LINE NO.	END OF MONTH BALANCE	[A]	[B]	[C]
		COMPANY AS FILED 13-Month Avg	STAFF ADJUSTMENTS	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]	[B]	[C]
		COMPANY AS FILED (CSB 3-1)	STAFF ADJUSTMENTS	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	<u>\$ 1,955,373</u>	<u>\$ (1,955,373)</u>	<u>\$ -</u>

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]	[B]	[C]
		COMPANY AS FILED (CSB 3-1)	STAFF ADJUSTMENTS	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]

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
<b>REVENUES:</b>						
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
<b>EXPENSES:</b>						
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	<b>INTEREST ON LONG-TERM DEBT &amp; OTHER DEDUCTIONS</b>					
25	Interest on Long-term Debt	\$ 13,547,749	\$ (234,585)	\$ 13,313,164	\$ -	\$ 13,313,164
26	Other Interest & Other Deductions	\$ 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	<b>MARGINS (LOSS) AFTER INTEREST EXPENSE</b>	\$ (6,490,061)	\$ 3,816,281	\$ (2,673,780)	\$ -	\$ 4,099,540
29	<b>NON-OPERATING MARGINS</b>					
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	<b>EXTRAORDINARY ITEMS</b>					
34	<b>NET MARGINS (LOSS)</b>	\$ (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)

**SUMMARY OF OPERATING INCOME ADJUSTMENTS - TEST YEAR**

LINE NO.	REVENUES:	(A) COMPANY AS FILED	(B) Post-Test Year Revenues and Expenses Ref. Sch CSB-13	(C) Revenue and Expense Annualizations Ref. Sch CSB-14	(D) Asset Retirement Obligation Ref. Sch CSB-15	(E) Mechanism Tracker (Base Power Cost) Ref. Sch CSB-16	(F) Overhaul Accrual Expense Ref. Sch CSB-17	(G) Transmission Expense Annualization for Contracts Ref. Sch CSB-18	(H) Normalized Legal Expense Ref. Sch CSB-19
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	<b>Total Revenues</b>	\$ 137,611,450	\$ 551,934	\$ 1,271,908	\$ -	\$ -	\$ -	\$ -	\$ -
<b>OPERATING EXPENSES:</b>									
9	Operations - Production, Fuel	\$ 59,803,425	\$ -	\$ 264,376	\$ -	\$ -	\$ -	\$ -	\$ -
10	Operations - Production, Steam	\$ 8,764,555	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
11	Operations - Production, Other	\$ 1,335,333	\$ 407,983	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
12	Operations - Other Pwr Supply, Demand	\$ 5,769,587	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
13	Operations - Other Pwr Supply - Energy	\$ 12,420,888	\$ -	\$ -	\$ -	\$ (250,000)	\$ -	\$ -	\$ -
14	Operations - Transmission	\$ 8,036,486	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15	Operations - Administrative and General	\$ 9,191,902	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	Maintenance - Production, Steam	\$ 10,170,045	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17	Maintenance - Production, Other	\$ 2,809,881	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
18	Maintenance - Transmission	\$ 28,388	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
19	Maintenance - General Plant	\$ 63,958	\$ -	\$ -	\$ -	\$ -	\$ -	\$ (19,560)	\$ -
20	Depreciation and Amortization	\$ 7,608,735	\$ -	\$ -	\$ (69,446)	\$ -	\$ -	\$ -	\$ -
21	ACC Gross Revenue Taxes	\$ 288,752	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
22	Taxes	\$ 3,346,839	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
23	<b>Total Operating Expenses</b>	\$ 129,638,774	\$ 407,983	\$ 264,376	\$ (69,446)	\$ (250,000)	\$ (657,788)	\$ (19,560)	\$ 539,989
24	<b>Operating Margin Before Interest on L.T.- Debt</b>	\$ 7,972,676	\$ 143,951	\$ 1,007,531	\$ 69,446	\$ 250,000	\$ 657,788	\$ 19,560	\$ (539,989)
<b>INTEREST ON LONG-TERM DEBT &amp; OTHER DEDUCTIONS</b>									
25	Interest on Long-term Debt	\$ 13,547,749	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
26	Other Interest & Other Deductions	\$ 914,988	\$ -	\$ -	\$ (572,598)	\$ -	\$ -	\$ -	\$ -
27	<b>Total Interest &amp; Other Deductions</b>	\$ 14,462,737	\$ -	\$ -	\$ (572,598)	\$ -	\$ -	\$ -	\$ -
28	<b>MARGINS (LOSS) AFTER INTEREST EXPENSE</b>	\$ (6,490,061)	\$ 143,951	\$ 1,007,531	\$ 642,044	\$ 250,000	\$ 657,788	\$ 19,560	\$ (539,989)
<b>NON-OPERATING MARGINS</b>									
30	Interest Income	\$ 582,014	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
31	Other Non-operating Income	\$ 1,380,437	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
32	<b>Total Non-Operating Margins</b>	\$ 1,962,451	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
33	<b>EXTRAORDINARY ITEMS</b>	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
34	<b>NET MARGINS (LOSS)</b>	\$ (4,527,610)	\$ 143,951	\$ 1,007,531	\$ 642,044	\$ 250,000	\$ 657,788	\$ 19,560	\$ (539,989)

Footnote Explanations

- <sup>1</sup> Includes account nos. 500, 502 to 509
- <sup>2</sup> Includes account nos. 546, 548 to 550
- <sup>3</sup> Includes account nos. 555 to 557
- <sup>4</sup> Includes account nos. 510 to 515

LINE NO.	DESCRIPTION	(I) ADJ #8	(J) ADJ #9	(K) ADJ #10	(L) ADJ #11	(M) ADJ #12	(N) ADJUSTED
		Fuel Expense Ref: Sch CSB-20	Advertising Expense Ref: Sch CSB-21	Contributions & Other Expenses Ref: Sch CSB-22	ACC. Gross Rev Assessment Ref: Sch CSB-23	Interest on Long Term Debt Ref: Sch CSB-24	STAFF ADJUSTED
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	\$ -	\$ -	\$ -	\$ (147,146)	\$ -	\$ 50,996,438
5	Total Electric Revenue	\$ -	\$ -	\$ -	\$ (147,146)	\$ -	\$ 137,806,824
6	Other Operating Revenue	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,481,322
7	<b>Total Revenues</b>	\$ -	\$ -	\$ -	\$ (147,146)	\$ -	\$ 139,288,146
8	<b>OPERATING EXPENSES:</b>						
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	\$ -	\$ (46,241)	\$ (159,891)	\$ -	\$ -	\$ 8,036,486
15	Operations - Administrative and General	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 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	<b>Total Operating Expenses</b>	\$ (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	<b>INTEREST ON LONG-TERM DEBT &amp; OTHER DEDUCTIONS</b>						
26	Interest on Long-term Debt	\$ -	\$ -	\$ -	\$ -	\$ (234,585)	\$ 13,313,164
27	Other Interest & Other Deductions	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 342,390
28	<b>Total Interest &amp; Other Deductions</b>	\$ -	\$ -	\$ -	\$ -	\$ (234,585)	\$ 13,655,554
29	<b>MARGINS (LOSS) AFTER INTEREST EXPENSE</b>	\$ 1,053,073	\$ 46,241	\$ 159,891	\$ 141,606	\$ 234,585	\$ (2,673,780)
30	<b>NON-OPERATING MARGINS</b>						
31	Interest Income	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 582,014
32	Other Nonoperating Income	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,380,437
33	<b>Total Non-Operating Margins</b>	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 1,962,451
34	<b>EXTRAORDINARY ITEMS</b>	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
35	<b>NET MARGINS (LOSS)</b>	\$ 1,053,073	\$ 46,241	\$ 159,891	\$ 141,606	\$ 234,585	\$ (711,329)

**OPERATING INCOME ADJUSTMENT NO. 1 - POST-TEST YEAR REVENUE AND EXPENSE  
FOR COAL BLENDING PLANT**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	<b>Revenues</b>			
2	AEPCO Adjustment No. 5 - Fuel Expense	\$ (551,934)	\$ 551,934	\$ -
3	<b>Total Revenues</b>	<u>\$ (551,934)</u>	<u>\$ 551,934</u>	<u>\$ -</u>
4	<b>Expenses</b>			
5	AEPCO Adjustment No. 5 - Fuel Expense	\$ (1,534,274)	\$ 1,534,274	\$ -
6	AEPCO Adjustment No. 6 - SO2 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	<b>Total Operating Expenses</b>	<u>\$ (407,983)</u>	<u>\$ 407,983</u>	<u>\$ -</u>
10	<b>Operating Margin Before Interest on L.T. Debt</b>	\$ (143,951)	\$ 143,951	\$ -
11	AEPCO Adjustment No. 8 - Interest on L.T.-Debt (see Note)	\$ 532,465	\$ -	\$ 532,465
12	<b>Operating Margin After Interest on L.T. Debt</b>	<u>\$ (676,416)</u>	<u>\$ 143,951</u>	<u>\$ (532,465)</u>

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]

**OPERATING INCOME ADJUSTMENT NO. 2 - REVENUE AND EXPENSE ANNUALIZATIONS**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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	<b>Revenue Annualization Adjustment</b>	\$ -	\$ 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	<b>Adjustment to Expenses</b>	\$ -	\$ 264,376	\$ 264,376

Calculation of Annualization Factor							
Number of Customers							
	Anza	Duncan	Graham	Mohave	Sulphur	Trico	Total
14	2002	3,702	2,446	7,481	31,701	43,113	116,074
15	2003	3,824	2,484	7,623	32,804	44,431	119,895
16	Increase	122	38	142	1,103	1,318	3,821
17	% Increase	3.30%	1.55%	1.90%	3.48%	3.06%	3.29%
18	2003 Growth Rate						3.29%
19	Annualization Factor - 2003 Growth Rate divided by 2						1.6459%

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	1.65%	
	Adjustment to Expenses	\$ 264,376	

41 References:  
42 Column A: Cooperative Data Request Response CSB 6-1  
43 Column B: Testimony, CSB  
44 Column C: Column [A] + Column [B]

**OPERATING INCOME ADJUSTMENT NO. 3 - ASSET RETIREMENT OBLIGATION**

LINE NO.	DESCRIPTION	Effects on Net Margin				
		[A]	[B]	[C]	[D]	[E]
		AEP CO ACTUAL TEST YEAR Sch C-1, Page 1	AEP CO ADJUSTMENTS TO ACTUAL Sch C-1, Page 4	AEP CO 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]

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

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	<b>Base Cost of Power Revenue</b>			
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	<b>Adjustment to match Coop proposed power expense to revenue</b>	\$ 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	<b>Adjustment to reflect Staff's adjustments to power costs</b>	\$ 41,276,627	\$ (7,716,227)	\$ 33,560,400
8	<b>Total</b>	\$ 34,714,097	\$ (1,153,697)	\$ 33,560,400
9	<b>Base Cost of Power Expense</b>			
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	<b>Total Fuel Costs</b>	\$ 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	<b>Total Purchased Energy Costs</b>	\$ 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	<b>Total Firm and Non-Firm Wheeling Expenses</b>	\$ 77,291	\$ 7,939,635	\$ 8,016,926
37	<b>TOTAL FUEL COSTS &amp; PURCHASED ENERGY</b>	\$ 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	<b>Total Non-Tariff Sales Fuel Recovery, Energy and Demand</b>	\$ 26,705,282	\$ 23,367,330	\$ 50,072,612
53	<b>Member Fuel Costs-Base Cost of Pwr Exp (Line 37 - Line 52)</b>	\$ 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]

**OPERATING INCOME ADJUSTMENT NO. 5 - OVERHAUL ACCRUAL EXPENSE**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Overhaul Accrual Expense	\$4,787,508	\$ (657,788)	\$ 4,129,720

LINE NO.		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]

**OPERATING INCOME ADJUSTMENT NO. 6 - TRANSMISSION EXPENSE ANNUALIZATION FOR CONTRACTS**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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)				
	Per Cooperative	Adjustments	Per Staff	
4				
5				
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 References:

- 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.  
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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	<b>2003 Legal Expenses excl Rail Transportation Tariff Exp - Per Coop (Data Requ Response CSB 13-5)</b>	<b>\$ 903,512</b>
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	<b>Normalized Legal Expense - Per Staff</b>	<b>\$ 1,443,501</b>
10	Legal Expense - Per Cooperative (Line 1)	\$ 903,512
11	<b>Staff's Adjustment (Line 9 - Line 10)</b>	<b>539,989</b>

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.  
Docket No. E-01773A-04-0528  
Test Year Ended December 31, 2003

Schedule CSB-19.1

**NORMALIZED RAILROAD LEGAL EXPENSES**

<b>LINE NO.</b>	<b>DESCRIPTION</b>	<b>NORMALIZED RAILROAD TRANSPORTATION TARIFF LEGAL EXPENSE</b>	
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	<b>Staff's Adjustment</b>	\$	<b>(1,172,117)</b>

9 References:

10 Cooperative Data Request Response CSB 1-33, CSB 13-1, CSB 14-1, CSB 14-2, and Testimony, CSB

**NORMALIZED LEGAL EXPENSE**  
**Excluding Railroad Transportation Tariff Legal Expense**

LINE NO.	DESCRIPTION	Normalized Legal Expense Calculation (Excl Rail Transp)
1	<b>2003 Legal Expenses excl Rail Transportation Tariff Expense - Per Cooperative (CSB 13-5)</b>	\$ 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	<b>Adjusted 2003 Legal Expenses</b>	<u>\$ 712,664</u>
8	<b>2002 Total Legal Expenses - Per Cooperative</b>	\$ 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	<b>Adjusted 2002 Legal Expenses</b>	<u>\$ 799,496</u>
13	<b>2004 Total Legal Expenses - Per Cooperative</b>	\$ 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	<b>Adjusted 2004 Legal Expenses</b>	<u>\$ 957,955</u>
17	<b>Total Adjusted 2002, 2003 and 2004 Legal Expenses (Line 7 + Line 12 + Line 16)</b>	\$ 2,470,115
18	<b>Normalized Legal Expense (Line 17 divided by 3) - Per Staff</b>	\$ 823,372
19	Legal Expense - Per Cooperative (Line 1)	\$ 903,512
20	<b>Staff's Adjustment (Line 18 - Line 19)</b>	<u>(80,140)</u>
21	References:	
22	Data Request Responses CSB 13-5 and CSB 1-33; Schedules CSB-19.1 and CSB-19.2	

**OPERATING INCOME ADJUSTMENT NO. 8 - FUEL EXPENSE**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
<b>Summary of Variable Coal Fuel Costs</b>				
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	<b>Rail Invoices/Demurrge (Legal)</b>	<b>\$ 2,346,719.65</b>	<b>\$ (2,346,719.65)</b>	<b>\$ -</b>
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	<b>Steam 2 Dollars Burned (Line 13 x Line 14)</b>	<b>\$ 20,589,635.13</b>	<b>\$ (492,909.45)</b>	<b>\$ 20,096,725.68</b>
16	Adjustment to reconcile to actual Steam 2 Dollars Burned	\$ (213,586.55)	\$ 1,369.95	\$ (212,216.60)
17	<b>Actual Steam 2 Dollars Burned</b>	<b>\$ 20,376,048.58</b>	<b>\$ (491,539.50)</b>	<b>\$ 19,884,509.08</b>
18	Steam 3 Tons Burned	786,745.15	-	786,745.15
19	<b>Steam 3 Dollars Burned (Line 13 x Line 18)</b>	<b>\$ 22,514,833.38</b>	<b>\$ (538,998.10)</b>	<b>\$ 21,975,835.28</b>
20	Adjustment to reconcile to actual Steam 3 Dollars Burned	\$ (152,978.79)	\$ (335.59)	\$ (153,314.38)
21	<b>Actual Steam 3 Dollars Burned</b>	<b>\$ 22,361,854.59</b>	<b>\$ (539,333.69)</b>	<b>\$ 21,822,520.90</b>
22	<b>Total Steam Dollars Burned (Line 17 + Line 21)</b>	<b>\$ 42,737,903.17</b>	<b>\$ (1,030,873.19)</b>	<b>\$ 41,707,029.98</b>
23	<b>Procurement Costs</b>	<b>\$ 1,487,755.23</b>	<b>\$ -</b>	<b>\$ 1,487,755.23</b>
24	<b>Fixed Costs - Interest on L.T. Debt (CSB 3-14)</b>	<b>\$ 295,864.69</b>	<b>\$ (22,199.90)</b>	<b>\$ 273,664.79</b>
25	<b>Total Coal Fuel Costs</b>	<b>\$ 44,521,523.09</b>	<b>\$ (1,053,073.09)</b>	<b>\$ 43,468,450.00</b>

Reference: Data Request Response CSB 3-14

Arizona Electric Power Cooperative, Inc.  
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Schedule CSB-21

**OPERATING INCOME ADJUSTMENT NO. 9 - ADVERTISING EXPENSE**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		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]

**OPERATING INCOME ADJUSTMENT NO. 10 - CHARITABLE CONTRIBUTIONS & OTHER EXPENSES**

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A]	[B]	[C]
			COMPANY AS FILED	STAFF ADJUSTMENTS	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]

**OPERATING INCOME ADJUSTMENT NO. 11 - ACC GROSS REVENUE ASSESSMENT**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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]

**RAMIREZ**

**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.

1 **INTRODUCTION**

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

3 A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona  
4 Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff").  
5 My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

6  
7 **Q. Briefly describe your responsibilities as a Public Utilities Analyst.**

8 A. In my position as a Public Utilities Analyst, I perform studies to estimate the cost of  
9 capital component of the revenue requirement in rate proceedings. I also perform other  
10 financial analyses.

11  
12 **Q. Please describe your educational background and professional experience.**

13 A. In 2002, I graduated summa cum laude from Arizona State University, receiving a  
14 Bachelor of Science degree in Global Business with a specialization in finance. While  
15 attending Arizona State University, I successfully completed the Barrett Honors College  
16 curriculum. My course of studies included classes in corporate and international finance,  
17 investments, accounting, statistics, and economics. I began employment as a Staff Public  
18 Utilities Analyst in 2003. Since that time, I have provided recommendations to the  
19 Commission on financings and prepared various studies in the field of cost of capital and  
20 econometrics. I have also attended seminars related to general regulatory and business  
21 issues.

22  
23 **Q. What is the scope of your testimony in this case?**

24 A. I discuss Arizona Electric Power Cooperative, Inc.'s ("AEP" or "Applicant") current  
25 capital structure and provide Staff's recommended operating income. I also provide the

1 times interest earned ("TIER") and debt service coverage ("DSC") ratios resulting from  
2 Staff's recommended operating income.  
3

4 **SUMMARY OF TESTIMONY AND RECOMMENDATIONS**

5 **Q. Briefly summarize how your testimony is organized.**

6 **A.** This testimony is organized in three sections. Section I presents the Applicant's long-term  
7 debt and patronage equity balances. Section II discusses AEPCO's capital structure.  
8 Finally, Section III discusses Staff's recommended TIER and DSC ratios for the  
9 Applicant.  
10

11 **Q. Have you prepared any exhibits to your testimony?**

12 **A.** Yes. I prepared three schedules (AXR-1 to AXR-3) that support Staff's  
13 recommendations.  
14

15 **Q. What is Staff's recommended operating income for the Applicant?**

16 **A.** Staff recommends an operating income no less than \$17,755,094 for AEPCO (which is the  
17 operating income that would result from the Applicant's proposed revenues).  
18

19 **Q. What TIER and DSC ratios would result from Staff's minimum recommended  
20 operating income of \$17,755,094?**

21 **A.** Operating income of \$17,755,094 would produce a 1.33 TIER and a 0.91 DSC.  
22

23 **AEPCO'S LONG-TERM DEBT AND PATRONAGE AND EQUITY BALANCE**

24 **Q. What is the amount of AEPCO's long-term debt outstanding?**

25 **A.** The Applicant had \$218,909,935 in long-term debt outstanding as of November 1, 2004,

1 and it is expected to incur \$13,313,164 in interest expense related to its long-term debt  
2 during the year.

3  
4 **Q. What were AEPCO's patronage equity balances for the years ended 2003, 2002 and**  
5 **2001?**

6 **A.** AEPCO's patronage equity balances for the years ended 2003, 2002 and 2001 were  
7 \$10,754,721, \$17,803,568 and \$13,904,998, respectively.

8  
9 **AEPCO'S CAPITAL STRUCTURE**

10 **Q. What was AEPCO's actual end of test year capital structure?**

11 **A.** The Applicant's actual end of test year capital structure was composed by 95.2 percent  
12 debt and 4.8 percent patronage equity<sup>1</sup>. Schedule AXR-1 presents the Applicant's capital  
13 structures for the years 2001, 2002 and 2003.

14  
15 **Q. Is AEPCO concerned with its current capital structure?**

16 **A.** Yes. In his direct testimony, the Applicant's witness, Mr. William K. Edwards, has  
17 emphasized the importance for AEPCO to develop a stronger patronage equity base.  
18 Moreover, Mr. Edwards recognizes and supports the efforts made by both the Commission  
19 and AEPCO to establish long-term goals for AEPCO's patronage equity (Decision No.  
20 64227, dated November 29, 2001, and Decision No. 65210, dated September 20, 2002).

21  
22  
23

---

<sup>1</sup> Staff has calculated the capital structure by taking into account long-term debt and equity.

1 **Q. How does AEPCO's capital structure compare to other Generation and**  
2 **Transmission ("G&T") utilities' capital structure?**

3 **A.** Mr. William Edwards has compared AEPCO's capital structure to the Capital structure of  
4 55 G&T utilities' capital structure. As mentioned in his testimony, AEPCO's capital  
5 structure is more leveraged than Mr. Edwards' G&T utilities sample (See Mr. Edwards  
6 Direct Testimony, Page 8, Line 16-17). Schedule AXR-2 presents the capital structure of  
7 some G&T cooperatives that are rated by *Standard & Poor's* ("S&P") and the Applicant's  
8 capital structure for the test year ended December 2003. The average capital structure of  
9 the G&T cooperatives is composed of 81.0 percent debt and 19.0 percent patronage equity  
10 as opposed to the Applicant's capital structure composed of 95.2 percent debt and 4.8  
11 percent patronage equity.

12  
13 **Q. Is Staff concerned with the Applicant's actual end of test year capital structure?**

14 **A.** Yes. AEPCO's capital structure is highly leveraged as it has remained for several years.  
15 The Applicant's capital structure has multiple potential negative effects including: (1)  
16 higher debt costs for new issuances; (2) reduced ability to incur new debt and finance  
17 capital improvements; and (3) places upward pressure on rates to cover debt service  
18 obligations.

19  
20 **Q. Has the Commission shown concern with highly leveraged cooperatives?**

21 **A.** Yes. In Decision No. 58405 (dated September 3, 1993), the Commission stated that  
22 "...there is a balance to be struck between keeping rates competitive and eliminating  
23 negative equity, but we fail to see any strong commitment or serious steps taken on  
24 AEPCO's part to build its equity (Page 23, lines 6-9)". In addition, the Commission  
25 ordered Arizona Electric Power Cooperative ("AEPCO") (Decision No. 64227, dated

1 November 29, 2001) and SWTCO (Decision No. 64991, dated June 26, 2002) to establish  
2 long-range goals to improve their patronage equity positions. In addition, the Commission  
3 ordered Trico Electric Cooperative, Inc. ("Trico") to file a capital improvement plan with  
4 the Commission (Decision No. 67412, dated November 2, 2004). As discussed previously,  
5 highly leveraged capital structures present potentially negative consequences.

6

7 **Q. Does the Rural Utilities Service ("RUS") have any restrictions in regard to**  
8 **distribution of patronage dividends for highly leverage cooperatives?**

9 **A.** Yes. AEPCO's audited financial statements for the years ended December 31, 2003 and  
10 2002, state "RUS mortgage provisions require written approval of any declaration or  
11 payment of capital credits. These provisions restrict the payment of capital credits to 25  
12 percent of the margins received by the Cooperative in the preceding year, unless total  
13 membership capital exceeds 40 percent of the total assets of the Cooperative (See Exhibit  
14 GEP-1, note to financial statement 12)".

15

16 **Q. Does the National Rural Utilities Cooperative Finance Corporation ("CFC") have**  
17 **any restrictions in regard to distribution of patronage dividends for highly leverage**  
18 **cooperatives?**

19 **A.** Yes. The CFC requires a borrower to have a capital structure composed of at least 30  
20 percent patronage equity to distribute 100 percent of its net earnings as patronage  
21 dividends. If the borrower has a capital structure composed of less than 30 percent  
22 patronage equity, it would be able to distribute as patronage dividends only 30 percent of  
23 its patronage capital or operating margins for the preceding year.

24

1 **Q. What approach does Staff recommend to improve AEPCO's capital structure?**

2 A. Staff recommends steadily growing the Applicant's patronage equity by setting rates that  
3 balance the interest of the ratepayers and AEPCO's long-term financial health. AEPCO  
4 has not shown how its proposed rates will improve its highly leveraged capital structure in  
5 a reasonable timeframe. Staff anticipates that the Applicant will use the opportunity  
6 provided by rebuttal testimony to explain how its proposed rate will adequately satisfy its  
7 capital structure deficiency.  
8

9 **OPERATING INCOME, TIER AND DCS RATIOS**

10 **Q. What do the times interest earned ("TIER") and the debt service coverage ("DSC")**  
11 **ratios represent?**

12 A. TIER represents the number of times operating income covers interest expense on long-  
13 term debt. A TIER greater than 1.0 means that operating income is greater than interest  
14 expense.

15 DSC represents the number of times internally generated cash covers required principal  
16 and interest payments on long-term debt. A DSC greater than 1.0 indicates that operating  
17 cash flow is sufficient to cover debt obligations.  
18

19 **Q. Do the Applicant's lenders have debt covenants for TIER and DSC?**

20 A. Yes. The Rural Utilities Service ("RUS") requires AEPCO to maintain a minimum TIER  
21 of 1.05 and a minimum DSC of 1.0 on an annual average best two of three year basis.  
22

23 **Q. What TIER and DSC level does the Applicant claim will result from its proposed**  
24 **revenues?**

1 A. The Applicant claims its proposed revenues would result in a 1.29 TIER and a 1.05 DSC.  
2 AEPCO's witness, Mr. Edwards, states in his direct testimony that "...these are minimum  
3 ratios to provide some financial stability and allow for equity improvement (Mr. Edwards  
4 Direct Testimony, Page 11, Line 4 & 5)".

5

6 **Q. What TIER and DSC level does Staff conclude would result from the Applicant's**  
7 **proposed revenues?**

8 A. Staff has calculated that AEPCO's proposed revenues would result in a TIER of 1.33  
9 which also equates to a 0.91 DSC. The Applicant's proposed revenues are not sufficient  
10 to service its debt obligations.

11

12 **Q. Has the Applicant demonstrated that its proposed revenues are sufficient to improve**  
13 **its equity position in a reasonable timeframe?**

14 A. No. The Applicant has provided no support to demonstrate that its proposed revenues are  
15 sufficient to provide patronage equity growth to achieve a capital structure of at least 30  
16 percent patronage equity in a reasonable timeframe.

17

18 **Q. What does Staff recommend in regard to AEPCO's revenues, TIER, and DSC?**

19 A. Staff recommends no reduction to AEPCO's proposed operating revenue. Staff's analysis  
20 shows that the Applicant's proposed revenues are inadequate to cover its debt service  
21 obligations. The Applicant's current financial situation and proposed revenues would not  
22 support additional debt financing such as its November 4, 2004 request for authorization  
23 for debt financing (Docket No. E-01773A-04-0793).

1

2 **CONCLUSION**

3 **Q. Please summarize Staff's recommendations.**

4 **A.** Staff recommends that the Commission adopt operating revenues of no less than those  
5 proposed by the Applicant. The Applicant's proposed revenues fail to provide sufficient  
6 internally generated cash flow to finance, directly or indirectly through additional future  
7 debt financing, plant replacement, improvement and expansion requirements. The  
8 Applicant has not demonstrated that its proposed revenue is consistent with the  
9 Commission's order (Decision No. 64227, dated November 29, 2001) to establish long-  
10 range goals to improve its patronage equity position. Staff recommends that the Applicant  
11 improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

12

13 Staff also recommends that the Commission restrict the distribution of future patronage  
14 dividends by AEPCO until it has achieved a capital structure composed of at least 30  
15 percent patronage equity.

16

17 **Q. Does this conclude your direct testimony?**

18 **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 <sup>1</sup>	% Patronage Equity <sup>1</sup>
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. <sup>2</sup>	95.2%	4.8%

<sup>1</sup> Information based on annual reports for the year ended 2003

<sup>2</sup> Based on the Company's rate filing

<u>AEPCCOS' TIER and DSC With Staff's Recommended Rates<sup>1</sup></u>				
1	Operating Income	\$ 17,755,095	<b>TIER</b>	
2	Depreciation & Amort.	\$ 7,539,289	[1+3] ÷ [5]	1.33
3	Income Tax Expense	\$ -	<b>DSC</b>	
4			[1+2+3] ÷ [5+6]	0.91
5	Interest Expense	\$ 13,313,164		
6	Repayment of Principal	\$ 14,360,494		

<sup>1</sup> The amounts reflect Staff's pro forma adjustments and the Applicant's proposed revenue

KEENE

**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  
BARBARA KEENE  
PUBLIC UTILITIES ANALYST  
UTILITIES DIVISION  
ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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**APPENDICES**

1. Resume of Barbara Keene
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.

1 **INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Barbara Keene. My business address is 1200 West Washington Street,  
4 Phoenix, Arizona 85007.

5  
6 **Q. By whom are you employed and in what capacity?**

7 A. I am employed by the Utilities Division of the Arizona Corporation Commission as a  
8 Public Utilities Analyst. My duties include evaluation of electric utility special contracts,  
9 review of utility tariff filings, assessment of utility demand-side management programs,  
10 and analysis of electric utility production costs and marginal costs. A copy of my résumé  
11 is provided in the Appendix.

12  
13 **Q. As part of your employment responsibilities, were you assigned to review matters  
14 contained in Docket Nos. E-04100A-04-0527 and E-01773A-04-0528?**

15 A. Yes.

16  
17 **Q. What is the purpose of your testimony?**

18 A. My testimony is concerned with a fuel and purchased power cost adjustor, a demand-side  
19 management ("DSM") adjustor, and rate design for Arizona Electric Power Cooperative  
20 ("AEPCO").

21  
22 **FUEL AND PURCHASED POWER COST ADJUSTOR**

23 **Q. What has AEPCO requested in regard to an adjustor?**

24 A. AEPCO (witness Gary Pierson's direct testimony, pages 14-15) has requested that the  
25 Commission approve an adjustor mechanism that would enable the recovery of increases  
26 and decreases in the fuel and purchased energy costs over which AEPCO has little  
27 control, without the time and expense of a rate case.

28

1 **Q. Does AEPCO currently have a fuel and purchased power cost adjustor?**

2 A. Not currently. AEPCO did have a Purchased Power and Fuel Adjustment Clause  
3 (“PPFAC”) that was eliminated, at AEPCO's request, in Decision No. 64677 (March 27,  
4 2002). The PPFAC, created in 1982, was a very complicated mechanism without clear  
5 understanding about its structure, leading to disagreements between AEPCO and Staff  
6 over the years. The PPFAC was discontinued as of August 1, 2001. However, at that  
7 time AEPCO indicated it would explore a revised adjustor mechanism in the future.

8

9 **Q. How does AEPCO propose that the new adjustor mechanism work?**

10 A. Mr. Pierson's direct testimony, page 15, suggests that an adjustor base be established in  
11 this rate case and that changes from the base would be tracked monthly and recouped as a  
12 positive or negative charge in the next quarter's billing to the Class A members. The base  
13 cost (AEPCO's Schedule H-2A) would include fuel costs (less fixed costs), purchased  
14 power energy costs, and non-firm wheeling costs. The costs would be offset by the fuel  
15 cost recovery portion of non-tariff sales. In response to BEK 16-3, Mr. Pierson has  
16 changed the request for a quarterly adjustment to a semi-annual adjustment.

17

18 **Q. What is Staff's position regarding an adjustor mechanism?**

19 A. Staff is not opposed to the establishment of a Fuel and Purchased Power Cost Adjustor  
20 (“FPPCA”) with certain features and conditions.

21

22 **Q. Please describe the structure of the adjustor mechanism that Staff would not  
23 oppose.**

24 A. The FPPCA would track changes in the cost of fuel for AEPCO's generating units and  
25 power purchased from others. The adjustor rate would be calculated by comparing the  
26 rolling 12-month average of actual fuel and purchased power costs to the base cost  
27 established in this rate case. The rate would be applied to customer bills as a kilowatt-  
28 hour (kWh) charge.

1 **Q. What cost components would be included in the adjustor?**

2 A. The cost components would be the costs recorded in RUS Accounts 501 (fuel costs for  
3 steam power generation, less legal fees, less fixed fuel costs except for gas reservation),  
4 547 (fuel costs for other power generation), 555 (purchased power costs, both demand  
5 and energy), and 565 (wheeling costs, both firm and non-firm). The prudent direct costs  
6 of contracts used for hedging fuel and purchased power costs may also be included.  
7 Power supply costs directly assignable to special contract customers would not be  
8 included in the calculation. Non-Class A sales for resale (RUS Account 447), less  
9 revenue for legal expenses, would be credited against the cost components.

10

11 **Q. How does Staff's proposal differ from AEPCO's proposal regarding the components**  
12 **in the adjustor?**

13 A. Staff proposes to include gas reservation charges, demand charges for purchased power,  
14 firm wheeling costs, and non-energy charge revenue from non-Class A sales for resale  
15 that AEPCO did not propose to be included in the adjustor.

16

17 **Q. Why is Staff proposing that those items be included?**

18 A. Gas reservation charges should be included because they are a part of the cost of  
19 obtaining natural gas for operating power plants.

20

21 Demand charges for purchased power should be included so that the method of cost  
22 recovery does not influence decision making when negotiating contracts. Some contracts  
23 in the marketplace are structured with only a per kWh energy charge that would include  
24 capacity costs. Other contracts are structured so that capacity costs are recovered through  
25 a per kW demand charge. AEPCO should negotiate these contracts so that they obtain  
26 the best deal for ratepayers. If only energy charges went into the adjustor, the method of  
27 cost recovery could influence the resulting structure of the contracts.

28

1 Firm wheeling costs should be included in the adjustor because they should be considered  
2 when negotiating purchased power and wheeling contracts. If only non-firm wheeling  
3 costs were included in the adjustor, the method of cost recovery could influence the type  
4 of contract that AEPCO would negotiate.

5  
6 Including all revenue from non-Class A sales for resale as an offset to costs allows the  
7 Class A members to benefit from the margins of those sales. Since Class A members pay  
8 for the costs of the resources, it only seems fair that they benefit from the non-Class A  
9 sales.

10  
11 **Q. How often would the adjustor rate be reset?**

12 A. The adjustor rate, initially set at zero, would be reset semi-annually on October 1, 2006,  
13 and April 1, 2007, and thereafter on October 1 and April 1 of each subsequent year.  
14 AEPCO would submit a publicly available report, with a revised tariff, that shows the  
15 calculation of the new rate on September 1, 2006, and March 1, 2007, and thereafter on  
16 September 1 and March 1 of each subsequent year. The adjustor rate would become  
17 effective with billings for October and April unless suspended by the Commission.

18  
19 **Q. Are the above dates different from those proposed by AEPCO?**

20 A. Yes. Staff changed the dates to have the new rates go into effect before the winter season  
21 and before the summer season, taking into account the probable time for a Commission  
22 decision in this case.

23  
24 **Q. Would there be a balancing account?**

25 A. Yes. The dollars associated with the calculation of the adjustor rate would be  
26 accumulated in a balancing account.

1 **Q. At what amount should the base cost be set?**

2 A. The base cost of fuel and purchased power would be set at \$0.01657 per kWh.  
3 Derivation of the base costs is shown in Appendix 2.

4  
5 **Q. Would the structure of the FPPCA have the same problems as the old PPFAC?**

6 A. No. The old PPFAC required that individual supply resources be matched to specific  
7 customer classes, without a clear-cut method of how to do it. The new FPPCA would not  
8 require the matching because all of the costs of resources are added together, and all of  
9 the non-Class A member sales are credited against the costs.

10  
11 **Q. Please describe Staff's recommended conditions.**

12 A. Staff is not opposed to an adjustment mechanism with the following conditions:

13 1. **The FPPCA would expire in five years unless it is extended by the**  
14 **Commission.** AEPCO would file a report that addresses the FPPCA's operation,  
15 its merits, and its shortcomings and that provides recommendations as to whether  
16 the FPPCA should remain in effect. In order to allow time for review of the  
17 adjustor before the five-year expiration date, the report should be filed in its next  
18 rate case application or no later than four years from the effective date of  
19 implementation of the FPPCA. The Commission would consider whether to  
20 continue the FPPCA after AEPCO has filed its FPPCA report or during AEPCO's  
21 next rate case, whichever comes first.

22 2. **The Commission or its Staff would have the right to review the prudence of**  
23 **fuel and power purchases at any time.** Conducting a prudence review involves  
24 reviewing the utility's purchasing activities both as individual transactions and as  
25 an overall supply portfolio, generating unit performance, and other related issues.  
26 Such a review would consider what the utility knew or should have known at the  
27 time actions were taken. Prudence reviews can be time consuming. In light of  
28

1 these issues, the Commission should not be limited as to when it may conduct a  
2 prudence review of AEPCO's purchasing practices.

3 **3. The Commission or its Staff would have the right to review any calculations**  
4 **associated with the FPPCA at any time.** The Commission needs the flexibility  
5 to monitor the calculations on a frequent and regular basis to ensure clarity and  
6 the correctness of those calculations for the ratepayers.

7 **4. Any costs flowed through the FPPCA would be subject to refund if the**  
8 **Commission later determines that the costs were not prudently incurred.**  
9 This condition would give AEPCO an incentive to minimize costs.

10 **5. AEPCO would file monthly reports to Staff's Compliance Section detailing**  
11 **all calculations related to the FPPCA.** The first report would be due 60 days  
12 from the effective date of a Commission order in this rate case. Thereafter, these  
13 reports would be due on the first day of the third month following the end of the  
14 reporting month for which the information applies. The reports would be publicly  
15 available and would contain, at a minimum, the following items:

- 16 a. bank balance calculation, including all inputs and outputs;
- 17 b. total power and fuel costs;
- 18 c. Class A member sales in both kWh and dollars by member;
- 19 d. a detailed listing of all items excluded from the FPPCA calculations;
- 20 e. a detailed listing of any adjustments to the reports;
- 21 f. non-class A member sales;
- 22 g. system losses in MW and MWh;
- 23 h. monthly maximum demand in MW; and
- 24 i. identification of a contact person and phone number from AEPCO for  
25 questions.

26 **6. AEPCO would file additional monthly reports with Staff providing**  
27 **information on AEPCO's generating units, power purchases, and fuel**  
28 **purchases.** The first report would be due 60 days from the effective date of a

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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

1           b.     natural gas commodity costs, categorized by short-term purchases (one  
2                     month or less) and long-term purchases, including price per therm, total  
3                     cost, supply basin, and volume, by contract.

4           7.     **An AEPCO Officer would certify under oath that all information provided in**  
5                     **the required reports is true and accurate to the best of his or her information**  
6                     **and belief.** The Officer should be high level, either Chief Executive Officer,  
7                     Chief Operating Officer, or Chief Financial Officer.

8           8.     **AEPCO should file a plan of administration that describes how the FPPCA**  
9                     **would operate.** The plan would be filed for Staff review within 30 days of a  
10                    decision in this rate case.

11  
12     **DEMAND-SIDE MANAGEMENT**

13     **Benefits of DSM**

14     **Q.     What is DSM?**

15     A.     DSM is the planning, implementation, and evaluation of programs to shift peak load to  
16             off-peak hours, to reduce peak demand (kW), and to reduce energy consumption (kWh)  
17             in a cost-effective manner.

18  
19     **Q.     Does AEPCO and the rest of society benefit from having DSM programs?**

20     A.     Cost-effective DSM programs can meet the demand for electric energy services at a  
21             lower cost than purchasing or generating power. Reduced peak demand can delay the  
22             need for construction of new generation and transmission facilities. In addition, reducing  
23             energy needs reduces the operating costs of current generating facilities. Reduced energy  
24             production may also lead to reduced air emissions from power plants, reduced  
25             consumption of water by generating unit cooling towers, and reduced degradation of land  
26             at mining sites.

1 **Q. Why should AEPCO and Staff consider the benefits and costs of DSM to society**  
2 **rather than just to AEPCO?**

3 A. We are seeking the least cost means of meeting the demand for electric energy services.  
4 A program that is not least cost wastes society's resources. Because customer costs and  
5 new generation costs may not be part of AEPCO's costs, we need to look beyond  
6 AEPCO's costs and benefits. The Commission adopted the use of the societal cost test in  
7 its resource planning decision (Decision No. 57589).  
8

9 **Q. What are the societal benefits of a DSM program?**

10 A. From a societal perspective, relevant benefits come from avoiding new generating,  
11 transmission, and distribution capacity and avoiding burning of fuel and other variable  
12 costs. Because existing power plants have already been built and the associated societal  
13 costs have already been incurred, the fixed costs of existing power plants are sunk costs  
14 which cannot be avoided by a reduction in the demand for kW and kWh. Therefore, the  
15 only costs to society that can be avoided by DSM are those associated with the  
16 construction of new capacity and the variable costs associated with the generation of  
17 additional electricity.  
18

19 **Q. How can the societal costs of a DSM program be calculated?**

20 A. The costs to society to implement a DSM program are the incremental costs of any  
21 equipment, including installation and operating costs, and program administrative costs.  
22 Incentives offered to customers to participate are not societal costs, but are transfer  
23 payments (transfers of income from one person or organization to another without  
24 supplying goods or services for these payments).  
25

26 **Q. Does AEPCO currently have any DSM program?**

27 A. No. According to AEPCO's response to BEK 5-6, AEPCO currently does not administer  
28 or coordinate member distribution cooperative DSM programs. Following the

1 Commission's suspension of most of the Resource Planning rules in 1997, the institution  
2 of various DSM programs by some of AEPCO's member distribution cooperatives, and  
3 the cancellation of its PPFAC (which included a DSM component), AEPCO phased out  
4 its involvement in DSM programs.

5  
6 **Q. What DSM programs should AEPCO pursue?**

7 A. AEPCO should evaluate possible DSM programs, considering the costs and kW and kWh  
8 savings associated with each program. AEPCO should then select the most beneficial  
9 and cost-effective projects to pursue. Ideally, AEPCO should engage in DSM programs  
10 as long as the incremental societal benefits (deferred capacity, avoided fuel costs, and  
11 avoided environmental impacts) are greater than the incremental cost of those programs  
12 to society.

13  
14 Because AEPCO is a wholesaler, it should work with its member distribution  
15 cooperatives to develop and implement programs as was done in the past.

16  
17 **Cost Recovery of DSM Programs**

18 **Q. What cost recovery mechanisms could be used to recover AEPCO's DSM costs?**

19 A. Possible mechanisms include using a deferral account with amortization into base rates,  
20 simply putting a level of costs in base rates, recovery through any fuel and purchased  
21 power adjustor approved for AEPCO, or setting up a separate DSM adjustment  
22 mechanism.

23  
24 **Q. Should AEPCO recover its DSM costs through a deferral account with base rate  
25 amortization?**

26 A. No. When a deferral account is used, pre-approved DSM costs are placed in the deferral  
27 account and earn interest until the utility's next rate case, when the costs are considered  
28 for base rate cost recovery. If there are significant DSM activities taking place, the

1 deferral account balance grows quickly, including the attendant interest, and can become  
2 a major cost which has to be dealt with in the utility's next rate case. In addition, a  
3 deferral account may not allow for the timely recovery of DSM costs to the same extent  
4 as some other cost recovery mechanisms.

5  
6 **Q. Should AEPCO recover its DSM costs directly through base rates with no deferral**  
7 **accounting?**

8 A. No. Placing DSM costs in base rates does not provide the Commission and AEPCO with  
9 flexibility to increase or decrease DSM spending, as circumstances dictate. Additionally,  
10 a utility could choose to end its DSM activities, and there would be no way to remove the  
11 DSM funding from base rates until the next rate case.

12  
13 **Q. Should AEPCO recover its DSM costs through a fuel and purchased power adjustor**  
14 **(if approved for AEPCO)?**

15 A. No. While recovery of DSM costs through a fuel and purchased power adjustor would  
16 provide timely and more flexible cost recovery, it would complicate the administration of  
17 the fuel and purchased power adjustor.

18  
19 **Q. How should AEPCO recover its costs for DSM programs?**

20 A. Staff recommends that AEPCO be allowed to recover its costs for pre-approved DSM  
21 programs through a separate DSM adjustment mechanism. Recovery of pre-approved  
22 DSM costs through a DSM adjustment mechanism would provide the flexibility to adjust  
23 the level of DSM spending as needed in the future, while also providing timely recovery  
24 of pre-approved DSM costs. It would also provide a separate and specific accounting for  
25 pre-approved DSM costs.

26  
27 A DSM adjustment mechanism would allow the costs associated with pre-approved  
28 programs to be recovered as the level of expenses associated with those programs

1 changes. In addition, separating these expenses from other expenses included in base  
2 rates provides an incentive to initiate programs at any time rather than in the context of a  
3 rate case.

4  
5 **Q. How would customers be billed?**

6 A. The DSM adjustment mechanism, as a charge per kWh, would be included on customer  
7 bills as a separate line item.

8  
9 **Q. How would the proposed DSM adjustment mechanism work?**

10 A. The proposed DSM adjustment mechanism would consist of an account where the costs  
11 for pre-approved DSM programs would be recorded for each program by AEPCO as the  
12 costs were incurred. Revenues received through the DSM adjustor would be credited to  
13 the account. The per kWh adjustor rate would initially be set at zero. By February 1 of  
14 each year, AEPCO would file a request and supporting documentation with Staff to set a  
15 new adjustor rate to be effective on March 1. The new rate would be calculated by  
16 dividing the account balance by the number of kWh used by customers in the previous  
17 calendar year.

18  
19 **Q. What kinds of costs should AEPCO be able to recover?**

20 A. Staff recommends that AEPCO recover the program costs associated with pre-approved  
21 DSM projects. Program costs include administrative expenses, monitoring expenses, any  
22 incentives such as rebates, promotional expenses, educational program expenses, and the  
23 costs of demonstration facilities.

1 **Implementation of DSM Programs**

2 **Q. How should AEPCO implement DSM programs?**

3 A. AEPCO should submit proposed programs to the Commission for approval. After a  
4 program is approved, AEPCO may begin entering the costs for that program as they are  
5 incurred into the DSM adjustment mechanism account.

6  
7 **Q. What should AEPCO include in a DSM program proposal?**

8 A. The proposal should include a description of the program, objectives and rationale for the  
9 program, identification of the market segment at which the program is aimed; expected  
10 level of program participation, an estimate of the baseline, estimated societal benefits and  
11 savings from the program, estimated societal costs of the program, marketing and  
12 delivery strategy, utility costs and budget, an implementation schedule, a monitoring and  
13 evaluation plan, and any proposed performance incentives.

14  
15 Staff would consider whether the benefits of the measures to society exceed the costs to  
16 society. In addition, Staff would consider the reasonableness of any customer incentives  
17 proposed by AEPCO. Staff would then provide the Commission with a recommendation  
18 regarding the DSM proposal. New programs could be added or existing programs  
19 terminated anytime during the year subject to Commission approval.

20  
21 **Q. Why should each program proposal include a monitoring and evaluation plan?**

22 A. AEPCO should include a monitoring plan in each program proposal because AEPCO  
23 needs to monitor and evaluate all DSM programs to reliably ensure that they are cost-  
24 effective. Monitoring and evaluation should:

- 25 1. determine participation rates, energy savings, and demand reductions;  
26 2. assess the utility's program implementation process;  
27 3. provide information on whether to continue, modify, or terminate a program; and  
28 4. determine the persistence and reliability of DSM.

1 **Q. What are Staff's recommendations regarding monitoring?**

2 A. If the monitoring activity reveals that the program is not working as well as expected,  
3 AEPCO should modify or terminate the program. AEPCO should file an application with  
4 the Commission about any plans to terminate a program before such termination occurs.  
5 AEPCO should provide its plans for notification to potential participants. If a program is  
6 terminated, AEPCO would be expected to give proper notice to potential participants as  
7 well as honor existing commitments.

8  
9 **Q. How can Staff and the Commission monitor AEPCO's efforts?**

10 A. Staff recommends that AEPCO submit annual reports to the Commission containing, at a  
11 minimum, the following information separately for each program: a brief description of  
12 the program; predetermined program goals, objectives, and savings targets; the level of  
13 customer participation; costs incurred during the reporting period disaggregated by type  
14 of cost (such as administrative costs, rebates, and monitoring costs); a description of  
15 evaluation and monitoring activities and results; kW and kWh savings; benefits and net  
16 benefits in dollars; any program-specific performance incentive calculations; problems  
17 encountered and proposed solutions; and proposed program modifications. Findings  
18 from all research projects and other significant information should be included. Each  
19 annual report would be due on February 1, reporting for the previous calendar year.

20  
21 Staff also recommends that AEPCO file quarterly reports that consist of a tabular  
22 summary of expenditures compared to the budget. Quarterly reports would be due on  
23 May 1 (for January through March), August 1 (for April through June), and November 1  
24 (for July through September). Information on the last quarter of the year would be  
25 included in the annual report.

26  
27 In addition, the Commission may review program costs and performance in future rate  
28 cases.

1 **RATE DESIGN**

2 **Q. What do you recommend as AEPCO's rates for its Class A members?**

3 A. Based on Staff's recommended revenue requirements, the rates should be set as follows:

4 Full Requirements

5 Demand charge \$12.90 per kW of demand coincident with AEPCO  
6 monthly peak

7 Energy charge \$0.02079 per kWh used during billing period

8 Partial Requirements

9 O&M charge \$7.48 per kW of allocated capacity based on coincident  
10 AEPCO demand

11 Energy charge \$0.02079 per kWh used during billing period

12 Fixed Charge \$707,392 per month for Mohave

13  
14 These rates would result in an overall increase for Class A members of 7.8 percent.  
15 Mohave Electric's increase would be 15.3 percent, while the increase for the other  
16 distribution cooperatives would be 4.1 percent each.

17  
18 **SUMMARY OF STAFF RECOMMENDATIONS**

19 **Q. Please summarize Staff's recommendations.**

20 A. 1. Staff recommends that a fuel and purchased power cost adjustor be established for  
21 AEPCO but only with certain features and conditions.

22 2. Staff recommends that the base cost of fuel and purchased power be set at  
23 \$0.01659 per kWh.

24 3. Staff recommends that AEPCO engage in cost-effective DSM programs.

25 4. Staff recommends that AEPCO be allowed to recover its program costs for pre-  
26 approved DSM projects through a DSM adjustment mechanism.

27 5. Staff recommends that AEPCO submit annual and quarterly DSM reports to the  
28 Commission.

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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," *NRRRI 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 AEP CO Adjustor**

RUS  
Account

501	fuel costs for steam power generation less MEC Schedule A adjustment less City of Mesa adjustments less legal fees less fixed fuel costs (except gas reservation)	\$46,830,878 -550,220 -407,498 -1,030,873 -295,865 <b>\$44,546,422</b>
547	fuel costs for other power generation	<b>\$15,464,540</b>
555	purchased power costs (demand & energy) less MEC Schedule A adjustment less City of Mesa adjustments plus Purchase Power adjustment less PNM adjustment	\$16,270,579 -333,790 -169,803 88,139 -250,000 <b>\$15,605,125</b>
565	wheeling costs (firm & non-firm) plus wheeling contract adjustment	\$8,036,486 -19,560 <b>\$8,016,926</b>
	<b>Costs</b>	<b>\$83,633,013</b>
447	non-Class A sales for resale plus MEC Schedule B reclassification less City of Mesa adjustments less revenue for legal expenses	\$51,757,181 142,921 -903,664 -923,826 <b>\$50,072,612</b>
	<b>Revenues</b>	<b>\$50,072,612</b>
	<b>Base Cost (Costs-Revenues)</b>	<b>\$33,560,401</b>
	Class A kWh sales	2,025,326,533
	<b>\$/kWh</b>	<b>\$0.01657</b>

**J. SMITH**

**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

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**EXHIBITS**

Engineering Report, Docket No. E-01773A-01-0701 .....	JDS-1
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 ("AEPSCO") filed a rate application with the Arizona Corporation Commission ("ACC or Commission") on July 23, 2004. The 2003 calendar year was selected by AEPSCO 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. AEPSCO 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 AEPSCO 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 AEPSCO's rate application is used and useful.

1 **WITNESS BACKGROUND AND QUALIFICATION**

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

3 A. My name is Jerry D. Smith. I am an Electric Utility Engineer employed by the Arizona  
4 Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff").  
5 My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

6  
7 **Q. Please describe your educational background.**

8 A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science  
9 degree in Electrical Engineering. I received a Masters of Science degree in Electrical  
10 Engineering from New Mexico State University in 1977 majoring in power systems and  
11 electric utility management.

12  
13 **Q. Do you hold any special licenses or certificates?**

14 A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

15  
16 **Q. Briefly describe your responsibilities as an Electric Utility Engineer.**

17 A. I joined the Commission's Utilities Division Staff as an electric engineer in 1999. In my  
18 capacity as an Electric Utility Engineer, I have investigated the quality of service provided  
19 by electric utilities in Arizona and been responsible for three biennial transmission  
20 assessments regarding the reliability of existing and planned Arizona transmission  
21 facilities. During my employment at the Commission, I have investigated numerous  
22 system disturbances on behalf of the Commission. A 1999 blackout of Southern Arizona,  
23 a 2001 blackout of Gila Bend, and several extra high voltage ("EHV") disturbances  
24 occurring in 2003 and 2004 are among the system disturbances I have investigated. My  
25 most recent investigations were of the Westwing and Deer Valley Substation fires.

26

1 I chaired a series of Commission Distributed Generation workshops in 1999 and have  
2 participated in the revision and application of electric retail competition rules throughout  
3 Arizona. I have also inspected physical electric utility plant consisting of generation,  
4 transmission and distribution facilities. Such facility inspections were necessary to make a  
5 "used and useful" determination for rate case applications and to ascertain the level of  
6 security, safety, operational integrity, and maintenance exhibited by such facilities.

7  
8 **Q. Please describe other pertinent work experience.**

9 A. I have over 27 years of experience as an engineer and manager in the electric utility  
10 industry. I was employed by the Salt River Project from 1968 through 1995. During that  
11 time I: 1) analyzed and planned transmission and distribution system improvements; 2)  
12 managed the design and consultation services required for retail customer projects; and 3)  
13 served as primary contact for local municipalities regarding siting of facilities and  
14 utilizing funds for aesthetic treatment of water and power facilities. I also performed  
15 ancillary functions such as development and management of capital improvement budgets;  
16 formation and modification of system planning, operational and maintenance policies,  
17 procedures and practices; and creation, modification and administration of new  
18 contribution in aid of construction charges and tariffs.

19  
20 **Q. Have you previously testified before this Commission?**

21 A. Yes. I have extensive experience testifying before the Commission. I have testified on  
22 numerous occasions regarding quality of service to electric customers in the City of  
23 Nogales and Santa Cruz County. I was a Staff witness regarding the 2003 competitive  
24 wholesale power solicitations required by the Commission. I have provided testimony for  
25 over 35 power plant and transmission line applications for a Certificate of Environmental  
26 Compatibility. My experience filing engineering reports and providing testimony for the

1 Commission in rates cases is most applicable to this case. I have provided engineering  
2 reports and rate case testimony for Duncan Valley Electric Cooperative, Navapache  
3 Electric Cooperative, and the Arizona Public Service Company and an Open Access  
4 Transmission Tariff ("OATT") case for Southwest Transmission Cooperative.  
5

6 **PURPOSE AND PREPARATION OF TESTIMONY**

7 **Q. What is the purpose of your testimony in this case?**

8 A. I am providing testimony concerning the security, safety, operational integrity, and  
9 maintenance status of AEPCO's Apache Station power plant. My testimony considers  
10 both test-year facilities and *post* test-year facilities filed by the applicant for inclusion in  
11 this rate case. This testimony documents the justification of need previously considered  
12 by this Commission for all new *post* test-year capital improvements proposed for inclusion  
13 in the rate base by AEPCO. Finally my testimony determines to what degree the test-year  
14 and post test-year AEPCO facilities are "used and useful."  
15

16 **Q. How have you prepared for your testimony?**

17 A. I have reviewed information on file, issued data requests to AEPCO, inspected AEPCO's  
18 Apache Station generating plant and talked with AEPCO, Southwest Transmission  
19 Cooperative ("SWTC") and Sierra Southwest Cooperative Services ("Sierra Southwest")  
20 personnel.  
21

22 **Q. When did you inspect AEPCO's facilities?**

23 A. I inspected AEPCO's Apache Station and all on-site facilities appurtenant to the power  
24 plant during a December 9, 2004 site visit. A summary report of my findings is attached  
25 as Exhibit JS-3.  
26

1 **Q. What AEPCO, SWTC and Sierra Southwest personnel have you talked with**  
2 **concerning this docket?**

3 A. I have talked with Mr. Dirk Minson, Chief Financial Officer; Mr. Gary Pierson, Financial  
4 Services Manager; Mr. Larry Huff, General Manager; Mr. Gary Grim, Transmission  
5 Engineering Manager; Mr. Mark Schwirtz, Plant Manager; and Mr. Charles Walling,  
6 Generation Engineering Manager.

7  
8 **Q. What documentation have you reviewed in preparing your testimony?**

9 A. I have reviewed all rate application material filed by the applicant and numerous responses  
10 to Staff data requests. I also reviewed testimony and ACC engineering reports filed for  
11 two prior AEPCO power plant financing applications<sup>1</sup>. ACC engineering reports for the  
12 two respective financing cases are attached as Exhibit JS-1 and Exhibit JS-2.

13  
14 **Q. Is your testimony herein based upon the aforementioned facility site observations,**  
15 **conclusions drawn from review of available documentation, information gathered by**  
16 **talking with applicant personnel and your educational background and work**  
17 **experience as a utility professional?**

18 A. Yes it is.

19  
20 **FACILITIES CONSIDERED IN TESTIMONY**

21 **Q. Have you reviewed AEPCO's application and testimony regarding facilities it**  
22 **proposes to include in rate base for this case?**

23 A. Yes. I reviewed AEPCO's Schedule E-5 that provides a detailed account of utility plant.  
24 AEPCO witness, Mr. Dirk Minson's testimony indicates that the addition of a new

---

<sup>1</sup> Docket No. E-01773A-01-0701 and Docket No. E-01773A-02-0112.

1 Combustion Turbine Unit 4 ("CT4") in October 2002 and the addition of a coal blending  
2 facility are among the primary reasons for requesting a rate increase.  
3

4 **Q. What other facilities are considered in your testimony?**

5 A. AEPCO's Schedule E-5 also includes other recent capital improvements contained in  
6 AEPCO's 2001-2004 Construction Work Plan. ACC Engineering Staff reviewed  
7 AEPCO's construction plans at the time of its 2001 and 2002 financing applications with  
8 this Commission. Those facilities include four key capital improvements:

- 9 1. Consolidation and upgrade of controls in a common control room for Apache  
10 Steam Turbine Units 1, 2 and 3,
- 11 2. A deluge fire protection system for Steam Turbine Units 2 and 3 cooling towers,
- 12 3. A new coal blending system, and
- 13 4. A deep well system upgrade to replace the well displaced by the new coal blending  
14 system.

15  
16 The Combustion Turbine Unit 4 construction was completed in October of 2002. All of  
17 other capital improvements, with the exception of the coal blending system, were  
18 constructed in 2002 and 2003. The coal blending facility was completed in April of 2004.  
19

20 **JUSTIFICATION OF NEED FOR RECENT IMPROVEMENTS**

21 **Q. Briefly describe how AEPCO established with the Commission a justification of need  
22 for Combustion Turbine Unit 4.**

23 A. AEPCO filed a financing application with the Commission in 2001 for funds to construct  
24 Combustion Turbine Unit 4.<sup>2</sup> Exhibit JS-1 is a copy of the Engineering Report filed by  
25 Staff in that case. That report offers numerous citations that document the need for the

---

<sup>2</sup> Docket No. E-01773A-01-0701.

1 new 38 Megawatt ("MW") generator. AEPCO's inability to meet its generating reserve  
2 requirements beginning in 2001 were first exposed to the Commission at an Energy  
3 Workshop held on February 16, 2001. The generator did not become operational until  
4 October 2002. This means APCO was deficient in generating reserves for a period of two  
5 years.

6  
7 AEPCO provided further justification of need for the CT4 generator via Sections 8, 17, 18  
8 and 19 of Rural Utility Service ("RUS") and Capital Financing Corporation ("CFC")  
9 financing materials. AEPCO filed those materials in support of its financing application  
10 with the Commission. ACC Staff concluded in an Engineering Report<sup>3</sup> that "AEPCO was  
11 pursuing the only option available to meet its short-term generation reserve requirements."  
12 The report also noted the \$30 million estimated cost of the proposed project was  
13 consistent with costs of similar facilities constructed by others. The Commission  
14 approved the requested financing for this project.

15  
16 **Q. Briefly describe how AEPCO established with the Commission a justification of need**  
17 **for other recent major capital improvements.**

18 **A.** AEPCO filed a financing application with the Commission in 2002 for funds to construct  
19 its other recent capital improvements.<sup>4</sup> Exhibit JS-2 is a copy of the Engineering Report  
20 filed by Staff in that case. The report determined that the proposed improvements would  
21 favorably impact the reliability, plant efficiency and operational economics of Apache  
22 Station. Upgrades of Apache Station controls would improve combustion efficiencies,  
23 reduce spare parts and increase unit reliability. Installing a fire deluge protection system  
24 for Steam Turbine Unit 2 and 3 cooling towers would reduce the risk of fires. The coal  
25 blending system would provide the capability to blend coal from three sources to achieve

---

<sup>3</sup> Exhibit JS-1.

<sup>4</sup> Docket No. E-01773A-02-0112.

1 an optimal fuel blend from both an economic performance and an emissions standpoint.  
2 The deep well system improvements were necessary to replace a well displaced by the  
3 coal blending project and gain access to the aquifer at a greater depth. ACC Engineering  
4 Staff found the proposed Apache Station improvements to be appropriate and necessary  
5 given the age and operational status of the existing facilities. Nevertheless, Staff deferred  
6 a “used and useful” determination until such time that AEPCO filed for a rate adjustment<sup>5</sup>.  
7 The Commission approved the requested financing authority for these capital  
8 improvement projects.

9  
10 **USED AND USEFUL DETERMINATION**

11 **Q. Please describe how you determined if all of the capital improvements addressed by**  
12 **your testimony were used and useful.**

13 A. On December 9, 2004, I toured the Apache Station power plant. I observed all of the  
14 AEPCO capital improvements for which justification of need had been previously  
15 established with the Commission and for which the Commission had approved financing  
16 authority. Photos were taken to document my observations and are attached to the  
17 Engineering Report of the site visit. This report is attached as Exhibit JS-3.

18  
19 **Q. Please summarize your observations of the Apache Station facilities.**

20 A. I observed each of the 7 generating units, the natural gas and coal fuel supply facilities, the  
21 power plant water facilities and the emergency equipment and supplies. The power plant  
22 complies with National Electric Safety Code (“NESC”) security and safety requirements.  
23 All of the generating units were operational. All natural gas and coal facilities were  
24 observed to be operational and well maintained. The associated fuel was secure and safely  
25 managed. The new coal blending facilities appeared well designed and effectively

---

<sup>5</sup> Exhibit JS-2.

1 integrated into the pre-existing infrastructure. With the exception of an inactive ash pond,  
2 all plant water facilities were observed to be operational, in use and adequately  
3 maintained. The inactive ash pond is to be retired at some future date once financing is  
4 authorized.

5  
6 During my tour of the plant, I observed that personnel seemed well trained to respond to  
7 both operational and emergency events. The improved control room SCADA equipment,  
8 operational controls, informational displays, computers, and communication equipment  
9 enabled operating personnel to quickly respond to a boiler feed pump problem while I  
10 toured the control room. The plant has appropriate and sufficient emergency medical and  
11 fire fighting equipment and sufficient supplies to effectively manage emergency events as  
12 well. Furthermore, the site is being managed with a primary focus on personnel safety and  
13 operational safety.

14  
15 **Q. Has Staff determined if the capital improvements made by AEPCO are “used and**  
16 **useful?”**

17 **A.** Yes. All facilities observed during my December 9, 2004 tour of Apache Station were  
18 operational and well maintained. The inactive ash pond is planned for retirement. The  
19 new CT4 generator, new control room and controls for Steam Turbine Units 1, 2 and 3,  
20 the new coal blending facilities, the fire protection upgrades, and deep well system for  
21 plant water needs all appear well designed and constructed to comply with current  
22 industry standards. Therefore, the subject AEPCO power plant facilities are found to be  
23 used and useful.

24  
25  
26

1 **SUMMARY OF TESTIMONY CONCLUSIONS**

2 **Q. Please summarize the conclusions of your testimony.**

3 A. Utility plant improvements constructed by AEPCO between October 2002 and July 2004  
4 were appropriate and necessary to maintain reliable, efficient and cost effective service to  
5 its members and the wholesale market. The justifications of need for such facilities were  
6 established before the Commission in prior proceedings. All utility plant contained in  
7 AEPCO's rate application is "used and useful" in supplying the energy needs of existing  
8 retail customers.

9

10 **Q. Does this conclude your direct testimony?**

11 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 its 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.

JDS

CC: Steve Olea, Acting Director, Utilities Division

# 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.
<b>TOTAL</b>		<b>\$26,764,321.</b>

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

# 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

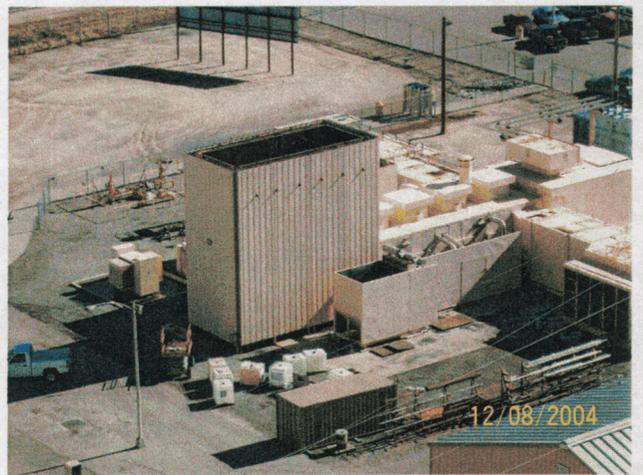


Figure 4. Combustion Turbine Unit 3



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

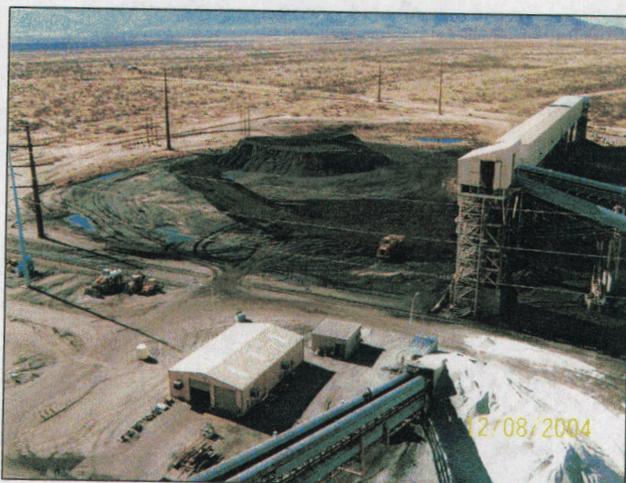


Figure 9. Coal Facilities



Figure 10. Coal Dump Conveyors



Figure 11. Coal Conveyors to Plant

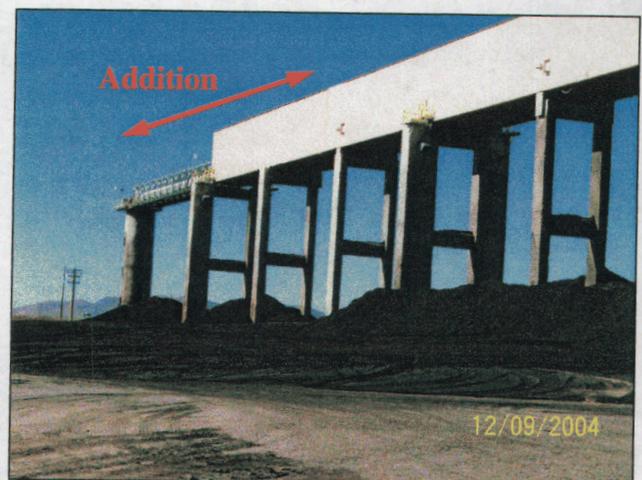


Figure 12. Coal Blending Facilities

EXHIBIT 3  
Water Facilities

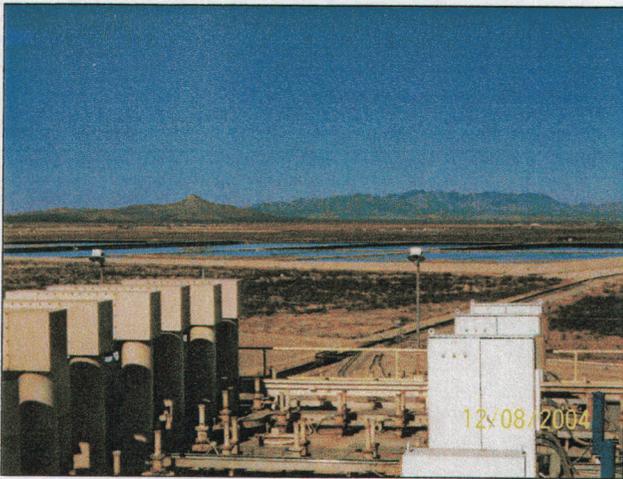


Figure 13. New Cooling Water Ponds

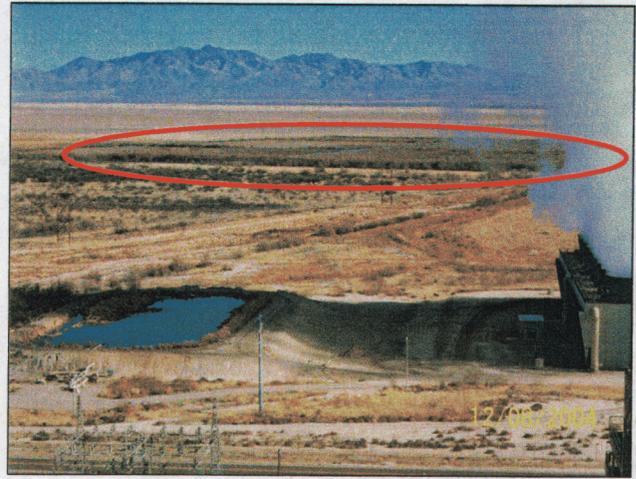


Figure 14. Inactive Ash Pond

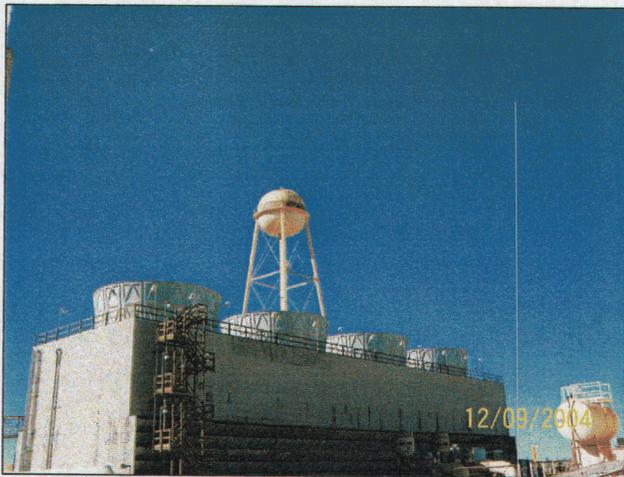


Figure 15. Water Supply Tank



Figure 16. Pair of Cooling Towers East of Plant

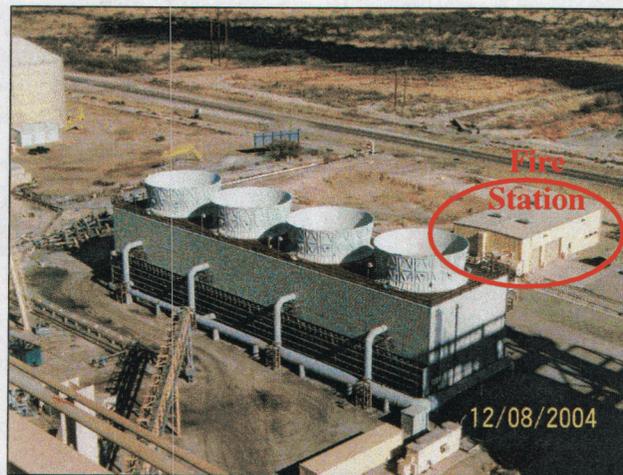


Figure 17. New Cooling Tower

EXHIBIT 4  
Emergency and Fire Fighting Facilities



Figure 18. Fire Truck / Emergency Vehicles

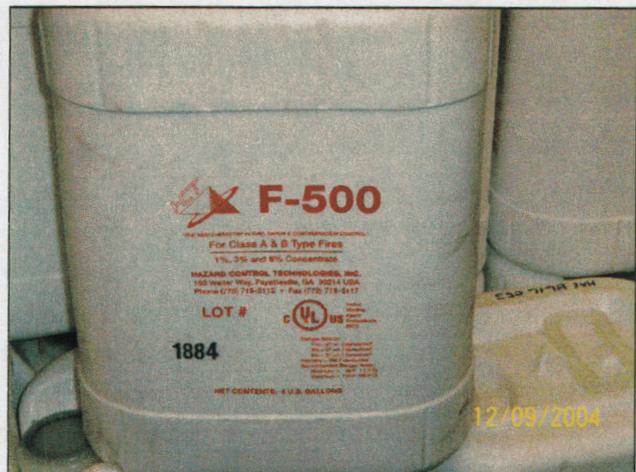


Figure 19. F-500 Fire Retardant



Figure 20. Fire Fighting Water Feed Pumps



Figure 21. Control Room

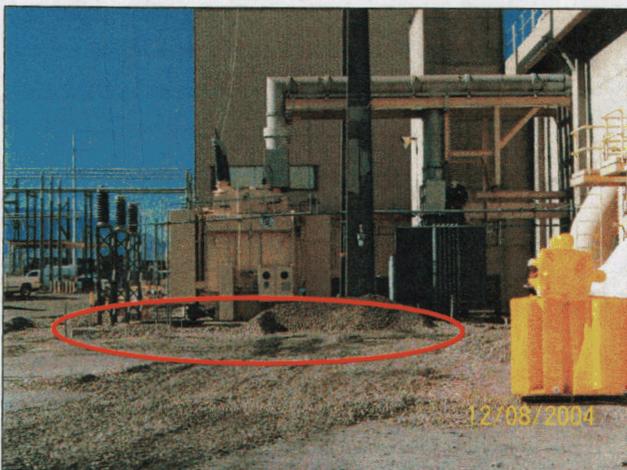


Figure 22. ST #1 Step-up Transformer



Figure 23. ST #2 Step-up Transformer

**DIRECT  
TESTIMONY  
OF  
CRYSTAL S. BROWN  
ALEJANDRO RAMIREZ  
ERIN CASPER  
JERRY D. SMITH**

**DOCKET NO. E-01773A-04-0527**

**IN THE MATTER OF THE APPLICATION OF  
SOUTHWEST TRANSMISSION  
COOPERATIVE, INC. FOR A RATE INCREASE**

**FEBRUARY 23, 2005**

**BROWN**

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-04100A-04-0527  
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 )

DIRECT TESTIMONY OF  
CRYSTAL S. BROWN  
PUBLIC UTILITIES ANALYST V  
UTILITIES DIVISION  
ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2005

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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.

1 **INTRODUCTION**

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

3 A. My name is Crystal S. Brown. I am a Public Utilities Analyst V employed by the Arizona  
4 Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff").  
5 My business address is 1200 West Washington Street, Phoenix, Arizona 85007.  
6

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

8 A. I am responsible for the examination and verification of financial and statistical  
9 information included in utility rate applications. In addition, I develop revenue  
10 requirements, prepare written reports, testimonies, and schedules that include Staff  
11 recommendations to the Commission. I am also responsible for testifying at formal  
12 hearings on these matters.  
13

14 **Q. Please describe your educational background and professional experience.**

15 A. I received a Bachelor of Science Degree in Business Administration from the University  
16 of Arizona and a Bachelor of Science Degree in Accounting from Arizona State  
17 University.  
18

19 Since joining the Commission, I have participated in numerous rate cases and other  
20 regulatory proceedings involving large electric, gas, telecommunications, and water  
21 utilities. I have testified on matters involving regulatory accounting and auditing. During  
22 the past six years, I have attended utility-related seminars on regulation, accounting,  
23 finance and income taxes designed to provide continuing and updated education in these  
24 areas. Various professional and industry organizations sponsored these seminars.  
25

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

6  
7 **Q. What is the scope of your testimony in this case?**

8 A. I am presenting Staff's analysis and recommendations in the areas of rate base, operating  
9 income, and revenue requirement regarding Southwest Transmission Cooperative, Inc.'s  
10 ("Southwest Transmission" or "Cooperative") application for a permanent rate increase.  
11 Staff witness Alejandro Ramirez is presenting Staff's times interest earned ratio ("TIER")  
12 and debt service coverage ("DSC") ratio analysis and recommendations. Staff witness  
13 Erin Casper is presenting Staff's recommendations regarding the rate design. Staff  
14 witness Jerry Smith is presenting Staff's engineering analysis and recommendations.

15  
16 **Q. What is the basis of your recommendations?**

17 A. I performed a regulatory audit of Southwest Transmission's application to determine  
18 whether sufficient, relevant, and reliable evidence exists to support the Company's  
19 requested rate increase. The regulatory audit consisted of examining and testing the  
20 financial information, accounting records, and other supporting documentation and  
21 verifying that the accounting principles applied were in accordance with the Commission  
22 adopted National Rural Utilities Service ("RUS") Uniform System of Accounts  
23 ("USOA").  
24  
25

1 **BACKGROUND**

2 **Q. Please review the background of this application.**

3 A. Southwest Transmission was formed as a result of the restructuring of Arizona Electric  
4 Cooperative, Inc. ("AEPCO"). Prior to August 2001, AEPCO provided both generation  
5 and transmission services to its customers. Pursuant to Decision No. 59943, dated  
6 December 26, 1996, the Commission approved a phased-in transition to electric  
7 competition. In 2001, AEPCO received Commission approval to restructure into three  
8 separate affiliated cooperatives: AEPCO, Southwest Transmission, and Sierra Southwest  
9 Cooperative ("Sierra Southwest").

10  
11 AEPCO became a generation cooperative. Southwest Transmission became a  
12 transmission cooperative. Sierra Southwest became a cooperative that provides wholesale  
13 marketing and support services, including staffing of non-core positions to AEPCO and  
14 Southwest Transmission.

15  
16 Decision No. 63868 required that the Cooperatives provide the Director of the Utilities  
17 Division with "an informational submission" that was required within "35 months of the  
18 date of closing"<sup>1</sup> for the restructuring. Decision No. 65367, dated November 5, 2002,  
19 modified this requirement to include full Arizona Administrative Code R14-2-103  
20 information and set the rate filing date at July 1, 2004. On July 23, 2004, Southwest  
21 Transmission filed an application for a permanent rate increase. On August 27, 2004,  
22 Staff filed a Letter of Sufficiency.

23  
24 Southwest Transmission is a certificated Arizona-based transmission cooperative that  
25 provided electric transmission service to six Class A members as well as certain other

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<sup>1</sup> Decision No. 63868, Page 14, Finding of Fact No. 74

1 customers during the Test Year. Southwest's current rates were authorized in Decision  
2 No. 65367, dated November 5, 2002 and Decision No. 62758, dated July 27, 2000.  
3 Decision No. 65367 authorized total revenues of \$29,129,952 to provide a 7.99 percent  
4 rate of return on a \$65,856,223 original cost rate base. Decision No. 62758 authorized the  
5 transfer of the Regulatory Asset Charge ("RAC") from AEPCO to Southwest  
6 Transmission.

7  
8 **Q. What is the primary reason for the Cooperative's requested permanent rate**  
9 **increase?**

10 A. The primary reason indicated by the Cooperative for the rate increase is the anticipated  
11 loss of approximately \$2.8 million in revenues due to Morenci Water and Electric's  
12 ("MW&E") planned bypass of Southwest Transmission's system.

13  
14 **CONSUMER SERVICE**

15 **Q. Please provide a brief history of customer complaints received by the Commission**  
16 **regarding Southwest Transmission.**

17 A. Staff reviewed the Commission's records and found no formal complaints from its  
18 members from 2001 to 2004. Five opinions against the rate increase have been received  
19 from retail customers of the distribution member cooperative in Mohave County as of  
20 February 8, 2005.

21  
22 **SUMMARY OF PROPOSED REVENUES**

23 **Q. Please summarize the Company's filing.**

24 A. The Cooperative's application, as filed, proposes total annual operating revenue of  
25 \$31,521,986, an increase of \$3,666,668, or 13.16<sup>2</sup> percent, over claimed Test Year

<sup>2</sup> 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.

1 revenue of \$27,855,318. Southwest Transmission's operating revenues include  
2 \$2,707,122 of RAC revenues.

3

4 **Q. Please summarize Staff's recommended revenue.**

5 Staff recommends total annual operating revenue of \$28,814,864, an increase of  
6 \$3,666,668, or 14.58 percent, over Staff adjusted Test Year revenues of \$25,148,196.  
7 Staff recognizes \$2,559,926 of non-operating RAC cash flow.

8

9 Staff recommends operating revenue no less than that proposed by the Cooperative which  
10 (excluding normalized RAC collections of \$2,559,926) would produce an operating  
11 margin of \$3,439,610 for a 4.51 percent rate of return rate return on a Staff adjusted  
12 original cost rate base of \$76,345,655 to provide a 0.65 times interest earned ratio  
13 ("TIER") and a 0.81 debt service coverage ratio ("DSC"). Including the RAC, the TIER  
14 and DSC improve to 1.13 and 1.02, respectively.

15

16 **Q. What Test Year did Southwest Transmission use in this filing?**

17 A. Southwest Transmission's rate filing is based on the twelve months ended December 31,  
18 2003 ("Test Year").

19

20 **Q. Please summarize the rate base and operating income recommendations and  
21 adjustments addressed in your testimony for Southwest Transmission.**

22 A. My testimony addresses the following issues:

23

24 Plant Acquisition Adjustment – This adjustment decreases Plant in Service by \$4,413 to  
25 properly reflect the original cost rate base and to be consistent with Decision No. 65367.

26

1            Accumulated Depreciation – This adjustment increases Accumulated Depreciation by  
2            \$25,756 to remove retirement work in progress.

3  
4            Member Advances – This adjustment decreases rate base by \$228,188. This adjustment  
5            recognizes that the interest paid to the Members is recovered through operating expense,  
6            and consequently, the advances which are directly related to the interest expense should be  
7            removed from rate base to prevent double recovery.

8  
9            Working Capital – This adjustment decreases Working Capital by \$2,265,954 to reflect  
10           Staff's different calculation of certain Working Capital components and to eliminate the  
11           Cooperative's selective recognition of components.

12  
13           Plant Held for Future Use – This adjustment decreases rate base by \$377,214 to reflect  
14           land that will be liquidated.

15  
16           Deferred Debit – This adjustment decreases rate base by \$145,705 to remove items that  
17           are not generally included in rate base.

18  
19           Regulatory Asset Charge ("RAC") Revenue – This adjustment decreases operating margin  
20           by \$2,707,122 and increases non-operating revenue by \$2,559,926. This adjustment  
21           recognizes that RAC collections will cease once the deferred asset has been fully  
22           amortized. This adjustment also normalizes the revenues expected from the RAC.

23  
24           Normalized Legal Expense – This adjustment decreases operating expenses by \$83,799 to  
25           remove legal expenses that provided no benefit to Members.

26

1           Employee Vacancy Level Normalization Adjustment – This adjustment decreases  
2           operating expenses by \$113,684 to normalize the level of employee vacancies.

3  
4           Food and Other Expense – This adjustment decreases operating expenses by \$57,773 to  
5           remove expenses that were not needed to provide safe and reliable service.

6  
7           Interest Expense on Long-term Debt – This adjustment decreases net margin by \$133,675  
8           to reflect Staff's recommended interest on long-term debt.

9  
10       **RATE BASE**

11  
12       **Fair Value Rate Base**

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

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

17  
18       **Rate Base Summary**

19       **Q. Please summarize Staff's adjustments to Southwest Transmission's rate base shown**  
20       **on Schedules CSB-2.**

21       **A.** Staff's adjustments to Southwest Transmission's rate base resulted in a net decrease of  
22       \$3,047,230, from \$79,392,885 to \$76,345,655. This decrease was primarily due to  
23       reducing the working capital requirement.

24  
25  
26

1 **Rate Base Adjustment 1 – Plant Acquisition Adjustment**

2 **Q. What is Southwest Transmission proposing for its Plant Acquisition Adjustment?**

3 A. Southwest Transmission is proposing \$4,413 for the Plant Acquisition Adjustment as  
4 shown on Schedule CSB-4.

5  
6 **Q. The \$4,413 Plant Acquisition Adjustment is not material to rate base. Why is Staff  
7 proposing that it be removed from rate base for rate making purposes?**

8 A. In Decision No. 65367, dated November 5, 2002, Staff recommended that the plant  
9 acquisition adjustment be removed because the adjustment was questionable and Staff had  
10 not audited the adjustment.<sup>3</sup> The Commission adopted Staff's recommendation to remove  
11 Southwest Transmission's acquisition adjustment from rate base (Page 4 at line 23).

12  
13 **Q. Did Staff audit the plant acquisition adjustment in this rate proceeding?**

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

16  
17 **Q. Should the plant acquisition adjustment be included in rate base?**

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

23  
24  
25  

---

<sup>3</sup> Decision No. 65367, page 4, lines 6 through 9

1 **Q. What is Staff recommending?**

2 A. Staff recommends decreasing plant in service by \$4,413 as shown on Schedules CSB-3  
3 and CSB-4.

4

5 **Rate Base Adjustment 2 – Accumulated Depreciation**

6 **Q. What is Southwest Transmission proposing for Accumulated Depreciation?**

7 A. Southwest Transmission is proposing \$54,763,401 for Accumulated Depreciation. That  
8 amount is composed of \$54,789,157 in accumulated depreciation of plant in service and a  
9 \$25,756 reduction of accumulated depreciation for a retirement work in progress as shown  
10 on Schedule CSB-5.

11

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

13 A. No. Retirement work in progress should reflect a coordinated treatment of the plant to be  
14 retired, accumulated depreciation, salvage value and disposal cost. The retirement should  
15 be completed before rate base is adjusted.

16

17 In Decision No. 65367<sup>4</sup>, dated November 5, 2002, Staff recommended that a retirement  
18 work in progress be removed because the amount was questionable and unaudited.<sup>5</sup> The  
19 Commission adopted Staff's recommendation. In the instant case, Staff audited the  
20 retirement work in progress and determined that it should be removed.

21

22 **Q. What is Staff recommending?**

23 A. Staff recommends increasing Accumulated Depreciation by \$25,756, from \$54,763,401 to  
24 \$54,789,157 to remove retirement work in progress from rate base as shown on Schedules  
25 CSB-3 and CSB-5.

---

<sup>4</sup> Page 24 at line 23

<sup>5</sup> Decision No. 65367, page 4, lines 6 through 9

1 **Rate Base Adjustment 3 – Member Advances**

2 **Q. What programs does Southwest Transmission have that result in Member**  
3 **Advances?**

4 A. Southwest Transmission has two types of programs that result in member advances:  
5 member investments and member prepaid transmission bills. The member investment  
6 program allows members to invest funds with the Cooperative and the Cooperative pays  
7 interest on those funds. The prepaid transmission program allows members to make  
8 prepayments on their monthly transmission bills and the Cooperative pays interest on  
9 those prepaid bills.

10  
11 **Q. How does the Cooperative treat the balance of Member Advances and the interest**  
12 **paid on those funds in its filing?**

13 A. The Cooperative did not deduct Member Advances of \$228,188<sup>6</sup> in its rate base  
14 calculation but it included the \$3,281<sup>7</sup> of interest paid to members for use of their funds as  
15 an operating expense. An inequity is created by the Cooperative's proposal because it  
16 provides for recovery of Southwest Transmission's Member Advances costs by treating  
17 the related interest as an operating expense without also recognizing that AEPCO has use  
18 of the fund advanced by members.

19  
20 **Q. What is the effect of the Cooperative's proposed treatment?**

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

---

<sup>6</sup> Per data request response CSB 2-28

<sup>7</sup> Per data request response CSB 6-1

1 **Q. Did the Commission deduct Member Advances in the rate base calculation of the**  
2 **prior rate proceeding in which Southwest Transmission and AEPCO were one**  
3 **cooperative?**

4 A. Yes. The Commission, in Decision No. 58405<sup>8</sup>, deducted Member Advances in the rate  
5 base calculation.

6  
7 **Q. What is Staff recommending?**

8 A. Consistent with Decision No. 58405, Staff recommends that \$228,188 in Member  
9 Advances be deducted from rate base as shown on Schedules CSB-3 and CSB-6.

10

11 **Rate Base Adjustment 4 – Working Capital**

12 **Q. What is Southwest Transmission proposing for Working Capital?**

13 A. Southwest Transmission is proposing \$3,122,117 for Working Capital. That amount is  
14 composed of \$858,420 for materials and supplies, \$908,046 for prepayments, and  
15 \$1,355,651 for CFC Certificates and Bonds as shown on Schedule CSB-7.

16

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

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

20

21 Working Capital - Materials and Supplies

22 **Q. What amount did Southwest Transmission include for Materials and Supplies in its**  
23 **proposed Working Capital calculation?**

24 A. Southwest Transmission included \$858,420 for Materials and Supplies inventory in its  
25 working capital calculation.

---

<sup>8</sup> Page 6, at line 9

1 **Q. How did Southwest Transmission calculate the Materials and Supplies balance**  
2 **proposed in rate base?**

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

6  
7 **Q. Does use of the 13-month average calculation proposed by Southwest Transmission**  
8 **measure the average monthly balance for each month of the Test Year?**

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

11  
12 **Q. What method provides a more accurate measurement of the average balance each**  
13 **month?**

14 A. A 12-month average based on the average inventory balance for each month of the Test  
15 Year. To illustrate, the average monthly balance for January is calculated by adding the  
16 beginning balance on January 1<sup>st</sup> (i.e., the ending balance on December 31<sup>st</sup> of prior year)  
17 to the ending balance on January 31<sup>st</sup>, and dividing the total by two. The 12 monthly  
18 averages are totaled and divided by 12 to obtain an average balance.

19  
20 **Q. What does Staff recommend for the Materials and Supplies balance in the Working**  
21 **Capital calculation?**

22 A. Staff recommends \$856,163 for Materials and Supplies as shown on Schedule CSB-7.  
23  
24  
25  
26

1 Working Capital - Prepayments, CFC Certificates and Bonds  
2

3 **Q. Is Southwest Transmission proposing to include Prepayments, CFC Certificates and**  
4 **Bonds in the Working Capital calculation?**

5 A. Yes. Southwest Transmission is proposing \$908,046 for prepayments and \$1,355,651 in  
6 CFC Certificates and Bonds.

7  
8 **Q. Does Southwest Transmission's proposal to include Prepayments, CFC Certificates**  
9 **and Bonds in the Working Capital calculation represent an inequitable, selective**  
10 **adjustment to increase rate base?**

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

16  
17 The Cooperative chose not to conduct a lead-lag study, and accordingly, omitted a major  
18 component of Working Capital. It is inequitable to ignore a major component of the  
19 Working Capital analysis and selectively recognize other components. Had a lead-lag  
20 study been conducted, it might have shown that Working Capital is a negative component  
21 of rate base.

22  
23 **Q. What factors imply that a lead-lag study could result in Working Capital being a**  
24 **negative component of rate base?**

25 A. Interest and property tax expenses are components of a lead-lag study. The Cooperative  
26 has approximately \$5 million in interest expense and \$2 million in property taxes. The  
27 Cooperative collects cash used to make interest and property tax expense payments prior

1 to the dates payment is due. For the period that Southwest Transmission holds these funds  
2 before payment, they are a source of cost-free capital. If a lead-lag study were performed,  
3 this source of cost-free cash would be a significant negative factor in calculation of the net  
4 working capital.

5  
6 **Q. Does the Cooperative receive interest on the CFC Certificates and Bonds?**

7 A. Yes. In response to CSB 2-23, the Cooperative stated that it received approximately  
8 \$67,782<sup>9</sup>. Therefore, including the CFC certificates and bonds in rate base would provide  
9 a second return on these investments.

10  
11 **Q. Did the Commission remove Prepayments and CFC Certificates and Bonds from**  
12 **rate base of the prior rate proceeding in which Southwest Transmission and AEPCO**  
13 **were one cooperative?**

14 A. The Commission removed prepayments in Decision No. 58405<sup>10</sup>. The Cooperative had  
15 not included CFC Certificates and Bonds in the rate base of that proceeding, therefore, it  
16 was not addressed in Decision No. 58405.

17  
18 **Q. What is Staff recommending for Prepayments and CFC Certificates and Bonds?**

19 A. Consistent with Decision No. 58405, Staff recommends removal of Prepayments. Staff  
20 also recommends removal of CFC Certificates and Bonds from Working Capital as shown  
21 on Schedules CSB-3 and CSB-7.

22  
23 **Q. What is Staff's recommended adjustment to Working Capital?**

24 A. Staff recommends decreasing Working Capital by \$2,265,954 from \$3,122,117 to  
25 \$856,163 as shown on Schedules CSB-3 and CSB-7.

<sup>9</sup> Per response to CSB 2-23, the \$1.355 million Equity Term Certificates accrues interest at 5.00 % annually.

<sup>10</sup> Page 6, at line

1 **Rate Base Adjustment 5 – Plant Held for Future Use**  
2

3 **Q. What amount in Plant Held for Future Use is Southwest Transmission proposing to**  
4 **include in rate base?**

5 A. Southwest Transmission is proposing to include \$377,214 of land classified as Plant Held  
6 for Future Use in rate base.

7  
8 **Q. Does Southwest Transmission have a plan for future use of the land?**

9 A. No, it does not. In response to CSB 2-29, the Cooperative indicated that the land was  
10 purchased for a substation site's right-of-ways. The location of the substation changed,  
11 the land was no longer needed and will likely be liquidated.

12  
13 **Q. What is Staff recommending?**

14 A. Staff recommends removal of the \$377,214 in Plant Held for Future Use from Rate Base  
15 as shown on Schedules CSB-3 and CSB-8.

16  
17 **Rate Base Adjustment 6 – Deferred Debit**  
18

19 **Q. What amount in Deferred Debits is Southwest Transmission proposing to include in**  
20 **Rate Base?**

21 A. Southwest Transmission is proposing \$145,705 for Deferred Debits as shown on Schedule  
22 CSB-9. The amount is composed of \$193 for preliminary survey and investigation  
23 charges, \$57,657 for Job Tickets, and \$87,855 for unamortized losses on reacquired  
24 debt.<sup>11</sup>

25  
26  

---

<sup>11</sup> Per response to CSB 2-22

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

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

6  
7 Unamortized losses on reacquired debt present no future cash requirements for the  
8 Cooperative. Since Staff recommends a revenue requirement dependent on cash flow  
9 needs, there is no revenue requirement directly related to the carrying balance. Moreover,  
10 to the extent that losses on reacquired debt were refinanced with new debt, Staff is  
11 recommending recovery of these costs via operating and RAC revenue that provides TIER  
12 and DSC ratios exceeding 1.0. Including the unamortized loss on reacquired debt in rate  
13 base would be inequitable and serve only as a selective adjustment to augment rate base in  
14 the same manner as prepayments, CFC Bonds and Certificates.

15  
16 **Q. Did the Commission remove the deferred debit from the rate base of the prior rate  
17 proceeding in which Southwest Transmission and AEPCO were one cooperative?**

18 A. Yes, the Commission, in Decision No. 58405<sup>12</sup>, removed the Deferred Debit from rate  
19 base.

20  
21 **Q. What is Staff recommending?**

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

24  
25

---

<sup>12</sup> Page 6, at line 8 ½

1 **OPERATING INCOME**

2  
3 **Operating Income Summary**

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

6 A. As shown on Schedules CSB-10 and CSB-11, Staff's analysis resulted in Test Year  
7 revenues of \$25,148,196, expenses of \$25,375,254, and operating income before interest  
8 expense on long-term debt of (\$227,058).

9  
10 **Operating Income Adjustment No. 1 – Regulatory Asset Charge**

11 **Q. What is the source and purpose of the regulatory asset charge?**

12 A. In Decision No. 62758, the Commission transferred the regulatory asset charge ("RAC")  
13 from AEPCO to Southwest Transmission. The initial purpose of the RAC was to recover  
14 deferred debt refinancing costs and costs associated with the buy-out of the Carbon Coal  
15 all-requirements contract. The RAC, as authorized by the Commission, is scheduled to  
16 decrease each year over the amortization term until the deferred cost is fully recovered.

17  
18 **Q. Did Staff make an adjustment to the revenue generated by regulatory asset charge in**  
19 **the Test Year?**

20 A. Yes, Staff reclassified the RAC collections from operating revenue and recognized it as a  
21 separate source of cash flow since it will cease when the regulatory asset is fully  
22 recovered. Staff also reduced the amount of RAC revenue from the actual Test Year  
23 amount of \$2,707,122 to \$2,559,926. Staff's lower amount represents a three-year  
24 normalization to recognize the known, scheduled decreasing RAC level as shown on  
25 Schedule CSB-12.

1 **Q. What is Staff recommending?**

2 A. Staff recommends reducing operating revenue by \$2,707,122 and recognizing \$2,559,926  
3 of RAC cash flow as shown on Schedules CSB-11 (lines 6 and 32) and CSB-12 (lines 5  
4 and 9).

5  
6 **Operating Income Adjustment No. 2 – Normalized Legal Expense**

7 **Q. What is Southwest Transmission proposing for Outside Services, Legal expenses?**

8 A. Southwest Transmission is proposing \$316,875<sup>13</sup> for Outside Services, Legal expenses as  
9 shown on Schedule CSB-13, line 4. Staff discusses the components of its legal expense  
10 normalization adjustment separately.

11

12 ACC Jurisdiction Related Legal Expense

13

14 **Q Does the Cooperative propose to include legal expenses that provide no benefit to**  
15 **ratepayers in its revenue requirement?**

16 A. Yes. Southwest Transmission incurred and requests recovery of legal expenses related to  
17 its filing that requested that the Cooperative not be subject to ACC regulation (Decision  
18 No. 66835, dated March 12, 2004).

19

20 **Q. What is Staff recommending?**

21 A. Staff recommends reducing Outside Services, Legal Expense by \$77,936 as shown on  
22 Schedule CSB-13, line 2 to eliminate the legal expenses related to the ACC jurisdictional  
23 filing.

24

25

---

<sup>13</sup> Per data request response to CSB 2-40.

1 Redacted Minutes and Legal Invoices

2 **Q. Did Southwest Transmission fail to support any of its legal expenses?**

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

7  
8 **Q. Did Staff inform Southwest Transmission of the likely consequence of not providing  
9 the requested information?**

10 A. Yes, in a letter dated September 29, 2004, addressed to both Southwest Transmission and  
11 AEPCO, Staff indicated that failure to provide complete legal invoices will result in a  
12 disallowance of such costs.

13  
14 **Q. What was the total amount of expenses related to the redacted legal invoices and  
15 minutes that Staff recommends to be disallowed?**

16 A. The total amount was \$5,863<sup>14</sup> as shown on Schedule CSB-13 line 3.

17  
18 **Q. Did the Commission find it appropriate to disallow legal expenses from AEPCO  
19 prior to Southwest Transmission's spinoff?**

20 A. Yes. In AEPCO's prior rate proceeding before Southwest Transmission was spunoff,  
21 Staff recommended that \$464,000<sup>15</sup> in legal expenses paid to a law firm should be  
22 disallowed because it was imprudent for Southwest Transmission to have entered into the  
23 fee arrangements with the law firm. The Commission adopted Staff's recommendation.

24  

---

<sup>14</sup> 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.

<sup>15</sup> Decision No. 58405, page 12, lines 5-12 and lines 21-23.

1 **Q. Does Southwest Transmission's denial of access to records provide concerns beyond**  
2 **whether these legal costs are related to the provision of utility service and**  
3 **recoverable?**

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

7  
8 **Q. Does Staff have any other recommendations regarding redacted issues?**

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

14

15 **Operating Income Adjustment No. 3 – Employee Vacancy Level**

16 **Q. What is an employee vacancy level?**

17 A. An employee vacancy level reflects the number of employee positions that are not  
18 occupied.

19

20 **Q. What were the Cooperative's vacancy levels for the years 2001, 2002, and 2003?**

21 A. The Cooperative's vacancy levels for the years 2001, 2002, and 2003 were 5, 3, and 1<sup>16</sup>,  
22 respectively, as shown on Schedule CSB-14.

23

24

25

---

<sup>16</sup> Per data request response to CSB 2-37

1 **Q. What is an appropriate way to recognize the year-to-year variances in the employee**  
2 **vacancy rate and associated costs to provide an average level of costs?**

3 A. The employee vacancy rate can be normalized by recognizing the average vacancy rate.  
4 Staff averaged the employee vacancy rates for the years 2001, 2002 and 2003 to calculate  
5 a normalized vacancy rate. Then, Staff calculated the difference between the Test Year  
6 rate and the normalized rate and multiplied that difference by the average salary level for  
7 those years to determine an adjustment to reflect salaries at the normalized levels. This  
8 calculation is shown on Schedule CSB-14.

9  
10 **Q. What is Staff recommending?**

11 A. Staff recommends decreasing operating expense by \$113,684 as shown on Schedules  
12 CSB-11 and CSB-14.

13

14 **Operating Income Adjustment No. 4 – Food and Other Expenses**

15 **Q. What is Southwest Transmission proposing for food, entertainment, and similar**  
16 **expenses?**

17 A. Southwest Transmission is proposing \$57,773 for food, entertainment, and similar  
18 expenses as shown on Schedule CSB-15.

19

20 **Q. Are these expenses necessary for the provision of safe and reliable service?**

21 A. No, these costs are not necessary for the provision of safe and reliable service.

22

23 **Q. What ratemaking treatment does Staff recommend for these types of expenses?**

24 A. Since these costs are not necessary to provide service, Staff recommends that they be  
25 recognized as non-operating expenses and excluded from the revenue requirement.

26

1 **Q. What is Staff recommending?**

2 A. Staff recommends decreasing operating expense by \$57,773 as shown on Schedules CSB-  
3 11 and CSB-15.

4

5 **Non-Operating Income Adjustment No. 5 – Interest Expense on Long-term Debt**

6 **Q. What is the Cooperative proposing for Interest Expense on Long-term Debt?**

7 A. Southwest Transmission is proposing \$5,168,413 for Interest Expense on Long-term Debt  
8 as shown on Schedule CSB-16.

9

10 **Q. Did Staff accept the proposed Interest Expense on Long-term Debt amount?**

11 A. No, Staff did not. As discussed in the testimony of Staff Witness, Alejandro Ramirez,  
12 Staff determined that the appropriate amount of interest expense on long-term debt is  
13 \$5,302,088.

14

15 **Q. What is Staff recommending?**

16 A. Staff recommends increasing the Interest Expense on Long-term Debt by \$133,675 as  
17 shown on Schedules CSB-11 and CSB-16.

18

19 **Arizona Corporation Commission Gross Revenue Assessment**

20 **Q. What came to Staff's attention during the course of the audit concerning the ACC**  
21 **assessment?**

22 A. Southwest Transmission's application did not report collecting any amount for an ACC  
23 assessment. This is consistent with the Cooperative's annual report filed with the  
24 Commission for the year 2003. The Commission did not assess the Cooperative because  
25 the Cooperative reported \$0 for intra-state revenues in its 2003 utilities annual report. In a  
26 letter addressed to the Utilities Division Compliance section, dated December 10, 2004,

1 Southwest Transmission stated, "SWTransco did not pay any annual assessment amounts  
2 in 2003 pursuant to A.R.S. §40-401 because it did not have any "gross operating revenues  
3 derived from intrastate operations during the preceding calendar year."  
4

5 **Q. Is Staff currently investigating this matter?**

6 A. Yes.  
7

8 **Q. What does Staff recommend pending the outcome of this investigation?**

9 A. If the Commission determines that Southwest Transmission should be assessed, Staff  
10 recommends that the assessment be flowed through similar to sales taxes. This flow-  
11 through was authorized by the Commission in Decision No. 58405, prior to the  
12 restructuring of Southwest Transmission and AEPCO. On footnote 9, page 17, of that  
13 decision, the Commission states that "The gross revenue tax will in the future be  
14 recovered through a bill add-on." Therefore, the assessment should not be included in the  
15 cost of service.  
16

17 **Jurisdictional Separation**

18 **Q. Did Southwest Transmission maintain separation between Commission jurisdiction  
19 and non-jurisdiction revenues and expenses ?**

20 A. No, it did not. The Cooperative serves a California member for which separate revenues  
21 and expenses were not maintained.  
22

23 **Q. Is the Cooperative required to maintain separation of the revenues and expenses for  
24 the California member?**

25 A. Yes. The Arizona Administrative Code R14-2-103 B4 states the following:  
26

1 Separation of nonjurisdictional properties, revenues and expenses associated  
2 with the rendition of utility service not subject to the jurisdiction of the  
3 Commission must be identified and properly segregated in a recognized  
4 manner when appropriate.  
5

6 **Q. Can Staff identify some cooperatives that provided jurisdictionally separated**  
7 **information in their rate filings?**

8 A. Yes. Duncan Valley Electric Cooperative, Inc. and Garkane Power Association, Inc.  
9 provide jurisdictionally separated information in compliance with the Administrative  
10 Code. These cooperatives generate much smaller revenues than Southwest Transmission.  
11 The jurisdictionally separated financial information helps to verify that Arizona ratepayers  
12 are not paying more than their fair share of the cost of providing service.  
13

14 **Q. What is Staff recommending?**

15 A. Staff recommends that the Cooperative comply with Arizona Administrative Code R14-2-  
16 103(B)(4) in its next rate filing.  
17

18 **Q. Does this conclude your direct testimony?**

19 A. Yes, it does.

**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	<b>Recommended Increase in Operating Revenue</b>	\$ 3,666,668	\$ 3,666,668	\$ 3,666,668	\$ <b>3,666,668</b>
7	Percent Increase (Line 6 / Line 10)	13.16%	14.58%	14.58%	<b>14.58%</b>
8	Network Service and Other Revenue	\$ 25,148,196	\$ 25,148,196	\$ 25,148,196	\$ 25,148,196
9	Regulatory Asset Charge ("RAC") <sup>1</sup>	\$ 2,707,122	\$ -	\$ -	\$ -
10	Adjusted Test Year Operating Revenue	\$ 27,855,318	\$ 25,148,196	\$ 25,148,196	\$ 25,148,196
11	<b>Total Annual Operating Revenue</b>	\$ 31,521,986	\$ 28,814,864	\$ 28,814,864	\$ <b>28,814,864</b>
12	<b>Operating Margin</b>	\$ 5,891,477	\$ 3,184,355	\$ 3,439,610	\$ <b>3,439,610</b>
13	<b>Net Margin</b>	\$ 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	<b>Staff Operating TIER (L3+L12+L14) / L4</b>	N/A	N/A	1.13	<b>0.65</b>
18	Cooperative DSC (L2+L4+L13)/(L4+L5)	1.11	0.88	N/A	N/A
19	<b>Staff DSC (L2+L3+L12+L14)/(L4+L5)</b>	N/A	N/A	1.02	<b>0.81</b>
20	<b>Adjusted Rate Base</b>	\$ 79,392,885	\$ 79,392,885	\$ 76,345,655	\$ <b>76,345,655</b>
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.

**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	\$ 131,516,270
2	Less: Accumulated Depreciation	(55,772,833)	(55,798,589)
3	Net Plant in Service	<u>\$ 75,747,850</u>	<u>\$ 75,717,681</u>
 <u>LESS:</u>			
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)
 <u>ADD:</u>			
10	Working Capital	\$ 3,122,116	\$ 856,162
11	Plant Held for Future Use	\$ 377,214	\$ -
12	Deferred Debits	\$ 145,705	\$ -
13	<b>Total Rate Base</b>	<u>\$ 79,392,885</u>	<u>\$ 76,345,655</u>

References:

Column [A], Company Schedule B-1, Page 1;  
Column [B]: Schedule CSB-4  
Column [C]: Column [A] + Column [B]

Southwest Transmission Cooperative, Inc.  
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 Test Year Ended December 31, 2003

**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
<b>PLANT IN SERVICE:</b>									
1	Intangible Plant	\$ 2,160,171							\$ 2,155,758
2	Transmission Plant - Structures & Improvements	4,139,476	(4,413)						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							1,783,828
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							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
<b>LESS:</b>									
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)
<b>ADD:</b>									
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

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

Footnote Explanations  
 1 Includes account nos. 350 and 359  
 2 Includes account nos. 389,390,393,394,395,398, & 399

**RATE BASE ADJUSTMENT NO. 1 - ACQUISITION ADJUSTMENT**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED (Sch E-5)	STAFF ADJUSTMENTS	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	<u>\$ 2,160,171</u>	<u>\$ (4,413)</u>	<u>\$ 2,155,758</u>

3 To remove unauthorized acquisition 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]

Southwest Transmission Cooperative, Inc.  
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Schedule CSB-5

**RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEPRECIATION**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	STAFF AS ADJUSTED
1	Accumulated Depreciation	\$ (54,789,157)	\$ -	\$ (54,789,157)
2	Accumulated Depr, Retirement Work In Progress	\$ 25,756	\$ (25,756)	\$ -
3	<b>Total Accumulated Depreciation (Line 1+Line 2)</b>	<b>\$ (54,763,401)</b>	<b>\$ (25,756)</b>	<b>\$ (54,789,157)</b>

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]

**RATE BASE ADJUSTMENT NO. 3 - MEMBER ADVANCES**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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.  
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Schedule CSB-7

**RATE BASE ADJUSTMENT NO. 4 - WORKING CAPITAL**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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	<b>Total Working Capital</b>	<b>\$ 3,122,117</b>	<b>\$ (2,265,954)</b>	<b>\$ 856,163</b>

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]

**MATERIALS AND SUPPLIES BALANCE CALCULATION**

LINE NO.	END OF MONTH BALANCE	[A]	[B]	[C]
		COMPANY AS FILED 13-Month Avg	STAFF ADJUSTMENTS	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.  
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Schedule CSB-8

**RATE BASE ADJUSTMENT NO. 5 - PLANT HELD FOR FUTURE USE**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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]

**RATE BASE ADJUSTMENT NO. 6 - DEFERRED DEBITS**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED (CSB 3-1)	STAFF ADJUSTMENTS	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	<u>\$ 145,705</u>	<u>\$ (145,705)</u>	<u>\$ -</u>

5 References:

- 6 Column [A]: Cooperative Schedule B-1, CSB 2-22  
7 Column [B]: Testimony, CSB  
8 Column [C]: Column [A] + Column [B]

**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	<b>REVENUES:</b>					
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	<b>EXPENSES:</b>					
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	<b>INTEREST ON LONG-TERM DEBT &amp; OTHER DEDUCTIONS</b>					
18	Interest on Long-term Debt	\$ 5,168,413	\$ 133,675	\$ 5,302,088	\$ -	\$ 5,302,088
19	Other Interest & Other Deductions	232,030	-	232,030	-	232,030
20	Total Interest & Other Deductions	\$ 5,400,443	\$ 133,675	\$ 5,534,118	\$ -	\$ 5,534,118
21	<b>MARGINS (LOSS) AFTER INTEREST EXPENSE</b>	\$ (3,175,634)	\$ (2,585,542)	\$ (5,761,176)	\$ 3,666,668	\$ (2,094,508)
22	<b>NON-OPERATING MARGINS</b>					
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	<b>REGULATORY ASSET CHARGE</b>	\$ -	\$ 2,559,926	\$ 2,559,926	\$ -	\$ 2,559,926
27	<b>NET MARGINS (LOSS)</b>	\$ (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)

**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-14	Ref: Sch CSB-13	Ref: Sch CSB-14	Ref: Sch CSB-15	Ref: Sch CSB-16	
<b>REVENUES:</b>								
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	Ancillary Services From AEP/CO	-	-	-	-	-	-	-
9	Special Contracts	673,342	-	-	-	-	-	673,342
10	Total Revenues	\$ 27,855,318	\$ (2,707,122)	\$ -	\$ -	\$ -	\$ -	\$ 25,148,196
<b>OPERATING EXPENSES:</b>								
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)	\$ (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)
<b>INTEREST ON LONG-TERM DEBT &amp; OTHER DEDUCTIONS</b>								
23	Interest on Long-term Debt	\$ 5,168,413	-	-	-	-	\$ 133,675	\$ 5,302,088
24	Other Interest & Other Deductions	232,030	-	-	-	-	-	232,030
25	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)
<b>NON-OPERATING MARGINS</b>								
28	Interest Income	\$ 172,901	-	-	-	-	-	\$ 172,901
29	Other Non-operating Income	107,971	-	-	-	-	-	107,971
30	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)

**OPERATING INCOME ADJUSTMENT NO. 1 - REGULATORY ASSET CHARGE**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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]	[B]	[C]
	COMPANY AS FILED	STAFF ADJUSTMENTS	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

		RAC	
		Decision No.62758	
21			
22			
23		2004 RAC \$	0.00137
24		2005 RAC \$	0.00133
25	<b>Note:</b>	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		

**References:**

- 31 Column A: Cooperative Schedule C1, Page 3, Line 6
- 32 Column B: Testimony, CSB
- 33 Column C: Column [A] + Column [B]

**OPERATING INCOME ADJUSTMENT NO. 2 - NORMALIZED LEGAL EXPENSE**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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				
	Firm Name	Date	Invoice No.	Amount
5				
6				
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				
	Firm Name	Date	Invoice No.	Amount
19				
20				
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]

**OPERATING INCOME ADJUSTMENT NO. 3 - EMPLOYEE VACANCY LEVEL NORMALIZATION**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		COMPANY AS FILED	STAFF ADJUSTMENTS	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	<b>Adjustment to Normalize Employee Vacancy Level</b>			<b>\$ (113,684)</b>

13 References:

- 14 Column A: Company Data Request Response CSB 2-37
- 15 Column B: Testimony, CSB
- 16 Column C: Column [A] + Column [B]

**OPERATING INCOME ADJUSTMENT NO. 4 - FOOD & OTHER EXPENSES**

LINE NO.	DATA REQUEST RESPONSE	DESCRIPTION	[A]	[B]	[C]
			COMPANY AS FILED	STAFF ADJUSTMENTS	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**

LINE NO.	DESCRIPTION	[A]	[B]	[C]
		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]

**RAMIREZ**

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 ) DOCKET NO. E-01773A-04-0527  
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 )

DIRECT  
TESTIMONY  
OF  
ALEJANDRO RAMIREZ  
PUBLIC UTILITIES ANALYST III  
UTILITIES DIVISION  
ARIZONA CORPORATION COMMISSION

FEBRUARY 23, 2004

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SWTCO's Capital Structure.....	3
Conclusion.....	8

**SCHEDULES**

SWTCO's Historical Capital Structure.....	AXR-1
Sample G&T Cooperatives' Capital Structure.....	AXR-2
SWTCO's TIER, DSC Ratios and Capital Structure.....	AXR-3

**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.

1 **INTRODUCTION**

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

3 A. My name is Alejandro Ramirez. I am a Public Utilities Analyst employed by the Arizona  
4 Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff").  
5 My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

6  
7 **Q. Briefly describe your responsibilities as a Public Utilities Analyst.**

8 A. In my position as a Public Utilities Analyst, I perform studies to estimate the cost of  
9 capital component of the revenue requirement in rate proceedings. I also perform other  
10 financial analyses.

11  
12 **Q. Please describe your educational background and professional experience.**

13 A. In 2002, I graduated summa cum laude from Arizona State University, receiving a  
14 Bachelor of Science degree in Global Business with a specialization in finance. While  
15 attending Arizona State University, I successfully completed the Barrett Honors College  
16 curriculum. My course of studies included classes in corporate and international finance,  
17 investments, accounting, statistics, and economics. I began employment as a Staff Public  
18 Utilities Analyst in 2003. Since that time, I have provided recommendations to the  
19 Commission on financings and prepared various studies in the field of cost of capital and  
20 econometrics. I have also attended seminars related to general regulatory and business  
21 issues.

22  
23 **Q. What is the scope of your testimony in this case?**

24 A. I discuss Southwest Transmission Cooperative, Inc.'s ("SWTCO" or "Applicant") current  
25 capital structure and provide Staff's recommended operating income. I also provide the

1 times interest earned ("TIER") and debt service coverage ("DSC") ratios resulting from  
2 Staff's recommended operating income.

3  
4 **SUMMARY OF TESTIMONY AND RECOMMENDATIONS**

5 **Q. Briefly summarize how your testimony is organized.**

6 **A.** This testimony is organized in three sections. Section I presents the Applicant's long-term  
7 debt and patronage equity balances. Section II discusses SWTCO's capital structure.  
8 Finally, Section III discusses Staff's recommended operating income, TIER and DSC  
9 ratios for the Applicant.

10  
11 **Q. Have you prepared any exhibits to your testimony?**

12 **A.** Yes. I prepared three schedules (AXR-1 to AXR-3) that support Staff's  
13 recommendations.

14  
15 **Q. What is Staff's recommended operating income for the Applicant?**

16 **A.** Staff recommends an operating income no less than \$3,439,610 for SWTCO (which is the  
17 operating income that would result from the Applicant's proposed revenues).

18  
19 **Q. What TIER and DSC ratios would result from Staff's minimum recommended  
20 operating income of \$3,439,610?**

21 **A.** Staff has calculated that an operating income of \$3,439,610 would allow SWTCO to  
22 achieve a TIER of 0.65 which also equates to a 0.81 DSC. Staff has also calculated a  
23 TIER of 1.13 and a DSC of 1.02 when including the Regulatory Asset Charge ("RAC")  
24 (Schedule AXR-4). Only by taking the RAC into account does the Applicant have the  
25 capacity to meet its debt service obligations.

1 **SWTCO'S LONG-TERM DEBT AND PATRONAGE EQUITY BALANCE**

2 **Q. What is the amount of SWTCO's long-term debt outstanding?**

3 A. The Applicant had \$94,164,787 in long-term debt outstanding as of November 1, 2004,  
4 and it is expected to incur \$5,302,088 in interest expense related to its long-term debt  
5 during the year.

6  
7 **Q. What were SWTCO's patronage equity balances for the years ended 2003, 2002 and**  
8 **2001?**

9 A. SWTCO's patronage equity balances for the years ended 2003, 2002 and 2001 were  
10 \$4,240,180, \$2,218,235 and \$1,812,664, respectively.

11  
12 **SWTCO'S CAPITAL STRUCTURE**

13 **Q. What was SWTCO's actual end of test year capital structure?**

14 A. The Applicant's actual end of test year capital structure was composed by 95.3 percent  
15 debt and 4.7 percent patronage equity<sup>1</sup>. Schedule AXR-1 presents the Applicant's capital  
16 structures for the years 2001, 2002 and 2003.

17  
18 **Q. Is SWTCO concerned with its current capital structure?**

19 A. Yes. In his direct testimony, the Applicant's witness, Mr. William K. Edwards, has  
20 emphasized the importance for SWTCO to develop a stronger equity base. Moreover, Mr.  
21 Edwards recognizes and supports the efforts made by both the Commission and SWTCO  
22 to establish long-term goals for SWTCO's patronage equity (Decision No. 64991, dated  
23 June 26, 2002).

24  

---

<sup>1</sup> Staff has calculated the capital structure by taking into account long-term debt and equity.

1 **Q. How does SWTCO's capital structure compare to other G&T utilities' capital**  
2 **structure?**

3 **A.** Mr. William Edwards has compared SWTCO's capital structure to the Capital structure of  
4 55 G&T utilities' capital structure. As mentioned in his testimony, SWTCO's capital  
5 structure is more leveraged than Mr. Edwards' G&T utilities sample (See Mr. Edwards  
6 Direct Testimony, Page 10, Line 18-21). Schedule AXR-2 presents the capital structure of  
7 some G&T cooperatives that are rated by *Standard & Poor's* ("S&P") and the Applicant's  
8 capital structure for the test year ended December 2003. The average capital structure of  
9 the G&T cooperatives is composed of 81.0 percent debt and 19.0 percent patronage equity  
10 as opposed to the Applicant's capital structure composed of 95.3 percent debt and 4.7  
11 percent patronage equity.

12  
13 **Q. Is Staff concerned with the Applicant's actual end of test year capital structure?**

14 **A.** Yes. SWTCO's capital structure is highly leveraged as it has remained for several years.  
15 The Applicant's capital structure has multiple potential negative effects including: (1)  
16 higher debt costs for new issuances; (2) reduced ability to incur new debt and finance  
17 capital improvements; and (3) places upward pressure on rates to cover debt service  
18 obligations.

19  
20 **Q. Has the Commission shown concern with highly leveraged cooperatives?**

21 **A.** Yes. The Commission ordered SWTCO (Decision No. 64991, dated June 26, 2002) and  
22 Arizona Electric Power Cooperative ("AEPSCO") (Decision No. 64227, dated November  
23 29, 2001) to establish long-range goals to improve their patronage equity positions. In  
24 addition, the Commission ordered Trico Electric Cooperative, Inc. ("Trico") to file a  
25 capital improvement plan with the Commission (Decision No.67412, dated November 2,

1           2004). As discussed previously, highly leveraged capital structures present potentially  
2           negative consequences.

3

4           **Q. Does the Rural Utilities Service (“RUS”) have any restrictions in regard to**  
5           **distribution of patronage dividends for highly leverage cooperatives?**

6           **A.** Yes. SWTCO’s audited financial statements for the years ended December 31, 2003 and  
7           2002, state “RUS mortgage provisions require written approval of any declaration or  
8           payment of capital credits. These provisions restrict the payment of capital credits to 25  
9           percent of the margins received by the Cooperative in the preceding year, unless total  
10          membership capital exceeds 40 percent of the total assets of the Cooperative (See Exhibit  
11          GEP-1, note to financial statement 7)”.

12

13          **Q. Does the National Rural Utilities Cooperative Finance Corporation (“CFC”) have**  
14          **any restrictions in regard to distribution of patronage dividends for highly leverage**  
15          **cooperatives?**

16          **A.** Yes. The CFC requires a borrower to have a capital structure composed of at least 30  
17          percent patronage equity to distribute 100 percent of its net earnings as patronage  
18          dividends. If the borrower has a capital structure composed of less than 30 percent  
19          patronage equity, it would be able to distribute as patronage dividends only 30 percent of  
20          its patronage capital or operating margins for the preceding year.

21

22          **Q. What approach does Staff recommend to improve SWTCO’s capital structure?**

23          **A.** Staff recommends steadily growing the Applicant’s patronage equity by setting rates that  
24          balance the interest of the ratepayers and SWTCO’s long-term financial health. SWTCO

1 has not shown how its proposed rates will improve its highly leveraged capital structure in  
2 a reasonable timeframe. Staff anticipates that the Applicant will use the opportunity  
3 provided by rebuttal testimony to explain how its proposed rate will adequately satisfy its  
4 capital structure deficiency.

5

6 **III. OPERATING INCOME, TIER AND DSC RATIOS**

7 **Q. What do the times interest earned ratio ("TIER") and debt service coverage ratio**  
8 **("DSC") represent?**

9 **A.** TIER represents the number of times operating income covers interest expense on long-  
10 term debt. A TIER greater than 1.0 means that operating income is greater than interest  
11 expense.

12 DSC represents the number of times internally generated cash covers required principal  
13 and interest payments on long-term debt. A DSC greater than 1.0 indicates that operating  
14 cash flow is sufficient to cover debt obligations.

15

16 **Q. Do the Applicant's lenders have debt covenants for TIER and DSC?**

17 **A.** Yes. The Rural Utilities Service ("RUS") requires SWTCO to maintain a minimum TIER  
18 of 1.05 and a minimum DSC of 1.0 on an annual average best two of three years basis.

19

20 **Q. What TIER and DSC level does the Applicant claim will result from its proposed**  
21 **revenues?**

22 **A.** The Applicant claims its proposed revenues would result in a 1.15 TIER and a 1.11 DSC.  
23 SWTCO's witness, Mr. Edwards, states in his direct testimony that "...these are minimum

1 ratios to provide some financial stability and *modest progress* toward equity goals  
2 [emphasis added] (Mr. Edwards Direct Testimony, Page 11, Line 4 & 5)". Moreover, Mr.  
3 Edwards recognizes that SWTCO has a long way to go towards improved financial  
4 strength.

5

6 **Q. What TIER and DSC level does Staff conclude would result from the Applicant's**  
7 **proposed revenues?**

8 **A.** Staff has calculated that SWTCO's proposed increase in revenues would result in a TIER  
9 of 0.65 which also equates to a 0.81 DSC. Staff has also calculated a TIER of 1.13 and a  
10 DSC of 1.02 when including the Regulatory Asset Charge ("RAC") (Schedule AXR-4).  
11 Only by taking the RAC into account does the Applicant have the capacity to meet its debt  
12 service obligations.

13

14 **Q. Has the Applicant demonstrated that its proposed revenues are sufficient to improve**  
15 **its equity position in a reasonable timeframe?**

16 **A.** No. The Applicant has provided not support to demonstrate that its proposed revenues are  
17 insufficient to provide patronage equity growth to achieve a capital structure of at least 30  
18 percent patronage equity in a reasonable timeframe.

19

20 **Q. What operating revenues does Staff recommend?**

21 **A.** Staff recommends operating revenues no less than what SWTCO is proposing  
22 (\$28,814,864 without taking into account the RAC or 31,374,790 including the RAC).  
23 Staff recognizes that the Applicant's proposed revenues barely allow the Applicant to

1 cover its debt service. Staff also recognizes that to improve its equity position in a  
2 reasonable timeframe, higher rates are needed.

3

4 **CONCLUSION**

5 **Q. Please summarize Staff's recommendations.**

6 A Staff recommends that the Commission adopt a revenue requirement no less than that  
7 proposed by the Applicant. The Applicant's proposed revenues fail to provide sufficient  
8 internally generated cash flow to finance, directly or indirectly through additional future  
9 debt financing, plant replacement, improvement and expansion requirements. The  
10 Applicant has not demonstrated that its proposed revenue is consistent with the  
11 Commission's order (Decision No. 64991, dated June 26, 2002) to establish long-range  
12 goals to improve its patronage equity position. Staff recommends that the Applicant  
13 improve its equity position to 30 percent of the capital structure in a reasonable timeframe.

14

15 Staff also recommends that the Commission restrict the distribution of future patronage  
16 dividends by SWTCO until it has achieved a capital structure composed of at least 30  
17 percent patronage equity.

18

19 **Q. Does this conclude your direct testimony?**

20 **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 <sup>1</sup>	% Patronage Equity <sup>1</sup>
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. <sup>2</sup>	95.3%	4.7%

<sup>1</sup> Information based on annual reports for the year ended 2003

<sup>2</sup> Based on the Company's rate filing

<u>SWTCO'S TIER and DSC With Staff's Recommended Rates<sup>1</sup></u>				
1	Operating Income	\$ 3,439,610	<b>TIER Without RAC</b>	
2	Regulatory Asset Charge ("RAC")	\$ 2,559,926	[1+5] + [7]	0.65
3	Total Regulated Revenues	<u>\$ 5,999,536</u>	<b>TIER With RAC</b>	
4	Depreciation & Amort.	\$ 6,852,107	[3+5] + [7]	1.13
5	Income Tax Expense	\$ -		
6				
7	Interest Expense	\$ 5,302,088	<b>DSC Without RAC</b>	
8	Repayment of Principal	\$ 7,358,610	[1+4+5] + [7+8]	0.81
			<b>DSC With RAC</b>	
			[3+4+5] + [7+8]	1.02

<sup>1</sup> The amounts reflect Staff's pro forma adjustments and Staff's minimum recommended revenue

**CASPER**

**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.<sup>1</sup> 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.

---

<sup>1</sup> Southwest's proposed revenue includes revenues from the regulatory asset charge and is equal to \$28,814,864 + \$2,707,122 = \$31,521,986.

1 **INTRODUCTION**

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

3 A. My name is Erin Casper. I am a Public Utility Analyst employed by the Arizona  
4 Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff").  
5 My business address is 1200 West Washington Avenue, Phoenix, Arizona 85007.  
6

7 **Q. Briefly describe your responsibilities as a Public Utility Analyst.**

8 A. In my capacity as a Public Utility Analyst, I provide recommendations to the Commission  
9 on energy and telecommunications issues. My current energy-related responsibilities  
10 include review and evaluation of demand-side management issues, utility rate-case filings,  
11 and rate design.  
12

13 **Q. Please describe your educational background and professional experience.**

14 A. I graduated from the University of Wisconsin in 2001, receiving a Bachelor of Science  
15 degree in Economics and Music. From May, 2001 to May, 2004, I was a Staff Economist  
16 with the economic consulting firm of Laurits R. Christensen Associates in Madison,  
17 Wisconsin. As a Staff Economist, I worked on projects in the electric and gas utilities  
18 industry and in patent infringement and antitrust litigation cases. Among my duties as a  
19 Staff Economist, I prepared rate-case filing schedules and analysis for both electric and  
20 gas utilities including revenue requirement, cost of capital, cost of service, and rate design.  
21 Since joining the Arizona Corporation Commission in June of 2004, I have attended  
22 various seminars and classes on general energy industry and regulatory issues.  
23

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

25 A. I will address the cost allocation and rate recommendations for Southwest Transmission  
26 Cooperative's ("Southwest" or "Southwest Transmission" or "Cooperative") application

1 for a general rate increase. In particular, I will explain the calculation of the point-to-point  
2 and network transmission rates, ancillary service rates, and adjustments to recognize  
3 certain grandfathered and discounted point-to-point contracts. I will also describe the  
4 process by which ancillary services are offered to customers by Southwest via Arizona  
5 Electric Power Cooperative ("AEPSCO"). Staff witnesses Crystal Brown, Alejandro  
6 Ramirez, and Jerry Smith will provide testimony covering other aspects of Southwest's  
7 rate application.

8  
9 **SUMMARY OF RECOMMENDATIONS**

10 **Q. Briefly summarize the important concepts in transmission ratemaking.**

11 A. The Federal Energy Regulatory Commission ("FERC") has established that transmission  
12 providers must offer transmission service on a non-discriminatory open access basis.  
13 FERC Order No. 888 requires that a transmission company file an open access  
14 transmission tariff ("OATT") that offers firm and non-firm point-to-point service, firm  
15 network service, and six ancillary services. In that order, FERC indicated that it would  
16 consider alternative pricing methodologies, but that embedded cost-based rates would  
17 remain acceptable. Additionally, FERC indicated that while developing point-to-point  
18 rates using the annual system peak ("1 CP") is the standard methodology, it would no  
19 longer summarily reject firm point-to-point rates based on different cost allocations such  
20 as the average of the twelve monthly peaks ("12 CP"). With respect to network service,  
21 FERC concluded that the load ratio allocation method would remain the standard  
22 methodology but that it would consider rates based on different cost allocation methods on  
23 a case by case basis. FERC Order No. 888 also established that transmission providers  
24 must offer six ancillary services including (1) Scheduling, System Control and Dispatch  
25 Service; (2) Reactive Supply and Voltage Control; (3) Regulation and Frequency  
26 Response Service; (4) Energy Imbalance Service; (5) Operating Reserve-Spinning; and (6)

1           Operating Reserve-Supplemental. The pro forma OATT sets forth standard rate design  
2           methodologies for point-to-point, network, and ancillary services.

3  
4           **Q. Please explain how Transmission Cooperatives are treated differently than Investor**  
5           **Owned Utilities both at the Federal and State levels.**

6           A. Southwest is financed by the Rural Utility Service (“RUS”) Fund and therefore claims  
7           status as a non-FERC jurisdictional entity. FERC Order No. 888 established that non-  
8           public or non-jurisdictional utilities that own, operate, or control transmission facilities  
9           must provide reciprocal transmission service as a condition of receiving open access  
10          transmission service from public utilities. One method of satisfying the reciprocity  
11          requirement is for the non-public utilities to voluntarily file a “safe harbor” OATT with  
12          FERC. The “safe harbor” tariff filings are subject to less regulatory scrutiny on the  
13          federal level than the tariffs filed by public utilities. FERC generally finds the OATT  
14          appropriate for “safe harbor” status if the tariff is substantially similar to the pro forma  
15          OATT set forth in Order No. 888. On May 10, 2004, FERC issued an order clarifying the  
16          “safe harbor” status of the OATT filed by Southwest.

17  
18          The Arizona Corporation Commission has jurisdiction over the rates and charges assessed  
19          by Southwest. The Commission also has jurisdiction over Southwest’s tariff. The  
20          Commission approved the rates and charges contained in Southwest’s current OATT in  
21          Decision No. 65367.

22  
23          **Q. Please identify the different types of transmission rates included in the rate design.**

24          A. Southwest Transmission offers firm and non-firm point-to-point transmission service, firm  
25          network transmission service, and six ancillary services (1) Scheduling, System Control  
26          and Dispatch Service (“Schedule 1”); (2) Reactive Supply and Voltage Control (“Schedule

1           2"); (3) Regulation and Frequency Response Service ("Schedule 3"); (4) Energy  
2           Imbalance Service ("Schedule 4"); (5) Operating Reserve-Spinning ("Schedule 5"); and  
3           (6) Operating Reserve-Supplemental ("Schedule 6").  
4

5       **Q.    In general, how did Staff calculate the recommended rates?**

6       A.    Staff calculated rates based on embedded costs for firm and non-firm point-to-point  
7           service, firm network service, and the six required ancillary services. The Total  
8           Transmission Revenue Requirement ("TTRR") is equal to Staff's recommended Total  
9           Revenue Requirement for Southwest Transmission less revenues from Schedule 1: Load  
10          Dispatching and System Control, Direct Assignment Facilities, Special Contracts, and  
11          Other Revenues. Point-to-point rates are calculated using the TTRR and the annual  
12          coincident peak demand. The monthly network transmission service revenue requirement  
13          is equal to the TTRR less the point-to-point revenues divided by twelve. Rates for the six  
14          ancillary services are cost-based and explained later in my testimony.

1 Q. What is the Cooperative's proposed rate design?

2 A. Southwest Transmission has proposed the following changes to its rates:  
3

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%

4  
5 Q. Did Staff adopt the ratemaking methodology used by Southwest Transmission in its  
6 proposed rate design?

7 A. In general, Staff employed the methods of cost allocation and rate design used by  
8 Southwest in its rate calculations. Staff has accepted Southwest's use of the annual  
9 system peak demand in the calculation of point-to-point rates. Staff has accepted the  
10 Cooperative's method of allocating the network service monthly revenue requirement  
11 based on its customers' load ratio shares. Staff has also utilized Southwest's cost  
12 allocation methodology for the purpose of determining the ancillary service rates  
13 (Schedules 1-6).  
14  
15  
16

1 **Q. What is Staff's recommended rate design?**

2 A. Based on Staff's overall revenue requirement, Staff recommends the following rates for  
3 Southwest Transmission Cooperative.  
4

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%

5  
6 **Q. Explain the differences in Staff's recommended rate design versus the Cooperative's  
7 proposed rate design.**

8 A. Staff's recommended revenue requirement net of regulatory asset revenues is equal to  
9 Southwest's \$28,814,864 proposed revenue requirement net of regulatory asset revenues.  
10 Staff's recommended revenue requirement is discussed in detail in the testimony of Staff  
11 witness Brown.

12  
13 As explained in greater detail below, the calculations of point-to-point and network  
14 service rates are largely based on the transmission revenue requirement and billing kW.  
15 However, where rate base, operating expenses, and/or the operating margin are used

1 explicitly to calculate rates, Staff's recommendations are used. For example, several  
2 point-to-point customers have discounts that are based, in part, on rate base, operating  
3 expenses, and operating margin. The cost-based ancillary service rates are also based in  
4 part on rate base, operating expenses, and operating margin. To the extent that Staff's  
5 recommendations for those items deviate from the Cooperative's proposed adjusted test  
6 year numbers, Staff's proposed rates will differ from the rates proposed by Southwest.

7  
8 **Q. Please discuss the billing KW and kWh Staff has used in your rate design.**

9 A. In its original filing, Southwest provided both 2003 test year and forecasted 2004 billing  
10 data for network customers. Southwest provided annualized 2003 test year loads for its  
11 point-to-point customers. In its rate calculations, the Cooperative utilized the forecasted  
12 2004 demands for its network customers along with the annualized 2003 contracted loads  
13 for its point-to-point customers. Staff has accepted the annualization adjustments made by  
14 Southwest for its point-to-point loads, and has used these billing units in the rate design.  
15 The adjustments recognize the termination of a 17.5 MW contract with the City of Mesa, a  
16 change in the contract with the Town of Thatcher. Staff believes these adjustments to  
17 contracted point-to-point loads are reasonable because they are known and measurable.  
18 However, it is Staff's general practice to use test year billing data. As such, Staff does not  
19 accept the 2004 forecasted load data for the Cooperative's network customers. Staff has  
20 used the 2003 test year billing data for network loads. Schedule EEC-1 shows the  
21 differences in billing data utilized by Southwest and Staff in the rate design.

22  
23 **Q. How does Staff's use of the 2003 test year billing kW for network loads affect the**  
24 **rate calculation?**

25 A. As is discussed below, the calculation of the point-to-point rate is dependent on the annual  
26 system coincident peak demand. Using the 2003 test year billing kW rather than the

1 forecasted 2004 demand increases the annual system coincident peak demand slightly.  
2 The slight increase in annual system peak demand results in a slightly lower point-to-point  
3 rate.

4  
5 In addition, the actual 2003 test year billing units yield different load ratio shares and  
6 subsequently, a different estimated allocation of the network service revenue requirement  
7 among Southwest's network customers than do the forecasted billing units. However, this  
8 estimated allocation is for informational purposes only. When new rates take effect, the  
9 actual 12-month rolling average load ratio shares will be used to allocate the network  
10 service revenue requirement among Southwest's network service customers.

11  
12 **POINT-TO-POINT TRANSMISSION SERVICE**

13 **Q. Please explain point-to-point transmission service.**

14 A. Point-to-point transmission service is the reservation and transmission of capacity and  
15 energy on either a firm or non-firm basis from designated point(s) of receipt to designated  
16 point(s) of delivery. Points of receipt are points of interconnection between the  
17 transmission provider and the customer or a 3<sup>rd</sup> party at which power is received onto the  
18 transmission provider's system. Points of delivery are points at which power is delivered  
19 by the transmission provider to the receiving party.

20  
21 **Q. Please describe the calculation of the firm point-to-point transmission service rates.**

22 A. Firm point-to-point ("PTP") rates are calculated by dividing the Total Transmission  
23 Revenue Requirement ("TTRR") by the Annual Coincident Peak Demand ("1 CP") of  
24 Southwest's system. Please see Schedule EEC-2 for the calculation of the PTP rate. The  
25 TTRR equals the Total Revenue Requirement less revenues from Schedule 1: Load  
26 Dispatching and System Control, Direct Assignment Facilities, Special Contracts, and

1 Other Revenues. The TTRR represents the amount of revenue that must be collected by  
2 point-to-point and network transmission service customers. Based on Staff's  
3 recommended overall revenue requirement and the system 1 CP, the recommended point-  
4 to-point rate is \$3.022/kW. This represents an increase of 7.45 percent over Southwest's  
5 present rate.

6  
7 **Q. Please explain why the Annual Coincident Peak Demand is used to calculate the firm**  
8 **point-to-point transmission rate.**

9 A. In Order No. 888, FERC allowed transmission providers more flexibility in setting rates as  
10 it did not mandate the use of a particular cost allocation methodology. FERC stated that it  
11 would no longer "summarily reject a firm point-to-point transmission rate developed by  
12 using the average of the 12 monthly system peaks."<sup>2</sup> However, using the annual system  
13 peak remains as a standard methodology. The use of 1 CP yields a lower PTP rate than  
14 the use of the twelve monthly system peaks ("12 CP") because the TTRR is divided by a  
15 larger denominator using the 1 CP. Southwest explained its rationale for using 1 CP to set  
16 point-to-point rates in its response to Staff's Ninth Set of Data Requests. The Cooperative  
17 stated that the use of the 1 CP in setting PTP rates reflects its need to remain competitive  
18 with neighboring utilities' point-to-point service rates. In addition, Southwest recognized  
19 that point-to-point transmission service is a less valuable service than network service and  
20 rates should reflect that fact.<sup>3</sup>

21  
22 Staff acknowledges that point-to-point service is a less valuable transmission service than  
23 network service which allows a customer to integrate and economically dispatch its  
24 resources. As such, it is appropriate for pricing to reflect the relative value of the services.

25 In addition, Southwest's transmission system was primarily built to serve its network

---

<sup>2</sup> FERC Order No. 888 page 301.

<sup>3</sup> Response to Staff's ninth set of data requests: 9-1.

1 customers, and it is the network customers that have priority with respect to the available  
2 transmission capacity. Southwest is entitled to recover its entire revenue requirement even  
3 if it is only serving network customers. To the extent there is available capacity, it is in  
4 the interest of the network customers for Southwest to offer and provide point-to-point  
5 service to non-member customers. Revenues from PTP service directly offset the network  
6 service revenue requirement that is allocated among the network customers. Staff  
7 concludes that it is in the interest of Southwest's members for the point-to-point rate to  
8 remain competitive. Using the 1 CP to set the PTP rate yields a lower and more  
9 competitive rate than the 12 CP.

10  
11 **Q. Did Staff consider any grandfathered contracts between Southwest and any of its**  
12 **customers in its recommended rate design?**

13 A. Yes. The total transmission revenue requirement must be recovered through point-to-  
14 point and network services. To the extent that Southwest is contractually obligated to  
15 provide service on a discounted basis to certain point-to-point customers, those discounts  
16 must be considered when setting rates that are designed to recover the total transmission  
17 revenue requirement. Therefore, the total revenue recovered from point-to-point  
18 transmission service reflects revenues collected from the standard point-to-point rates as  
19 well as the discounted rates for Morenci Water & Electric and the Town of Thatcher.

20  
21 **Q. Briefly describe the discount applied to the point-to-point rate for Morenci Water &**  
22 **Electric.**

23 A. Under its firm PTP service agreement with Southwest, Morenci Water & Electric  
24 ("MW&E") receives a discount based on the revenue requirement associated with the  
25 Greenlee 345/230 kV Transformer. The discount reflects MW&E's bypass of the  
26 Greenlee transformer. Whereas the standard PTP rate is calculated by dividing the TTRR

1 by the Annual Coincident Peak Demand ("1 CP"), the MW&E discounted PTP rate is  
2 calculated by dividing the TTRR less the revenue requirement associated with the  
3 Greenlee Transformer by the 1 CP. See Schedule EEC-3 for the calculation of the  
4 discount applied to the PTP rate for MW&E. Staff's recommended point-to-point rate for  
5 MW&E is \$3.007/kW. This represents a discount of \$0.015/kW from the recommended  
6 standard point-to-point rate.

7  
8 **Q. Briefly describe the discount applied to the point-to-point rate for the Town of**  
9 **Thatcher.**

10 A. Under its firm PTP service agreement with Southwest, the Town of Thatcher ("Thatcher")  
11 receives a discount based on the expenses associated with Southwest's wheeling contract  
12 with the Western Area Power Administration ("WAPA"). The discount reflects  
13 Thatcher's use of its own WAPA rights that allow it to avoid using Southwest's system  
14 from the Westwing Substation to the Apache Substation. Whereas the standard PTP rate  
15 is calculated by dividing the TTRR by the Annual Coincident Peak Demand ("1 CP"), the  
16 Thatcher discounted PTP rate is calculated by dividing the TTRR less the expenses  
17 associated with the WAPA wheeling contract by the 1 CP. See Schedule EEC-4 for the  
18 calculation of the discount applied to the PTP rate for Thatcher. Staff's recommended  
19 point-to-point rate for the Town of Thatcher is \$2.605/kW. This represents a discount of  
20 \$0.417/kW from the recommended standard point-to-point rate.

21  
22 **Q. Please describe the calculation of the non-firm point-to-point transmission service**  
23 **rates.**

24 A. FERC Order No. 888 established that the non-firm rate for point-to-point service should  
25 be capped at the firm rate. FERC concluded that pricing flexibility for non-firm service is  
26 acceptable but that any discounts given for non-firm point-to-point service must be offered

1 to all similarly situated customers. In its current OATT, Southwest sets forth its rate for  
2 non-firm PTP transmission service. The current rate for non-firm PTP service is equal to  
3 the firm PTP rate. Southwest has indicated that it provides non-firm PTP service on a  
4 limited and non-discriminatory basis.<sup>4</sup> The Cooperative's proposed non-firm rate for  
5 point-to-point service is set equal to the firm rate. Consistent with current practice, Staff's  
6 recommended non-firm point-to-point transmission rate is set equal to the recommended  
7 firm rate of \$3.022/kW. Please see Schedule EEC-2 for the calculation of the firm and  
8 non-firm point-to-point rates.

9  
10 **NETWORK TRANSMISSION SERVICE**

11 **Q. Please explain network transmission service.**

12 A. Network transmission service allows a customer to efficiently and economically dispatch  
13 and regulate its network resources to serve its network load within the area served by the  
14 transmission provider. Essentially, a customer taking service under Southwest's network  
15 transmission service tariff may inject power at any point on the system for delivery to any  
16 point on the system so long as those delivery points are designated as "network load."  
17 Network service allows a transmission customer to use Southwest's transmission system  
18 in a comparable manner to the way in which a vertically integrated utility uses its own  
19 transmission system.

20  
21 **Q. Please describe the calculation of the firm network transmission service rates.**

22 A. Network transmission service is priced differently than point-to-point in that the average  
23 dollar per kW may change from month to month for a given customer. The pro forma  
24 OATT established by FERC Order No. 888 allows a transmission utility to set an annual  
25 network service transmission revenue requirement ("NSRR") to be allocated among all

---

<sup>4</sup> Southwest Transmission's Responses to Staff's Ninth Set of Data Requests: STF 9-3.

1 network transmission customers. The annual network service transmission revenue  
2 requirement is equal to the Total Transmission Revenue Requirement less the point-to-  
3 point revenues. Please see Schedule EEC-5 for the total revenues from point-to-point  
4 customers. The annual NSRR is divided by twelve to obtain the monthly NSRR.  
5 Schedule EEC-6 presents the calculation of the network service revenue requirement.  
6 Staff's recommended monthly NSRR is \$1,420,542. The monthly NSRR is allocated  
7 among Southwest's network service customers using each customer's load ratio share.  
8 Each customer's load ratio share is equal to that customer's twelve-month rolling average  
9 network transmission service demand (measured in kW) divided by the total of all  
10 network service customers' twelve-month rolling average demand. Each customer's load  
11 ratio share is computed monthly. Each customer pays its monthly load ratio share times  
12 the monthly NSRR. Schedule EEC-7 shows the estimated allocation of the network  
13 service revenue requirement among Southwest's network service customers. Load Ratios  
14 used in revenue allocation shown in Schedule EEC-7 are based on 2002 and 2003 billing  
15 kW. When new rates take effect, actual rolling 12-month average Load Ratio Shares will  
16 be used to allocate the Network Service Revenue Requirement.

17  
18 **ANCILLARY SERVICES**

19 **Q. Please explain the six ancillary services that Southwest is required to offer.**

20 A. Ancillary services are those services that are necessary to support the transmission of  
21 capacity and energy from resources to loads while maintaining reliable operation of the  
22 transmission provider's transmission system. FERC requires that transmission providers  
23 offer six ancillary services. Scheduling, System Control and Dispatch Service ("Schedule  
24 1") is required to schedule the movement of power through, out of, within, or into a  
25 control area. Reactive Supply and Voltage Control ("Schedule 2") is the provision of  
26 reactive power needed to maintain transmission voltage on the transmission facilities

1 within acceptable limits. Regulation and Frequency Response Service ("Schedule 3")  
2 provides the continuous balancing of resources and load to maintain scheduled  
3 interconnection frequency at sixty cycles per second. Energy Imbalance Service  
4 ("Schedule 4") is provided when a difference occurs between scheduled and actual  
5 delivery of energy to a load located within a control area over an hour. Operating  
6 Reserve-Spinning ("Schedule 5") provides reserve power needed to serve load  
7 immediately to maintain reliability in the event of a system contingency. Operating  
8 Reserve-Supplemental ("Schedule 6") provides reserve power needed to serve load within  
9 fifteen minutes to maintain reliability in the event of a system contingency.

10  
11 Of these services, FERC determined that the transmission provider is required to provide  
12 and the customer must purchase from the provider the first two services (Schedules 1-2).  
13 The remaining four services (Schedules 3-6) must be offered by the transmission provider  
14 but the customer has the option to acquire the services from the transmission provider, a  
15 third party, or self-provide.

16  
17 **Q. Please explain the calculation of the rate for Schedule 1: System Control and Load**  
18 **Dispatch.**

19 **A.** The rate for Schedule 1 is based on Southwest's costs to schedule the movement of power  
20 through, out of, within, or into its control area. The rate is based on the system control  
21 and load dispatching expenses incurred by Southwest less the payment from AEPCO for  
22 the use of the Energy Management System owned by Southwest divided by the average  
23 capacity of the generation dispatched by Southwest. Schedule EEC-8 shows the  
24 calculation of the rate for Schedule 1. Staff's recommended rate for Schedule 1 is equal to  
25 Southwest's proposed rate of \$0.289/kW which represents a decrease of 37.86 percent  
26 from the present rate. Southwest explained that the proposed decrease in the rate for

1 Schedule 1 is a result of the reclassification of revenue credits including the Energy  
2 Management System payment from AEPCO and an increase in generating capacity.<sup>5</sup>  
3

4 **Q. Is Southwest capable of providing all of the ancillary services using its own facilities?**

5 A. As a stand-alone transmission provider, Southwest does not have its own source of  
6 generation resources with which to provide the generation-related ancillary services  
7 including Reactive Supply and Voltage Control, Regulation and Frequency Response  
8 Service, Energy Imbalance Service, Operating Reserve-Spinning, and Operating Reserve-  
9 Supplemental ("Schedules 2-6"). In order to fulfill its obligation to offer these five  
10 generation-related ancillary services, the Cooperative procures them from AEPCO. The  
11 rates charged to Southwest by AEPCO for its ancillary services are based on AEPCO's  
12 embedded costs to provide these services. Southwest passes the cost-based rates directly  
13 on to its transmission customers.  
14

15 **Q. Do the rates for the generation-related ancillary services reflect Southwest's costs?**

16 A. Indirectly, the rates that Southwest has proposed for Schedules 2-6 reflect its costs to  
17 provide those services in that they are the rates they will pay AEPCO to provide those  
18 services to its customers. However, the costs included in the "cost-based" rates for  
19 Schedules 2-6 are costs that AEPCO incurs to provide those services.  
20

21 **Q. Did Staff use AEPCO's costs to calculate the rates for the generation-related  
22 ancillary services?**

23 A. Yes. Although Schedules 2-6 are included in Southwest's open access transmission tariff,  
24 the costs to provide these generation-related services are incurred by AEPCO and passed  
25 on to Southwest. Therefore, Staff's recommended expenses, plant balances, and revenue

---

<sup>5</sup> Southwest Transmission's Responses to Staff's Ninth Set of Data Requests: STF 9-12.

1 requirements for AEPCO were used to calculate the rates for Schedules 2–6. Schedules 9,  
2 10, and 11 show the derivation of the generation-related ancillary services.

3  
4 **Q. Is Southwest earning a rate of return on Schedules 2-6?**

5 A. No. When a customer buys any generation-related ancillary services from Southwest,  
6 Southwest purchases those services from AEPCO at cost-based rates and passes AEPCO's  
7 cost-based rates on to the customer. The rate the customer pays for generation-related  
8 ancillary services is the same cost-based rate that Southwest pays to AEPCO for the  
9 provision of the generation-related ancillary services.

10  
11 **REGULATORY ASSET CHARGE**

12 **Q. Please explain the Regulatory Asset Charge.**

13 A. Pursuant to Decision No. 62758, Southwest was authorized to collect a Regulatory Asset  
14 Charge ("RAC") to be assessed against all kWh sold to Southwest's Class A members  
15 according to the schedule set forth in the order. The RAC is to remain in effect until the  
16 full amount of regulatory assets assumed by Southwest is recovered. The initial total  
17 regulatory assets to be recovered was equal to \$21,849,000. The RAC is to be collected  
18 over an eleven year period from December, 1999 through December, 2012 and is adjusted  
19 downward on an annual basis as set forth in the order. The RAC rate for 2005 is equal to  
20 \$0.00133 per kWh as specified in Decision No. 62758 and Southwest's current OATT.

21  
22 **Q. What is Staff's recommendation with respect to the Regulatory Asset Charge?**

23 A. Staff recommends that the Commission require Southwest to provide annual status reports  
24 that detail how much revenue has been collected through the RAC since December, 1999.  
25 The report should detail the billing kWh, RAC rate, and revenues collected through the

1 RAC by Class A member, by year. Southwest should file the report on February 1 of each  
2 year beginning February 1, 2006.

3  
4 Staff also recommends that the Commission order that Southwest discontinue the  
5 assessment of the Regulatory Asset Charge at such time as it has collected the full  
6 \$21,849,000 regardless of whether that event coincides with the projected schedule set  
7 forth in Decision No. 62758.

8

9 **Q. Does this conclude your testimony?**

10 **A. Yes, it does.**

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**Comparison of Billing Units**

Month	Actual 2003 Test Year Billing Units			Forecast 2004 Billing Units		
	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	<b>697,093</b>	466,214	229,000	<b>695,214</b>
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	<b>697,093</b>	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

**Calculation of the Point-to-Point Rate**

<u>Total Revenue Requirement = O&amp;M + Depr&amp;Amort + Taxes + Operating Margin</u>		
O&M		16,237,302
Depreciation & Amortization		6,852,107
Taxes		2,285,845
Operating Margin		3,439,610
<b>Total Revenue Requirement</b>		<b>28,814,864</b>
<u>Less Other Operating Revenues</u>		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Revenues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
<b>Total Other Operating Revenues</b>		<b>1,602,240</b>
<b>Transmission Revenue Requirement (including Schedule 1)</b>		<b>27,212,624</b>
<b>Schedule 1 Revenues</b>	<b>\$ / kW</b>	
Schedule 1 - PiP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
<b>Total Schedule 1 Revenues</b>		<b>1,933,749</b>
<b>Total Transmission Revenue Requirement</b>		<b>25,278,875</b>

**Point to Point Transmission Service (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 Monthly kW	Standard PTP Rate	Standard PTP Revenue
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
<b>Total</b>			<b>\$5,911,032</b>

**Calculation of the Discount to the Point-to-Point Rate for Morenci Water & Electric**

**25,278,875**

**Total Transmission Revenue Requirement**

**Greenlee Transformer Revenue Credit for MW&E**

(Remove Required Revenue Allocated to Greenlee Transformer from Total Transmission Revenue Requirement)	571,326
Net Investment Greenlee Transformer	4.505%
Carrying Charge on Investment in Plant*	25,740
Carrying Cost - Greenlee	100,869
O&M Expenses - Greenlee	126,609
<u>Revenue Requirement Allocated to Greenlee Transformer</u>	<u>25,152,266</u>
<b><u>MW&amp;E Transmission Revenue Requirement</u></b>	<b><u>25,152,266</u></b>

**Point to Point Transmission Service (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
<b>Total</b>			<b>\$2,165,040</b>

\* The Carrying Cost is equal to Staff's Recommended (Operating Margin / Rate Base)

**Calculation of the Discount to the Point-to-Point Rate for the Town of Thatcher**

Total Transmission Revenue Requirement	<b>25,278,875</b>
<b>Discount for Town of Thatcher - WAPA Wheeling Expenses</b> (Remove WAPA Wheeling Expenses from Total Transmission Revenue Requirement) WAPA Wheeling Costs \$3,484,188	3,484,188
<b>Town of Thatcher Transmission Revenue Requirement</b>	<b>21,794,687</b>

**Point to Point Transmission Service (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		Thatcher		Thatcher	
	Monthly kW	Monthly kW	Discount PTP Rate	Discount PTP Rate	Discount PTP Revenue	Discount PTP Revenue
Jan	4,000	4,000	\$2.605	\$2.605	\$10,420	\$10,420
Feb	4,000	4,000	\$2.605	\$2.605	\$10,420	\$10,420
Mar	4,000	4,000	\$2.605	\$2.605	\$10,420	\$10,420
Apr	4,000	4,000	\$2.605	\$2.605	\$10,420	\$10,420
May	6,000	6,000	\$2.605	\$2.605	\$15,630	\$15,630
Jun	6,000	6,000	\$2.605	\$2.605	\$15,630	\$15,630
Jul	6,000	6,000	\$2.605	\$2.605	\$15,630	\$15,630
Aug	6,000	6,000	\$2.605	\$2.605	\$15,630	\$15,630
Sep	6,000	6,000	\$2.605	\$2.605	\$15,630	\$15,630
Oct	6,000	6,000	\$2.605	\$2.605	\$15,630	\$15,630
Nov	4,000	4,000	\$2.605	\$2.605	\$10,420	\$10,420
Dec	4,000	4,000	\$2.605	\$2.605	\$10,420	\$10,420
<b>Total - Town of Thatcher</b>					<b>\$156,300</b>	

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**Calculation of the Point-to-Point Revenues**

**Point to Point Transmission Service (1 CP method)**

	Revenue Requirement	TY 2003 (kW)	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	25,152,266	697,093		\$36.08	\$0.015	\$3.007

Point-to-Point Service	Standard Ave		Thatcher Ave		MW&E Ave		Thatcher	
	Monthly kW	Monthly kW	Monthly kW	Monthly kW	Monthly kW	Monthly kW	Discount Rate	MW&E Discount PTP Rate
Jan	163,000	4,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Feb	163,000	4,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Mar	163,000	4,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Apr	163,000	4,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
May	163,000	6,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Jun	163,000	6,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Jul	163,000	6,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Aug	163,000	6,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Sep	163,000	6,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Oct	163,000	6,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Nov	163,000	4,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007
Dec	163,000	4,000	60,000	60,000	\$3.022	\$2.605	\$3.007	\$3.007

Point-to-Point Service	Standard PTP Revenue		Thatcher Discount Revenue		MW&E Discount PTP Revenue		Total PTP Annual Revenues	
	Revenue	Revenue	Revenue	Revenue	Revenue	Revenue	Revenue	Revenue
Jan	\$492,586	\$10,420	\$180,420	\$180,420	\$683,426	\$683,426	\$683,426	\$683,426
Feb	\$492,586	\$10,420	\$180,420	\$180,420	\$683,426	\$683,426	\$683,426	\$683,426
Mar	\$492,586	\$10,420	\$180,420	\$180,420	\$683,426	\$683,426	\$683,426	\$683,426
Apr	\$492,586	\$15,630	\$180,420	\$180,420	\$688,636	\$688,636	\$688,636	\$688,636
May	\$492,586	\$15,630	\$180,420	\$180,420	\$688,636	\$688,636	\$688,636	\$688,636
Jun	\$492,586	\$15,630	\$180,420	\$180,420	\$688,636	\$688,636	\$688,636	\$688,636
Jul	\$492,586	\$15,630	\$180,420	\$180,420	\$688,636	\$688,636	\$688,636	\$688,636
Aug	\$492,586	\$15,630	\$180,420	\$180,420	\$688,636	\$688,636	\$688,636	\$688,636
Sep	\$492,586	\$15,630	\$180,420	\$180,420	\$688,636	\$688,636	\$688,636	\$688,636
Oct	\$492,586	\$15,630	\$180,420	\$180,420	\$688,636	\$688,636	\$688,636	\$688,636
Nov	\$492,586	\$10,420	\$180,420	\$180,420	\$683,426	\$683,426	\$683,426	\$683,426
Dec	\$492,586	\$10,420	\$180,420	\$180,420	\$683,426	\$683,426	\$683,426	\$683,426
<b>Total Revenues</b>	<b>\$5,911,032</b>	<b>\$156,300</b>	<b>\$2,165,040</b>	<b>\$2,165,040</b>	<b>\$8,232,372</b>	<b>\$8,232,372</b>	<b>\$8,232,372</b>	<b>\$8,232,372</b>

**Point-to-Point Revenue Total**

**Calculation of the Network Service Revenue Requirement**

<u>Total Revenue Requirement = O&amp;M + Depr&amp;Amort + Taxes + Operating Margin</u>		
O&M		16,237,302
Depr&Amort		6,852,107
Taxes		2,285,845
Operating Margin		3,439,610
<b>Total Revenue Requirement</b>		<b>28,814,864</b>
<u>Less Other Operating Revenues</u>		
Direct Assignment		515,580
Regulatory Asset Charge		-
Other Revenues		413,318
Special Contracts		673,342
Ancillary Service (Schedules 2-6)		-
<b>Total Other Operating Revenues</b>		<b>1,602,240</b>
<b>Transmission Revenue Requirement (including Schedule 1)</b>		<b>27,212,624</b>
<b>Schedule 1 Revenues</b>	<b>\$ / KW</b>	
Schedule 1 - PtP Revenue	0.289	790,704
Schedule 1 - Network Services Revenue	0.289	1,143,045
<b>Total Schedule 1 Revenues</b>		<b>1,933,749</b>
<b>Total Transmission Revenue Requirement</b>		<b>25,278,875</b>
<b>Less: Point-to-Point Revenue Total</b>		<b>8,232,372</b>
<b>Network Services Annual Revenue Requirement</b>		<b>17,046,503</b>
<b>Network Services Monthly Revenue Requirement</b>		<b>1,420,542</b>

Network Services Revenue Requirement	2003 TY Billing Demand kW	Recommended Revenue Requirement Network Service	Average Network Service \$/kW
<b>Annual</b>		<b>17,046,503</b>	<b>\$4.310</b>
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

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**Estimated Allocation of the Network Service Revenue Requirement\***

NETWORK CUSTOMERS	January	February	March	April	May	June	July	August	September	October	November	December	Total 2003	Average
Anza	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
2002 kW Demand														
Loads 2003	5,436	5,556	6,012	5,486	7,452	7,920	9,516	9,264	6,844	6,708	5,424	6,036	82,464	6,872
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
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	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
2002 kW Demand														
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
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	49,927	4,077
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	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
2002 kW Demand														
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
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
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	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
2002 kW Demand														
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
12 Month Rolling Avg	85,747	85,493	85,447	82,955	83,439	86,663	87,850	89,016	90,100	92,850	93,248	94,002	1,056,829	88,069
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	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
2002 kW Demand														
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
12 Month Rolling Avg	92,515	91,889	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
Revenue - 2003 Load	448,486	446,310	445,550	453,525	449,455	443,045	436,627	431,456	425,349	424,416	424,955	424,707	5,253,877	437,823
Trico	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
2002 kW Demand														
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
12 Month Rolling Avg	70,096	69,805	69,823	69,991	69,446	69,632	70,832	72,095	72,163	73,980	75,028	75,814	857,813	71,484
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	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
2002 kW Demand														
Power Sales using	6,320	6,220	5,990	6,260	6,780	6,900	6,360	5,920	6,100	5,700	2,780	2,660	67,980	5,665
Network Service	7,078	6,940	6,782	6,668	6,620	6,618	6,538	6,470	6,420	6,332	6,005	5,665	67,337	6,511
Cyprus TB and PD	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	-	-	-	-	13,579	-	-	-	-	11,570	-	-	25,149	2,096
2002 kW Demand														
Loads 2003	-	-	-	-	21,304	-	-	-	-	15,590	-	-	139,722	11,644
12 Month Rolling Avg	2,096	2,096	2,096	2,096	2,740	2,740	2,740	2,740	2,740	2,740	2,740	2,740	33,900	2,740
Revenue - 2003 Load	10,160	10,165	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	7,344	7,793	7,344	8,119	13,281	15,178	16,014	14,974	15,245	9,649	7,038	7,691	24,378	2,032
2002 kW Demand														
Loads 2003	2,644	3,293	3,905	4,582	5,688	6,963	8,288	9,535	10,806	10,818	10,827	10,836	130,036	10,836
12 Month Rolling Avg	12,815	16,003	18,947	22,379	27,597	33,196	38,565	43,346	46,169	47,061	46,656	46,704	401,677	33,473
Revenue - 2003 Load	259,849	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	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
2002 kW Demand														
Loads 2003	293,034	292,310	292,764	290,812	292,800	287,545	305,119	312,493	318,676	326,403	326,234	329,598	3,679,786	306,649
12 Month Rolling Avg	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
Revenue - 2003 Load	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
Average														

\* 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.

**Calculation of Schedule 1: System Control and Load Dispatch**

<b>Costs: System Control and Load Dispatch</b>	<b>Southwest Adjusted 2003 TY</b>	<b>Staff Adjustments</b>	<b>Staff Adjusted 2003 TY</b>
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 AEPSCO	(306,624)	-	(306,624)
<b>Total Cost - System Control and Load Dispatch</b>	<b>2,235,345</b>	<b>(9)</b>	<b>2,235,336</b>

<b>Generation Capacity</b>	<b>Net kW Rate</b>
Apache Units (@SRSG)	585,300
Purchased Pwr (PNM & TECO)	29,667
Federal Hydro (CRSP & PD)	29,113
<b>Total Generation Capacity</b>	<b>644,080</b>

<b>Annual Rate (\$ / kW)</b>	<b>\$ 3.471</b>
<b>Monthly Rate (\$ / kW)</b>	<b>\$ 0.289</b>

**Point-to-Point Schedule 1**

<b>Month</b>	<b>Present Rate</b>	<b>Recommended Rate</b>	<b>Present Revenue</b>	<b>Recommended Revenue</b>
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
<b>Total Schedule 1 Revenues from Point-to-Point Customers</b>			<b>1,154,592</b>	<b>790,704</b>

**Network Service Schedule 1**

<b>Month</b>	<b>Present Rate</b>	<b>Recommended Rate</b>	<b>Present Revenue</b>	<b>Recommended Revenue</b>
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
<b>Total Schedule 1 Revenues from Network Customers</b>			<b>1,669,083</b>	<b>1,143,045</b>

Southwest Transmission Cooperative, Inc.  
 Docket No. E-04100A-04-0527  
 Test Year Ended December 31, 2003

Schedule EEC-9

**Calculation of Schedule 2: Cost of Reactive Power (VAR) Production**

Line No.	Power Factor	Gross Nameplate 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%
<b>Total Capacity</b>				<b>85.7%</b>

8 1 - Power Factor 14.30%

	Account	Original Cost	Net Plant in Service
<b>AEPSCO System Investment in Power Production Facilities</b>			
9	Total Production Plant in Service	389,590,504	203,345,337
10	Turbogenerator Systems	55,169,579	26,798,200
11	Accessory Electric Equipment	19,941,398	9,686,381
<b>Separation of Production Plant Allocation to VAR Production</b>			
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 (AEPSCO)	1.33	9.363%
17	Annualized Required Revenue Allocation to VAR Production	\$	<b>534,743</b>

**Schedule 2: Reactive Power (VAR) Production**

	Billing Unit	Demand kW	\$/KW/year	\$/KW/month
18	Network Service Rate	557,598 \$	0.9590	\$ 0.0800
19	Point-to-Point Rate	697,093 \$	0.7671	\$ 0.0640

**Calculation of Schedule 4: Energy Imbalance**

<b>Southwest Transmission Proposed Rate</b>					
<b>Costs: Energy Imbalance</b>	<b>TY 2003</b>	<b>TY 2003</b>	<b>TY 2003</b>	<b>TY 2003</b>	<b>TY 2003</b>
	<b>Southwest Per</b>	<b>Southwest Pro</b>	<b>Southwest</b>	<b>Southwest Cost of</b>	<b>Southwest</b>
<b>Incremental Energy Costs</b>	<b>Books</b>	<b>Forma</b>	<b>Adjusted</b>	<b>Service: Energy</b>	<b>Schedule 4 Costs</b>
		<b>Adjustments</b>			
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
<b>Total</b>	<b>79,971,095</b>	<b>(2,045,646)</b>	<b>77,925,449</b>	<b>67,981,909</b>	<b>67,981,909</b>
Total Energy Sales (kWh)					3,281,912,645
Southwest Transmission Proposed - Cost per kWh					\$ 0.02071
<b>Southwest Transmission Proposed - Cost per MWH</b>					<b>\$ 20.71</b>

<b>Staff Recommended Rate</b>			
<b>Costs: Energy Imbalance</b>	<b>TY 2003</b>	<b>TY 2003</b>	<b>TY 2003</b>
	<b>Southwest</b>	<b>Staff Adjustments</b>	<b>Staff</b>
<b>Incremental Energy Costs</b>	<b>Cost of</b>	<b>to Cost of Service:</b>	<b>Recommended</b>
	<b>Service:</b>	<b>Energy</b>	<b>Schedule 4 Costs</b>
	<b>Energy</b>		
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
<b>Total</b>	<b>67,981,909</b>	<b>(1,280,873)</b>	<b>66,701,036</b>
Total Energy Sales (kWh)			3,281,912,645
Staff Recommended - Cost per kWh			\$ 0.02032
<b>Staff Recommended - Cost per MWH</b>			<b>\$ 20.32</b>

**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	Depreciation Expenses	Required Return on Production Plant	Annual Revenue Requirement	Revenue Requirement per KW
<b>Total to Allocate</b>			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
<b>Total</b>	<b>585,300</b>	<b>365,582,060</b>	<b>25,165,359</b>	<b>9,589,717</b>	<b>3,346,839</b>	<b>7,539,289</b>	<b>19,428,883</b>	<b>65,070,087</b>	<b>\$ 111.17</b>

**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
<b>Total</b>	<b>448,400</b>		<b>57,652,506</b>
Annual Generation Capacity Rate		\$	128.574
Monthly Generation Capacity Rate		\$	10.714
Required Reserve Percentage			3.99%
<b>Schedule 3 Monthly Rate (\$/KW)</b>		\$	<b>0.4280</b>

**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
<b>Total</b>	<b>371,000</b>		<b>53,739,961</b>
Annual Generation Capacity Rate		\$	144.852
Monthly Generation Capacity Rate		\$	12.071
Required Reserve Percentage			5.35%
<b>Schedule 5 Monthly Rate (\$/KW)</b>		\$	<b>0.6460</b>

**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
<b>Total</b>	<b>60,000</b>		<b>5,601,518</b>
Annual Generation Capacity Rate		\$	93.359
Monthly Generation Capacity Rate		\$	7.780
Required Reserve Percentage			5.36%
<b>Schedule 6 Monthly Rate (\$/KW)</b>		\$	<b>0.4170</b>

J. SMITH

**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

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Used and Useful Determination.....	7
Summary of Testimony Conclusions.....	8

**EXHIBITS**

Engineering Report, Docket No. E-01773A-01-0112 .....	JDS-1
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.

1 **WITNESS BACKGROUND AND QUALIFICATIONS**

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

3 A. My name is Jerry D. Smith. I am an Electric Utility Engineer employed by the Arizona  
4 Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff").  
5 My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

6  
7 **Q. Please describe your educational background.**

8 A. I graduated from the University of New Mexico in 1968 with a Bachelor of Science  
9 degree in Electrical Engineering. I received a Masters of Science degree in Electrical  
10 Engineering from New Mexico State University in 1977 majoring in power systems and  
11 electric utility management.

12  
13 **Q. Do you hold any special licenses or certificates?**

14 A. I am licensed with the State of Arizona as a Professional Engineer - Electrical.

15  
16 **Q. Briefly describe your responsibilities as an Electric Utility Engineer.**

17 A. I joined the Commission's Utilities Division Staff as an electric engineer in 1999. In my  
18 capacity as an Electric Utility Engineer, I have investigated the quality of service provided  
19 by electric utilities in Arizona and been responsible for three biennial transmission  
20 assessments regarding the reliability of existing and planned Arizona transmission  
21 facilities. During my employment at the Commission, I have investigated numerous  
22 system disturbances on behalf of the Commission. A 1999 blackout of Southern Arizona,  
23 a 2001 blackout of Gila Bend, and several extra high voltage ("EHV") disturbances  
24 occurring in 2003 and 2004 are among the system disturbances I have investigated. My  
25 most recent investigations were of the Westwing and Deer Valley Substation fires.

26

1 I chaired a series of Commission Distributed Generation workshops in 1999 and have  
2 participated in the revision and application of electric retail competition rules throughout  
3 Arizona. I have also inspected physical electric utility plant consisting of generation,  
4 transmission and distribution facilities. Such facility inspections were necessary to make a  
5 "used and useful" determination for rate case applications and to ascertain the level of  
6 security, safety, operational integrity, and maintenance exhibited by such facilities.

7

8 **Q. Please describe other pertinent work experience.**

9 A. I have over 27 years of experience as an engineer and manager in the electric utility  
10 industry. I was employed by the Salt River Project from 1968 through 1995. During that  
11 time I: 1) analyzed and planned transmission and distribution system improvements; 2)  
12 managed the design and consultation services required for retail customer projects; and 3)  
13 served as primary contact for local municipalities regarding siting of facilities and  
14 utilizing funds for aesthetic treatment of water and power facilities. I also performed  
15 ancillary functions such as development and management of capital improvement budgets;  
16 formation and modification of system planning, operational and maintenance policies,  
17 procedures and practices; and creation, modification and administration of new  
18 contribution in aid of construction charges and tariffs.

19

20 **Q. Have you previously testified before this Commission?**

21 A. Yes. I have extensive experience testifying before the Commission. I have testified on  
22 numerous occasions regarding quality of service to electric customers in the City of  
23 Nogales and Santa Cruz County. I was a Staff witness regarding the 2003 competitive  
24 wholesale power solicitations required by the Commission. I have provided testimony for  
25 over 35 power plant and transmission line applications for a Certificate of Environmental  
26 Compatibility. My experience filing engineering reports and providing testimony for the

1 Commission in rates cases is most applicable to this case. I have provided engineering  
2 reports and rate case testimony for Duncan Valley Electric Cooperative, Navapache  
3 Electric Cooperative, and the Arizona Public Service Company and an Open Access  
4 Transmission Tariff ("OATT") case for Southwest Transmission Cooperative ("SWTC").  
5

6 **PURPOSE AND PREPARATION OF TESTIMONY**

7 **Q. What is the purpose of your testimony in this case?**

8 A. I am providing Staff's testimony concerning the security, safety, operational integrity, and  
9 maintenance status of SWTC's transmission facilities. My testimony considers both test-  
10 year facilities and *post* test-year facilities filed by the applicant for inclusion in this rate  
11 case. This testimony documents the justification of need previously considered by this  
12 Commission for all new *post* test-year capital improvements proposed for inclusion in the  
13 rate base by SWTC. Finally my testimony determines to what degree the test-year and  
14 post test-year SWTC facilities are "used and useful."  
15

16 **Q. How have you prepared for your testimony?**

17 A. I have reviewed information on file, issued data requests to SWTC, inspected SWTC's  
18 Winchester Transmission Project facilities and talked with SWTC, Arizona Electric Power  
19 Cooperative ("AEPSCO") and Sierra Southwest Cooperative Services ("Sierra Southwest")  
20 personnel.  
21

22 **Q. When did you inspect AEPSCO's facilities?**

23 A. I inspected SWTC's utility plant during a December 9, 2004 site visit of the Apache  
24 Substation, Winchester Substation and the new 230 kV line between the two substations.  
25 A summary report of my findings is attached as Exhibit JS-2.  
26

1 **Q. What AEPCO, SWTC and Sierra Southwest personnel have you talked with**  
2 **concerning this docket?**

3 A. I have talked with Mr. Dirk Minson, Chief Financial Officer; Mr. Gary Pierson, Financial  
4 Services Manager; Mr. Larry Huff, General Manager; and Mr. Gary Grim, Transmission  
5 Engineering Manager.

6  
7 **Q. What documentation have you reviewed in preparing your testimony?**

8 A. I have reviewed all rate application material filed by the applicant and numerous responses  
9 to Staff data requests. I also reviewed testimony and ACC engineering reports filed for a  
10 2002 SWTC financing application,<sup>1</sup> the Winchester Transmission Project line siting case<sup>2</sup>,  
11 and the Commission's three Biennial Transmission Assessments. The ACC engineering  
12 report for the financing case is attached as Exhibit JS-1 and the report for my tour of the  
13 Winchester Transmission Project is attached as Exhibit JS-2.

14  
15 **Q. Is your testimony herein based upon the aforementioned facility site observations,**  
16 **conclusions drawn from review of available documentation, information gathered by**  
17 **talking with applicant personnel and your educational background and work**  
18 **experience as a utility professional?**

19 A. Yes it is.

20  
21 **FACILITIES CONSIDERED IN TESTIMONY**

22 **Q. Have you reviewed AEPCO's application and testimony regarding facilities it**  
23 **proposes to include in rate base for this case?**

24 A. Yes. I reviewed SWTC's Schedule E-5 that provides a detailed account of its utility plant.  
25 SWTC witness, Mr. Dirk Minson's testimony indicates that the addition of a new

---

<sup>1</sup> Docket No. E-01773A-02-0261.

<sup>2</sup> Docket No. L-00000C-03-0121.

1 Winchester Transmission Project completed in May of 2004 is chief among the  
2 transmission system maintenance and upgrades necessitating a rate increase.  
3

4 **Q. What other facilities are considered in your testimony?**

5 A. SWTC's Schedule E-5 also includes other capital improvements contained in SWTC's  
6 2001-2004 Construction Work Plan. These construction plans were reviewed by ACC  
7 Engineering Staff at the time of SWTC's 2002 financing application with this  
8 Commission. Those facilities fell into three key capital improvements categories:

- 9 1. New substations and substation transformer additions for member distribution  
10 cooperatives, accompanied by appurtenant communication and Supervisory  
11 Control and Data Acquisition ("SCADA") equipment and transmission line  
12 improvements,
- 13 2. Routine line and transmission substation changes, and
- 14 3. The Winchester 230 kV Transmission Project.

15  
16 The Winchester Transmission Project was completed in May of 2004. SWTC made a *post*  
17 test-year adjustment to include the Winchester Project in its rate base. All other capital  
18 improvements were constructed in 2002 and 2003.  
19

20 **JUSTIFICATION OF NEED FOR RECENT IMPROVEMENTS**

21 **Q. Briefly describe how SWTC established with the Commission a justification of need**  
22 **for the recent improvements.**

23 A. On June 22, 1999 a SWTC 230 kV transmission line outage, caused by a fire, interrupted  
24 service to most communities in Southern Arizona. The outage resulting in tripping the  
25 Apache Station power plant and numerous transmission lines interconnected at the Apache  
26 Substation. This cascading event occurred because of insufficient area transmission

1 capacity due to another SWTC line being out of service for planned maintenance and  
2 repair when the event occurred. The Commission held a special open meeting on August  
3 19, 1999 to consider the cause and effects of this event.<sup>3</sup> The Commission's Second  
4 Biennial Transmission Assessment<sup>4</sup> documented that SWTC planned a Winchester Project  
5 to enhance its transmission system reliability, mitigate transmission line overloads for  
6 single contingency outages and reduce the need for remedial action schemes during  
7 multiple contingency outages.

8  
9 The need for the Winchester Project was also documented in SWTC's 2001-2004  
10 Construction Work Plan. SWTC filed the work plan in support of their 2002 financing  
11 application with the Commission. Exhibit JS-1 is a copy of the Engineering Report filed  
12 by Staff in that case. Staff's report reaffirmed the need for SWTC's Winchester Project.<sup>5</sup>

13  
14 SWTC provided further justification of need for the Winchester Project in its transmission  
15 line siting case in 2003.<sup>6</sup> During those proceedings testimony established that the  
16 proposed project would help accommodate the Combustion Turbine Unit 4 addition at  
17 Apache Station. Testimony also reaffirmed that the project would help mitigate the cause  
18 and effects of the 1999 blackout in Southern Arizona, solve local transmission overloads  
19 and provide SWTC a 345 kV interconnection for transmission transactions. The ACC  
20 approved the Certificate of Environmental Compatibility ("CEC") for the project on May  
21 16, 2003 after balancing the need for the line against its likely environmental impact.

22  
23  
24  

---

<sup>3</sup> E-00000A-01-0120.

<sup>4</sup> Docket No. E-00000D-02-0065.

<sup>5</sup> Exhibit JS-1

<sup>6</sup> Docket No. L-00000C-03-0121.

1 **USED AND USEFUL DETERMINATION**

2 **Q. Please describe how you determined if the Winchester Project was used and useful.**

3 A. On December 9, 2004, I toured the SWTC Winchester Project. I observed all of the  
4 associated capital improvements at Apache Substation, the new Winchester Substation,  
5 and the new transmission line between the two substations. Photos were taken to  
6 document my observations and are attached to the Engineering Report of the site visit.  
7 This report is attached as Exhibit JS-2.

8  
9 **Q. Please summarize your observations of the Winchester Project.**

10 A. All transmission facilities observed during the December 9, 2004 tour of SWTC facilities  
11 were operational, designed and constructed to comply with National Electric Safety Code  
12 ("NESC") requirements. Both the Apache Substation and the Winchester substations  
13 were secure regarding public access and displayed proper safety warnings. The pre-  
14 existing Apache Substation transmission facilities were well maintained and the new 230  
15 kV and 345 kV lines and associated equipment were designed and constructed in  
16 accordance with current NESC and the Institute of Electrical and Electronic Engineers  
17 ("IEEE") standards.

18  
19 **Q. Has Staff determined if the capital improvements made by SWTC are "used and  
20 useful?"**

21 A. Yes. All the transmission facilities I observed during my December 9, 2004 tour of  
22 Apache Substation, Winchester Substation and the new transmission lines between the  
23 two substations were operational and well maintained. Therefore, Staff concludes the  
24 SWTC transmission facilities are used and useful.

1 **SUMMARY OF TESTIMONY CONCLUSIONS**

2 **Q. Please summarize the conclusions of your testimony.**

3 A. Utility plant improvements constructed by SWTC between January 2003 and July 2004  
4 were appropriate and necessary to maintain reliable, efficient and cost effective service to  
5 its members and the wholesale market. The justifications of need for such facilities were  
6 established before the Commission in prior proceedings. All utility plant contained in  
7 SWTC's rate application is "used and useful" in reliably delivering the energy needs of  
8 existing retail customers.

9

10 **Q. Does this conclude your direct testimony?**

11 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.
<b>TOTAL</b>		<b>\$30,853,924.</b>

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 its 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 3 miles. 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

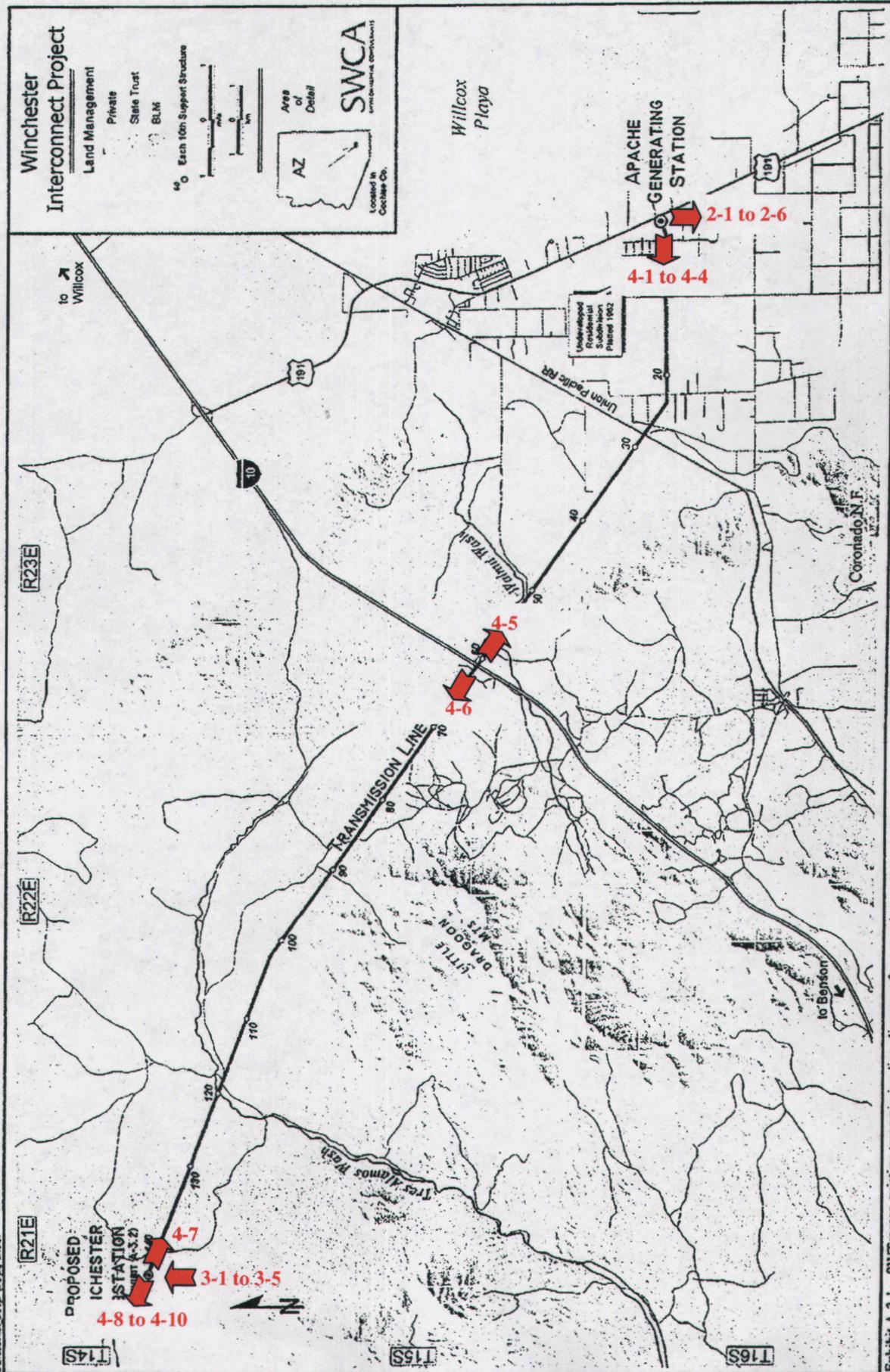


Exhibit A-3.1. SWTrancoo existing transmission line alignment for upgrade.

EXHIBIT 2  
Apache Substation

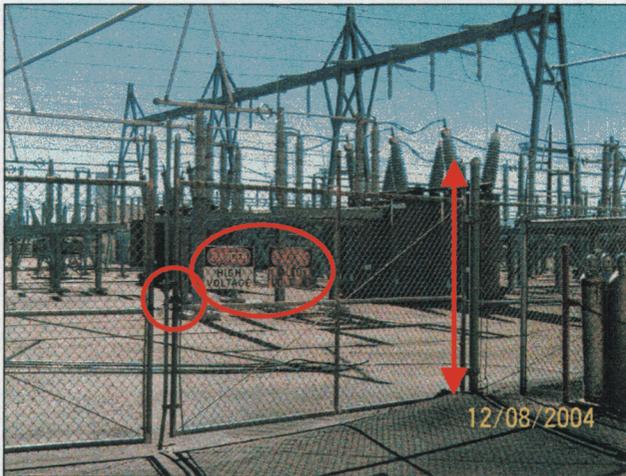


Figure 2-1. Gate and Fence



Figure 2-2. Signage

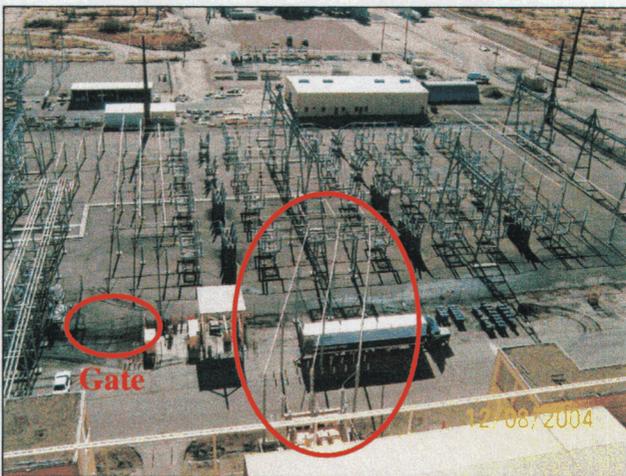


Figure 2-3. 230 kV Switchyard

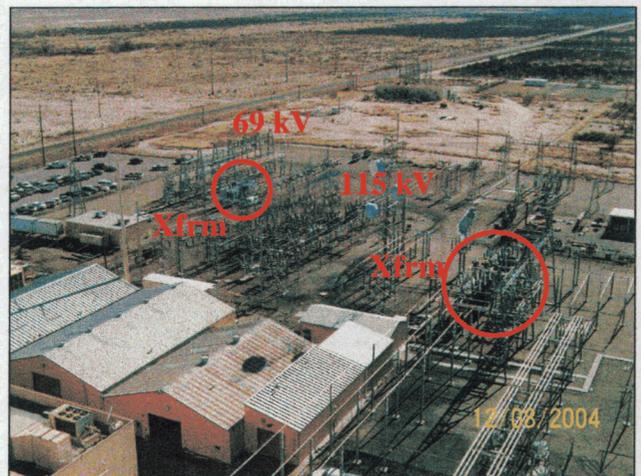


Figure 2-4. 115 kV & 69 kV Switchyards

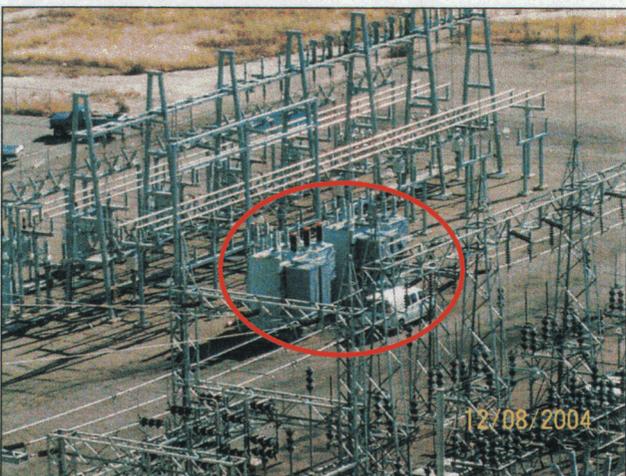


Figure 2-5. 115/69 kV Transformers

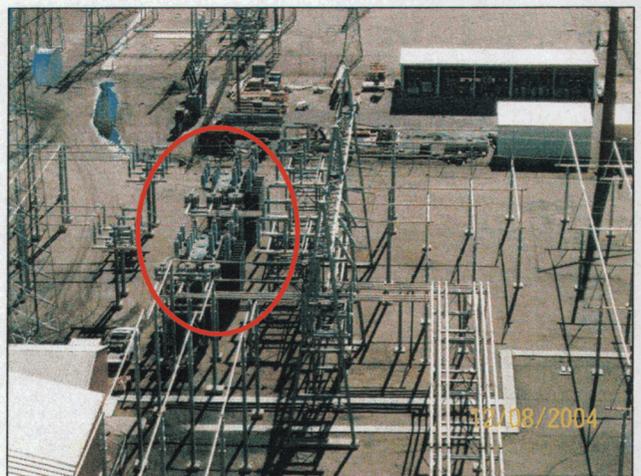


Figure 2-6. 230/115 kV Transformers

EXHIBIT 3  
Winchester Substation

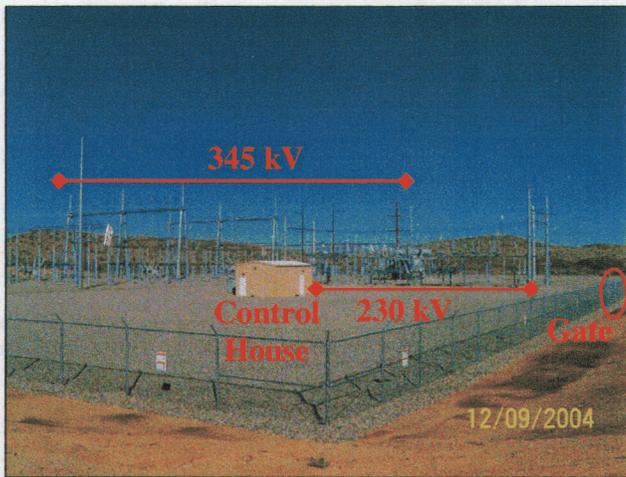


Figure 3-1. Winchester Site and Fencing



Figure 3-2. Gate and Signage



Figure 3-3. 230 kV Switchyard



Figure 3-4. SCADA and Relays  
Nameplate



Figure 3-5. 345/230 kV Transformer

EXHIBIT 4  
Apache to Winchester 230 kV Line

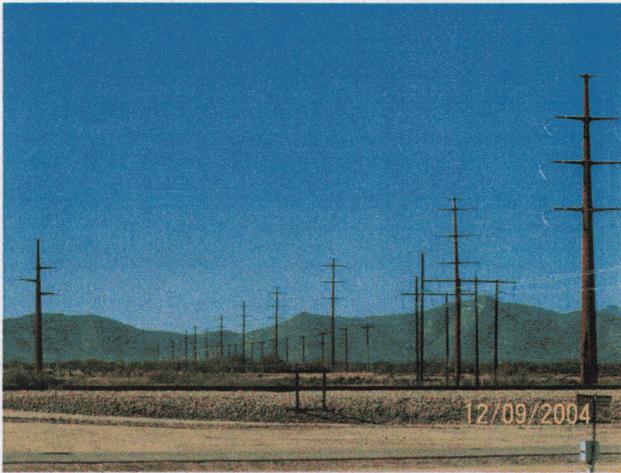


Figure 4-1. Westerly Egress from Apache



Figure 4-2 Railroad Crossings at Apache

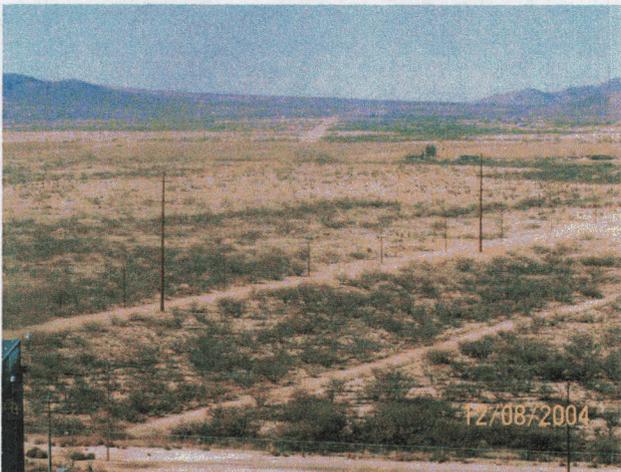


Figure 4-3. Westerly 230 kV Corridor at Apache

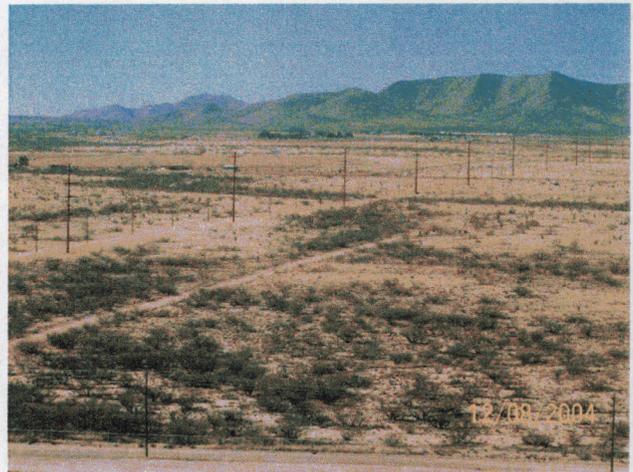


Figure 4-4. 230 kV Corridor West of Apache

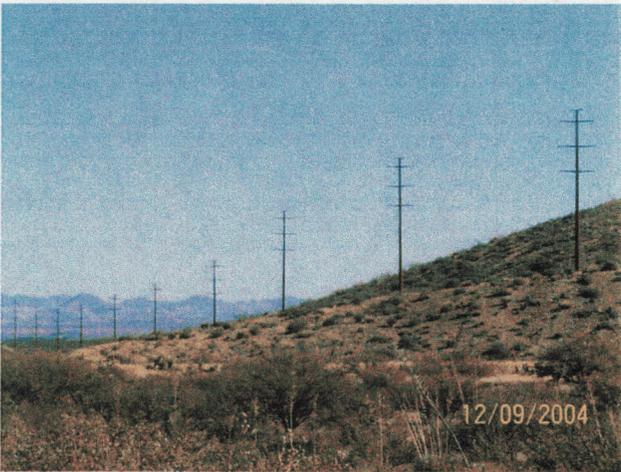


Figure 4-5. 230 kV Line SE of I-10 Crossing

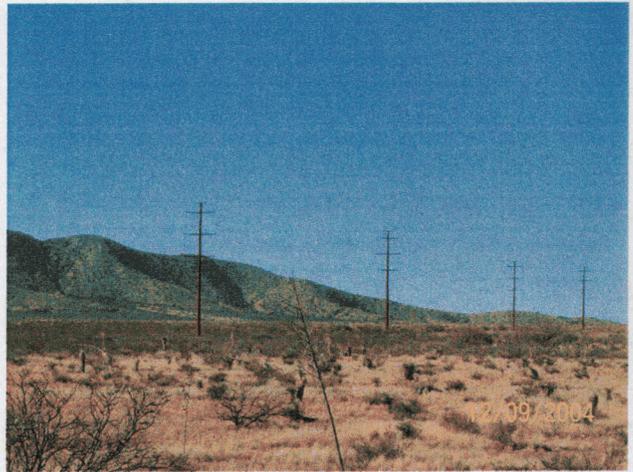


Figure 4-6. 230 kV Line NW of I-10 Crossing

(EXHIBIT 4 continued)

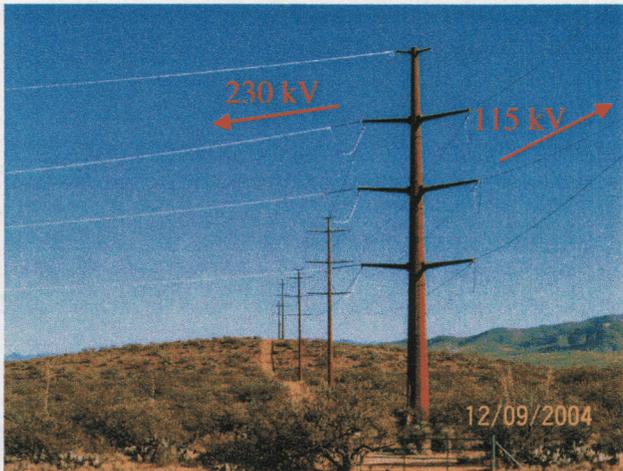


Figure 4-7. Southerly 230 kV Winchester Ingress Egress



Figure 4-8. Northerly 115 kV Winchester

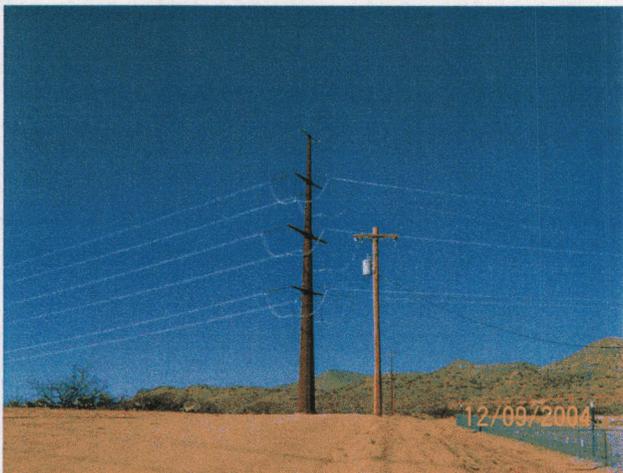


Figure 4-9. NE 345 kV Winchester Ingress

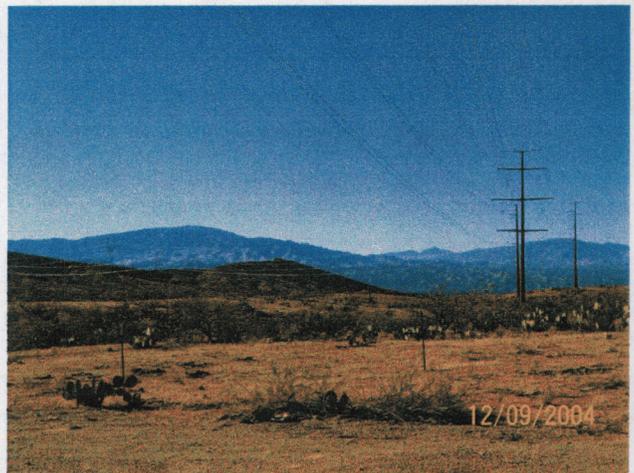


Figure 4-10. NW 345 kV Winchester Egress