NEW APPLICATION
ORIGINAL

0000009993

BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
CHAIRMAN
WILLIAM A. MUNDELL
COMMISSIONER
JEFF HATCH-MILLER
COMMISSIONER
MIKE GLEASON
COMMISSIONER
KRISTIN K. MAYES
COMMISSIONER

Arizona Corporation Commission
DOCKETED
JUL 23 2004
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AZ CORP COMMISSION
DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF THE 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-1773A-__-_____

APPLICATION E-01773A-04-0528

GALLAGHER & KENNEDY, P.A.
2575 E. CAMELBACK ROAD
PHOENIX, ARIZONA 85016-9225
(602) 530-8000

The Arizona Electric Power Cooperative, Inc. ("AEPCO"), by and through its undersigned attorneys, in support of its Application states as follows:

1. AEPCO is a non-profit electric generation cooperative, which supplies all or most of the power needs of its five Arizona Class A Member distribution cooperatives. The distribution cooperatives, in turn, use the power supplied by AEPCO to meet the electricity needs of their retail member owners in rural areas of the state.

2. AEPCO's 14-member Board of Directors oversees all aspects of its operations. Twelve members of the Board are elected by AEPCO's six Class A Member distribution cooperatives, whose Board members are elected annually by their retail member/consumers. AEPCO's Board has authorized the filing of this rate application.

3. Pursuant to the requirements of A.A.C. R14-2-103, submitted herewith and incorporated herein are Schedules and Direct Testimony of Messrs. Minson, Pierson, Daniel and Edwards in support of this Application. In summary, the Schedules and Testimony provide justification for AEPCO's request for an approximate 10% rate increase and a Debt Service Coverage Ratio of 1.05, which will return AEPCO to mortgage compliance following its net margin loss of just over $7 million in the 2003 test year.

4. This is the first requested general rate increase on the AEPCO system since 1984. In fact, since 1986, AEPCO has reduced member rates by approximately 22% and, in addition, has returned more than $25 million in purchased power and fuel bank refunds to its members. The impact of this requested wholesale rate increase on the retail consumer is difficult to estimate because AEPCO's members have different rate levels and structures. In general, however, generation costs account for approximately 40% of the end rate cost of service. AEPCO estimates a monthly bill impact of roughly $3.00 for a user of 750 kwh.

5. More specifically, AEPCO requests that the Commission approve (a) revised Class A Member all-requirements tariff rates of $13.79/kw month and an energy charge of $0.02071/kwh and (b) revised partial requirements agreement rates for the Mohave Electric Cooperative of (i) a fixed charge of $705,795 per month, (ii) an O&M rate of $7.25/kw month and (iii) an energy charge of $0.02071/kwh.

6. As discussed in the testimony of Mr. Minson, AEPCO also requests that the Commission approve revised, lower depreciation rates for its Apache Steam Units 2 and 3. Further, as discussed in the testimony of Mr. Pierson, AEPCO requests that the Commission approve a fuel and purchased energy adjustor which will allow AEPCO either to recover from or

refund to its members changes in its fuel and purchased energy costs without the necessity of a general rate application.

7. As mentioned previously, AEPCO suffered a net margin loss of more than $7 million in the 2003 test year and expects to incur another margin loss in the current year. For this reason, AEPCO would request that the Commission enter its Order approving the requested rate relief as promptly as possible.

Having fully stated its Application, AEPCO requests that the Commission enter its Order:

1. Approving the revised rates requested herein;

2. Approving the revised depreciation rates for its Apache Steam Units 2 and 3;

3. Approving a fuel and purchased energy adjustor clause; and

4. Granting AEPCO such other and further relief as it deems appropriate under the premises.

RESPECTFULLY SUBMITTED this 23rd day of July, 2004.

GALLAGHER & KENNEDY, P.A.

By Michael M. Grant

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Phoenix, Arizona 85016-9225
Attorneys for Arizona Electric Power Cooperative, Inc.

Original and thirteen copies of this Application, Schedules and Direct Testimony filed this 23rd day of July, 2004, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Copies of the foregoing hand delivered this 23rd day of July, 2004, to:

Chairman Marc Spitzer
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Commissioner William Mundell
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Commissioner Jeff Hatch-Miller
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Arizona Electric Power Cooperative, Inc.

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BEFORE THE ARIZONA CORPORATION COMMISSION

A.A.C. R14-2-103 SCHEDULES

IN SUPPORT OF

THE ARIZONA ELECTRIC POWER COOPERATIVE, INC.

RATE APPLICATION

DOCKET NO. E-01773A

JULY 2004

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Arizona Electric Power Cooperative, Inc.
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A

Arizona Electric Power Cooperative, Inc.

SCHEDULE A-1

Computation of Increase in Gross Revenue Requirements
Test Year End 12/31/2003

7/7/2004

LINE NO.			ORIGINAL COST		
1.	ADJUSTED RATE BASE	$	222,147,011	(a)	
2.	ADJUSTED ELECTRIC OPERATING INCOME (MARGINS)		7,972,676	(b)	
3.	CURRENT RATE OF RETURN		3.59%		
4.	REQUIRED ELECTRIC OPERATING INCOME (MARGINS)		16,422,692	(c)	
5.	REQUIRED RATE OF RETURN		7.39%		
6.	OPERATING INCOME DEFICIENCY		8,450,016		
7.	INCREASE (decrease) IN GROSS REV. REQUIREMENTS	$	8,450,016		
	CUSTOMER CLASSIFICATION		PROJECTED REVENUE INC. DUE TO RATES		% DOLLAR INCREASE
			(d)		(d)
8.	MEMBER CONTRACTS (ALL REQUIREMENTS)	$	8,450,016		9.86%
9.	OTHER FIRM CONTRACTS (PARTIAL REQ.)		-		0.00%
10.	TOTAL	$	8,450,016		9.86%

SUPPORTING SCHEDULES:
(a) B-l, LINE 9
(b) A-2, LINE 3
(c) G-2, LINE 8
(d) H-1

Arizona Electric Power Cooperative, Inc.

SCHEDULE A-2
7/7/2004

Summary Results of Operations

LINE NO.		-PRIOR YEARS- 12/31/2001 (a)	12/31/2002 (a)	12/31/2003 TEST YEAR ACTUAL (a)	TEST YEAR ADJUSTED (b)	PROJ. YEAR PRESENT RATES (c)	12/31/2003 PROPOSED RATES (c)
1.	GROSS REVENUE	$ 212,445,118	$ 155,378,616	$ 151,179,395	$ 137,611,450	$ 137,611,450	$ 146,061,466
2.	OPERATING EXPENSES	188,050,933	139,424,383	143,380,706	129,638,774	129,638,774	129,638,774
3.	ELECTRIC OPERATING INCOME (MARGINS)	24,394,185	15,954,233	7,798,689	7,972,676	7,972,676	16,422,692
4.	TOTAL INTEREST & OTHER DEDUCTIONS	16,623,860	13,231,623	13,000,954	14,462,737	14,462,737	14,462,737
5.	TOTAL OTHER NON OPERATING INCOME	2,660,895	1,175,960	1,963,753	1,962,451	1,962,451	1,962,451
5a.	EXTRAORDINARY ITEMS	-	-	(3,810,335)	-	-	-
6.	NET INCOME (MARGINS)	$ 10,431,220	$ 3,898,570	$ (7,048,847)	$ (4,527,610)	$ (4,527,610)	$ 3,922,406
7.	THROUGH 14.	NOT APPLICABLE					
15.	TIMES TOTAL INTEREST EARNED (TIER)	1.65	1.30	0.42	0.67	0.67	1.29
16.	DEBT SERVICE COVERAGE (DSC)	1.27	1.00	0.62	0.70	0.70	1.05

SUPPORTING SCHEDULES:
(a) E-2, PAGES 1 & 2
(b) C-1, PAGES 3 & 4
(c) F-1, PAGES 1 & 2

Arizona Electric Power Cooperative, Inc.

SCHEDULE A-3

Summary of Capital Structure

7/7/2004

LINE NO.	DESCRIPTION	PRIOR YEARS 12/31/2001	PRIOR YEARS 12/31/2002 (a)	ACTUAL TEST YEAR 12/31/2003 (c)	END OF PROJECTED YR 12/31/2003 (c)
1.	SHORT-TERM DEBT	$ -	$ -	$ -	$ -
2.	LONG-TERM DEBT	202,660,476	210,418,005	213,294,620	228,500,238
3.	TOTAL DEBT (a)	202,660,476	210,418,005	213,294,620	228,500,238
4.	PREFERRED STOCK	-	-	-	-
5.	MARGINS AND EQUITY (b)	13,904,998	17,803,568	10,754,721	21,725,974
6.	TOTAL CAPITAL	216,565,474	228,221,573	224,049,341	250,226,212
	CAPITALIZATION RATIOS: (%)				
7.	SHORT-TERM DEBT	0.00%	0.00%	0.00%	0.00%
8.	LONG-TERM DEBT	93.58%	92.20%	95.20%	91.32%
9.	TOTAL DEBT	93.58%	92.20%	95.20%	91.32%
10.	PREFERRED STOCK	0.00%	0.00%	0.00%	0.00%
11.	MARGINS AND EQUITY	6.42%	7.80%	4.80%	8.68%
		100.00%	100.00%	100.00%	100.00%
12.	WEIGHTED COST OF SHORT TERM DEBT	0.00	0.00	0.00	0.00
13.	WEIGHTED COST OF LONG TERM DEBT	6.09%	6.02%	5.60%	5.98%
14.	WEIGHTED COST OF SENIOR CAPITAL	NOT APPLICABLE			

SUPPORTING SCHEDULES:
(a) D-2
(b) E-1, PAGE 2 LINE 25
(c) D-1

Arizona Electric Power Cooperative, Inc.

SCHEDULE A-4

Construction Expenditures and Gross Utility Plant in Service

7/7/2004

LINE NO.		CONSTRUCTION EXPENDITURES		NET PLANT ADDITIONS		GROSS UTILITY PLANT IN SERVICE	
1.	12/31/2001	16,780,223	(a)	(110,040,864)		343,797,323	(d)
2.	12/31/2002	23,155,056	(a)	(33,511,573)		377,308,896	(c)
3.	12/31/2003	11,928,062	(a)	2,342,235	(c)	379,651,131	(c)
4.	2004	6,405,000	(b)	19,064,869		398,716,000	
5.	2005	4,462,000	(b)	6,701,000		405,417,000	
6.	2006	12,012,000	(b)	10,074,000		415,491,000	

SUPPORTING SCHEDULES:
(a) E-3, LINE 15
(b) F-3, LINE 6
(c) E-5, PAGE 2, LINE 39
(d) E-1, PAGE 1, LINE 1

Arizona Electric Power Cooperative, Inc.

Summary of Changes in Financial Position

SCHEDULE A-5

7/7/2004

LINE NO.		-PRIOR YEARS (a)-			12 MOS. ENDED 12/31/2003	
		12/31/2001	12/31/2002	ACTUAL TEST YEAR	PRESENT RATES (b)	PROPOSED RATES (b)
1.	NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 3,340,806	$ 11,108,419	$ 21,026,771	$ 21,284,054	$ 29,734,070
2.	NET CASH USED IN INVESTING ACTIVITIES	(35,552,814)	(22,487,951)	(13,631,300)	(13,631,300)	(13,631,300)
3.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(6,112,361)	8,417,946	(7,665,429)	(7,665,429)	(7,665,429)
4.	NET DECREASE IN CASH AND CASH EQ.	$ (38,324,369)	$ (2,961,586)	$ (269,958)	$ (12,675)	$ 8,437,341

SUPPORTING SCHEDULES:
(a) E-3
(b) F-2

B

Arizona Electric Power Cooperative, Inc.

Summary of Original Cost Rate Base

SCHEDULE B-1
7/7/2004

LINE NO.		ORIGINAL COST RATE BASE*	
1.	GROSS UTILITY PLANT IN SERVICE	$ 389,603,749	(a)
2.	LESS: ACCUMULATED DEPRECIATION & AMORT.	(186,190,519)	(a)
3.	NET UTILITY PLANT IN SERVICE	$ 203,413,230	(a)
	LESS:		
4.	CUSTOMER ADVANCES FOR CONSTRUCTION	-	
5.	CONTRIBUTION IN AID OF CONSTRUCTION	-	
6.	ADD: ALLOWANCE FOR WORKING CAPITAL	16,778,408	(b)
7.	PLANT HELD FOR FUTURE USE	-	(c)
8.	DEFERRED DEBITS	1,955,373	(d)
9.	TOTAL RATE BASE	$ 222,147,011	(e)

* INCLUDING PRO FORMA ADJUSTMENTS

SUPPORTING SCHEDULES:
(a) B-2 LINES 10,13, & 14
(b) B-5, PAGE 1
(c) E-5, PAGE 2
(d) E-1, PAGE 1

RECAP SCHEDULES:
(e) A-1

Arizona Electric Power Cooperative, Inc.

Original Cost Rate Base Pro Forma Adjustments

SCHEDULE B-2
7/7/2004

LINE NO.		ACTUAL TEST YEAR 12/31/2003 (a)	PRO FORMA ADJUSTMENTS 12/31/2003 (a)	ADJUSTED TEST YEAR 12/31/2003	
	PRODUCTION:				
1.	GROSS PLANT	$ 355,639,476	$ 9,952,618	$ 365,592,094	
2.	ACCUMULATED DEPRECIATION	(174,884,002)	(308,531)	(175,192,533)	
3.	NET PLANT	180,755,474	9,644,087	190,399,561	
	TRANSMISSION:				
4.	GROSS PLANT	2,771,771	-	2,771,771	
5.	ACCUMULATED DEPRECIATION	(1,167,581)	-	(1,167,581)	
6.	NET PLANT	1,604,190	-	1,604,190	
	GENERAL & INTANGIBLE:				
7.	GROSS PLANT	21,239,884	-	21,239,884	
8.	ACCUMULATED DEPRECIATION	(9,667,411)	-	(9,667,411)	
9.	NET PLANT	11,572,473	-	11,572,473	
9A.	RWIP	54,648	-	54,648	
10.	TOTAL GROSS PLANT	379,651,131	9,952,618	389,603,749	(b)
11.	TOTAL ACCUM DEPRECIATION & R	(185,664,346)	(308,531)	(185,972,877)	
12.	ACCUMULATED AMORTIZATION	(217,642)	-	(217,642)	
13.	TOTAL ACCUM DEPREC. & AMORT.	(185,881,988)	(308,531)	(186,190,519)	(b)
14.	TOTAL NET PLANT	$ 193,769,143	$ 9,644,087	$ 203,413,230	(b)

SUPPORTING SCHEDULES:
(a) E-5, PAGES 1 AND 2

RECAP SCHEDULES:
(b) B-1 LINES 1,2, & 3

Arizona Electric Power Cooperative, Inc.

RCND Rate Base Pro Forma Adjustments

SCHEDULE B-3
7/7/2004

LINE NO.		ACTUAL AT TEST YEAR 12/31/2003	PRO FORMA ADJUSTMENTS 12/31/2003	ADJUSTED TEST YEAR 12/31/2003
1.	GROSS UTILITY PLANT IN SERVICE	$ -	$ -	$ -
2.	LESS: ACCUMULATED DEPRECIATION	-	-	-
3.	NET UTILITY PLANT IN SERVICE	$ -	$ -	$ -

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.

RCND by Major Plant Accounts

LINE NO.		RCN	DEPR.	RCND	PRO FORMA ADJUST.	ADJUSTED RCND
	INTANGIBLE PLANT:					
1.	301ORGANIZATION	$ -	$ -	$ -	$ -	$ -
2.	114 ACQUISITION ADJUSTMENT	-	-	-	-	-
3.	302 FRANCHISE ADJUSTMENT	-	-	-	-	-
4.	SUBTOTAL INTANGIBLE	-	-	-	-	-
	STEAM PRODUCTION PLANT:					
5.	310 LAND AND LAND RIGHTS	-	-	-	-	-
6.	311 STRUCTURES AND IMPROVEMENTS	-	-	-	-	-
7.	312 BOILER EQUIPMENT	-	-	-	-	-
8.	314 TURBINE GENERATORS	-	-	-	-	-
9.	315 ACCESSORY ELEC. EQUIPMEN	-	-	-	-	-
10.	316 MISC. POWER EQUIPMENT	-	-	-	-	-
11.	SUBTOTAL STEAM PRODUCTION	-	-	-	-	-
	OTHER PRODUCTION PLANT:					
12.	340 LAND AND LAND RIGHTS	-	-	-	-	-
13.	341 STRUCTURES AND IMPROVEMENTS	-	-	-	-	-
14.	342 FUEL HLDRS PRODRS & ACCE	-	-	-	-	-
15.	343 PRIME MOVERS	-	-	-	-	-
16.	344 GENERATORS	-	-	-	-	-
17.	345 ACCESSORY ELEC. EQUIPMENT	-	-	-	-	-
18.	346 MISC. POWER EQUIPMENT	-	-	-	-	-
19.	SUBTOTAL OTHER PRODUCTION	-	-	-	-	-
	TRANSMISSION PLANT:					
20.	350 LAND AND LAND RIGHTS	-	-	-	-	-
21.	352 STRUCTURES AND IMPRVMNT	-	-	-	-	-
22.	353 STATION EQUIPMENT	-	-	-	-	-
23.	354 TOWERS AND FIXTURES	-	-	-	-	-
24.	355 POLES AND FIXTURES	-	-	-	-	-
25	356 OVERHEAD CONDUCTORS	-	-	-	-	-
26.	359 ROADS AND TRAILS	-	-	-	-	-
27.	SUBTOTAL TRANSMISSION	-	-	-	-	-
	GENERAL PLANT:					
28.	309 LAND AND LAND RIGHTS	-	-	-	-	-
29.	390 ACCOUNTS 390 - 399	-	-	-	-	-
30.	SUBTOTAL GENERAL	-	-	-	-	-
31.	TOTAL	$ -	$ -	$ -	$ -	$ -

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.

RCND by Major Plant Accounts

LINE NO.		ADJ. 1	ADJ. 2	ADJ. 3	ADJ. 4	TOTAL ADJUSMENTS
	INTANGIBLE PLANT:					
1.	301 ORGANIZATION	$ -	$ -	$ -	$ -	$ -
2.	114 ACQUISITION ADJUSTMENT	-	-	-	-	-
3.	302 FRANCHISE ADJUSTMENT	-	-	-	-	-
4.	SUBTOTAL INTANGIBLE	-	-	-	-	-
	STEAM PRODUCTION PLANT:					
5.	310 LAND AND LAND RIGHTS	-	-	-	-	-
6.	311 STRUCTURES AND IMPROVEMEN	-	-	-	-	-
7.	312 BOILER EQUIPMENT	-	-	-	-	-
8.	314 TURBINE GENERATORS	-	-	-	-	-
9.	315 ACCESSORY ELEC. EQUIPMENT	-	-	-	-	-
10.	316 MISC. POWER EQUIPMENT	-	-	-	-	-
11.	SUBTOTAL STEAM PRODUCTION	-	-	-	-	-
	OTHER PRODUCTION PLANT:					
12.	340 LAND AND LAND RIGHTS	-	-	-	-	-
13.	341 STRUCTURES AND IMPROVEMEN	-	-	-	-	-
14.	342 FUEL HLDRS PRODCRS & ACC	-	-	-	-	-
15.	343 PRIME MOVERS	-	-	-	-	-
16.	344 GENERATORS	-	-	-	-	-
17.	345 ACCESSORY ELEC. EQUIPMENT	-	-	-	-	-
18.	346 MISC. POWER EQUIPMENT	-	-	-	-	-
19.	SUBTOTAL OTHER PRODUCTION	-	-	-	-	-
	TRANSMISSION PLANT:					
20.	350 LAND AND LAND RIGHTS	-	-	-	-	-
21.	352 STRUCTURES AND IMPROVEMEN	-	-	-	-	-
22.	353 STATION EQUIPMENT	-	-	-	-	-
23.	354 TOWERS AND FIXTURES	-	-	-	-	-
24.	355 POLES AND FIXTURES	-	-	-	-	-
25.	356 OVERHEAD CONDUCTORS	-	-	-	-	-
26.	359 ROADS AND TRAILS	-	-	-	-	-
27.	SUBTOTAL TRANSMISSION	-	-	-	-	-
	GENERAL PLANT:					
28.	389 LAND AND LAND RIGHTS	-	-	-	-	-
29.	390 ACCOUNTS 390 - 399	-	-	-	-	-
30.	SUBTOTAL GENERAL	-	-	-	-	-
31.	TOTAL	$ -	$ -	$ -	$ -	$ -

RECAPSCHEDULES:

Arizona Electric Power Cooperative, Inc.
Computation of Working Capital

LINE NO.			
1.	CASH WORKING CAPITAL	$ -	(a)
2.	FUEL STOCK	5,581,933	(b)
3.	MATERIALS AND SUPPLIES	5,265,561	(c)
4.	PREPAYMENTS	908,046	(d)
5.	CFC CERTIFICATES & BONDS	5,022,869	/1
6.	TOTAL WORKING CAPITAL	$ 16,778,408	(e)

SUPPORTING SCHEDULES:
(a) B-5, PAGE 2
(b) B-5, PAGE 3
(c) B-5, PAGE 4
(d) B-5, PAGE 5

RECAP SCHEDULES:
(e) B-1 Line 6

/1 REFERENCE DECEMBER GENERAL LEDGER, ACCOUNTS 1230320 & 1230322 &1230325

Arizona Electric Power Cooperative, Inc.

Calculation of Cash Working Capital

LINE NO.			
1.	TOTAL PRO FORMA O & M EXPENSES EXCL PRO FORMA FUEL & OTHER EXP	$	-
	NET OTHER O & M EXPENSE LAG		
2.	A. DAYS		-
3.	B. PERCENT	0.00%	
4.	CASH WORKING CAPITAL OTHER THAN FUEL		-
5.	FUEL EXPENSE		-
	FUEL EXPENSE LAG:		
6.	A. LAG IN REVENUES (DAYS)		-
7.	B. LAG IN EXPENSES (DAYS)		-
8.	C. NET LAG -DAYS		-
9.	D. PERCENT	0.00%	
10.	CASH WORKING CAPITAL FUEL		-
11.	TOTAL CASH WORKING CAPITAL	$	-

SUPPORTING SCHEDULES:

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.

Calculation of Fuel-Stock Working Capital

LINE NO.		PER BOOKS	PRO FORMA ADJUSTMENTS	AS ADJUSTED	
1.	DECEMBER (Prior Yr)	$ 12,593,707	$ -	$ 12,593,707	
2.	JANUARY	9,882,757	-	9,882,757	
3.	FEBRUARY	7,224,478	-	7,224,478	
4.	MARCH	6,057,671	-	6,057,671	
5.	APRIL	6,477,405	-	6,477,405	
6.	MAY	5,511,506	-	5,511,506	
7.	JUNE	5,055,282	-	5,055,282	
8.	JULY	4,229,219	-	4,229,219	
9.	AUGUST	3,536,683	-	3,536,683	
10.	SEPTEMBER	2,529,010	-	2,529,010	
11.	OCTOBER	2,484,622	-	2,484,622	
12.	NOVEMBER	3,600,518	-	3,600,518	
13.	DECEMBER	3,382,266	-	3,382,266	
14.	TOTAL	$ 72,565,124	$ -	$ 72,565,124	
15.	13-MONTH AVERAGE	$ 5,581,933	$ -	$ 5,581,933	(a)

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) B-5, PAGE 1

Arizona Electric Power Cooperative, Inc.

Calculation of Materials & Supplies Working Capital

LINE NO.		PER BOOKS	PRO FORMA ADJUSTMENTS	AS ADJUSTED	
1.	DECEMBER (Prior Yr)	$ 5,199,651	$ -	$ 5,199,651	
2.	JANUARY	5,170,130	-	5,170,130	
3.	FEBRUARY	5,127,900	-	5,127,900	
4.	MARCH	4,896,182	-	4,896,182	
5.	APRIL	4,977,902	-	4,977,902	
6.	MAY	5,158,387	-	5,158,387	
7.	JUNE	5,089,094	-	5,089,094	
8.	JULY	5,318,376	-	5,318,376	
9.	AUGUST	5,313,413	-	5,313,413	
10.	SEPTEMBER	5,339,052	-	5,339,052	
11.	OCTOBER	5,377,843	-	5,377,843	
12.	NOVEMBER	5,685,470	-	5,685,470	
13.	DECEMBER	5,798,889	-	5,798,889	
14.	TOTAL	$ 68,452,289	$ -	$ 68,452,289	
15.	13-MONTH AVERAGE	$ 5,265,561	$ -	$ 5,265,561	(a)

SUPPORTING SCHEDULES:

RECAP SCHEDULE:
(a) B-5, PAGE 1

Arizona Electric Power Cooperative, Inc.

Calculation of Prepayments Working Capital

LINE NO.		PER BOOKS	PRO FORMA ADJUSTMENTS	AS ADJUSTED
1.	DECEMBER (Prior Yr)	$ 1,100,074	$ -	$ 1,100,074
2.	JANUARY	1,046,904	-	1,046,904
3.	FEBRUARY	963,918	-	963,918
4.	MARCH	846,793	-	846,793
5.	APRIL	730,385	-	730,385
6.	MAY	624,672	-	624,672
7.	JUNE	542,245	-	542,245
8.	JULY	967,330	-	967,330
9.	AUGUST	816,682	-	816,682
10.	SEPTEMBER	1,071,225	-	1,071,225
11.	OCTOBER	1,001,338	-	1,001,338
12.	NOVEMBER	1,021,059	-	1,021,059
13.	DECEMBER	1,071,971	-	1,071,971
14.	TOTAL	$11,804,596	$ -	$11,804,596
15.	13-MONTH AVERAGE	$908,046	$ -	$908,046 (a)

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) B-5, PAGE 1

C

Arizona Electric Power Cooperative, Inc.
Reclassified Year End Income Statement

LINE NO.		PER BOOKS 12/31/2003 (a) (c)	RECLASSIFIED ADJUST. (b)	RECL TEST YR 12/31/2003
	REVENUES:			
1.	CLASS A MEMBERS	$ 85,811,247	$ (142,921)	$ 85,668,326
2.	FUEL ADJUSTMENT	-	-	-
3.	NON-CLS A, NON-FIRM & NON-MEM	51,757,181	142,921	51,900,102
4.	TOTAL ELECTRIC REVENUE:	137,568,428	-	137,568,428
5.	OTHER OPERATING REVENUE	13,610,967	(12,053,059)	1,557,908
6.	TOTAL OPERATING REVENUE	151,179,395	(12,053,059)	139,126,336
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	62,295,417	-	62,295,417
8.	PRODUCTION - STEAM A/C 500	1,929,564	-	1,929,564
9.	A/C 502	3,724,301	(1,890,721)	1,833,580
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	1,965,819	(558,361)	1,407,458
13.	A/C 506 & 509	2,743,982	-	2,743,982
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	444,395	-	444,395
17.	A/C 548	918,066	(557,746)	360,320
18.	A/C 549	510,877	-	510,877
19.	A/C 550	12,354	-	12,354
	OTHER POWER SUPPLY			
20.	- DEMAND A/C 555	6,631,387	-	6,631,387
21.	- ENERGY A/C 555	9,639,192	-	9,639,192
22.	A/C 556	3,680,604	(1,094,843)	2,585,761
23.	A/C 557	2,329,157	(2,309,280)	19,877
24.	TRANSMISSION	15,341,229	(8,648,936)	6,692,293
25.	ADMINISTRATIVE & GENERAL	9,204,100	(182,871)	9,021,229
26.	TOTAL OPERATIONS	121,370,444	(15,242,758)	106,127,686
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	811,089	-	811,089
28.	A/C 511	253,280	-	253,280
29.	A/C 512	6,401,254	-	6,401,254
30.	A/C 513	261,485	-	261,485
31.	A/C 514	2,322,842	-	2,322,842
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	172,226	-	172,226
34.	A/C 552	67,470	-	67,470
35.	A/C 553	1,888,607	-	1,888,607
36.	A/C 554	669,320	-	669,320
37.	TRANSMISSION	34,568	(6,522)	28,046
38.	GENERAL PLANT	63,958	-	63,958
39.	TOTAL MAINTENANCE	12,946,099	(6,522)	12,939,577

Arizona Electric Power Cooperative, Inc.

Reclassified Year End Income Statement

LINE NO.		PER BOOKS 12/31/2003 (a) (c)	RECLASSIFIED ADJUST. (b)	RECL TEST YR 12/31/2003
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 8,774,082	$ -	$ 8,774,082
41.	ACC GROSS REVENUE TAXES	288,752	-	288,752
42.	TAXES	1,329	3,196,221	3,197,550
43.	TOTAL OTHER	9,064,163	3,196,221	12,260,384
44.	TOTAL OPERATING EXPENSES	143,380,706	(12,053,059)	131,327,647
45.	ELECTRIC OPERATING MARGINS	7,798,689	-	7,798,689
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	12,200,997	-	12,200,997
47.	INTEREST CHARGES TO CONSTR	(68,586)	-	(68,586)
48.	OTHER INTEREST EXPENSE	166,468	-	166,468
49.	OTHER DEDUCTIONS	702,075	-	702,075
50.	TOTAL INTEREST & OTHER DEDUCTIONS	13,000,954	-	13,000,954
51.	OPERATING MARGINS	(5,202,265)	-	(5,202,265)
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	582,014	-	582,014
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	1,381,739	-	1,381,739
55.	TOTAL OTHER NON OPERATING INCOME	1,963,753	-	1,963,753
55a.	EXTRAORDINARY ITEMS	(3,810,335)	-	(3,810,335)
56.	NET INCOME (MARGINS)	($7,048,847)	$ -	($7,048,847)

SUPPORTING SCHEDULES:
(a) RUS FORM 12A
(b) C-2 PAGES 1 & 2

RECAP SCHEDULE:
(c)A-2

Arizona Electric Power Cooperative, Inc.

Adjusted Year End Income Statement

LINE NO.		RECL TEST YR 12/31/2003 (c)	PRO FORMA ADJUST. (a)	ADJ TEST YR 12/31/2003 (b)
	REVENUES:			
1.	CLASS A MEMBERS	$ 85,668,326	$ 17,298	$ 85,685,624
2.	FUEL ADJUSTMENT	-	-	-
3.	NON-CLS A, NON-FIRM & NON-MEM	51,900,102	(1,455,598)	50,444,504
4.	TOTAL ELECTRIC REVENUE:	137,568,428	(1,438,300)	136,130,128
5.	OTHER OPERATING REVENUE	1,557,908	(76,586)	1,481,322
6.	TOTAL OPERATING REVENUE	139,126,336	(1,514,886)	137,611,450
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	62,295,417	(2,491,992)	59,803,425
8.	PRODUCTION - STEAM A/C 500	1,929,564	70,344	1,999,908
9.	A/C 502	1,833,580	877,223	2,710,803
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	1,407,458	30,066	1,437,524
13.	A/C 506 & 509	2,743,982	(127,662)	2,616,320
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	444,395	22	444,417
17.	A/C 548	360,320	6,424	366,744
18.	A/C 549	510,877	941	511,818
19.	A/C 550	12,354	-	12,354
	OTHER POWER SUPPLY			
20.	- DEMAND A/C 555	6,631,387	(861,800)	5,769,587
21.	- ENERGY A/C 555	9,639,192	446,346	10,085,538
22.	A/C 556	2,585,761	(270,288)	2,315,473
23.	A/C 557	19,877	-	19,877
24.	TRANSMISSION	6,692,293	1,344,193	8,036,486
25.	ADMINISTRATIVE & GENERAL	9,021,229	170,673	9,191,902
26.	TOTAL OPERATIONS	106,127,686	(805,510)	105,322,176
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	811,089	29,685	840,774
28.	A/C 511	253,280	2,590	255,870
29.	A/C 512	6,401,254	32,427	6,433,681
30.	A/C 513	261,485	3,274	264,759
31.	A/C 514	2,322,842	52,119	2,374,961
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	172,226	110	172,336
34.	A/C 552	67,470	168	67,638
35.	A/C 553	1,888,607	8,950	1,897,557
36.	A/C 554	669,320	3,030	672,350
37.	TRANSMISSION	28,046	342	28,388
38.	GENERAL PLANT	63,958	-	63,958
39.	TOTAL MAINTENANCE	12,939,577	132,695	13,072,272

Arizona Electric Power Cooperative, Inc.

Adjusted Year End Income Statement

LINE NO.		RECL TEST YR 12/31/2003 (c)	PRO FORMA ADJUST. (a)	ADJ TEST YR 12/31/2003 (b)
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 8,774,082	$ (1,165,347)	$ 7,608,735
41.	ACC GROSS REVENUE TAXES	288,752	-	288,752
42.	TAXES	3,197,550	149,289	3,346,839
43.	TOTAL OTHER	12,260,384	(1,016,058)	11,244,326
44.	TOTAL OPERATING EXPENSES	131,327,647	(1,688,873)	129,638,774
45.	ELECTRIC OPERATING MARGINS	7,798,689	173,987	7,972,676
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	12,200,997	1,346,752	13,547,749
47.	INTEREST CHARGES TO CONSTRUCTION	(68,586)	-	(68,586)
48.	OTHER INTEREST EXPENSE	166,468	-	166,468
49.	OTHER DEDUCTIONS	702,075	115,031	817,106
50.	TOTAL INTEREST & OTHER DEDUCTIONS	13,000,954	1,461,783	14,462,737
51.	OPERATING MARGINS	(5,202,265)	(1,287,796)	(6,490,061)
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	582,014	-	582,014
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	1,381,739	(1,302)	1,380,437
55.	TOTAL OTHER NON OPERATING INCOME	1,963,753	(1,302)	1,962,451
55a.	EXTRAORDINARY ITEMS	(3,810,335)	3,810,335	-
56.	NET INCOME (MARGINS)	$ (7,048,847)	$ 2,521,237	$ (4,527,610)

SUPPORTING SCHEDULES:
(a) C-2 PAGES 3 - 10

RECAP SCHEDULE:
(b) A-2
(c) C-1 PAGES 1 & 2

Arizona Electric Power Cooperative, Inc.

Income Statement Reclassification Adjustments

LINE NO.	(a)	1 SWTC REVENUE RECLASSIFICATION	2 PROPERTY TAX RECLASSIFICATION	3 MEC SCHEDULE B RECLASSIFICATION	4 TOTAL RECLASSIFICATIONS
	REVENUES:				
1.	CLASS A MEMBERS	$ -	$ -	$ (142,921)	$ (142,921)
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	142,921	142,921
4.	TOTAL ELECTRIC	-	-	-	-
5.	OTHER OPERATING REVENUE	(12,053,059)	-	-	(12,053,059)
6.	TOTAL OPERATING REVENUE	(12,053,059)	-	-	(12,053,059)
	OPERATING EXPENSES:				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	-	-	-	-
8.	PRODUCTION - STEAM A/C 500	-	-	-	-
9.	A/C 502	-	(1,890,721)	-	(1,890,721)
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	(558,361)	-	(558,361)
13.	A/C 506 & 509	-	-	-	-
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	-
17.	A/C 548	-	(557,746)	-	(557,746)
18.	A/C 549	-	-	-	-
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	-	-	-	-
21.	- ENERGY A/C 555	-	-	-	-
22.	A/C 556	(1,094,843)	-	-	(1,094,843)
23.	A/C 557	(2,309,280)	-	-	(2,309,280)
24.	TRANSMISSION	(8,648,936)	-	-	(8,648,936)
25.	ADMINISTRATIVE & GENERAL	-	(182,871)	-	(182,871)
26.	TOTAL OPERATIONS	(12,053,059)	(3,189,699)	-	(15,242,758)
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C S10	-	-	-	-
28.	A/C 511	-	-	-	-
29.	A/C 512		-	-	-
30.	A/C 513	-	-	-	-
31.	A/C 514	-	-	-	-
32.	A/C 515	-	-	-	-
33.	PRODUCTION - OTHER - A/C 551	-	-	-	-
34.	A/C 552	-	-	-	-
35.	A/C 553	-	-	-	-
36.	A/C 554	-	-	-	-
37.	TRANSMISSION	-	(6,522)	-	(6,522)
38.	GENERAL PLANT	-	-	-	-
39.	TOTAL MAINTENANCE	-	(6,522)	-	(6,522)

Arizona Electric Power Cooperative, Inc.

Income Statement Reclassification Adjustments

7/7/2004

LINE NO.	(a)	1 SWTC REVENUE RECLASSIFICATION	2 PROPERTY TAX RECLASSIFICATION	3 MEC SCHEDULE B RECLASSIFICATION	4 TOTAL RECLASSIFICATIONS
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ -
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	3,196,221	-	3,196,221
43.	TOTAL OTHER	-	3,196,221	-	3,196,221
44.	TOTAL OPERATING EXPENSES	(12,053,059)	-	-	(12,053,059)
45.	ELECTRIC OPERATING MARGINS	-	-	-	-
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	-	-	-	-
47.	INTEREST CHARGES TO CONSTR	-	-	-	-
48.	OTHER INTEREST EXPENSE	-	-	-	-
49.	OTHER DEDUCTIONS	-	-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	-	-	-	-
51.	OPERATING MARGINS	-	-	-	-
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	-
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	-
55a.	EXTRAORDINARY ITEMS	-	-	-	-
56.	NET INCOME (MARGINS)	$ -	$ -	$ -	$ -

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) C-1,PAGES 1 AND 2

Arizona Electric Power Cooperative, Inc.
Income Statement Pro-Forma Adjustments

LINE NO.		1 MEC SCHEDULE A ADJUSTMENT	2 CITY OF MESA ADJUSTMENTS	3 ANCILLARY SERVICES REVENUE	4 LABOR ADJUSTMENT
1.	CLASS A MEMBERS	$ (382,774)	$ 400,072	$ -	$ -
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-	(903,664)	-	-
4.	TOTAL ELECTRIC	(382,774)	(503,592)	-	-
5.	OTHER OPERATING REVENUE	-	-	(76,586)	-
6.	TOTAL OPERATING REVENUE	(382,774)	(503,592)	(76,586)	-
	OPERATING EXPENSES:				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	(550,220)	(407,498)	-	-
8.	PRODUCTION - STEAM A/C 500	-	-	-	70,344
9.	A/C 502	-	-	-	56,612
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	30,066
13.	A/C 506 & 509	-	-	-	39,407
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	22
17.	A/C 548	-	-	-	6,424
18.	A/C 549	-	-	-	941
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	-	-	-	-
21.	- ENERGY A/C 555	(333,790)	(169,803)	-	-
22.	A/C 556	-	(36,925)	-	26,785
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-	(245,438)	-	-
25.	ADMINISTRATIVE & GENERAL	-	-	-	155,744
26.	TOTAL OPERATIONS	(884,010)	(859,664)	-	386,345
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	29,685
28.	A/C 511	-	-	-	2,590
29.	A/C 512	-	-	-	32,427
30.	A/C 513	-	-	-	3,274
31.	A/C 514	-	-	-	52,119
32.	A/C 515	-	-	-	-
33.	PRODUCTION - OTHER - A/C 551	-	-	-	110
34.	A/C 552	-	-	-	168
35.	A/C 553	-	-	-	8,950
36.	A/C 554	-	-	-	3,030
37.	TRANSMISSION	-	-	-	342
38.	GENERAL PLANT	-	-	-	-
39.	TOTAL MAINTENANCE	-	-	-	132,695

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		1 MEC SCHEDULE A ADJUSTMENT	2 CITY OF MESA ADJUSTMENTS	3 ANCILLARY SERVICES REVENUE	4 LABOR ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ -
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	-
43.	TOTAL OTHER	-	-	-	-
44.	TOTAL OPERATING EXPENSES	(884,010)	(859,664)	-	519,040
45.	ELECTRIC OPERATING MARGINS	501,236	356,072	(76,586)	(519,040)
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	-	-	-	-
47.	INTEREST CHARGES TO CONSTR	-	-	-	-
48.	OTHER INTEREST EXPENSE	-	-	-	-
49.	OTHER DEDUCTIONS	-	-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	-	-	-	-
51.	OPERATING MARGINS	501,236	356,072	(76,586)	(519,040)
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	(1,302)
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	(1,302)
55a.	EXTRAORDINARY ITEMS	-	-	-	-
56.	NET INCOME (MARGINS)	$ 501,236	$ 356,072	$ (76,586)	$ (520,342)

SUPPORTING SCHEDULES:
(1) Adjustments - MEC Schedule A Adjustment
(2) Adjustments - City of Mesa Adjustment
(3) Adjustments - Ancillary Services Revenue
(4) Adjustments - Labor Adjustment

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		5 FUEL ADJUSTMENT	6 SO2 ALLOWANCE ADJUSTMENT	7 ASH SALES CREDIT ADJUSTMENT	8 COAL BLENDER ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ -
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	(551,934)	-	-	-
4.	TOTAL ELECTRIC	(551,934)	-	-	-
5.	OTHER OPERATING REVENUE	-	-	-	-
6.	TOTAL OPERATING REVENUE	(551,934)	-	-	-
	OPERATING EXPENSES:				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	(1,534,274)	-	-	-
8.	PRODUCTION - STEAM A/C 500	-	-	-	-
9.	A/C 502	-	-	820,611	-
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	-
13.	A/C 506 & 509	-	(167,069)	-	-
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	-
17.	A/C 548	-	-	-	-
18.	A/C 549	-	-	-	-
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	-	-	-	-
21.	- ENERGY A/C 555	-	-	-	-
22.	A/C 556	-	-	-	-
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-	-	-	-
25.	ADMINISTRATIVE & GENERAL	-	-	-	14,929
26.	TOTAL OPERATIONS	(1,534,274)	(167,069)	820,611	14,929
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	-
28.	A/C 511	-	-	-	-
29.	A/C 512	-	-	-	-
30.	A/C 513	-	-	-	-
31.	A/C 514	-	-	-	-
32.	A/C 515	-	-	-	-
33.	PRODUCTION - OTHER - A/C 551	-	-	-	-
34.	A/C 552	-	-	-	-
35.	A/C 553	-	-	-	-
36.	A/C 554	-	-	-	-
37.	TRANSMISSION	-	-	-	-
38.	GENERAL PLANT	-	-	-	-
39.	TOTAL MAINTENANCE	-	-	-	-

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		5 FUEL ADJUSTMENT	6 SO2 ALLOWANCE ADJUSTMENT	7 ASH SALES CREDIT ADJUSTMENT	8 COAL BLENDER ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ 308,531
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	149,289
43.	TOTAL OTHER	-	-	-	457,820
44.	TOTAL OPERATING EXPENSES	(1,534,274)	(167,069)	820,611	472,749
45.	ELECTRIC OPERATING MARGINS	982,340	167,069	(820,611)	(472,749)
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	-	-	-	532,465
47.	INTEREST CHARGES TO CONSTR	-	-	-	-
48.	OTHER INTEREST EXPENSE	-	-	-	-
49.	OTHER DEDUCTIONS	-	-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	-	-	-	532,465
51.	OPERATING MARGINS	982,340	167,069	(820,611)	(1,005,214)
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	-
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	-
55a.	EXTRAORDINARY ITEMS	-	-	-	-
56.	NET INCOME (MARGINS)	$ 982,340	$ 167,069	$ (820,611)	$ (1,005,214)

SUPPORTING SCHEDULES:
(5) Adjustments - Fuel Adjustment
(6) Adjustments - SO2 Allowances Adjustment
(7) Adjustments - Ash Sales Credit Adjustment
(8) Adjustments - Coal Blender Ajustment

Arizona Electric Power Cooperative, Inc.
Income Statement Pro Forma Adjustments

LINE NO.		9 GT FFB FINANCING ADJUSTMENT	10 DEPRECIATION ADJUSTMENT	11 PURCHASE POWER ADJUSTMENT	12 WHEELING ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ -
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	-	-
4.	TOTAL ELECTRIC	-	-	-	-
5.	OTHER OPERATING REVENUE	-	-	-	-
6.	TOTAL OPERATING REVENUE	-	-	-	-
	OPERATING EXPENSES				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	-	-	-	-
8.	PRODUCTION - STEAM A/C 500	-	-	-	-
9.	A/C 502	-	-	-	-
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	-
13.	A/C 506 & 509	-	-	-	-
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	-
17.	A/C 548	-	-	-	-
18.	A/C 549	-	-	-	-
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				
20.	- DEMAND A/C 555	-	-	(861,800)	-
21.	- ENERGY A/C 555	-	-	949,939	-
22.	A/C 556	-	-	-	(260,148)
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-	-	-	1,589,631
25.	ADMINISTRATIVE & GENERAL	-	-	-	-
26.	TOTAL OPERATIONS	-	-	88,139	1,329,483
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	-
28.	A/C 511	-	-	-	-
29	A/C 512	-	-	-	-
30.	A/C 513	-	-	-	-
31	A/C 514	-	-	-	-
32	A/C 515	-	-	-	-
33	PRODUCTION - OTHER - A/C 551	-	-	-	-
34.	A/C 552	-	-	-	-
35.	A/C 553	-	-	-	-
36.	A/C 554	-	-	-	-
37.	TRANSMISSION	-	-	-	-
38.	GENERAL PLANT	-	-	-	-
39.	TOTAL MAINTENANCE	-	-	-	-

Arizona Electric Power Cooperative, Inc.
Income Statement Pro Forma Adjustments

LINE NO.		9 GT FFB FINANCING ADJUSTMENT	10 DEPRECIATION ADJUSTMENT	11 PURCHASE POWER ADJUSTMENT	12 WHEELING ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ (1,473,878)	$ -	$ -
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	-
43.	TOTAL OTHER	-	(1,473,878)	-	-
44.	TOTAL OPERATING EXPENSES	-	(1,473,878)	88,139	1,329,483
45.	ELECTRIC OPERATING MARGINS	-	1,473,878	(88,139)	(1,329,483)
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	1,190,178	-	-	-
47.	INTEREST CHARGES TO CONSTR	-	-	-	-
48.	OTHER INTEREST EXPENSE	-	-	-	-
49.	OTHER DEDUCTIONS	-	-	-	-
50.	TOTAL INTEREST & OTHER DEDUCTIONS	1,190,178	-	-	-
51.	OPERATING MARGINS	(1,190,178)	1,473,878	(88,139)	(1,329,483)
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	-
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	-
55a.	EXTRAORDINARY ITEMS	-	-	-	-
56.	NET INCOME (MARGINS)	$ (1,190,178)	$ 1,473,878	$ (88,139)	$ (1,329,483)

SUPPORTING SCHEDULES:

(9)Adjustments - GT4 FFB Financing Adjustment

(10)Adjustments - Depreciation Adjustment

(11)Adjustments - Purchase Power Adjustment

(12)Adjustments - Wheeling Adjustment

Arizona Electric Power Cooperative, Inc.

Income Statement Pro Forma Adjustments

LINE NO.		13 INTEREST ADJUSTMENT	14 OTHER DEDUCTIONS ADJUSTMENT	15 ARO ADJUSTMENT	TOTAL PRO-FORMA ADJUSTMENT
1.	CLASS A MEMBERS	$ -	$ -	$ -	$ 17,298
2.	FUEL ADJUSTMENT	-	-	-	-
3.	NON-CLS A, NON-FIRM & NON-ME	-	-	-	(1,455,598)
4.	TOTAL ELECTRIC	-	-	-	(1,438,300)
5.	OTHER OPERATING REVENUE	-	-	-	(76,586)
6.	TOTAL OPERATING REVENUE	-	-	-	(1,514,886)
	OPERATING EXPENSES				
	OPERATIONS				
7.	PRODUCTION -FUEL A/C 501 & 547	-	-	-	(2,491,992)
8.	PRODUCTION - STEAM A/C 500	-	-	-	70,344
9.	A/C 502	-	-	-	877,223
10.	A/C 503	-	-	-	-
11.	A/C 504	-	-	-	-
12.	A/C 505	-	-	-	30,066
13.	A/C 506 & 509	-	-	-	(127,662)
14.	A/C 507	-	-	-	-
15.	A/C 508	-	-	-	-
16.	PRODUCTION - OTHER - A/C 546	-	-	-	22
17.	A/C 548	-	-	-	6,424
18.	A/C 549	-	-	-	941
19.	A/C 550	-	-	-	-
	OTHER POWER SUPPLY				-
20.	- DEMAND A/C 555	-	-	-	(861,800)
21.	- ENERGY A/C 555	-	-	-	446,346
22.	A/C 556	-	-	-	(270,288)
23.	A/C 557	-	-	-	-
24.	TRANSMISSION	-	-	-	1,344,193
25.	ADMINISTRATIVE & GENERAL	-	-	-	170,673
26.	TOTAL OPERATIONS	-	-	-	(805,510)
	MAINTENANCE				
27.	PRODUCTION - STEAM - A/C 510	-	-	-	29,685
28.	A/C 511	-	-	-	2,590
29	A/C 512	-	-	-	32,427
30.	A/C 513	-	-	-	3,274
31	A/C 514	-	-	-	52,119
32	A/C 515	-	-	-	-
33	PRODUCTION - OTHER - A/C 551	-	-	-	110
34.	A/C 552	-	-	-	168
35.	A/C 553	-	-	-	8,950
36.	A/C 554	-	-	-	3,030
37.	TRANSMISSION	-	-	-	342
38.	GENERAL PLANT	-	-	-	-
39.	TOTAL MAINTENANCE	-	-	-	132,695

Arizona Electric Power Cooperative, Inc.
Income Statement Pro Forma Adjustments

LINE NO.		13 INTEREST ADJUSTMENT	14 OTHER DEDUCTIONS ADJUSTMENT	15 ARO ADJUSTMENT	TOTAL PRO-FORMA ADJUSTMENT
	OTHER:				
40.	DEPRECIATION & AMORTIZATION	$ -	$ -	$ -	$ (1,165,347)
41.	ACC GROSS REVENUE TAXES	-	-	-	-
42.	TAXES	-	-	-	149,289
43.	TOTAL OTHER	-	-	-	(1,016,058)
44.	TOTAL OPERATING EXPENSES	-	-	-	(1,688,873)
45.	ELECTRIC OPERATING MARGINS	-	-	-	173,987
	INTEREST & OTHER DEDUCTIONS:				
46.	INTEREST ON LONG-TERM DEBT	(375,891)	-	-	1,346,752
47.	INTEREST CHARGES TO CONSTR	-	-	-	-
48.	OTHER INTEREST EXPENSE	-	-	-	-
49.	OTHER DEDUCTIONS	-	(266,003)	381,034	115,031
50.	TOTAL INTEREST & OTHER DEDUCTIONS	(375,891)	(266,003)	381,034	1,461,783
51.	OPERATING MARGINS	375,891	266,003	(381,034)	(1,287,796)
	OTHER NON OPERATING INCOME:				
52.	INTEREST INCOME	-	-	-	-
53.	AFUDC	-	-	-	-
54.	OTHER NONOPERATING INCOME	-	-	-	(1,302)
55.	TOTAL OTHER NON OPERATING INCOME	-	-	-	(1,302)
55a.	EXTRAORDINARY ITEMS	-	-	3,810,335	3,810,335
56.	NET INCOME (MARGINS)	$ 375,891	$ 266,003	$ 3,429,301	$ 2,521,237

SUPPORTING SCHEDULES:
(13)Adjustments - Interest Adjustment
(14)Adjustments - Other Deductions Adjustment
(15)Adjustments - ARO Adjustment

Arizona Electric Power Cooperative, Inc.

Computation of Gross Revenue Conversion Factor

SCHEDULE C-3

7/7/2004

LINE NO.		PERCENTAGE OF INCREMENTAL GROSS REVENUES
1.	FEDERAL INCOME TAX RATE	0.00000
2.	STATE INCOME TAX RATE	0.00000
3.	CORPORATION COMMISSION GROSS REVENUE TAX RATE	0.00200
4.	TOTAL TAX PERCENTAGE **	0.00200
5.	OPERATING INCOME PERCENT	0.00000
6.	GROSS REVENUE CONVERSION FACTOR (a)	0.00000

** Included as both a revenue and an expense so no revenue conversion adjustment required **

RECAPSCHEDULES:

D

Arizona Electric Power Cooperative, Inc.

SCHEDULE D-1

Summary Cost of Capital

7/7/2004

END OF ACTUAL TEST YEAR 12/31/2003

LINE NO.	INVESTED CAPITAL	AMOUNT (b)	%	COST RATE	COMPOSITE (b)
1.	LONG-TERM DEBT (a)	$213,294,620	0.00%	5.60%	5.60%
2.	SHORT-TERM DEBT (a)	0	0.00%	0.00%	0.00%
3.	TOTAL	$213,294,620	0.00%	5.60%	5.60%

END OF PROJECTED YEAR 12/31/2003

	INVESTED CAPITAL	AMOUNT (b)	%	COST RATE	COMPOSITE (b)
4.	LONG-TERM DEBT (a)	$228,500,238	0.00%	5.98%	5.98%
5.	SHORT-TERM DEBT (a)	0	0.00%	0.00%	0.00%
6.	TOTAL	$228,500,238	0.00%	5.98%	5.98%

SUPPORTING SCHEDULES:
(a) D-2

RECAP SCHEDULES:
(b) A-3

Arizona Electric Power Cooperative, Inc.

Cost Of Long-Term and Short-Term Debt

SCHEDULE D-2
7/7/2004

LINE NO.		END OF ACTUAL TEST YEAR 12/31/2003 OUTSTANDING	FACE RATE	ANNUAL INTEREST	END OF PROJECTED YEAR 12/31/2003 OUTSTANDING	FACE RATE	ANNUAL INTEREST
1.	FFB DEBT	$ 114,914,717	6.147%	$ 7,063,808	$ 153,820,335	6.113%	$ 9,402,651
2.	REA DEBT	4,851,102	4.452%	215,971	4,851,102	4.452%	215,971
3.	CFC SERIES 1997C BONDS	7,392,918	4.906%	362,697	7,392,918	4.906%	362,697
4.	CFC SERIES 1994A BONDS	17,867,061	1.050%	187,604	17,867,061	1.050%	187,604
5.	CENTRAL BANK FOR COOPERATIVES	27,304,914	7.740%	2,113,400	27,304,914	7.740%	2,113,400
6.	NRUCFC	40,963,908	2.668%	1,092,917	17,263,908	2.761%	476,717
7.	REGULATORY ASSET	-	0.000%	909,000	-	0.000%	909,000
8.	TOTAL LONG-TERM (b)	$ 213,294,620		$ 11,945,397	$ 228,500,238		13,668,040
9.	COST RATE (b)			5.600%			5.982%
	SHORT TERM:	-		0.00%	-		0.00%
10.	SHORT-TERM DEBT (b)	$ -		0.00%	$ -		0.00%
11.	COST RATE (b)			0.00%			0.00%

LINE NO.		END OF YEAR 2001 OUTSTANDING (a)	FACE RATE	ANNUAL INTEREST	END OF YEAR 2002 OUTSTANDING (a)	FACE RATE	ANNUAL INTEREST
	LONG-TERM DEBT:						
1.	FFB DEBT	$ 126,151,420	6.208%	$ 7,831,480	$ 123,605,087	6.144%	$ 7,594,297
2.	REA DEBT	6,440,809	4.361%	280,884	5,662,114	4.400%	249,133
3.	CFC SERIES 1997C BONDS	10,602,246	4.799%	508,802	9,034,665	4.859%	438,994
4.	CFC SERIES 1994A BONDS	18,676,135	2.600%	485,580	18,271,598	1.600%	292,346
5.	CENTRAL BANK FOR COOPERATIVES	28,900,139	7.740%	2,236,871	28,151,071	7.740%	2,178,893
6.	NRUCFC	11,889,727	4.176%	496,515	25,693,470	3.350%	860,731
7.	REGULATORY ASSET	-	0.000%	505,000	-	0.000%	1,058,000
8.	TOTAL LONG-TERM DEBT (b)	$ 202,660,476		$ 12,345,131	$ 210,418,005		$ 12,672,394
9.	COST RATE (b)			6.092%			6.022%
	SHORT TERM:	-		0.00%	-		0.00%
10.	SHORT-TERM DEBT (b)	$ -		0.00%	$ -		0.00%
11.	COST RATE (b)			0.00%			0.00%

SUPPORTING SCHEDULES:
(a) E-1,PAGE 2

RECAP SCHEDULES:
(b) A-3

Arizona Electric Power Cooperative, Inc.

SCHEDULE D-3

Cost Of Prefered Stock

7/7/2004

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

SCHEDULE D-4

Cost Of Common Stock

7/7/2004

NOT APPLICABLE

E

Arizona Electric Power Cooperative, Inc.

Comparative Balance Sheets

LINE NO.		PER BOOKS 12/31/2003	PRIOR YEAR 12/31/2002	PRIOR YEAR 12/31/2001
	ASSETS			
	UTILITY PLANT:			
1.	UTILITY PLANT IN SERVICE	$ 379,651,131	$ 377,308,896	$ 343,797,323
2.	LESS: ACCUMULATED DEPRECIATION AND AMORTIZATION	(185,881,988)	(179,550,282)	(172,617,523)
3.	TOTAL UTILITY PLANT IN SERVICE	193,769,143	197,758,614	171,179,800
4.	CONSTRUCTION WORK IN PROGRESS	9,795,448	2,334,254	13,878,042
5.	PLANT HELD FOR FUTURE USE	-	-	-
6.	NET UTILITY PLANT (a)	203,564,591	200,092,868	185,057,842
	CURRENT ASSETS:			
7.	GENERAL FUND CASH	380,663	410,548	513,780
8.	TEMPORARY INVESTMENTS	2,736,417	6,976,268	9,836,667
9.	ACCOUNTS RECEIVABLE	14,578,970	18,129,901	23,201,187
10.	FUEL INVENTORY	3,382,266	12,593,707	8,029,830
11.	MATERIALS AND SUPPLIES	5,798,889	5,199,651	4,956,399
12.	PREPAYMENTS & OTHER CURRENT ASSETS	1,448,699	1,415,734	1,133,036
13.	NOTES RECEIVABLE-CURRENT	-	-	-
14.	OTHER	8,094,019	3,995,093	2,759,210
15.	TOTAL CURRENT ASSETS	36,419,923	48,720,902	50,430,109
	OTHER ASSETS:			
16.	INV - ASSOC ORG	9,794,007	8,023,894	8,691,656
17.	INVESTMENTS	4,020,135	3,452,932	6,663,700
18.	DEFERRED DEBITS	1,955,373	1,715,626	1,966,714
19.	UNAMORTIZED DEBT	684,284	760,531	836,720
20.	REGULATORY ASSETS	4,226,488	4,271,349	3,906,798
21.	TOTAL OTHER ASSETS	20,680,287	18,224,332	22,065,588
22.	TOTAL ASSETS	$ 260,664,801	$ 267,038,102	$ 257,553,539

Arizona Electric Power Cooperative, Inc.

Comparative Balance Sheets

LINE NO.		PER BOOKS 12/31/2003	PRIOR YEAR 12/31/2002	PRIOR YEAR 12/31/2001
	LIABILITIES & EQUITY			
	EQUITY: (c) (d)			
23.	PATRONAGE CAPITAL	$ 17,803,568	$ 13,904,998	$ 4,606,942
24.	UNALLOCATED MARGINS	(7,048,847)	3,898,570	9,298,056
25.	TOTAL EQUITY	10,754,721	17,803,568	13,904,998
	LIABILITIES:			
	LONG-TERM DEBT: (b)			
26.	FFB DEBT	114,914,717	123,605,087	126,151,420
27.	REA DEBT	4,851,102	5,662,114	6,440,809
28.	CFC 1997C BONDS	7,392,918	9,034,665	10,602,246
29.	CFC 1994A BONDS	17,867,061	18,271,598	18,676,135
30.	CBC	27,304,914	28,151,071	28,900,139
31.	NRUCFC	40,963,908	25,693,470	11,889,727
32.	LESS CURRENT MATURITIES	(482,866)	-	-
33.	TOTAL LONG-TERM DEBT	212,811,754	210,418,005	202,660,477
	CURRENT LIABILITIES:			
34.	MEMBER ADVANCES & NOTES	1,834,000	4,978,804	4,584,386
35.	ACCOUNTS PAYABLE	13,259,745	7,752,719	10,091,554
36.	ACCRUED TAXES	1,727,253	2,119,162	2,199,941
37.	ACCRUED INTEREST	854,966	931,190	1,613,082
38.	CURRENT LIABILITY - OTHER	10,879,423	9,135,072	9,310,142
39.	CURRENT MATURITIES OF LONG TERM DEBT	-	-	-
40.	TOTAL CURRENT LIABILITIES	28,555,387	24,916,947	27,799,105
41.	ACCUMULATED OPERATING PROVISIONS	4,896,562	311,100	204,200
42.	DEFERRED CREDITS	3,646,375	13,588,479	12,984,759
43.	TOTAL LIABILITIES AND EQUITY	$ 260,664,799	$ 267,038,099	$ 257,553,539

SUPPORTING SCHEDULES:
(a) E-5, PAGE 2
(b) D-2, D-2A AND GENERAL LEDGER
(c) E-4

RECAP SCHEDULES:
(d) A-3 Line 5

Arizona Electric Power Cooperative, Inc.

Comparative Income Statements

LINE NO.		ACTUAL TEST YEAR 12/31/2003 (b)	PRIOR YEAR 12/31/2002	PRIOR YEAR 12/31/2001
	REVENUES:			
1.	CLASS A MEMBERS	$ 85,811,247	$ 79,623,648	$ 84,889,058
2.	FUEL ADJUSTMENT	-	-	8,294,176
3.	NON-CIS A, N-FIRM & N-MEMB	51,757,181	63,553,920	111,608,445
4.	TOTAL ELECTRIC REVENUE	137,568,428	143,177,568	204,791,679
5.	OTHER OPERATING REVENUE	13,610,967	12,201,048	7,653,439
6.	TOTAL OPERATING REVENUE	151,179,395	155,378,616	212,445,118
	OPERATING EXPENSES			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	62,295,417	56,992,331	75,290,554
8.	PRODUCTION - STEAM A/C 500	1,929,564	1,689,840	1,761,549
9.	A/C 502	3,724,301	4,394,709	4,611,926
10.	A/C 503	-	-	-
11.	A/C 504	-	-	-
12.	A/C 505	1,965,819	1,960,293	1,950,161
13.	A/C 506	2,743,982	2,132,579	2,362,103
14.	A/C 507	-	1,097	1,719
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	444,395	353,566	341,709
17.	A/C 548	918,066	752,531	876,537
18.	A/C 549	510,877	411,995	368,363
19.	A/C 550	12,354	9,084	4,571
	OTHER POWER SUPPLY	-		
20.	-DEMAND A/C 555	6,631,387	11,834,278	18,821,087
21.	- ENERGY A/C 555	9,639,192	10,506,900	28,065,717
22.	A/C 556	3,680,604	2,640,491	3,671,517
23.	A/C 557	2,329,157	2,101,273	763,169
24.	TRANSMISSION	15,341,229	15,949,082	11,406,465
25.	ADMINISTRATIVE & GENERAL	9,204,100	9,465,171	12,421,440
26.	TOTAL OPERATIONS	121,370,444	121,195,220	162,718,587
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	811,089	727,293	730,123
28.	A/C 511	253,280	177,019	206,315
29.	A/C 512	6,401,254	6,467,133	6,892,143
30.	A/C 513	261,485	245,988	461,533
31.	A/C 514	2,322,842	1,870,881	2,112,132
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	172,226	128,749	138,580
34.	A/C 552	67,470	57,772	28,933
35.	A/C 553	1,888,607	(133,389)	599,254
36.	A/C 554	669,320	327,700	335,129
37.	TRANSMISSION	34,568	24,153	1,160,136
38.	GENERAL PLANT	63,958	53,825	909,739
39.	TOTAL MAINTENANCE	12,946,099	9,947,124	13,574,017

Arizona Electric Power Cooperative, Inc.

Comparative Income Statements

LINE NO.		ACTUAL TEST YEAR 12/31/2003 (b)	PRIOR YEAR 12/31/2002	PRIOR YEAR 12/31/2001
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 8,774,082	$ 7,808,510	$ 11,519,596
41.	ACC GROSS REVENUE TAXES (a)	288,752	472,714	238,733
42.	TAXES	1,329	815	-
43.	TOTAL OTHER	9,064,163	8,282,039	11,758,329
44.	TOTAL OPERATING EXPENSES	143,380,706	139,424,383	188,050,933
45.	ELECTRIC OPERATING MARGINS	7,798,689	15,954,233	24,394,185
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	12,200,997	12,825,566	16,050,770
47.	INTEREST CHARGES TO CONSTR	(68,586)	(335,171)	(221,959)
48.	OTHER INTEREST EXPENSE	166,468	310,585	662,789
49.	OTHER DEDUCTIONS	702,075	430,643	132,260
50.	TOTAL INTEREST & OTHER DEDUCTIONS	13,000,954	13,231,623	16,623,860
51.	OPERATING MARGINS	(5,202,265)	2,722,610	7,770,325
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	582,014	681,304	1,981,737
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	1,381,739	494,656	679,158
55.	TOTAL OTHER NON OPERATING INCOME	1,963,753	1,175,960	2,660,895
55a.	EXTRAORDINARY ITEMS	(3,810,335)	-	-
56.	NET INCOME (MARGINS) (c)	$ (7,048,847)	$ 3,898,570	$ 10,431,220

SUPPORTING SCHEDULES:
(a) E-8 Line 4

RECAP SCHEDULES:
(b) C-1 PAGES 1 & 2
(c) A-2

Arizona Electric Power Cooperative, Inc.

Comparative Statement of Changes in Financial Position

SCHEDULE E-3

7/7/2004

LINE NO.			PER BOOKS 12/31/2003	PRIOR YEAR 12/31/2002	PRIOR YEAR 12/31/2001
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1.	NET MARGIN	(a)	$ (7,048,847)	$ 3,898,570	$ 10,431,220
	ADJUSTMENTS TO RECONCILE NET MARGIN TO NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES-				
2.	DEPREC. & AMORT.		8,692,283	7,726,667	9,730,505
3.	AMORTIZATION OF DEFERRED CHARGES		94,391	94,334	694,529
4.	AMORTIZATION OF OTHER DEFERRED CREDITS		(337,278)	(337,280)	(337,280)
5.	CUMULATIVE EFFECRT OF CHANGE IN ACCOUNTING PRINCIPLE		3,810,335	-	-
	CHANGES IN ASSETS AND LIABILITIES				
6.	RESTRICTED CASH AND CASH EQUIVALENTS		(581,791)	1,954,400	-
7.	RECEIVABLES		3,352,463	4,822,758	2,379,036
8.	INVENTORIES		8,612,202	(4,807,128)	(62,742)
9.	DEFERRED DEBITS		(47,035)	543,392	(733,721)
10.	ACCOUNTS PAYABLE		3,299,219	(2,299,311)	(15,582,224)
11.	ACCRUED INTEREST PAYABLE		(76,225)	(681,892)	(163,959)
12.	SHORTFALL CHARGE-BACK CONTINGENCY		-	-	-
13.	ACCRUED OVERHAUL		1,606,156	(69,618)	(4,501,806)
14.	OTHER , NET		(349,102)	263,527	1,487,248
	NET CASH PROVIDED BY OPERATING ACTIVITIES	(b)	$21,026,771	11,108,419	3,340,806
	CASH FLOWS FROM INVESTING ACTIVITIES:				
15.	CONSTRUCTION EXPENDITURES, NET (c)		(11,928,062)	(23,155,056)	(16,780,223)
16.	RESTRUCTURING TRANSFER OF CASH & CASH EQ.		-	-	(15,241,728)
17.	MATURITIES OF INVESTMENTS		159,037	717,090	2,339,710
18.	PURCHASE OF INVESTMENTS		(1,929,150)	(86,497)	(6,092,434)
19.	PATRONAGE CAPITAL RETIREMENT		66,875	36,512	221,861
20.	NET CASH USED IN INVESTING ACTIVITIES	(b)	(13,631,300)	(22,487,951)	(35,552,814)
	CASH FLOWS FROM FINANCING ACTIVITIES:				
21.	MEMBER ADVANCES, NET		(12,749,628)	1,335,418	(44,831)
22.	ISSUANCE OF LONG-TERM DEBT		15,429,150	19,587,886	9,744,114
23.	RETIREMENT OF LONG-TERM DEBT		(10,344,951)	(12,505,358)	(13,968,035)
23.	RETIREMENT OF PATRONAGE CAPITAL		-	-	(1,843,609)
24.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(b)	(7,665,429)	8,417,946	(6,112,361)
25.	NET DECREASE IN CASH AND CASH EQ.	(b)	(269,958)	(2,961,586)	(38,324,369)
26.	CASH AND CASH EQUIVALENTS, January 1		7,690,546	10,652,132	48,976,501
27.	CASH AND CASH EQUIVALENTS, December 31		$ 7,420,588	$ 7,690,546	$ 10,652,132
	SUPPLEMENTAL DISCLOSURES:				
28.	CASH PAID FOR INTEREST, NET OF AMOUNT CAPITALIZED		$ 12,303,028	$ 13,266,621	$ 16,110,560

SUPPORTING SCHEDULES:
(a) C-1, PAGE 2

RECAP SCHEDULES:
(b) A-5
(c) A-4

Arizona Electric Power Cooperative, Inc.

Statement of Change in Equity

SCHEDULE E-4
7/7/2004

LINE NO.		PATRONAGE CAPITAL			UNALLOCATED MARGINS	
1.	BALANCE, DEC. 31, 2000	$ 1,843,939			$ 6,127,407	
2.	UNALLOCATED MARGINS CHANGE	-			3,170,649	
3.	BALANCE, DEC. 31, 2001	4,606,942	(a)		9,298,056	
4.	UNALLOCATED MARGINS CHANGE	-			(5,399,486)	
5.	BALANCE, DEC. 31, 2002	13,904,998			3,898,570	(a)
6.	UNALLOCATED MARGINS CHANGE	-			(3,898,570)	
7.	NET EARNINGS (LOSS)				(7,048,847)	
8.	BALANCE, DEC. 31, 2003 \1	$ 17,803,568	(a)		$ (7,048,847)	(a)

SUPPORTING SCHEDULES:

\1. As reflected by REA Form 12a (Unaudited)

RECAP SCHEDULES:
(a) E-1, PAGE 2

Arizona Electric Power Cooperative, Inc.

Detail of Utility Plant

LINE NO.		END OF PRIOR YEAR 12/31/2002 /1	NET ADDITIONS	ACTUAL TEST YEAR 12/31/2003 /2	PRO FORMA ADJUSTMENT (a)	ADJUSTED TEST YEAR 12/31/2003
	INTANGIBLE PLANT:					
1.	301 ORGANIZATION	$ 4,545	$ -	$ 4,545	$ -	$ 4,545
2.	114 ACQUISITION ADJUSTMENT	13,238	-	13,238	-	13,238
3.	302 FRANCHISE AND CONSENT	744	-	744	-	744
4.	303 MISC. INTANGIBLE PLANT	-	-	-	-	-
5.	SUBTOTAL INTANGIBLE	18,527	-	18,527	-	18,527
	STEAM PRODUCTION PLANT:					
6.	310 LAND AND LAND RIGHTS	3,915,175	-	3,915,175	-	3,915,175
7.	311 STRUCTURES AND IMPROVEMENTS	34,923,477	-	34,923,477	-	34,923,477
8.	312 BOILER EQUIPMENT	200,304,569	1,862,238	202,166,807	-	202,166,807
9.	314 TURBINE GENERATORS	52,291,803	(407,021)	51,884,782	-	51,884,782
10.	315 ACCESSORY ELEC. EQUIPMENT	17,482,536	6,549	17,489,085	-	17,489,085
11.	316 MISC. POWER EQUIPMENT	3,990,741	51,752	4,042,493	-	4,042,493
12.	317 ASSET RETIREMENT OBLIGATION	-	1,962,630	1,962,630	-	1,962,630
13.	SUBTOTAL STEAM PRODUCTION	312,908,301	3,476,148	316,384,449	-	316,384,449
	OTHER PRODUCTION PLANT:					
14.	340 LAND AND LAND RIGHTS	1,160	-	1,160	-	1,160
15.	341 STRUCTURES AND IMPROVEMENTS	7,725	631,545	639,270	9,952,618	10,591,888
16.	342 FUEL HLDRS PRODCRS & ACCES	504,595	2,300,431	2,805,026	-	2,805,026
17.	343 PRIME MOVERS	7,060,493	22,092,737	29,153,230	-	29,153,230
18.	344 GENERATORS	2,363,833	920,964	3,284,797	-	3,284,797
19.	345 ACCESSORY ELEC. EQUIPMENT	843,659	1,608,654	2,452,313	-	2,452,313
20.	346 MISC. POWER EQUIPMENT	159,647	749,557	909,204	-	909,204
21.	SUBTOTAL OTHER PRODUCTION	10,941,112	28,303,888	39,245,000	9,952,618	49,197,618
	TRANSMISSION PLANT:					
22.	350 LAND AND LAND RIGHTS	-	-	-	-	-
23.	352 STRUCTURES AND IMPROVEMENTS	-	-	-	-	-
24.	353 STATION EQUIPMENT	1,753,724	770,718	2,524,442	-	2,524,442
25.	354 TOWERS AND FIXTURES	-	-	-	-	-
26.	355 POLES AND FIXTURES	-	173,130	173,130	-	173,130
27.	356 OVERHEAD CONDUCTORS	-	74,199	74,199	-	74,199
28.	359 ROADS AND TRAILS	-	-	-	-	-
29.	SUBTOTAL TRANSMISSION	1,753,724	1,018,047	2,771,771	-	2,771,771

Arizona Electric Power Cooperative, Inc.

Detail of Utility Plant

LINE NO.		END OF PRIOR YEAR 12/31/2002 /1		NET ADDITIONS	ACTUAL TEST YEAR 12/31/2003 /2		PRO FORMA ADJUSTMENT (a)	ADJUSTED TEST YEAR 12/31/2003	
	GENERAL PLANT:								
30.	389 LAND AND LAND RIGHTS	$ 147,862		$ -	$ 147,862		$ -	$ 147,862	
31.	390ACCOUNTS390-399	17,124,093		6,153	17,130,246		-	17,130,246	
32.	SUBTOTAL GENERAL	17,271,955		6,153	17,278,108		-	17,278,108	
	COMPLETED CONST - UNCLASSIFIED								
33.	GENERAL PLANT	3,897,623		45,626	3,943,249		-	3,943,249	
34.	LINES	-		-	-		-	-	
35.	SUBSTATION	-		-	-		-	-	
36.	GENERATION - STEAM	30,517,654		(30,507,627)	10,027		-	10,027	
37.	GENERATION - IC	-		-	-		-	-	
38.	TOTAL COMPLETED	34,415,277		(30,462,001)	3,953,276		-	3,953,276	
39.	TOTAL PLANT IN SERVICE	377,308,896	(b) (c)	2,342,235	379,651,131	(b) (c)	9,952,618	389,603,749	(d)
	ACCUMULATED DEPRECIATION (d)								
40.	PRODUCTION	(169,297,075)		(5,586,927)	(174,884,002)		(308,531)	(175,192,533)	
41.	TRANSMISSION	(1,092,490)		(75,091)	(1,167,581)		-	(1,167,581)	
42.	RETIREMENTS	141,620		(86,972)	54,648		-	54,648	
43.	GENERAL	(9,166,539)		(500,872)	(9,667,411)		-	(9,667,411)	
44.	ELEC PLT IN SERVICE	-		-	-		-	-	
45.	TOTAL	(179,414,484)		(6,249,862)	(185,664,346)		(308,531)	(185,972,877)	
46.	ACCUMULATED AMORTIZATION	(135,798)		(81,844)	(217,642)		-	(217,642)	
47.	TOTAL ACCUM DEPREC. & AMORT.	(179,550,282)	(b)	(6,331,706)	(185,881,988)	(b)	(308,531)	(186,190,519)	(d)
48.	NET PLANT IN SERVICE	197,758,614		(3,989,471)	193,769,143	(d)	9,644,087	203,413,230	(d)
49.	CWIP	2,334,254	(b)	7,461,194	9,795,448	(b)	-	9,795,448	
50.	PLANT HELD FOR FUTURE USE	-		-	-	(b)	-	-	(e)
51.	TOTAL NET PLANT	$ 200,092,868	(b)	$ 3,471,723	$ 203,564,591		$ 9,644,087	$ 213,208,678	

SUPPORTING SCHEDULES:
(a) E-5, PAGES 3 AND 4

/1 From General Ledger Balance Sheet
/2 From General Ledger Balance Sheet

RECAP SCHEDULES:
(b) E-l, PAGE 1 Lines 1-6
(c) A-4
(d) B-2 Lines 10-14
(e) B-1

Arizona Electric Power Cooperative, Inc.

Detail of Utility Plant / Pro Forma Adjustments

LINE NO.		COAL BLENDING FACILTIY ADJUSTMENT	TOTAL
	INTANGIBLE PLANT:		
1.	301 ORGANIZATION	$ -	$ -
2.	114 ACQUISITION ADJUSTMENT	-	-
3.	302 FRANCHISE AND CONSENT	-	-
4.	303 MISC. INTANGIBLE PLANT	-	-
5.	SUBTOTAL INTANGIBLE	-	-
	STEAM PRODUCTION PLANT:		
6.	310 LAND AND LAND RIGHTS	-	-
7.	311 STRUCTURES AND IMPROVEMENTS	-	-
8.	312 BOILER EQUIPMENT	-	-
9.	314 TURBINE GENERATORS	-	-
10.	315 ACCESSORY ELEC. EQUIPMENT	-	-
11.	316 MISC. POWER EQUIPMENT	-	-
12.	317 ASSET RETIREMENT OBLIGATION	-	-
13.	SUBTOTAL STEAM PRODUCTION	-	-
	OTHER PRODUCTION PLANT:		
14.	340 LAND AND LAND RIGHTS	-	-
15.	341 STRUCTURES AND IMPROVEMENTS	9,952,618	9,952,618
16.	342 FUEL HLDRS PRODCRS & ACCES	-	-
17.	343 PRIME MOVERS	-	-
18.	344 GENERATORS	-	-
19.	345 ACCESSORY ELEC. EQUIPMENT	-	-
20.	346 MISC. POWER EQUIPMENT	-	-
21.	SUBTOTAL OTHER PRODUCTION	9,952,618	9,952,618
	TRANSMISSION PLANT:		
22.	350 LAND AND LAND RIGHTS	-	-
23.	352 STRUCTURES AND IMPROVEMENTS	-	-
24.	353 STATION EQUIPMENT	-	-
25.	354 TOWERS AND FIXTURES	-	-
26.	355 POLES AND FIXTURES	-	-
27.	356 OVERHEAD CONDUCTORS	-	-
28.	359 ROADS AND TRAILS	-	-
29.	SUBTOTAL TRANSMISSION	-	-

Arizona Electric Power Cooperative, Inc.

Detail of Utility Plant / Pro Forma Adjustments

LINE NO.		COAL BLENDING FACILTIY ADJUSTMENT	TOTAL
	GENERAL PLANT:		
30.	389 LAND AND LAND RIGHTS	$ -	$ -
31.	390ACCOUNTS390-399	-	-
32.	SUBTOTAL GENERAL	-	-
	COMPLETED CONST - UNCLASSIFIED		
33.	GENERAL PLANT	-	-
34.	LINES	-	-
35.	SUBSTATION	-	-
36.	GENERATION - STEAM	-	-
37.	GENERATION - IC	-	-
38.	TOTAL COMPLETED	-	-
39.	TOTAL PLANT IN SERVICE	9,952,618	9,952,618
	ACCUMULATED DEPRECIATION		
40.	PRODUCTION	(308,531)	(308,531)
41.	TRANSMISSION	-	-
42.	RETIREMENTS	-	-
43.	GENERAL	-	-
44.	ELEC PLT IN SERVICE	-	-
45.	TOTAL	(308,531)	(308,531)
46.	ACCUMULATED AMORTIZATION	-	-
47.	TOTAL ACCUM DEPREC. & AMORT.	(308,531)	(308,531)
48.	NET PLANT IN SERVICE	9,644,087	9,644,087
49.	CWIP	-	-
50.	PLANT HELD FOR FUTURE USE	-	-
51.	TOTAL NET PLANT	$ 9,644,087	$ 9,644,087

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-6

Statement of Change in Equity

7/7/2004

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-7

Operating Statistics

7/7/2004

LINE NO.	ELECTRIC STATISTICS /1	TEST YEAR ENDED 12/31/2003	PRIOR YEAR ENDED 12/31/2002	PRIOR YEAR ENDED 12/31/2001
	MWH SALES:			
1.	CLASS A MEMBERS	2,027,671,490	1,806,449,282	1,732,573,000
2.	OTHER FIRM CONTRACT'S	1,117,704,528	1,414,441,339	2,041,972,000
3.	TOTAL	3,145,376,018	3,220,890,621	3,774,545,000
	AVERAGE NO. CUSTOMERS:			
4.	CLASS A MEMBERS	6	6	6
5.	OTHER FIRM CONTRACTS	7	7	9
6.	TOTAL	13	13	15
	AVERAGE MWH USE:			
7.	CLASS A MEMBERS	337,945,248	301,074,880	288,762,167
8.	OTHER FIRM CONTRACT'S	159,672,075	202,063,048	226,885,778
9.	TOTAL	497,617,324	503,137,929	515,647,944
10.	KWH PRODUCTION EXPENSE (a)	$ 67,981,909	$ 61,075,674	$ 101,046,083

SUPPORTING SCHEDULES:
(a) G-2A, Page 2

/1 REA FORM 12b FOR RESPECTIVE YEARS.
2. EXCLUDES ECONOMY & PD NON-FIRM SALES

Arizona Electric Power Cooperative, Inc.

SCHEDULE E-8

Taxes Charged to Operations

7/7/2004

LINE NO.	DESCRIPTION:	PER BOOKS 12/31/2003	PRIOR YEAR ENDED 12/31/2002	PRIOR YEAR ENDED 12/31/2001
	FEDERAL TAXES:			
1.	PAYROLL ESTIMATED	$ 688,271	$ 681,925	$ 1,044,097
	FEDERAL INCOME	900	-	-
	TOTAL FEDERAL TAXES	689,171	681,925	1,044,097
	STATE TAXES:			
2.	PAYROLL ESTIMATED	1,432	(551)	1,880
3.	PROPERTY	3,196,221	3,640,599	4,765,366
4.	GROSS REVENUE (a)	288,752	472,714	238,733
5.	STATE INCOME	117	15	-
6.	CALIFORNIA FRANCHISE TAX	313	800	-
7.	PAYROLL ESTIMATED	$ 3,486,835	$ 4,113,578	$ 5,005,979

RECAP SCHEDULES:
(a) E-2, PAGE 2

Arizona Electric Power Cooperative, Inc.

Notes to Financial Statements

SCHEDULE E-9

7/7/2004

SEE FINANCIAL STATEMENTS

F

Arizona Electric Power Cooperative, Inc.

Projected Income Statement / Present and Proposed Rates

LINE NO.		-ACTUAL- TESTYEAR 12/31/2003	-PROJECTED YEAR- PRESENT RATES 12/31/2003 (a)	PROPOSED RATES 12/31/2003
	REVENUES:			
1.	CLASS A MEMBERS	$ 85,811,247	$ 85,685,624	$ 94,135,640
2.	FUEL ADJUSTMENT	-	-	-
3.	NON-CIS A, N-FIRM & N-MEMB	51,757,181	50,444,504	50,444,504
4.	TOTAL ELECTRIC REVENUE	137,568,428	136,130,128	144,580,144
5	OTHER OPERATING REVENUE	13,610,967	1,481,322	1,481,322
6.	TOTAL OPERATING REVENUE (b)	151,179,395	137,611,450	146,061,466
	OPERATING EXPENSES:			
	OPERATIONS			
7.	PRODUCTION - FUEL A/C 501/547	62,295,417	59,803,425	59,803,425
8.	PRODUCTION - STEAM A/C 500	1,929,564	1,999,908	1,999,908
9.	A/C 502	3,724,301	2,710,803	2,710,803
10.	A/C 503	-	-	-
1L	A/C 504	-	-	-
12.	A/C 505	1,965,819	1,437,524	1,437,524
13.	A/C 506	2,743,982	2,616,320	2,616,320
14.	A/C 507	-	-	-
15.	A/C 508	-	-	-
16.	PRODUCTION - OTHER - A/C 546	444,395	444,417	444,417
17.	A/C 548	918,066	366,744	366,744
18.	A/C S49	510,877	511,818	511,818
19.	A/C 550	12,354	12,354	12,354
	OTHER POWER SUPPLY	-	-	-
20.	-DEMAND A/C 555	6,631,387	5,769,587	5,769,587
21.	- ENERGY A/C 555	9,639,192	10,085,538	10,085,538
22.	A/C 556	3,680,604	2,315,473	2,315,473
23.	A/C 557	2,329,157	19,877	19,877
24.	TRANSMISSION	15,341,229	8,036,486	8,036,486
25.	ADMINISTRATIVE & GENERAL	9,204,100	9,191,902	9,191,902
26.	TOTAL OPERATIONS	121,370,444	105,322,176	105,322,176
	MAINTENANCE			
27.	PRODUCTION - STEAM - A/C 510	811,089	840,774	840,774
28.	A/C 511	253,280	255,870	255,870
29.	A/C 512	6,401,254	6,433,681	6,433,681
30.	A/C 513	261,485	264,759	264,759
31.	A/C 514	2,322,842	2,374,961	2,374,961
32.	A/C 515	-	-	-
33.	PRODUCTION - OTHER - A/C 551	172,226	172,336	172,336
34.	A/C 552	67,470	67,638	67,638
35.	A/C 553	1,888,607	1,897,557	1,897,557
36.	A/C 554	669,320	672,350	672,350
37.	TRANSMISSION	34,568	28,388	28,388
38.	GENERAL PLANT	63,958	63,958	63,958
39.	TOTAL MAINTENANCE	12,946,099	13,072,272	13,072,272

Arizona Electric Power Cooperative, Inc.

Projected Income Statement / Present and Proposed Rates

LINE NO.		-ACTUAL- TESTYEAR 12/31/2003	-PROJECTED YEAR- PRESENT RATES 12/31/2003 (a)	PROPOSED RATES 12/31/2003
	OTHER:			
40.	DEPRECIATION & AMORTIZATION	$ 8,774,082	$ 7,608,735	$ 7,608,735
41.	ACC GROSS REVENUE TAXES	288,752	288,752	288,752
42.	TAXES	1,329	3,346,839	3,346,839
43.	TOTAL OTHER	9,064,163	11,244,326	11,244,326
44.	TOTAL OPERATING EXPENSES (b)	143,380,706	129,638,774	129,638,774
45.	ELECTRIC OPERATING MARGINS (b)	7,798,689	7,972,676	16,422,692
	INTEREST & OTHER DEDUCTIONS:			
46.	INTEREST ON LONG-TERM DEBT	12,200,997	13,547,749	13,547,749
47.	INTEREST CHARGES TO CONSTR	(68,586)	(68,586)	(68,586)
48.	OTHER INTEREST EXPENSE	166,468	166,468	166,468
49.	OTHER DEDUCTIONS	702,075	817,106	817,106
50.	TOTAL INTEREST & OTHER DEDUCTIONS (b)	13,000,954	14,462,737	14,462,737
51.	OPERATING MARGINS	(5,202,265)	(6,490,061)	1,959,955
	OTHER NON OPERATING INCOME:			
52.	INTEREST INCOME	582,014	582,014	582,014
53.	AFUDC	-	-	-
54.	OTHER NONOPERATING INCOME	1,381,739	1,380,437	1,380,437
55.	TOTAL OTHER NON OPERATING INCOME (b)	1,963,753	1,962,451	1,962,451
55a.	EXTRAORDINARY ITEMS (b)	(3,810,335)	-	-
56.	NET INCOME (MARGINS) (b)	$ (7,048,847)	$ (4,527,610)	$ 3,922,406

SUPPORTING SCHEDULES:
(a) C-1, PAGES 3 & 4

RECAP SCHEDULES:
(b) A-2

Arizona Electric Power Cooperative, Inc.

SCHEDULE F-2
7/7/2004

Projected Changes in Financial Position
Present and Proposed Rates

LINE NO.		ACTUAL TESTYEAR ENDED 12/31/2003 (a)	PROJECTED YEAR PRESENT RATES ENDED 12/31/2003 (b)	PROJECTED YEAR PROPOSED RATES ENDED 12/31/2003 (b)
1.	NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 21,026,771	$ 21,284,054	$ 29,734,070
2.	NET CASH USED IN INVESTING ACTIVITIES	(13,631,300)	(13,631,300)	(13,631,300)
3.	NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	(7,665,429)	(7,665,429)	(7,665,429)
4.	NET DECREASE IN CASH AND CASH EQ.	$ (269,958)	$ (12,675)	$ 8,437,341

SUPPORTING SCHEDULES:
(a) E-3

RECAP SCHEDULES:
(b) A-5

Arizona Electric Power Cooperative, Inc.

SCHEDULE F-3

Projected Construction Requirements

7/7/2004

LINE NO.		-ACTUAL- TESTYEAR ENDED 12/31/2003	-PROJECTED YEAR- YEAR ENDED 12/31/2004	YEAR ENDED 12/31/2005	YEAR ENDED 12/31/2006
1.	PRODUCTION PLANT	$ 11,244,953	$ 6,110,000	$ 4,153,000	$ 4,153,000
2.	TRANSMISSION PLANT	-	-	-	-
3.	GENERAL PLANT	338,025	295,000	309,000	309,000
4.	HEADQUARTERS BULDING	1,774	-	-	7,550,000
5.	RETIREMENTS	343,310	-	-	-
6.	TOTAL PLANT (a)	$ 11,928,062	$ 6,405,000	$ 4,462,000	$ 12,012,000

SUPPORTING SCHEDULES:

RECAP SCHEDULES:
(a) A-4

Arizona Electric Power Cooperative, Inc.

Assumptions Used in Developing Projections

SCHEDULE F-4
7/7/2004

LINE NO.		
1.	DSCR GOAL	1.05
2.	COAL	$27.70/TON
3.	GAS	$5.11/MCF
	PURCHASED POWER:	
4.	CRSP	$4.04/KW + $.009500/KWH
5.	PACIFICORP	$17.54/KW + $017030/KWH
6.	PANDA GILA RIVER	$4.84/KW + $053153/KWH
7.	PARKER DAVIS (Jan-Sept)	$0.77/KW + $0.001750/KWH
8.	PARKER DAVIS (Oct-Dec)	$1.21/KW + $0.002770/KWH
9.	PSNM	$25.00/KW + $0.018864/KWH
10.	ECONOMY	.038907/KWH
11.	FFB INTEREST RATE	6.1470%
12.	S-T INVESTMENT INTEREST	1.5790%
13.	STAFFING LEVELS	299
14.	PROPERTY TAXES	$3,654,781
	DEPRECIATION RATES:	
15.	STEAM UNITS	
	ST 1	3.10%
	ST 2	2.09%
	ST 3	1.81%
16.	COMBUSTION TURBINES	3.00%
17.	HEADQUARTERS	2.00%
18.	GENERAL PLANT	6.00%
19.	VEHICLES	3-10 YEARS MINUS SALVAGE
20.	COMMUNICATIONS	6.00%
21.	SYS. CONTROL & MICROWAVE	6.00%

G

Arizona Electric Power Cooperative, Inc.

SCHEDULE G-1

Cost of Service Summary - Present Rates

7/7/2004

LINE NO.		TOTAL SYSTEM
	REVENUES:	
1.	MEMBERS (a)	$ 85,685,624
2.	NON-MEMBERS (b)	50,444,504
3.	OTHER OPERATING REVENUE (b)	1,481,322
4.	TOTAL REVENUES	137,611,450
5.	OPERATING EXPENSES (c)	129,638,774
6.	ELECTRIC OPERATING MARGINS	7,972,676
7.	INCOME TAXES	-
8.	NET INCOME (MARGINS) (LINE 6 - LINE 7)	$ 7,972,676
9.	RATE BASE (d) (e)	$222,147,011
10.	RATE OF RETURN	3.59%

SUPPORTING SCHEDULES:
(a) H-1, LINE 1
(b) C-l PAGE 3, LINES 3 & 5
(c) G-6, LINE 38
(d) G-5, LINE 20

RECAP SCHEDULES:
(e) B-,l LINE 9

Arizona Electric Power Cooperative, Inc.

Cost of Service Summary - Developed Rates

SCHEDULE G-2
7/7/2004

LINE NO.		TOTAL SYSTEM
	REVENUES:	
1.	MEMBERS (a)	$ 94,135,640
2.	NON-MEMBERS (b)	50,444,504
3.	OTHER OPERATING REVENUE (b)	1,481,322
4.	TOTAL REVENUES	146,061,466
5.	OPERATING EXPENSES (c)	129,638,774
6.	ELECTRIC OPERATING MARGINS	16,422,692
7.	INCOME TAXES	-
8.	NET INCOME (MARGINS) (LINE 6 - LINE 7)	$ 16,422,692
9.	RATE BASE (d) (e)	$222,147,011
10.	RATE OF RETURN	7.39%

SUPPORTING SCHEDULES:
(a) H-1 LINE 1
(b) F-1, PAGE 1, LINES 3 & 5
(c) G-6 LINE 38
(d) G-5 LINE 20

RECAP SCHEDULES:
(e) B-1 LINE 9

Arizona Electric Power Cooperative, Inc.
Derivation Of Revenue Requirement and Rates

LINE NO.				
1.	DESIRED MEMBER REVENUE REQUIREMENT - DSCR 0f 1.05			$ 94,144,084
2.	LESS: ACC GOR ASSESSMENT		0.2%	184,136
3.	NET MEMBER REVENUE REQUIREMENT			93,959,948
4.	ENERGY RELATED REVENUE REQUIREMENTS	2,025,326,533	$0.02071	41,944,512
5.	FIXED AND O&M REVENUE REQUIREMENTS			52,015,436
6.	MOHAVE O&M REVENUE REQUIREMENTS	1,270,181	$ 7.25	9,208,812
7.	OTHER O&M REVENUE REQUIREMENTS	2,489,412	$ 7.29	18,147,813
8.	FIXED REVENUE REQUIREMENTS			24,658,811
9.	LESS: PANDA GILA RIVER FIXED COSTS	1,000,872		
10.	LESS: MOHAVE FIXED CHARGE	$ 23,657,939	35.8%	8,469,540
11.	FIXED DEMAND REVENUE REQUIREMENTS			$ 16,189,271
12.	TOTAL DEMAND BILLING UNITS		3,759,593	
13.	LESS: MOHAVE DEMAND BILLING UNITS		1,270,181	
14.	REMAINING DEMAND BILLING UNITS			2,489,412
15.	FIXED COSTS DEMAND RATE PORTION			$ 6.50
16.	MOHAVE MONTHLY FIXED CHARGE	$ 8,469,540	12	$ 705,795
17.	COMPUTATION OF ENERGY RATE:			
18.	ENERGY RELATED COSTS			$67,981,909
19.	SYSTEM SALES AS ADJUSTED - KWH			3,281,912,645
20.	ENERGY RATE - $/KWH			$0.02071
21.	COMPUTATION OF O&M RATE:			
22.	GENERATION DEMAND REVENUE REQUIREMENTS:			
23.	O&M RELATED COSTS		$41,965,513	52.61%
24.	FIXED RELATED COSTS		33,865,337	42.46%
25.	OPERATING MARGIN REQUIREMENT		3,930,850	4.93%
26.	SUBTOTAL		$79,761,700	100.00%
27.	REVENUE FROM OTHER SOURCES:		27,746,264	
28.	TOTAL		52,015,436	
29.	OPERATIONS & MAINTENANCE			$41,965,513
30.	OTHER REVENUES	27,746,264	52.61%	14,598,312
31.	O& M REVENUE REQUIREMENT			27,367,201
32.	LESS: EL PASO WHEELING COST (5/12)	102,500		
33.	NET O&M REVENUE REQUIREMENTS	27,264,701		
34.	LESS: MOHAVE O&M RATE	$ 7.25	1,270,181	9,208,812
35.	REMAINING O&M REVENUE REQUIREMT			$ 18,158,389
36.	TOTAL O&M DEMAND BILLING UNITS		3,759,593	
37.	LESS: MOHAVE O&M BILLING UNITS		1,270,181	
38.	REMAINING O&M DEMAND BILLING UNITS			2,489,412
39.	O&M DEMAND RATE			$ 7.29

Arizona Electric Power Cooperative, Inc.
Summary of Tariff Rates

LINE NO.				
1.	PRESENT RATES:			
2.	EFFECTIVE DATE		August 1, 2001	
3.	FULL REQUIREMENTS CUSTOMERS:			
4.	DEMAND CHARGE	$	12.44	Per kW Month
5.	ENERGY CHARGE	$	0.01989	Per kWh
6.	FUEL ADJUSTOR	$	-	Per kWh
7.	PPFAC BASE	$	0.01714	Per kWh
8.	ACC GOR ASSESSMENT		0.200%	Revenue Billed
9.	PARTIAL REQUIREMENTS CUSTOMERS:			
10.	FIXED CHARGE	$	688,556	Per Month
11.	O&M CHARGE	$	4.76	Per kW Month
12.	ENERGY CHARGE	$	0.01989	Per kWh
13.	FUEL ADJUSTOR	$	-	Per kWh
14.	PPFAC BASE	$	0.01714	Per kWh
15.	ACC GOR ASSESSMENT		0.200%	Revenue Billed
16.	PROPOSED RATES:			
17.	PROPOSED EFFECTIVE DATE		July 1, 2004	
18.	FULL REQUIREMENTS CUSTOMERS:			
19.	DEMAND CHARGE	$	13.79	Per kW Month
20.	ENERGY CHARGE	$	0.02071	Per kWh
21.	FUEL ADJUSTOR	$	-	Per kWh
22.	MFCA BASE	$	0.02038	Per kWh
23.	ACC GOR ASSESSMENT		0.200%	Revenue Billed
24.	PARTIAL REQUIREMENTS CUSTOMERS:			
25.	MOHAVE ELECTRIC COOPERATIVE, INC.			
26.	FIXED CHARGE	$	705,795	Per Month
27.	O&M CHARGE		$7.25	Per kW Month
28.	ENERGY CHARGE	$	0.02071	Per kWh
29.	FUEL ADJUSTOR	$	-	Per kWh
30.	MFCA BASE	$	0.02038	Per kWh
31.	ACC GOR ASSESSMENT		0.200%	Revenue Billed

Arizona Electric Power Cooperative, Inc.

Rate Base Allocation to Classes of Service

SCHEDULE G-3

7/7/2004

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

SCHEDULE G-4

Rate Base Allocation to Classes of Service

7/7/2004

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

Distribution of Rate Base by Function

SCHEDULE G-5
7/7/2004

LINE NO.		TOTAL	DEMAND	ENERGY	CUSTOMER	REVENUE
	PRODUCTION: (a)					
1.	GROSS PLANT	$ 365,592,094	$ 365,592,094	$ -	$ -	$ -
2.	ACCUMULATED DEPRECIATION	(175,192,533)	(175,192,533)	-	-	-
3.	NET PLANT	190,399,561	190,399,561	-	-	-
	TRANSMISSION: (a)					
4.	GROSS PLANT	2,771,771	2,771,771	-	-	-
5.	ACCUMULATED DEPRECIATION	(1,167,581)	(1,167,581)	-	-	-
6.	NET PLANT	1,604,190	1,604,190	-	-	-
	GENERAL & INTANGIBLE: (a)					
7.	GROSS PLANT	21,239,884	21,239,884	-	-	-
8.	ACCUMULATED DEPRECIATION	(9,667,411)	(9,667,411)	-	-	-
9.	NET PLANT	11,572,473	11,572,473	-	-	-
	OTHER RATE BASE ADDITIONS:					
10.	RWIP (a)	54,648	54,648	-	-	-
11.	DEFERRED DEBITS (b)	1,955,373	1,955,373	-	-	-
	WORKING CAPITAL: (c)					
12.	CASH/1	-	-	-	-	-
13.	FUEL STOCK	5,581,933	-	5,581,933	-	-
14.	MATERIALS & SUPPLIES	5,265,561	5,265,561	-	-	-
15.	PREPAYMENTS	908,046	908,046	-	-	-
16.	CFC CERTIFICATES	5,022,869	5,022,869	-	-	-
	RATE BASE DEDUCTIONS: (b)					
17.	ACCUMULATED AMORT. (a)	(217,642)	(217,642)	-	-	-
18.	CUST. ADVANCES FOR CONSTRUCTION	-	-	-	-	-
19.	CONTRIB. IN AID OF CONSTRUCTION	-	-	-	-	-
20.	TOTAL RATE BASE (d) (e)	$ 222,147,011	$ 216,565,079	$ 5,581,933	$ -	$ -

SUPPORTING SCHEDULES:
(a) B-2
(b) B-1, LINE 8
(c) B-5, PAGE 1

RECAP SCHEDULES:
(d) G-1
(e) A-1 LINE 1

Arizona Electric Power Cooperative, Inc.

Distribution of Expenses by Function
(Pro Forma Adjustments Included)

LINE NO.		TOTAL (a)	FIXED	O&M	ENERGY	CUSTOMER
	OPERATING EXPENSES:					
	OPERATIONS					
1	PRODUCTION - FUEL A/C 501/547	$ 59,803,425	$ 1,984,345	$ -	$ 57,819,080	$ -
2	PRODUCTION - STEAM A/C 500	1,999,908	-	1,999,908	-	-
3	A/C 502	2,710,803	402,630	2,308,173	-	-
4	A/C 503	-	-	-	-	-
5	A/C 504	-	-	-	-	-
6	A/C 505	1,437,524	74,469	1,363,055	-	-
7	A/C 506 & 509	2,616,320	-	2,616,320	-	-
8	A/C 507	-	-	-	-	-
9	A/C 508	-	-	-	-	-
10	PRODUCTION - OTHER - A/C 546	444,417	-	444,417	-	-
11	A/C 548	366,744	80,162	286,582	-	-
12	A/C 549	511,818	-	511,818	-	-
13	A/C 550	12,354	-	12,354	-	-
	OTHER POWER SUPPLY	-				
14	- DEMAND A/C 555	5,769,587	5,769,587	-	-	-
15	- ENERGY A/C 555	10,085,538	-	-	10,085,538	-
16	A/C 556	2,315,473	-	2,315,473	-	-
17	A/C 557	19,877	-	19,877	-	-
18	TRANSMISSION	8,036,486	-	7,959,195	77,291	-
19	ADMINISTRATIVE & GENERAL	9,191,902	75,018	9,116,884	-	-
20	TOTAL OPERATIONS	105,322,176	8,386,211	28,954,056	67,981,909	-
21	PRODUCTION - STEAM - A/C 510	840,774	-	840,774	-	-
22	A/C 511	255,870	-	255,870	-	-
23	A/C 512	6,433,681	-	6,433,681	-	-
24	A/C 513	264,759	-	264,759	-	-
25	A/C 514	2,374,961	58,901	2,316,060	-	-
26	A/C 515.	-			-	-
27	PRODUCTION - OTHER - A/C 551	172,336	-	172,336	-	-
28	A/C 552	67,638	-	67,638	-	-
29	A/C 553	1,897,557	-	1,897,557	-	-
30	A/C 554.	672,350	-	672,350	-	-
31	TRANSMISSION	28,388	1,914	26,474	-	-
32	GENERAL PLANT	63,958	-	63,958	-	-
33	TOTAL MAINTENANCE	13,072,272	60,815	13,011,457	-	-
	OTHER:					
34	DEPRECIATION & AMORTIZATION	7,608,735	7,608,735	-	-	-
35	ACC GROSS REVENUE TAXES	288,752	-	-	-	288,752
36	TAXES	3,346,839 (b)	3,346,839	-	-	-
37	TOTAL OTHER	11,244,326	10,955,574	-	-	288,752
38	TOTAL OPERATING EXPENSES	129,638,774	19,402,600	41,965,513	67,981,909	288,752
	INT. & OTHER DEDUCTIONS:					
39	INT. ON LONG-TERM DEBT	13,547,749	13,547,749			
40	INT. CHARGES TO CONST.	(68,586)	(68,586)			
41	OTHER INT. EXPENSE	166,468	166,468			
42	OTHER DEDUCTIONS	817,106	817,106			
43	TOTAL INT. & OTHER DED.	14,462,737	14,462,737	-	-	-
44	TOTAL EXPENSES	$ 144,101,511	$ 33,865,337 (c)	$ 41,965,513 (c)	$ 67,981,909	$ 288,752

SUPPORTING SCHEDULES:
(a) C-1, PAGES 3 & 4
(b) C-1, PAGE 4, LINES 48+49

RECAP SCHEDULES:
(c) G-2A, PAGE 1

Arizona Electric Power Cooperative, Inc.

Distribution of Expenses by Function

Summary Of Demand And Energy Credits Applied Against Functionalized Expense

LINE NO.		PER BOOKS DEMAND	PER BOOKS ENERGY	RECLASSIFICATIONS AND PRO FORMA ADJUSTMENTS DEMAND	RECLASSIFICATIONS AND PRO FORMA ADJUSTMENTS ENERGY	AS ADJUSTED DEMAND	AS ADJUSTED ENERGY
	CONTRACT SALES						
1.	TRICO PD SIERRITA	$ 968,803	$ 862,555	$ -	$ -	$ 968,803	$ 862,555
2.	CITY OF MESA	752,145	1,014,702	(752,145)	(1,014,702)	-	-
3.	CITY OF MESA(PSA)	2,999,853	2,725,136	-	(67,785)	2,999,853	2,657,351
4.	ED-2 POWER SUPPLY	1,261,189	1,411,281	-	(35,092)	1,261,189	1,376,189
5.	SRP	15,877,316	13,488,162	-	(449,057)	15,877,316	13,039,105
6.	SAFFORD	416,227	232,895	-	-	416,227	232,895
7.	MOHAVE SCHEDULE B SALES	-	-	-	142,921	-	142,921
8.		-	-	-	-	-	-
9.		-	-	-	-	-	-
10.		-	-	-	-	-	-
11.	TOTAL CONTRACT SALES	22,275,533	19,734,731	(752,145)	(1,423,715)	21,523,388	18,311,016
	ECONOMY SALES						
12.	MOHAVE NUCOR STEEL	269,962	387,044	-	-	269,962	387,044
13.	SRP	233,981	342,479	-	-	233,981	342,479
14.	SWTCO-ENERGY LOSSES	-	2,134,737	-	-	-	2,134,737
15.	OTHERS	1,711,891	4,649,629	-	863,183	1,711,891	5,512,812
16.	SRSG & OTHER	-	17,194	-	-	-	17,194
17.		-	-	-	-	-	-
18.		-		-	-	-	-
19.	TOTAL-INTERCHANGE SALES (Sum Lines 12 - 19)	2,215,834	7,531,083	-	863,183	2,215,834	8,394,266
	OTHER OPERATING REVENUE						
20.	MEMBERS TRANSMISSION	9,531,656	-	(9,531,656)	-	-	-
21.	MEMBERS SCHED SYS CNTL, DISPAT	1,094,843	-	(1,094,843)	-	-	-
22.	OTHER	2,984,468	-	(1,921,611)	-	1,062,857	-
23.	TOTAL OTHER OPERATING REVENUE (Sum Lines 20 - 23)	13,610,967	-	(12,548,110)	-	1,062,857	-
24.	TOTAL SALES REVENUE CREDITS (Lines 11 + 19)	$ 24,491,367	$ 27,265,814	$ (752,145)	$ (560,532)	$ 23,739,222	$ 26,705,282
25.	OTHER OPERATING REVENUE (b)	$ 13,610,967	$ -	$ (12,548,110)	$ -	$ 1,062,857	$ -

SUPPORTING SCHEDULES:
(b) C-1, PAGES 1 - 4

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.

Distribution of Expenses by Function
Classification of Purchased Power Expenses

LINE NO.		PER BOOKS- DEMAND	PER BOOKS- ENERGY	RECLASSIFICATIONS AND PRO FORMA ADJUSTMENTS DEMAND	RECLASSIFICATIONS AND PRO FORMA ADJUSTMENTS ENERGY	AS ADJUSTED DEMAND	AS ADJUSTED ENERGY
	CONTRACT PURCHASES						
1.	CRSP	$ 366,630	$ 309,547	$ -	$ -	$ 366,630	$ 309,547
2.	PACIFICORP	877,000	443,461	(877,000)	(443,461)	-	-
3.	PARKER DAVIS	223,410	217,629	-	-	223,410	217,629
4.	P S NEW MEXICO	4,150,000	1,963,061	-	-	4,150,000	1,963,061
5.	PANDA GILA RIVER	985,672	1,134,573	15,200	-	1,000,872	1,134,573
6.	SPINNING RESERVE	28,675	-	-	-	28,675	-
7.		-	-	-	-	-	-
8.		-	-	-	-	-	-
9.						-	-
10.						-	-
11.	TOTAL - CONTRACT PURCHASES (Sum Lines 1-11)	6,631,387	4,068,271	(861,800)	(443,461)	$5,769,587	$3,624,810
	INTERCHANGE PURCHASES						
12.	CITY OF BURBANK	-	383,143	-	-	-	383,143
13.	CALPINE	-	515,330	-	-	-	515,330
14.	PINNACLE WEST	-	-	-	-	-	-
15.	PSNM	-	620,102	-	-	-	620,102
16.	SRP	-	1,557,271	-	-	-	1,557,271
17.	TEP	-	240,997	-	-	-	240,997
18.	PD NONFIRM	-	60,600	-		-	60,600
19.	INTERCHANGE	-	(75,641)	-	-	-	(75,641)
20.	MISC	-	2,269,119	-	889,807	-	3,158,926
21.	TOTAL-INTERCHANGE PURCHASES (Sum Lines 12 - 20)	-	5,570,921	-	889,807	-	6,460,728
	TRANSMISSION BY OTHERS ETC						
22.	WHEELING FIRM A/C RUS 565	15,263,938	-	(7,304,743)	-	7,959,195	-
23.	WHEELING NONFIRM A/C RUS 565	-	77,291	-	-	-	77,291
24.	ANCILLARY SVS A/C 556	1,990,467	-	(1,354,991)	-	635,476	-
25.	RAC & DAF RUS A/C 557	2,309,280	-	(2,309,280)	-	-	-
26.						-	-
27.	TOTAL TRANSMISSION BY OTHERS ETC (Sum Lines 22 - 26)	19,563,685	77,291	(10,969,014)	-	8,594,671	77,291
28.	TOTAL PURCHASED POWER EXP (Lines 11 + 21)	(a) $ 6,631,387	(a) $ 9,639,192	(a) $ (861,800)	(a) $ 446,346	(a) $ 5,769,587	(a) $ 10,085,538

SUPPORTING SCHEDULES:
(a) C-1, PAGES 1 - 4

RECAP SCHEDULES:

Arizona Electric Power Cooperative, Inc.

SCHEDULE G-7

Development of Allocation Factors

7/7/2004

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

SCHEDULE G-8

Derivation of Fuel Base Charge

7/7/2004

SEE SCHEDULE H-2A

H

Arizona Electric Power Cooperative, Inc.

SCHEDULE H-1
7/7/2004

Analysis of Revenue by Detailed Class
2003- Annualized

LINE NO.	CLASS OF SERVICE	REVENUES IN TEST YEAR (a) PRESENT	REVENUES IN TEST YEAR (a) PROPOSED	PROPOSED INCREASE (b) AMOUNT	PROPOSED INCREASE (b) PERCENT
1.	TOTAL MEMBER REVENUES	$85,685,624	$94,135,640	$8,450,016	9.86%
2	OTHER TARIFF SALES	-	-	-	0.00%
3.	TOTALCOMPANY	$85,685,624	$94,135,640	$8,450,016	9.86%

SUPPORTING SCHEDULES:
(a) H-2, Page 1

RECAP SCHEDULES:
(b) A-1

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class
2003- Annualized

LINE NO.	CLASS OF SERVICE	CUSTOMERS (a)	kWh CONSUMPTION PRESENT (a)	kWh CONSUMPTION PROPOSED (a)	REVENUE PRESENT (a)	REVENUE PROPOSED (a)	PROPOSED INCREASE AMOUNT (a)	PERCENT (a)
	MEMBER CONTRACTS:							
1.	ANZA	1	44,660,813	44,660,813	$ 1,914,156	$ 2,062,105	$ 147,949	7.73%
2.	DUNCAN	1	26,782,590	26,782,590	1,159,334	1,249,418	90,084	7.77%
3.	GRAHAM	1	136,552,300	136,552,300	6,017,397	6,488,214	470,817	7.82%
4.	MOHAVE	1	716,978,668	716,978,668	28,590,756	32,592,036	4,001,280	14.00%
5.	SULPHUR	1	662,992,990	662,992,990	27,948,841	30,097,333	2,148,492	7.69%
6.	TRICO	1	437,359,172	437,359,172	20,055,140	21,646,534	1,591,394	7.94%
7.	TOTAL MEMBER CONTRACTS	6	2,025,326,533	2,025,326,533	85,685,624	94,135,640	8,450,016	9.86%
	OTHER FIRM CONTRACTS:							
8.	ED 2	1	67,738,398	67,738,398	2,672,470	2,672,470	-	0.00%
9.	MESA	1	130,846,053	130,846,053	5,724,989	5,724,989	-	0.00%
10.	SRP	1	799,064,000	799,064,000	29,365,478	29,365,478	-	0.00%
11.	TOTAL FIRM CONTRACTS:	3	997,648,451	997,648,451	37,762,937	37,762,937	-	0.00%
	TOTAL COMPANY	9	$ 3,022,974,984	$ 3,022,974,984	$ 123,448,561	$ 131,898,577	(b) $ 8,450,016	(b) 9.86%

SUPPORTING SCHEDULES:
(a) H-2 PAGES 2 THROUGH 8

RECAP SCHEDULES:
(b) H-1

Arizona Electric Power Cooperative, Inc.
Analysis of Revenue by Detailed Class
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ANZA

LINE NO.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	PRESENT RATE:													
1.	Demand Charge($/kW)	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	
2.	Energy Charge($/kWh)	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	
3.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
4.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
5.	ACC GOR Assessment	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	PROPOSED RATE:													
6.	Demand Charge($/kW)	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	
7.	Energy Charge($/kWh)	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	
8.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
9.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
10.	ACC GOR Assessment	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	BILLING DETERMINANTS:													
	PRESENT:													
11.	Demand (kW)	5,436	5,556	6,012	5,496	7,452	7,920	9,516	9,264	7,644	6,708	5,424	6,036	82,464
12.	Energy (kWh)	3,315,450	3,243,168	3,424,686	3,340,230	3,492,462	3,731,861	4,701,354	4,406,838	3,938,952	3,459,276	3,591,432	4,015,104	44,660,813
	PROPOSED:													
13.	Demand (kW)	5,436	5,556	6,012	5,496	7,452	7,920	9,516	9,264	7,644	6,708	5,424	6,036	82,464
14.	Energy (kWh)	3,315,450	3,243,168	3,424,686	3,340,230	3,492,462	3,731,861	4,701,354	4,406,838	3,938,952	3,459,276	3,591,432	4,015,104	44,660,813
	PRESENT REVENUE :													
15.	Demand	$ 67,624	$ 69,117	$ 74,789	$ 68,370	$ 92,703	$ 98,525	$ 118,378	$ 115,244	$ 95,091	$ 83,448	$ 67,475	$ 75,088	$ 1,025,852
16.	Energy	65,944	64,507	68,117	66,437	69,465	74,227	93,510	87,652	78,346	68,805	71,434	79,860	888,304
17.	ACC GOR Assessment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
18.	Fuel Bank Surcharge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19.	Total	$ 133,568	$ 133,624	$ 142,906	$ 134,807	$ 162,168	$ 172,752	$ 211,888	$ 202,896	$ 173,437	$ 152,253	$ 138,909	$ 154,948	$ 1,914,156
20.	Average Cost ($/KWH)	0.04029	0.04120	0.04173	0.04036	0.04643	0.04629	0.04507	0.04604	0.04403	0.04401	0.03868	0.03859	0.04286
	PROPOSED REVENUE:													
21.	Demand	$ 74,962	$ 76,617	$ 82,905	$ 75,790	$ 102,763	$ 109,217	$ 131,226	$ 127,751	$ 105,411	$ 92,503	$ 74,797	$ 83,236	$ 1,137,178
22.	Energy	68,663	67,166	70,925	69,176	72,329	77,287	97,365	91,266	81,576	71,642	74,379	83,153	924,927
23.	ACC GOR Assessment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24.	Fuel Bank Surcharge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
25.	Total	$ 143,625	$ 143,783	$ 153,830	$ 144,966	$ 175,092	$ 186,504	$ 228,591	$ 219,017	$ 186,987	$ 164,145	$ 149,176	$ 166,389	$ 2,062,105
26.	Average Cost ($/KWH)	0.04332	0.04433	0.04492	0.04340	0.05013	0.04998	0.04862	0.04970	0.04747	0.04745	0.04154	0.04144	0.04617
	CHANGE IN TOTAL COST:													
27.	REVENUE	$ 10,057	$ 10,159	$ 10,924	$ 10,159	$ 12,924	$ 13,752	$ 16,703	$ 16,121	$ 13,550	$ 11,892	$ 10,267	$ 11,441	$ 147,949
28.	PERCENT INC.	7.53%	7.60%	7.64%	7.54%	7.97%	7.96%	7.88%	7.95%	7.81%	7.81%	7.39%	7.38%	7.73%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class

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DUNCAN VALLEY

LINE NO.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	PRESENT RATE:													
1.	Demand Charge($/kW)	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	
2.	Energy Charge($/kWh)	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	
3.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
4.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
5.	ACC GOR Assessment	0.150%	0.150%	0.150%	0.150%	0.150%	0.150%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	PROPOSED RATE:													
6.	Demand Charge($/kW)	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	
7.	Energy Charge($/kWh)	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	
8.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
9.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
10.	ACC GOR Assessment	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	BILLING DETERMINANTS:													
	PRESENT:													
11.	Demand (kW)	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
12.	Energy (kWh)	1,832,310	1,726,840	1,949,820	1,910,380	2,417,440	2,676,200	3,217,790	2,929,400	2,482,760	1,961,810	1,661,060	2,016,780	26,782,590
	PROPOSED:													
13.	Demand (kW)	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
14.	Energy (kWh)	1,832,310	1,726,840	1,949,820	1,910,380	2,417,440	2,676,200	3,217,790	2,929,400	2,482,760	1,961,810	1,661,060	2,016,780	26,782,590
	PRESENT REVENUE :													
15.	Demand	$ 37,320	$ 40,803	$ 40,803	$ 42,545	$ 59,463	$ 67,176	$ 64,439	$ 59,961	$ 66,927	$ 57,224	$ 41,052	$ 46,775	$ 624,488
16.	Energy	36,445	34,347	38,782	37,997	48,083	53,230	64,002	58,266	49,382	39,020	33,038	40,114	532,706
17.	ACC GOR Assessment	116	118	125	126	169	189	270	248	242	200	155	182	2,140
18.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
19.	Total	$ 73,881	$ 75,268	$ 79,710	$ 80,668	$ 107,715	$ 120,595	$ 128,711	$ 118,475	$ 116,551	$ 96,444	$ 74,245	$ 87,071	$ 1,159,334
20.	Average Cost ($/KWH)	0.04032	0.04359	0.04088	0.04223	0.04456	0.04506	0.04000	0.04044	0.04694	0.04916	0.04470	0.04317	0.04329
	PROPOSED REVENUE:													
21.	Demand	$ 41,370	$ 45,231	$ 45,231	$ 47,162	$ 65,916	$ 74,466	$ 71,432	$ 66,468	$ 74,190	$ 63,434	$ 45,507	$ 51,850	$ 692,257
22.	Energy	37,947	35,763	40,381	39,564	50,065	55,424	66,640	60,668	51,418	40,629	34,401	41,768	554,668
23.	ACC GOR Assessment	159	162	171	173	232	260	276	254	251	208	160	187	2,493
24.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
25.	Total	$ 79,476	$ 81,156	$ 85,783	$ 86,899	$ 116,213	$ 130,150	$ 138,348	$ 127,390	$ 125,859	$ 104,271	$ 80,068	$ 93,805	$ 1,249,418
26.	Average Cost ($/KWH)	0.04337	0.04700	0.04400	0.04549	0.04807	0.04863	0.04299	0.04349	0.05069	0.05315	0.04820	0.04651	0.04665
	CHANGE IN TOTAL COST:													
27.	REVENUE	$ 5,595	$ 5,888	$ 6,073	$ 6,231	$ 8,498	$ 9,555	$ 9,637	$ 8,915	$ 9,308	$ 7,827	$ 5,823	$ 6,734	$ 90,084
28.	PERCENT INC.	7.57%	7.82%	7.62%	7.72%	7.89%	7.92%	7.49%	7.52%	7.99%	8.12%	7.84%	7.73%	7.77%

Arizona Electric Power Cooperative, Inc.

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GRAHAM COUNTY ELECTRIC

LINE NO.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	PRESENT RATE:													
1.	Demand Charge($/kW)	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	
2.	Energy Charge($/kWh)	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	
3.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
4.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
5.	ACC GOR Assessment	0.150%	0.150%	0.150%	0.150%	0.150%	0.150%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	PROPOSED RATE:													
6.	Demand Charge($/kW)	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	
7.	Energy Charge($/kWh)	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	
8.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
9.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
10.	ACC GOR Assessment	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	BILLING DETERMINANTS:													
	PRESENT:													
11.	Demand (kW)	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
12.	Energy (kWh)	8,075,369	7,764,689	9,877,625	8,936,770	11,394,505	15,244,915	18,436,151	17,408,044	12,391,403	9,658,700	8,099,147	9,264,982	136,552,300
	PROPOSED:													
13.	Demand (kW)	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
14.	Energy (kWh)	8,075,369	7,764,689	9,877,625	8,936,770	11,394,505	15,244,915	18,436,151	17,408,044	12,391,403	9,658,700	8,099,147	9,264,982	136,552,300
	PRESENT REVENUE :													
15.	Demand	$ 170,552	$ 180,144	$ 196,427	$ 212,413	$ 290,051	$ 393,465	$ 411,901	$ 411,714	$ 366,383	$ 283,321	$ 190,494	$ 183,341	$ 3,290,206
16.	Energy	160,619	154,440	196,466	177,752	226,637	303,221	366,695	346,246	246,465	192,112	161,092	184,280	2,716,025
17.	ACC GOR Assessment	521	525	619	612	809	1,091	1,631	1,586	1,275	990	735	772	11,166
18.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
19.	Total	$ 331,692	$ 335,109	$ 393,512	$ 390,777	$ 517,497	$ 697,777	$ 780,227	$ 759,546	$ 614,123	$ 476,423	$ 352,321	$ 368,393	$ 6,017,397
20.	Average Cost ($/KWH)	0.04107	0.04316	0.03984	0.04373	0.04542	0.04577	0.04232	0.04363	0.04956	0.04933	0.04350	0.03976	0.04407
	PROPOSED REVENUE:													
21.	Demand	$ 189,061	$ 199,693	$ 217,744	$ 235,464	$ 321,528	$ 436,164	$ 456,601	$ 456,394	$ 406,143	$ 314,067	$ 211,166	$ 203,237	$ 3,647,262
22.	Energy	167,241	160,807	204,566	185,081	235,980	315,722	381,813	360,521	256,626	200,032	167,733	191,878	2,828,000
23.	ACC GOR Assessment	713	721	845	841	1,115	1,504	1,677	1,634	1,326	1,028	758	790	12,952
24.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
25.	Total	$ 357,015.00	$ 361,221.00	$ 423,155.00	$ 421,386.00	$ 558,623.00	$ 753,390.00	$ 840,091.00	$ 818,549.00	$ 664,095.00	$ 515,127.00	$ 379,657.00	$ 395,905.00	$ 6,488,214.00
26.	Average Cost ($/KWH)	0.04421	0.04652	0.04284	0.04715	0.04903	0.04942	0.04557	0.04702	0.05359	0.05333	0.04688	0.04273	0.04751
	CHANGE IN TOTAL COST:													
27.	REVENUE	$ 25,323	$ 26,112	$ 29,643	$ 30,609	$ 41,126	$ 55,613	$ 59,864	$ 59,003	$ 49,972	$ 38,704	$ 27,336	$ 27,512	$ 470,817
28.	PERCENT INC.	7.63%	7.79%	7.53%	7.83%	7.95%	7.97%	7.67%	7.77%	8.14%	8.12%	7.76%	7.47%	7.82%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class
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MOHAVE ELECTRIC

LINE NO		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	PRESENT RATE:													
1.	Demand Charge($/kW)	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	$ 4.76	
2.	Energy Charge($/kWh)	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	
3.	Facility Charge	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	
4.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
5.	ACC GOR Assessment	0.150%	0.150%	0.150%	0.150%	0.150%	0.150%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	PROPOSED RATE:													
6.	Demand Charge($/kW)	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	$ 7.25	
7.	Energy Charge($/kWh)	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	
8.	Fixed Charge	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	
9.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
10.	ACC GOR Assessment	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	BILLING DETERMINANTS:													
	PRESENT:													
11.	Demand (kW)	75,802	78,000	71,000	79,799	119,200	139,137	147,400	147,429	139,200	112,214	77,000	84,000	1,270,181
12.	Energy (kWh)	56,201,606	49,352,444	41,909,823	53,048,635	58,639,160	63,229,000	77,861,000	77,545,000	66,289,000	58,917,000	54,474,000	59,512,000	716,978,668
	PROPOSED:													
13.	Demand (kW)	75,802	78,000	71,000	79,799	119,200	139,137	147,400	147,429	139,200	112,214	77,000	84,000	1,270,181
14.	Energy (kWh)	56,201,606	49,352,444	41,909,823	53,048,635	58,639,160	63,229,000	77,861,000	77,545,000	66,289,000	58,917,000	54,474,000	59,512,000	716,978,668
	PRESENT REVENUE :													
15.	Demand	$ 348,831	$ 371,280	$ 337,960	$ 368,213	$ 567,392	$ 662,292	$ 701,624	$ 701,762	$ 662,592	$ 534,139	$ 366,520	$ 399,840	$ 6,022,445
16.	Energy	1,117,850	981,620	833,586	1,055,137	1,166,333	1,257,625	1,548,655	1,542,370	1,318,488	1,171,859	1,083,488	1,183,694	14,260,705
17.	Fixed Charge	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	8,262,672
18.	ACC GOR Assessment	3,249	3,075	3,336	3,319	3,658	4,096	4,643	4,631	4,201	3,768	3,371	3,587	44,934
19.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
20.	Total	$ 2,158,486	$ 2,044,531	$ 1,863,438	$ 2,115,225	$ 2,425,939	$ 2,612,569	$ 2,943,478	$ 2,937,319	$ 2,673,837	$ 2,398,322	$ 2,141,935	$ 2,275,677	$ 28,590,756
21.	Average Cost ($/KWH)	0.03841	0.04143	0.04446	0.03987	0.04137	0.04132	0.03780	0.03788	0.04034	0.04071	0.03932	0.03824	0.03988
	PROPOSED REVENUE:													
22.	Demand	$ 549,565	$ 565,500	$ 514,750	$ 578,543	$ 864,200	$ 1,008,743	$ 1,068,650	$ 1,068,860	$ 1,009,200	$ 813,552	$ 558,250	$ 609,000	$ 9,208,813
23.	Energy	1,163,935	1,022,089	867,952	1,098,637	1,214,417	1,309,473	1,612,501	1,605,957	1,372,845	1,220,171	1,128,157	1,232,494	14,848,628
24.	Fixed Charge	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	8,469,540
25.	ACC GOR Assessment	4,839	4,587	4,177	4,766	5,569	6,048	6,774	6,761	6,176	5,479	4,784	5,095	65,055
26.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
27.	Total	$ 2,424,134	$ 2,297,971	$ 2,092,674	$ 2,387,741	$ 2,789,981	$ 3,030,059	$ 3,393,720	$ 3,387,373	$ 3,094,016	$ 2,744,997	$ 2,396,986	$ 2,552,384	$ 32,592,036
28.	Average Cost ($/KWH)	0.04313	0.04656	0.04993	0.04501	0.04758	0.04792	0.04359	0.04368	0.04667	0.04659	0.04400	0.04289	0.04546
	CHANGE IN TOTAL COST:													
27.	REVENUE	$ 265,648	$ 253,440	$ 229,236	$ 272,516	$ 364,042	$ 417,490	$ 450,242	$ 450,054	$ 420,179	$ 346,675	$ 255,051	$ 276,707	$ 4,001,280
28.	PERCENT INC.	12.31%	12.40%	12.30%	12.88%	15.01%	15.98%	15.30%	15.32%	15.71%	14.45%	11.91%	12.16%	14.00%

* Note: Numbers do not include Mohave suplemental purchases from AEPCO.

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class

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SULPHUR SPRINGS VALLEY

LINE NO		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	PRESENT RATE:													
1.	Demand Charge($/kW)	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	
2.	Energy Charge($/kWh)	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	
3.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
4.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
5.	ACC GOR Assessment	0.150%	0.150%	0.150%	0.150%	0.150%	0.150%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	PROPOSED RATE:													
6.	Demand Charge($/kW)	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	
7.	Energy Charge($/kWh)	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	
8.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
9.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
10.	ACC GOR Assessment	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	BILLING DETERMINANTS:													
	PRESENT:													
11.	Demand (kW)	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
12.	Energy (kWh)	48,232,044	44,395,334	49,432,320	49,487,331	58,239,658	64,228,545	71,901,875	68,006,831	59,777,079	50,998,718	45,285,889	53,007,366	662,992,990
	PROPOSED:													
13.	Demand (kW)	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
14.	Energy (kWh)	48,232,044	44,395,334	49,432,320	49,487,331	58,239,658	64,228,545	71,901,875	68,006,831	59,777,079	50,998,718	45,285,889	53,007,366	662,992,990
	PRESENT REVENUE :													
15.	Demand	$ 1,024,558	$ 1,056,878	$ 1,023,090	$ 1,038,329	$ 1,257,597	$ 1,399,052	$ 1,540,234	$ 1,507,902	$ 1,347,551	$ 1,267,014	$ 1,043,069	$ 1,205,026	$ 14,710,300
16.	Energy	959,335	883,023	983,209	984,303	1,158,387	1,277,506	1,430,128	1,352,656	1,188,966	1,014,365	900,736	1,054,317	13,186,931
17.	ACC GOR Assessment	3,121	3,043	3,158	3,182	3,799	4,207	6,228	5,993	5,312	4,767	4,069	4,731	51,610
18.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
19.	Total	$ 1,987,014	$ 1,942,944	$ 2,009,457	$ 2,025,814	$ 2,419,783	$ 2,680,765	$ 2,976,590	$ 2,866,551	$ 2,541,829	$ 2,286,146	$ 1,947,874	$ 2,264,074	$ 27,948,841
20.	Average Cost ($/KWH)	0.04120	0.04376	0.04065	0.04094	0.04155	0.04174	0.04140	0.04215	0.04252	0.04483	0.04301	0.04271	0.04216
	PROPOSED REVENUE:													
21.	Demand	$ 1,135,744	$ 1,171,571	$ 1,134,117	$ 1,151,010	$ 1,394,072	$ 1,550,879	$ 1,707,381	$ 1,671,541	$ 1,493,788	$ 1,404,512	$ 1,156,264	$ 1,335,796	$ 16,306,675
22.	Energy	998,886	919,427	1,023,743	1,024,883	1,206,143	1,330,173	1,489,088	1,408,421	1,237,983	1,056,183	937,871	1,097,783	13,730,584
23.	ACC GOR Assessment	4,269	4,182	4,316	4,352	5,200	5,762	6,393	6,160	5,464	4,921	4,188	4,867	60,074
24.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
25.	Total	$ 2,138,899	$ 2,095,180	$ 2,162,176	$ 2,180,245	$ 2,605,415	$ 2,886,814	$ 3,202,862	$ 3,086,122	$ 2,737,235	$ 2,465,616	$ 2,098,323	$ 2,438,446	$ 30,097,333
26.	Average Cost ($/KWH)	0.04435	0.04719	0.04374	0.04406	0.04474	0.04495	0.04454	0.04538	0.04579	0.04835	0.04634	0.04600	0.04540
	CHANGE IN TOTAL COST:													
27.	REVENUE	$ 151,885	$ 152,236	$ 152,719	$ 154,431	$ 185,632	$ 206,049	$ 226,272	$ 219,571	$ 195,406	$ 179,470	$ 150,449	$ 174,372	$ 2,148,492
28.	PERCENT INC.	7.64%	7.84%	7.60%	7.62%	7.67%	7.69%	7.60%	7.66%	7.69%	7.85%	7.72%	7.70%	7.69%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class

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TRICO ELECTRIC

LINE NO.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	PRESENT RATE:													
1.	Demand Charge($/kW)	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	$ 12.44	
2.	Energy Charge($/kWh)	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	0.01989	
3.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
4.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
5.	ACC GOR Assessment	0.150%	0.150%	0.150%	0.150%	0.150%	0.150%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	PROPOSED RATE:													
6.	Demand Charge($/kW)	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	$ 13.79	
7.	Energy Charge($/kWh)	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	0.02071	
8.	Fuel Adjustor	-	-	-	-	-	-	-	-	-	-	-	-	
9.	PPFAC Base	-	-	-	-	-	-	-	-	-	-	-	-	
10.	ACC GOR Assessment	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	0.200%	
	BILLING DETERMINANTS:													
	PRESENT:													
11.	Demand (kW)	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
12.	Energy (kWh)	28,616,792	26,448,825	28,087,967	26,589,231	36,163,241	44,641,482	52,742,941	49,279,609	43,731,413	36,492,960	29,652,027	34,912,684	437,359,172
	PROPOSED:													
13.	Demand (kW)	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
14.	Energy (kWh)	28,616,792	26,448,825	28,087,967	26,589,231	36,163,241	44,641,482	52,742,941	49,279,609	43,731,413	36,492,960	29,652,027	34,912,684	437,359,172
	PRESENT REVENUE :													
15.	Demand	$ 602,718	$ 692,547	$ 640,710	$ 654,692	$ 1,043,828	$ 1,227,455	$ 1,356,731	$ 1,345,063	$ 1,134,939	$ 1,047,485	$ 723,996	$ 847,276	$ 11,317,440
16.	Energy	569,188	526,067	558,670	528,860	720,679	887,857	1,049,057	980,171	869,818	725,845	589,779	694,413	8,700,404
17.	ACC GOR Assessment	1,844	1,907	1,883	1,855	2,784	3,307	5,013	4,857	4,184	3,693	2,746	3,223	37,296
18.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
19.	Total	$ 1,173,750	$ 1,220,521	$ 1,201,263	$ 1,185,407	$ 1,767,291	$ 2,118,619	$ 2,410,801	$ 2,330,091	$ 2,008,941	$ 1,777,023	$ 1,316,521	$ 1,544,912	$ 20,055,140
20.	Average Cost ($/KWH)	0.04102	0.04615	0.04277	0.04458	0.04887	0.04746	0.04571	0.04728	0.04594	0.04869	0.04440	0.04425	0.04586
	PROPOSED REVENUE:													
21.	Demand	$ 668,126	$ 767,703	$ 710,240	$ 725,740	$ 1,157,105	$ 1,360,659	$ 1,503,965	$ 1,491,030	$ 1,258,103	$ 1,161,159	$ 802,564	$ 939,223	$ 12,545,617
22.	Energy	592,654	547,755	581,702	550,663	748,941	924,525	1,092,306	1,020,581	905,678	755,769	614,093	723,042	9,057,709
23.	ACC GOR Assessment	2,522	2,631	2,584	2,553	3,812	4,570	5,193	5,023	4,328	3,834	2,833	3,325	43,208
24.	Fuel Bank Surcharge	-	-	-	-	-	-	-	-	-	-	-	-	-
25.	Total	$ 1,263,302	$ 1,318,089	$ 1,294,526	$ 1,278,956	$ 1,909,858	$ 2,289,754	$ 2,601,464	$ 2,516,634	$ 2,168,109	$ 1,920,762	$ 1,419,490	$ 1,665,590	$ 21,646,534
26.	Average Cost ($/KWH)	0.04415	0.04984	0.04609	0.04810	0.05281	0.05129	0.04932	0.05107	0.04958	0.05263	0.04787	0.04771	0.04949
	CHANGE IN TOTAL COST:													
27.	REVENUE	$ 89,552	$ 97,568	$ 93,263	$ 93,549	$ 142,567	$ 171,135	$ 190,663	$ 186,543	$ 159,168	$ 143,739	$ 102,969	$ 120,678	$ 1,591,394
28.	PERCENT INC.	7.63%	7.99%	7.76%	7.89%	8.07%	8.08%	7.91%	8.01%	7.92%	8.09%	7.82%	7.81%	7.94%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class

2003- Annualized

AEPCO

LINE NO		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	BILLING DETERMINANTS:													
	PRESENT:													
1.	Demand (kW)	228,758	241,946	229,828	241,885	339,750	395,220	428,082	423,947	381,233	332,350	243,084	273,510	3,759,593
2.	Energy (kWh)	146,273,571	132,931,300	134,682,241	143,312,577	170,346,466	193,752,003	228,861,111	219,575,722	188,610,607	161,488,464	142,763,555	162,728,916	2,025,326,533
	PROPOSED:													
3.	Demand (kW)	228,758	241,946	229,828	241,885	339,750	395,220	428,082	423,947	381,233	332,350	243,084	273,510	3,759,593
4.	Energy (kWh)	146,273,571	132,931,300	134,682,241	143,312,577	170,346,466	193,752,003	228,861,111	219,575,722	188,610,607	161,488,464	142,763,555	162,728,916	2,025,326,533
	PRESENT REVENUE :													
5.	Demand(Full Rqt.)	$ 1,902,772	$ 2,039,489	$ 1,975,819	$ 2,016,349	$ 2,743,642	$ 3,185,673	$ 3,491,683	$ 3,439,884	$ 3,010,891	$ 2,738,492	$ 2,066,086	$ 2,357,506	$ 30,968,286
6.	Demand (Partial Rqt.)	348,831	371,280	337,960	368,213	567,392	662,292	701,624	701,762	662,592	534,139	366,520	399,840	6,022,445
7.	Fixed Charge	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	8,262,672
8.	Energy	2,909,381	2,644,004	2,678,830	2,850,486	3,389,584	3,853,666	4,552,047	4,367,361	3,751,465	3,212,006	2,839,567	3,236,678	40,285,075
9.	ACC GOR Assessment	8,851	8,668	9,121	9,094	11,219	12,890	17,785	17,315	15,214	13,418	11,076	12,495	147,146
10.	Fuel Bank Surcharge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11.	Total	5,858,391	5,751,997	5,690,286	5,932,698	7,400,393	8,403,077	9,451,695	9,214,878	8,128,718	7,186,611	5,971,805	6,695,075	85,685,624
12.	Average Cost ($/KWH)	0.04005	0.04327	0.04225	0.04140	0.04344	0.04337	0.04130	0.04197	0.04310	0.04450	0.04183	0.04114	0.04231
	PROPOSED REVENUE:													
13.	Demand(Full Rqt.)	$ 2,109,263	$ 2,260,815	$ 2,190,237	$ 2,235,166	$ 3,041,384	$ 3,531,385	$ 3,870,605	$ 3,813,184	$ 3,337,635	$ 3,035,675	$ 2,290,298	$ 2,613,342	$ 34,328,989
14.	Demand (Partial Rqt.)	549,565	565,500	514,750	578,543	864,200	1,008,743	1,068,650	1,068,860	1,009,200	813,552	558,250	609,000	9,208,813
15.	Fixed Charge	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	8,469,540
16.	Energy	3,029,326	2,753,007	2,789,269	2,968,004	3,527,875	4,012,604	4,739,713	4,547,414	3,906,126	3,344,426	2,956,634	3,370,118	41,944,516
17.	ACC GOR Assessment	12,502	12,283	12,093	12,685	15,928	18,144	20,313	19,832	17,545	15,470	12,723	14,264	183,782
18.	Fuel Bank Surcharge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19.	Total	6,406,451	6,297,400	6,212,144	6,500,193	8,155,182	9,276,671	10,405,076	10,155,085	8,976,301	7,914,918	6,523,700	7,312,519	94,135,640
20.	Average Cost ($/KWH)	0.04380	0.04737	0.04612	0.04536	0.04787	0.04788	0.04546	0.04625	0.04759	0.04901	0.04570	0.04494	0.04648
	CHANGE IN TOTAL COST:													
21.	REVENUE	$ 548,060	$ 545,403	$ 521,858	$ 567,495	$ 754,789	$ 873,594	$ 953,381	$ 940,207	$ 847,583	$ 728,307	$ 551,895	$ 617,444	$ 8,450,016
22.	PERCENT INC.	9.36%	9.48%	9.17%	9.57%	10.20%	10.40%	10.09%	10.20%	10.43%	10.13%	9.24%	9.22%	9.86%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class

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TOTAL FOR TARIFF

LINE NO.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	BILLING DETERMINANTS:													
	PRESENT:													
1.	Demand (kW)	228,758	241,946	229,828	241,885	339,750	395,220	428,082	423,947	381,233	332,350	243,084	273,510	3,759,593
2.	Energy (kWh)	146,273,571	132,931,300	134,682,241	143,312,577	170,346,466	193,752,003	228,861,111	219,575,722	188,610,607	161,488,464	142,763,555	162,728,916	2,025,326,533
	PROPOSED:													
3.	Demand (kW)	228,758	241,946	229,828	241,885	339,750	395,220	428,082	423,947	381,233	332,350	243,084	273,510	3,759,593
4.	Energy (kWh)	146,273,571	132,931,300	134,682,241	143,312,577	170,346,466	193,752,003	228,861,111	219,575,722	188,610,607	161,488,464	142,763,555	162,728,916	2,025,326,533
	PRESENT REVENUE :													
5.	Demand(Full Rqt.)	$ 1,902,772	$ 2,039,489	$ 1,975,819	$ 2,016,349	$ 2,743,642	$ 3,185,673	$ 3,491,683	$ 3,439,884	$ 3,010,891	$ 2,738,492	$ 2,066,086	$ 2,357,506	$ 30,968,286
6.	Demand (Partial Rqt.)	348,831	371,280	337,960	368,213	567,392	662,292	701,624	701,762	662,592	534,139	366,520	399,840	$ 6,022,445
7.	Fixed Charge	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	688,556	$ 8,262,672
8.	Energy	2,909,381	2,644,004	2,678,830	2,850,486	3,389,584	3,853,666	4,552,047	4,367,361	3,751,465	3,212,006	2,839,567	3,236,678	40,285,075
9.	ACC GOR Assessment	8,851	8,668	9,121	9,094	11,219	12,890	17,785	17,315	15,214	13,418	11,076	12,495	147,146
10.	Fuel Bank Surcharge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
11.	Total	5,858,391	5,751,997	5,690,286	5,932,698	7,400,393	8,403,077	9,451,695	9,214,878	8,128,718	7,186,611	5,971,805	6,695,075	85,685,624
12.	Average Cost ($/KWH)	0.04005	0.04327	0.04225	0.04140	0.04344	0.04337	0.04130	0.04197	0.04310	0.04450	0.04183	0.04114	0.04231
	PROPOSED REVENUE:													
13.	Demand(Full Rqt.)	$ 2,109,263	$ 2,260,815	$ 2,190,237	$ 2,235,166	$ 3,041,384	$ 3,531,385	$ 3,870,605	$ 3,813,184	$ 3,337,635	$ 3,035,675	$ 2,290,298	$ 2,613,342	$ 34,328,989
14.	Demand (Partial Rqt.)	549,565	565,500	514,750	578,543	864,200	1,008,743	1,068,650	1,068,860	1,009,200	813,552	558,250	609,000	$ 9,208,813
15.	Fixed Charge	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	705,795	$ 8,469,540
16.	Energy	3,029,326	2,753,007	2,789,269	2,968,004	3,527,875	4,012,604	4,739,713	4,547,414	3,906,126	3,344,426	2,956,634	3,370,118	41,944,516
17.	ACC GOR Assessment	12,502	12,283	12,093	12,685	15,928	18,144	20,313	19,832	17,545	15,470	12,723	14,264	183,782
18.	Fuel Bank Surcharge	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
19.	Total	6,406,451	6,297,400	6,212,144	6,500,193	8,155,182	9,276,671	10,405,076	10,155,085	8,976,301	7,914,918	6,523,700	7,312,519	94,135,640
20.	Average Cost ($/KWH)	0.04380	0.04737	0.04612	0.04536	0.04787	0.04788	0.04546	0.04625	0.04759	0.04901	0.04570	0.04494	0.04648
	CHANGE IN TOTAL COST:													
21.	REVENUE	$ 548,060	$ 545,403	$ 521,858	$ 567,495	$ 754,789	$ 873,594	$ 953,381	$ 940,207	$ 847,583	$ 728,307	$ 551,895	$ 617,444	$ 8,450,016
22.	PERCENT INC.	9.36%	9.48%	9.17%	9.57%	10.20%	10.40%	10.09%	10.20%	10.43%	10.13%	9.24%	9.22%	9.86%

Arizona Electric Power Cooperative, Inc.

Analysis of Revenue by Detailed Class

2003- Annualized

AVERAGE COST-CLASS A MEMBERS

LINE NO.		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	AVG COST ($/kWh) - PRESENT RATES													
1.	AEC	$ 0.04029	$ 0.04120	$ 0.04173	$ 0.04036	$ 0.04643	$ 0.04629	$ 0.04507	$ 0.04604	$ 0.04403	$ 0.04401	$ 0.03868	$ 0.03859	$ 0.04286
2.	DVEC	$ 0.04032	$ 0.04359	$ 0.04088	$ 0.04223	$ 0.04456	$ 0.04506	$ 0.04000	$ 0.04044	$ 0.04694	$ 0.04916	$ 0.04470	$ 0.04317	$ 0.04329
3.	GCEC	$ 0.04107	$ 0.04316	$ 0.03984	$ 0.04373	$ 0.04542	$ 0.04577	$ 0.04232	$ 0.04363	$ 0.04956	$ 0.04933	$ 0.04350	$ 0.03976	$ 0.04407
4.	MEC	$ 0.03841	$ 0.04143	$ 0.04446	$ 0.03987	$ 0.04137	$ 0.04132	$ 0.03780	$ 0.03788	$ 0.04034	$ 0.04071	$ 0.03932	$ 0.03824	$ 0.03988
5.	SSVEC	$ 0.04120	$ 0.04376	$ 0.04065	$ 0.04094	$ 0.04155	$ 0.04174	$ 0.04140	$ 0.04215	$ 0.04252	$ 0.04483	$ 0.04301	$ 0.04271	$ 0.04216
6.	TEC	$ 0.04102	$ 0.04615	$ 0.04277	$ 0.04458	$ 0.04887	$ 0.04746	$ 0.04571	$ 0.04728	$ 0.04594	$ 0.04869	$ 0.04440	$ 0.04425	$ 0.04586
7.	AEPCO	$ 0.04005	$ 0.04327	$ 0.04225	$ 0.04140	$ 0.04344	$ 0.04337	$ 0.04130	$ 0.04197	$ 0.04310	$ 0.04450	$ 0.04183	$ 0.04114	$ 0.04231
	AVG COST ($/kWh) - PROPOSED RATES													
8.	AEC	$ 0.04332	$ 0.04433	$ 0.04492	$ 0.04340	$ 0.05013	$ 0.04998	$ 0.04862	$ 0.04970	$ 0.04747	$ 0.04745	$ 0.04154	$ 0.04144	$ 0.04617
9.	DVEC	$ 0.04337	$ 0.04700	$ 0.04400	$ 0.04549	$ 0.04807	$ 0.04863	$ 0.04299	$ 0.04349	$ 0.05069	$ 0.05315	$ 0.04820	$ 0.04651	$ 0.04665
10.	GCEC	$ 0.04421	$ 0.04652	$ 0.04284	$ 0.04715	$ 0.04903	$ 0.04942	$ 0.04557	$ 0.04702	$ 0.05359	$ 0.05333	$ 0.04688	$ 0.04273	$ 0.04751
11.	MEC	$ 0.04313	$ 0.04656	$ 0.04993	$ 0.04501	$ 0.04758	$ 0.04792	$ 0.04359	$ 0.04368	$ 0.04667	$ 0.04659	$ 0.04400	$ 0.04289	$ 0.04546
12.	SSVEC	$ 0.04435	$ 0.04719	$ 0.04374	$ 0.04406	$ 0.04474	$ 0.04495	$ 0.04454	$ 0.04538	$ 0.04579	$ 0.04835	$ 0.04634	$ 0.04600	$ 0.04540
13.	TEC	$ 0.04415	$ 0.04984	$ 0.04609	$ 0.04810	$ 0.05281	$ 0.05129	$ 0.04932	$ 0.05107	$ 0.04958	$ 0.05263	$ 0.04787	$ 0.04771	$ 0.04949
14.	AEPCO	$ 0.04380	$ 0.04737	$ 0.04612	$ 0.04536	$ 0.04787	$ 0.04788	$ 0.04546	$ 0.04625	$ 0.04759	$ 0.04901	$ 0.04570	$ 0.04494	$ 0.04648

SCHEDULE H-
2A
7/7/2004

Arizona Electric Power Cooperative, Inc.
Pro Forma Member Fuel Cost Adjuster Base

LINE NO.		PER BOOKS 12/31/2003	RECLASSIFICATIONS AND ADJUSTMENTS	AS ADJUSTED 12/31/2003
	SUMMARY OF FUEL COSTS:			
	COAL FIRED STEAM PLANT:			
1	FUEL COAL	$ 44,521,523	$ (2,491,992)	$ 42,029,531
2	FUEL GAS	2,309,354	-	2,309,354
3	FUEL OIL	-	-	-
4	LESS: FIXED FUEL COSTS	549,137	-	549,137
5	SUBTOTAL	46,281,740	(2,491,992)	43,789,748
	INTERNAL COMBUSTION PLANT:			
6	FUEL GAS	15,454,731	-	15,454,731
7	FUEL OIL	9,809	-	9,809
8	LESS: FIXED FUEL COSTS	1,435,208		
9	SUBTOTAL	14,029,332	0	14,029,332
10	TOTAL FUEL COSTS	60,311,072	(2,491,992)	57,819,080
	PURCHASED POWER ENERGY COSTS:			
	FIRM PURCHASES:			
11	CRSP	309,547	-	309,547
12	PACIFICORP	443,461	(443,461)	-
13	PARKER DAVIS	217,629	-	217,629
14	PUBLIC SERVICE COMPANY OF NEW MEXICO	1,963,061	-	1,963,061
15	PANDA GILA RIVER	1,134,573	-	1,134,573
16	SPINNING RESERVES	-	-	-
17	TOTAL FIRM PURCHASES:	4,068,271	(443,461)	3,624,810
18	NONFIRM PURCHASES:	5,570,921	889,807	6,460,728
19	TOTAL PURCHASED ENERGY COSTS	9,639,192	446,346	10,085,538
20	NON-FIRM WHEELING EXPENSES	77,291	0	77,291
21	TOTAL PURCHASED ENERGY & FUEL COSTS	70,027,555	(2,045,646)	67,981,909
22	TOTAL SYSTEM SALES - KWH	3,314,521,018	(32,608,373)	3,281,912,645
23	SYSTEM COST PER KWH	$ 0.02113		$ 0.02071
	LESS:			
	NON-TARIFF SALES FUEL RECOVERY:			
	CONTRACTUAL SALES FUEL RECOVERY:			
24	TRICO PD SIERRITA	862,555	-	862,555
25	CITY OF MESA	1,014,702	(1,014,702)	-
26	CITY OF MESA(PSA)	2,725,136	(67,785)	2,657,351
27	ED-2 POWER SUPPLY	1,411,281	(35,092)	1,376,189
28	SRP	13,488,162	(449,057)	13,039,105
29	SAFFORD	232,895	-	232,895
30	MOHAVE SCHEDULE B SALES	-	142,921	142,921
31	SUBTOTAL	19,734,731	(1,423,715)	18,311,016
	OTHER SALES FUEL RECOVERY:			
32	NON-FIRM SALES	7,531,083	863,183	8,394,266
33	SUBTOTAL	7,531,083	863,183	8,394,266
34	TOTAL NON-TARIFF SALES FUEL RECOVERY	27,265,814	(560,532)	26,705,282
35	MEMBER FUEL COSTS	$ 42,761,741	$ (1,485,114)	$ 41,276,627
36	CLASS A MEMBER KWH SALES	2,027,671,490	(2,344,957)	2,025,326,533
37	MEMER FUEL COST ADJUSTOR BASE - $/KWH	$ 0.02109		$ 0.02038

Arizona Electric Power Cooperative, Inc.
Typical Bill Analysis

SCHEDULE H-4

7/7/2004

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.

Bill Count

7/7/2004

NOT APPLICABLE

Arizona Electric Power Cooperative, Inc.
AEPCO
P.O. Box 670 • Benson, Arizona 85602-0670 • Phone 520-586-3631

BEFORE THE ARIZONA CORPORATION COMMISSION

TESTIMONY

IN SUPPORT OF

THE ARIZONA ELECTRIC POWER COOPERATIVE, INC.

RATE APPLICATION

DOCKET NO. E-01773A

JULY 2004

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A

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

INTRODUCTION

Q. Please state your name and business address.

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

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

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

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

A. I hold a B.S. Degree in Business Administration from Kansas State University and an M.B.A. from the University of Missouri. My entire 29-year career has been spent working directly or indirectly for electric cooperative utilities. I began my employment with AEPCO in 1982 and was promoted to the position of Chief Financial Officer in May 1990.

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

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

BACKGROUND

Q. Mr. Minson, please describe AEPCO.

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

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

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

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

Q. Does AEPCO have other members?

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

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

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

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

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

Q. How is AEPCO governed?

A. AEPCO's Board of Directors is comprised of 14 members, who oversee all aspects of the Cooperative's operations. Twelve of the Board members (two per Class A Member) are designated as the distribution cooperatives' representatives to the AEPCO Board by the distribution cooperative Boards, which in turn are elected by their retail member/consumers. The remaining two Board members represent the Class B and Class C Members.

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

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

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

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

OVERVIEW OF FILING

Q. Please summarize AEPCO's rate request.

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

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

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

Q. Do all Class A Members get the benefit of whatever cost recoveries and margins are made on sales to others by AEPCO?

A. Yes. The first step in our rate determination process is to credit to the benefit of all members whatever cost recoveries and margins that AEPCO has been able to achieve in its contract sales and economy sales to others. Thus, the proceeds of these sales to others are used to reduce each distribution cooperatives' cost of service and, in turn, the rates for generation service which their retail members have to pay.

Q. Can you estimate the impact that AEPCO's proposed rate increase would have on the retail member/owner's bill?

A. That is difficult because the distribution cooperatives have different retail rates and varying rate structures. However, generation service generally accounts for about 40% of the costs of the total delivered rate at retail. Assuming a residential rate of $0.10 per kwh, on average four cents of that rate would be attributable to AEPCO's generation service. Therefore, a residential consumer using 750 kwh per month would see approximately a $3.00 increase in the monthly bill as a result of this rate request.

Q. What are the primary reasons for the requested rate increase?

A. Obviously, AEPCO is subject to the same kind of inflationary pressures which affect all utilities and businesses in general. But, generally there are three primary cost areas which are driving this request. First, we have recently seen higher coal costs and, in particular, much higher and very volatile natural gas costs. Second, most of our generating assets at Apache are now 25 or more years old. Although the embedded costs associated with that plant are comparatively very low, as the units age, the overhaul and maintenance costs associated with them increase. Third, to meet increased demand and growth on the distribution cooperatives' systems, in October 2002, AEPCO brought on line Gas Turbine #4 at the Apache Station. This rate filing reflects the fixed costs associated with the interest, depreciation, insurance and property taxes associated with that new plant addition. It also reflects the fixed costs associated with a $10 million coal blending facility designed to reduce AEPCO's burned cost of coal. As a result, we have also reduced the burned cost of coal from approximately $1.65 MMBtu in the test year to $1.45 MMBtu.

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

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

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

A. Yes--markedly so. Referring to Schedule A-2, AEPCO suffered an actual net margin loss of slightly more than $7 million dollars in the 2003 test year. Although approximately $3.8 million of this loss was attributable to a one-time retirement write-off of certain ash pond facilities at Apache, adjusted test year results still produced a net margin loss of $4.5 million and a DSCR of only .70--far below our RUS mortgage minimum requirement of 1.0. Our operating results and margin experience have not improved for the first six months of 2004 and we expect another operating margin loss this year.

Q. Mr. Minson, do these financial results emphasize the need for rapid rate relief from the Commission?

A. Yes, for three primary reasons. First, as a non-profit cooperative, AEPCO has no stockholder class which can absorb operating losses. We must move quickly to bring our operating revenues back in line with our cost of service. Second, the RUS requires both prospective and retrospective TIER and DSCR results in determining AEPCO compliance under the terms of its mortgage and 7 CFR 1710.114. Given last year's achieved results and this year's expected performance, AEPCO will not meet those tests and must move quickly to remedy that situation. Third, AEPCO has been making steady progress in strengthening its equity position. Following a series of financial setbacks in the 1980's, including the loss of 125 MWs of copper industry load, AEPCO's <u>negative</u> equity position exceeded $51 million in 1990. While continuing to reduce member rates, we were able to improve that position substantially through a series of aggressive cost cutting and other cost saving measures to roughly $18 million in <u>positive</u> equity by

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

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

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

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

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

OTHER ISSUES

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

A. Yes, we are. An exhibit describing the revised depreciation rates is attached as Exhibit DCM-1. We would ask that the Commission approve these revised rates.

Q. Why is AEPCO seeking a revision in the rates?

A. In evaluating the financing for the construction of Gas Turbine #4, AEPCO commissioned a condition assessment study for its Apache Station Units 2 and 3 and associated common facilities. Prior to this study, their expected life was only through the year 2020. That would have limited the length of the loan we could have received for Gas Turbine #4 to roughly 15 years, which would have increased the costs of the plant and financing considerably. The Units have been well maintained and we believed their condition would support an extended life assessment. Burns & McDonnell conducted the condition assessment study and a copy of the Executive Summary of their report is attached as Exhibit DCM-2. The report concludes that the "units should provide service through the year 2035." Therefore, we would ask that the Commission approve the revised depreciation rates as reflected in Exhibit DCM-1.

Q. Do the revised depreciation rates have the effect of reducing the members' overall cost of service?

A. Yes. As Mr. Pierson will testify, the revised depreciation rates lower costs in the test year by slightly more than $1.47 million dollars.

Q. Mr. Minson, is AEPCO also requesting a purchased power and fuel adjustment clause in this proceeding?

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

CONCLUSION

Q. Do you have any concluding remarks?

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

Q. Does that conclude your testimony?

A. Yes, it does.

16662-1/1183015v2

Exhibit DCM-1

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Exhibit DCM-1

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

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

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

**: RUS approved these rates July 1995

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

Exhibit DCM-2

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

APACHE GENERATING STATION UNITS 2 & 3

Major Power Generation

And

Plant Electrical Equipment
Condition Assessment Report

EXECUTIVE SUMMARY

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

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

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

For long term planning Burns & McDonnell makes the following recommendations of equipment that may need to be refurbished due to normal time of service life. These recommendations are based on utility experience for similar units. It is recommended to have OEM inspections of major components such as the boiler, turbine/generator, boiler feed pumps and fans, and to perform an in-depth investigation prior to replacing and refurbishing existing equipment. The steam generators can be expected to have the lower water walls, the superheat and reheat sections changed out during the remaining life of the station. Steam turbine blades and bucket replacement, control valves, stop valves, and intercept valves could be expected to be refurbished, replaced, or upgraded. An overall plant controls system for Units 2 & 3 can be expected to replace the current controls of the units. High pressure heaters No. 5 & 6 for Unit 2 and heater No. 6 for Unit 3 are recommended to be changed to stainless steel in the next five years. Condenser tubes for both units should be replaced in the future. The air preheater cold end baskets should be changed out in the future. Controls upgrade for the bottom ash and fly ash system should be done in the future. Both units cooling towers will need to have the fill, support structures, and drift eliminators replaced in the next five years. In the event that Powder River Basin coal is brought on site, it is strongly recommended to install a coal yard and bunker room wash down system and replace the existing coal dust collection system with high capacity dust collection system. The auxiliary transformers for both units are operating at close to their design temperatures at an altitude higher than design. It is recommended to replace these transformers in the next 10 to 15 years.

B

DIRECT TESTIMONY AND EXHIBITS

OF

STEPHEN PAGE DANIEL

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

July, 2004

BEFORE THE
ARIZONA CORPORATION COMMISSION

Direct Testimony And Exhibits
Of
Stephen Page Daniel

On Behalf Of
Arizona Electric Power Cooperative, Inc.

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. Please outline your formal education.

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

Q. To what professional organizations do you belong?

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

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

A. My primary responsibilities involve providing rate and regulatory services related to electric utility industry matters and consulting services with regard to electric system power supply planning, including strategic planning for transmission resources and access and electric industry restructuring/deregulation matters.

Q. Please briefly describe your professional experience.

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

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

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

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

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

Q. Have you previously testified before regulatory commissions?

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

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

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

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

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

Q. Have you previously provided consulting services to AEPCO?

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

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

A. Yes.

II. <u>NATURE AND PURPOSE OF TESTIMONY</u>

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

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

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

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

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

A. Yes.

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

A. I reviewed various information such as the following:

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

III. COST CLASSIFICATION AND ALLOCATION

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

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

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

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

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

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

A. Electric utilities plan and construct generation facilities and enter into firm purchased power contracts to meet their capacity requirements (*i.e.*, firm load obligations), including adequate planning reserves, at the time of system peaks. The system planning and operations decisions also consider interchange capabilities with other entities. The planning, construction (or purchase implementation) and operation of the system is influenced by many factors, including: the types and sizes of units; daily, weekly, monthly and seasonal load variations; scheduled maintenance of facilities and necessary planning and operating reserves for contingencies; and unscheduled (or forced) outages.

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

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

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

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

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

- Timing of the commercialization of new power supply resources.

V. <u>AEPCO SYSTEM ASSESSMENT</u>

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

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

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

A. System Load Data

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

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

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

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

Q. Please describe the results of your load analysis.

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

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

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

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

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

B. <u>System Reserves</u>

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

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

C. <u>Commercialization of Installed Generating Capability and Long-Term Purchases</u>

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

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

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

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

VI. APPROPRIATE COST OF SERVICE DEMAND ALLOCATION METHODOLOGY

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

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

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

In light of these factors, AEPCO's monthly system peaks are all sufficiently important with regard to the planning and operation of the AEPCO system to be considered in the demand cost allocation methodology to be selected for cost-of-service purposes. Based on our analysis of all AEPCO loads and individual member distribution system loads, we have recommended that AEPCO adopt the 12-CP demand cost allocation methodology as the most appropriate for determining its cost of service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

16662-1/1183048v3

Exhibit SPD-1

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

PROFESSIONAL MEMBERSHIP: Institute of Electrical and Electronics Engineers

EXPERIENCE:

2/86-Present

Executive Vice President and principal of GDS Associates, Inc.

1/71-2/86

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

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

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

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

REGULATORY EXPERIENCE:

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

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

EXPERT TESTIMONY IN COURT PROCEEDINGS:

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

AFFIDAVITS IN COURT PROCEEDINGS:

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

OTHER EXPERT APPEARANCES:

(1) Kansas Legislature Electric Industry Restructuring Task Force

PUBLICATIONS

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

LECTURES/SEMINARS:

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

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

Exhibit SPD-2

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

I. INTRODUCTION

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

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

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

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

[3] Salt River Project ("SRP").

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

II. COST CLASSIFICATION

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

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

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

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

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

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

III. FACTORS FOR EVALUATION

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

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

> The pattern of monthly peak loads both in absolute MWs and with each monthly peak expressed as a percentage of the annual peak;
>
> The relationship of the monthly peaks in the non-peak months to the monthly peak(s) in any discernible peak season;
>
> The ratio of the lowest monthly peak to the annual system peak;
>
> The pattern of scheduled maintenance;
>
> Monthly generating reserves (*i.e.*, percentages of reserves remaining available to the utility after factoring in pre-scheduled maintenance and firm opportunity sales to and firm purchases from other entities); and
>
> Timing of the commercialization of new power supply resources.

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

IV. AEPCo SYSTEM ASSESSMENT

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

A. System Load Data

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

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

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

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

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

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

B. System Reserves

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

C. Installed Generating Capability and Long-Term Purchases

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

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

It should be noted that AEPCo also has two (2) hydro-based purchased power resources that have a summer-season characteristic to the scheduled deliveries. This characteristic is a function of the associated project marketing plans which take into account the water availability from the hydro resources. These seasonal purchased power characteristics, therefore, should not be considered strong indicators of an AEPCo summer peaking characteristic warranting a seasonal-based demand allocation methodology.

V. APPROPRIATE COST OF SERVICE DEMAND ALLOCATION METHODOLOGY

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

AEPCo's system peak occurs during the summer (*i.e.*, June-September) months.

AEPCo's summer-seasonal peaking characteristic is not sufficiently pronounced to warrant a seasonal-based demand cost allocation methodology (*e.g.*, 1-CP, 2-CP, 3-CP or 4-CP).

AEPCo's monthly non-summer peak loads are at or above 70% of its annual peak load and in many of those non-summer months are 85-95% of the annual system peak.

The nature of AEPCo's generation capability and purchased power arrangements reflect the importance of all monthly AEPCo peaks, particularly when considering pre-scheduled maintenance of resources.

AEPCo's seasonal long-term purchases are relatively modest and appear directed at meeting the portion of the annual peak in the summer that exceeds the non-summer peaks.

Although AEPCo has installed only one new generator in the last six (6) years, that unit was placed in commercial operation in October 2002, rather than at the beginning of the summer season, thus indicating that the summer peak is not the sole driver of new resource installations.

In light of the above observations, it is reasonable to conclude that AEPCo's monthly system peaks are all sufficiently important with regard to the planning and operation of the AEPCo system to be considered in the demand cost allocation methodology to be selected for cost-of-service purposes. Under the circumstances, it is recommended that AEPCo adopt the 12-CP demand cost allocation methodology as the most appropriate for determining the cost of service on the AEPCo system.

Attachment A

Summary of AEPCO's Total Coincident Actual Loads - MW

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

Attachment B

AEPCO
2003 Analysis of Monthly Peak Demands

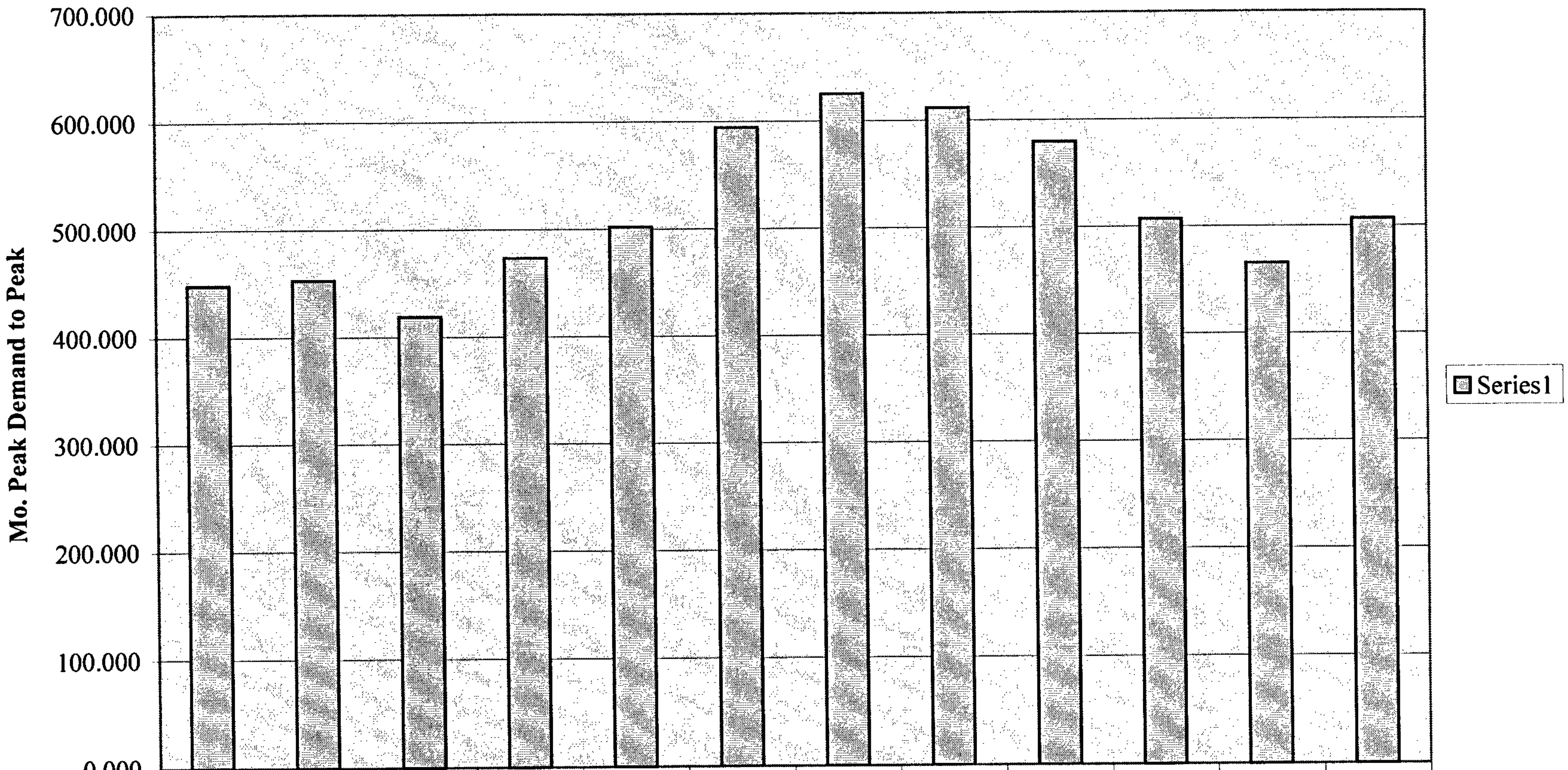
Relationship of Total System Monthly Peaks to Annual Peak

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

Test based upon Line 13: 5-Year Average Data	**Test 1**	**Average June-September Peaks**	**96.5%**
		Average All-Other Months	**77.0%**
		Difference	**19.5%**
	Test 2	**Lowest Average Peak to Peak**	**70.1%**
	Test 3	**Average 12 Peaks to Peak**	**83.5%**

(1) Monthly loads taken from Attachment A.

AEPCO - 1998 Peak Demands



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

AEPCO - 1999 Peak Demands

Attachment C
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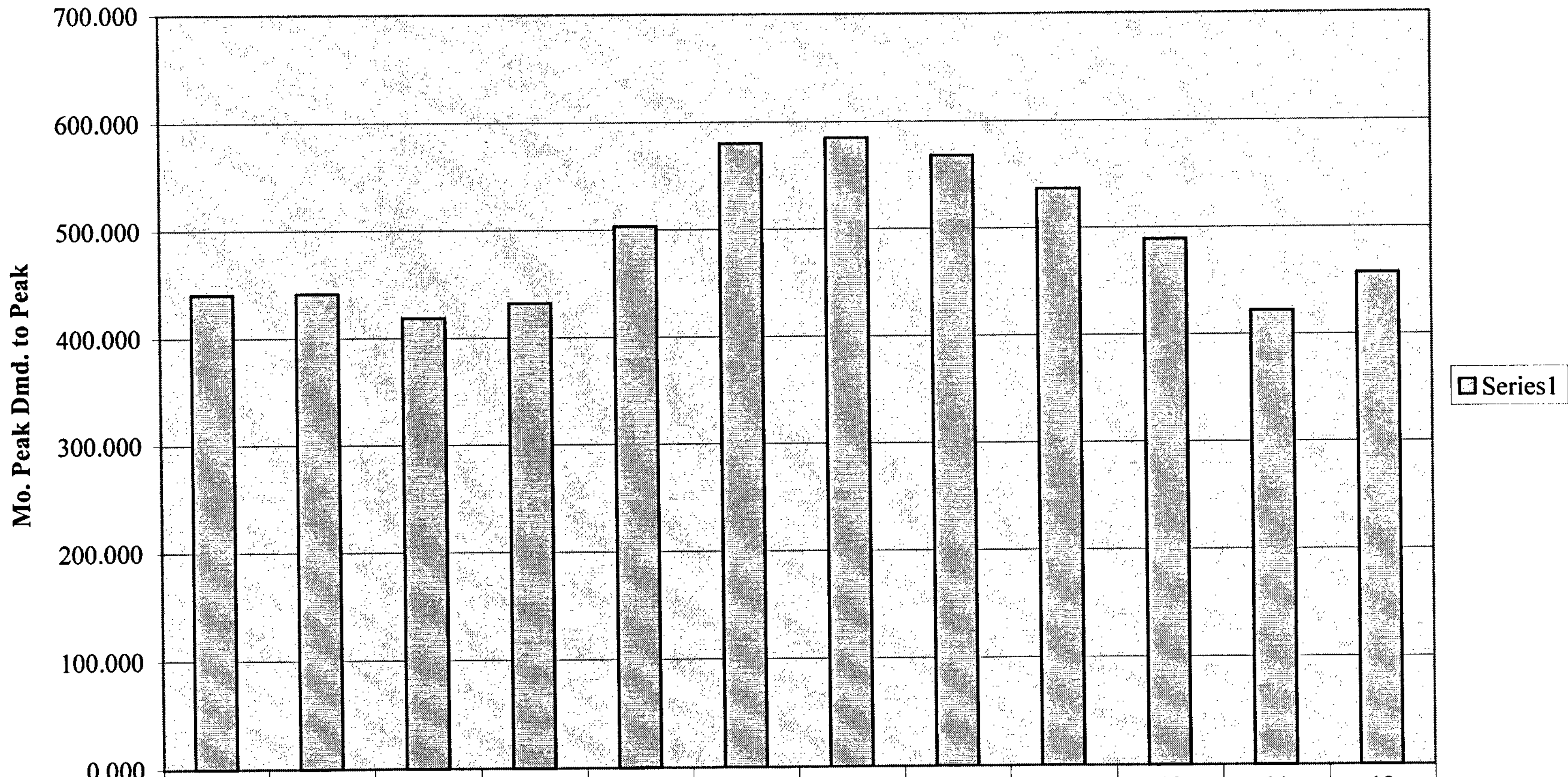
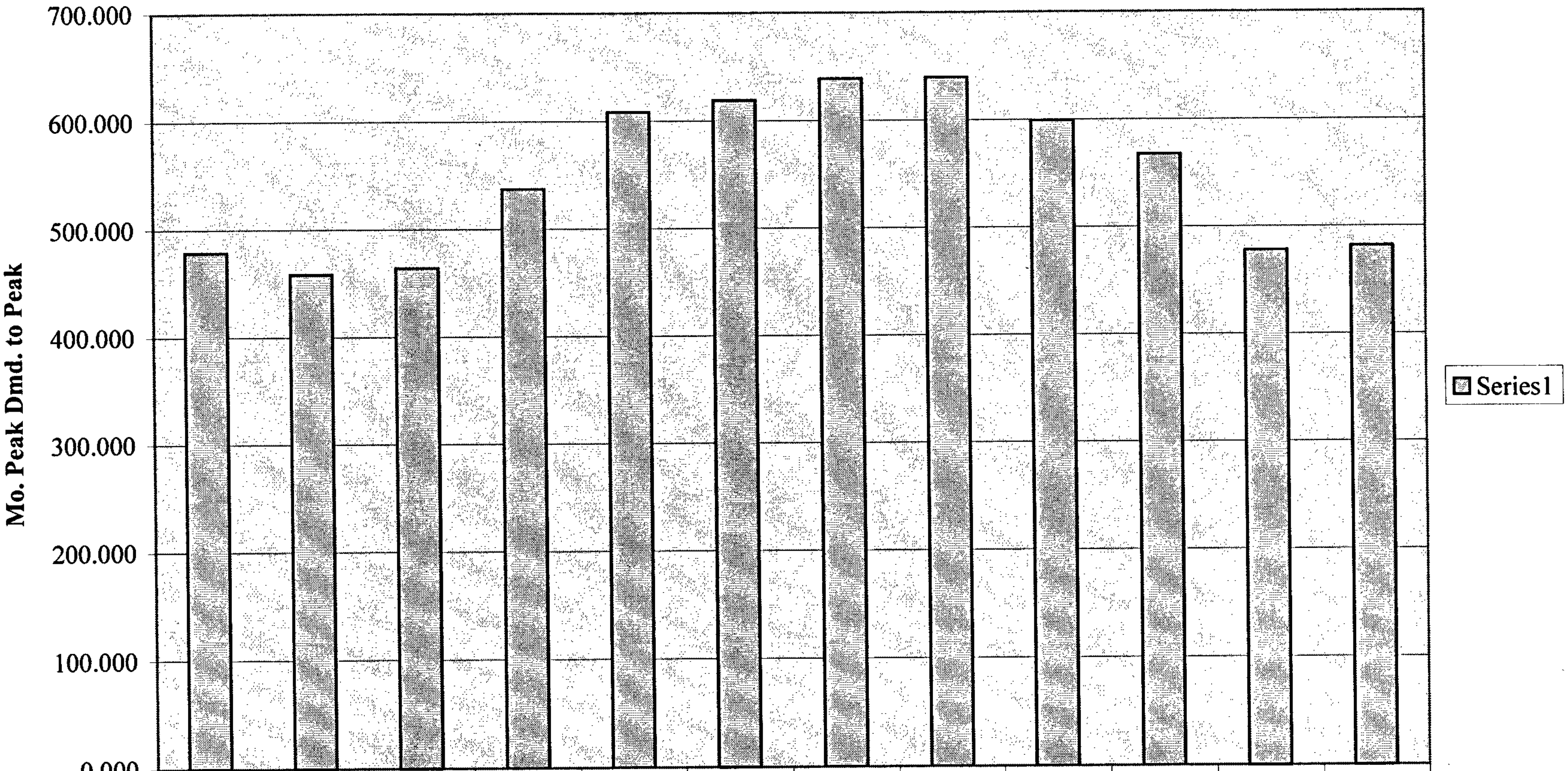


	1	2	3	4	5	6	7	8	9	10	11	12
Series1	440.592	441.512	418.653	432.413	503.442	580.050	585.253	568.347	536.896	489.116	422.141	457.080

Month - 1999

AEPCO - 2000 Peak Demands



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

Month - 2000

AEPCO - 2001 Peak Demands

Attachment C
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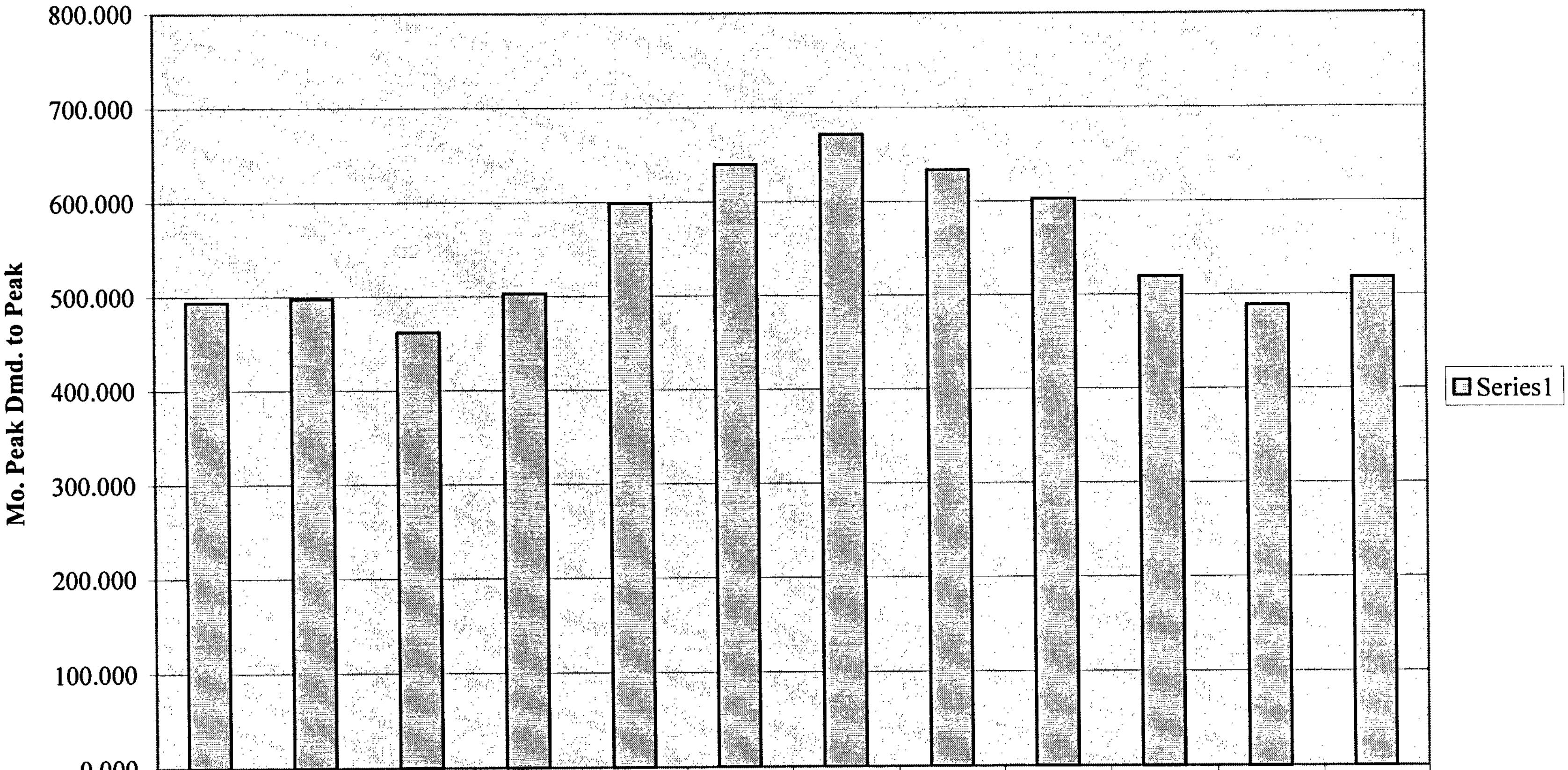

	1	2	3	4	5	6	7	8	9	10	11	12
Series1	494.189	497.681	462.057	503.290	598.675	639.689	671.588	633.780	602.680	519.665	488.851	518.307

Month - 2001

AEPCO - 2002 Peak Demands

Attachment C
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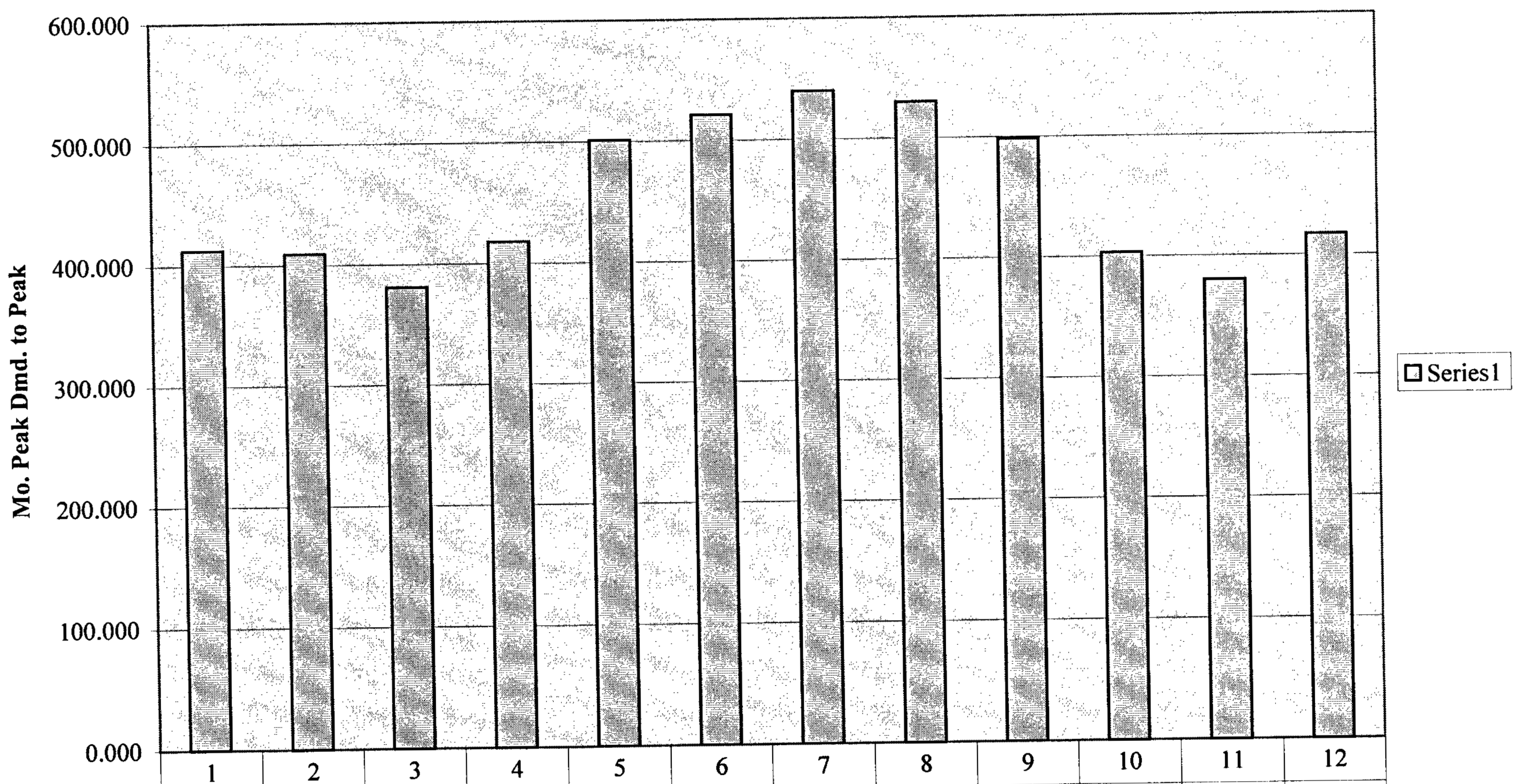
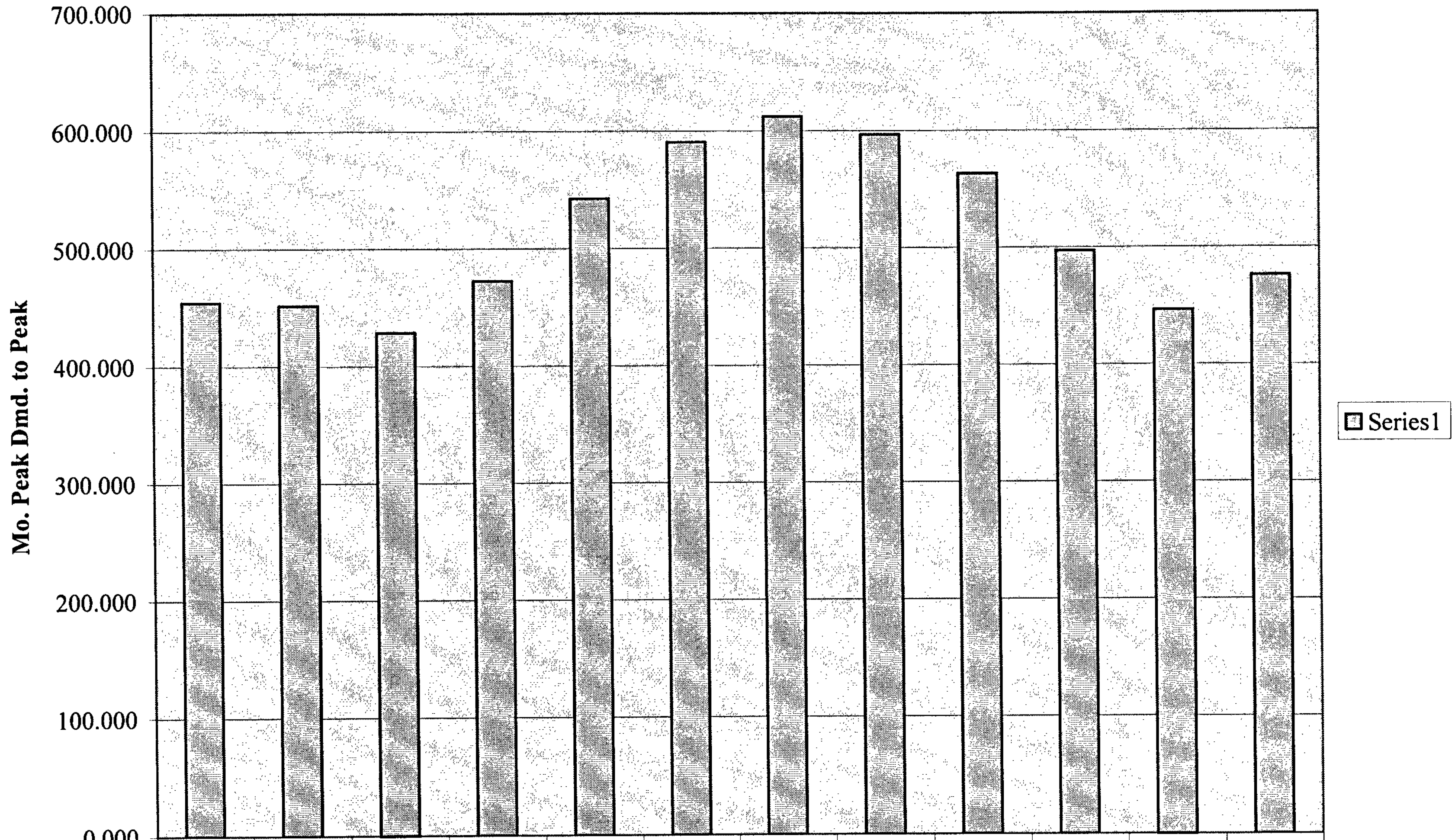


	1	2	3	4	5	6	7	8	9	10	11	12
Series1	412.849	409.456	381.253	418.004	501.220	521.179	539.968	530.082	498.654	403.060	379.998	417.299

Month - 2002

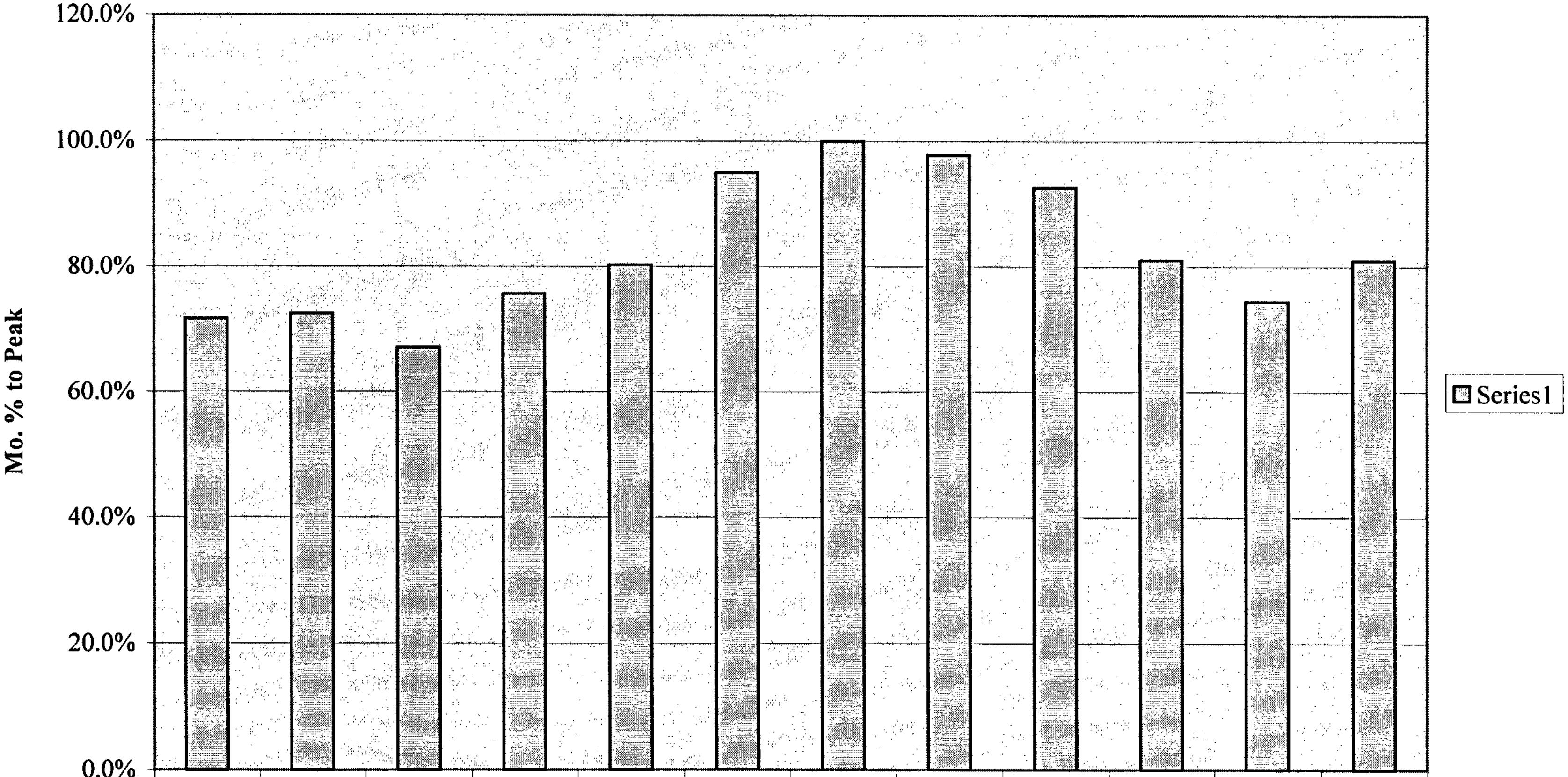
AEPCO Five-Year Avg. 1998-2002
Peak Demands



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

Month - 1998-2002 Five-Year Average

AEPCO 1998 - Peak %s

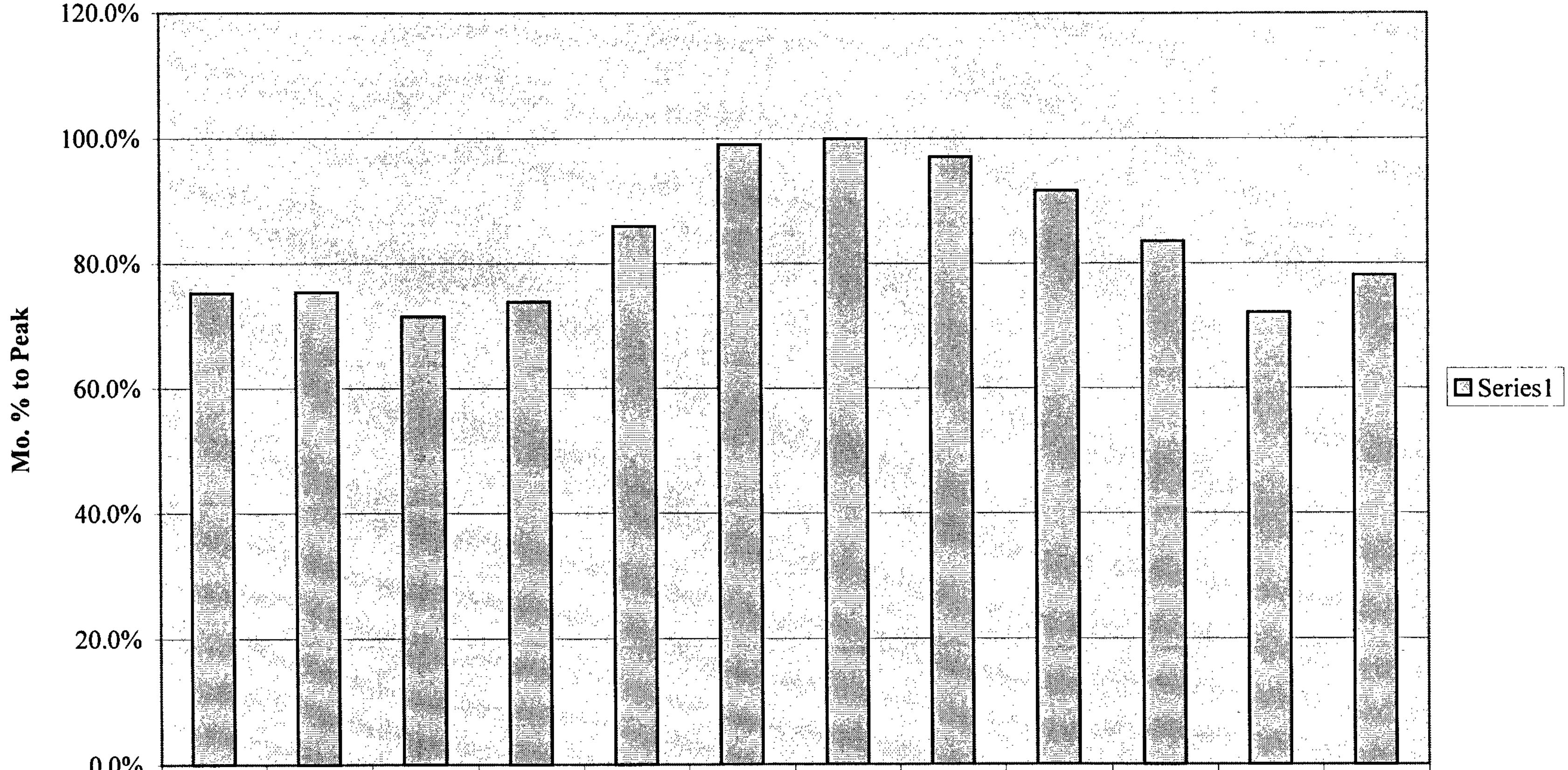


	1	2	3	4	5	6	7	8	9	10	11	12
Series1	71.7%	72.5%	67.0%	75.7%	80.3%	95.0%	100.0%	97.8%	92.7%	81.1%	74.4%	81.1%

Month - 1998

AEPCO - 1999 Peak %s

Attachment D
Page 2 of 6

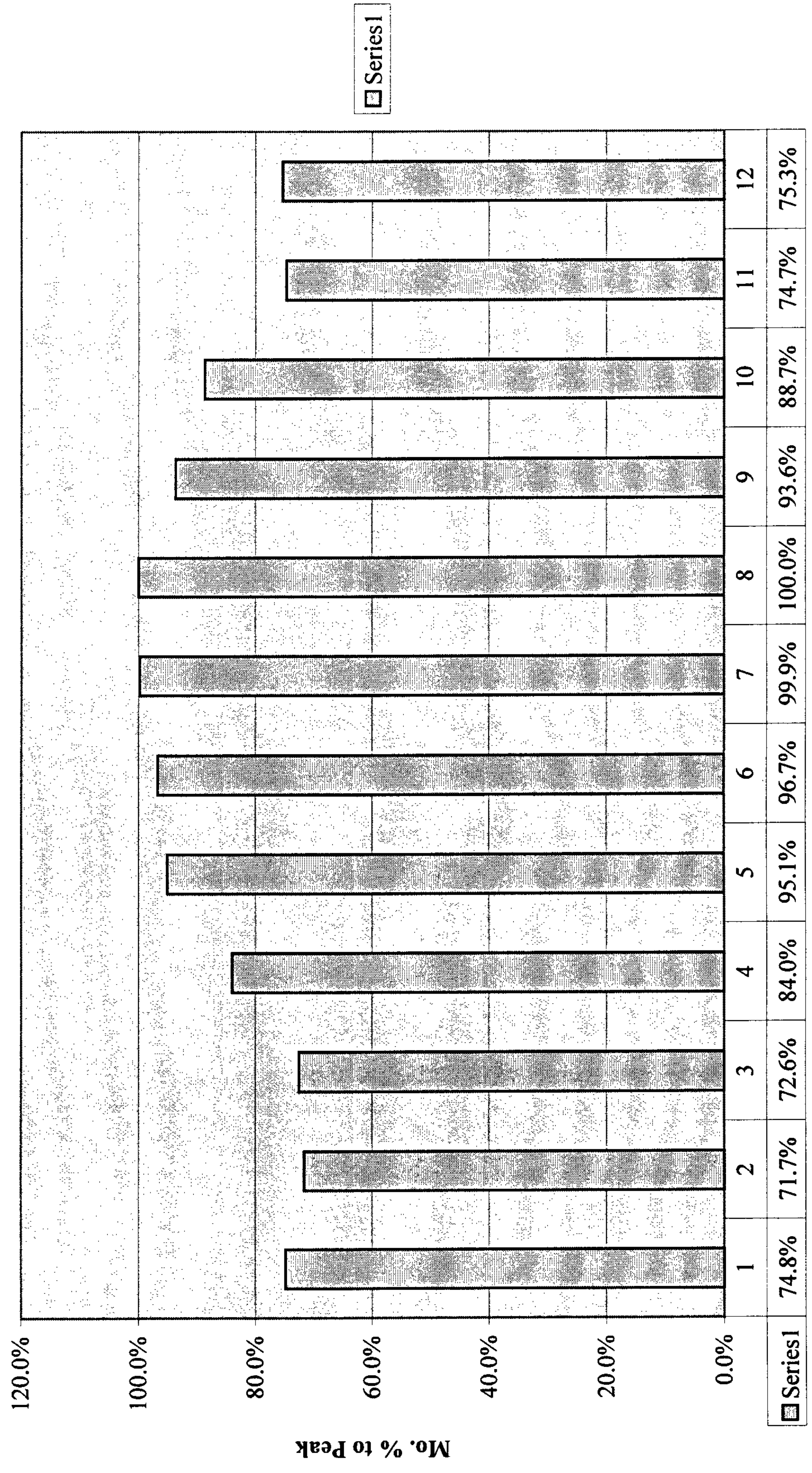


	1	2	3	4	5	6	7	8	9	10	11	12
Series1	75.3%	75.4%	71.5%	73.9%	86.0%	99.1%	100.0%	97.1%	91.7%	83.6%	72.1%	78.1%

Month - 1999

Attachment D
Page 3 of 6

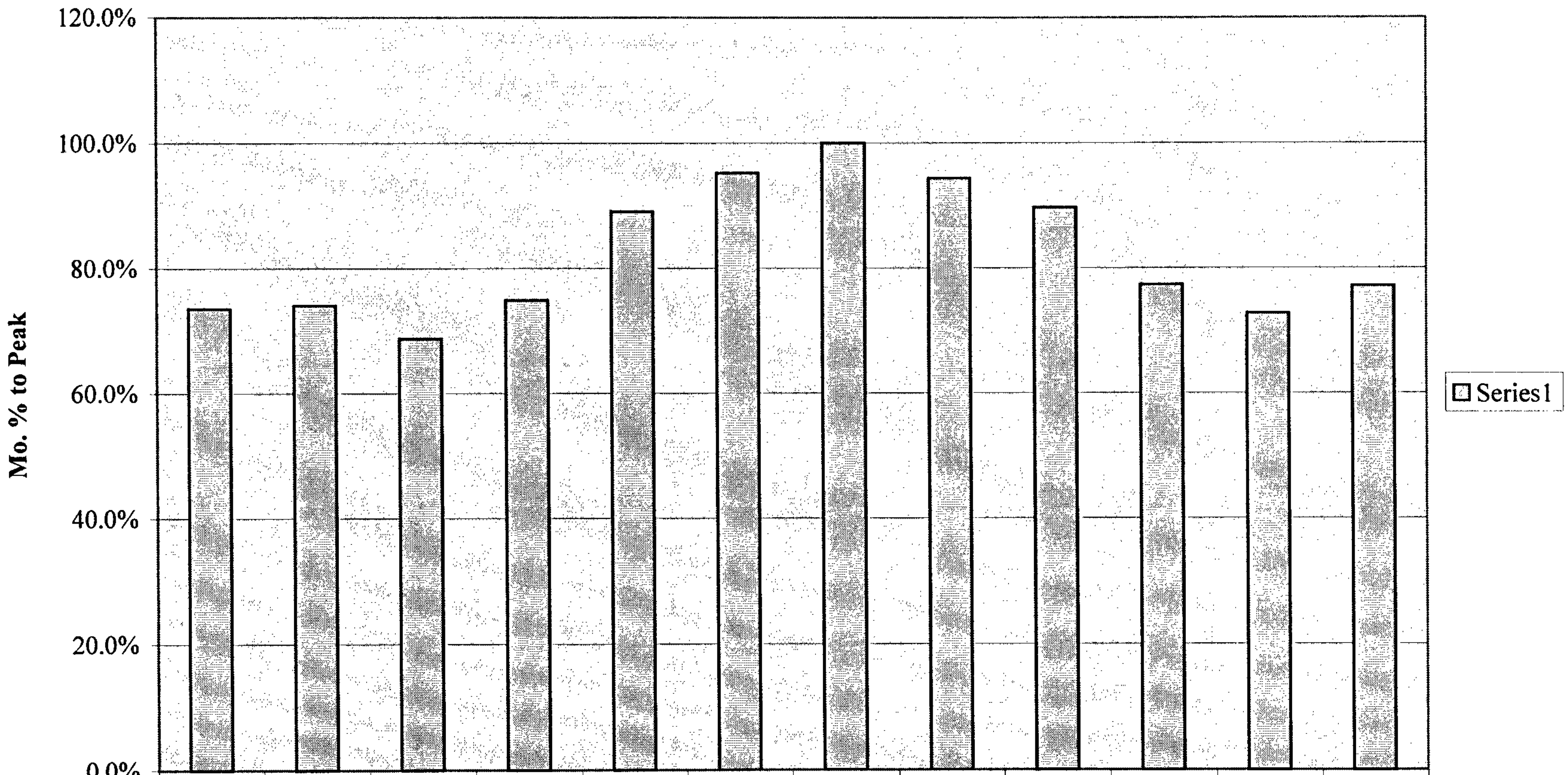
AEPCO - 2000 Peak %s



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

AEPCO - 2001 Peak %s

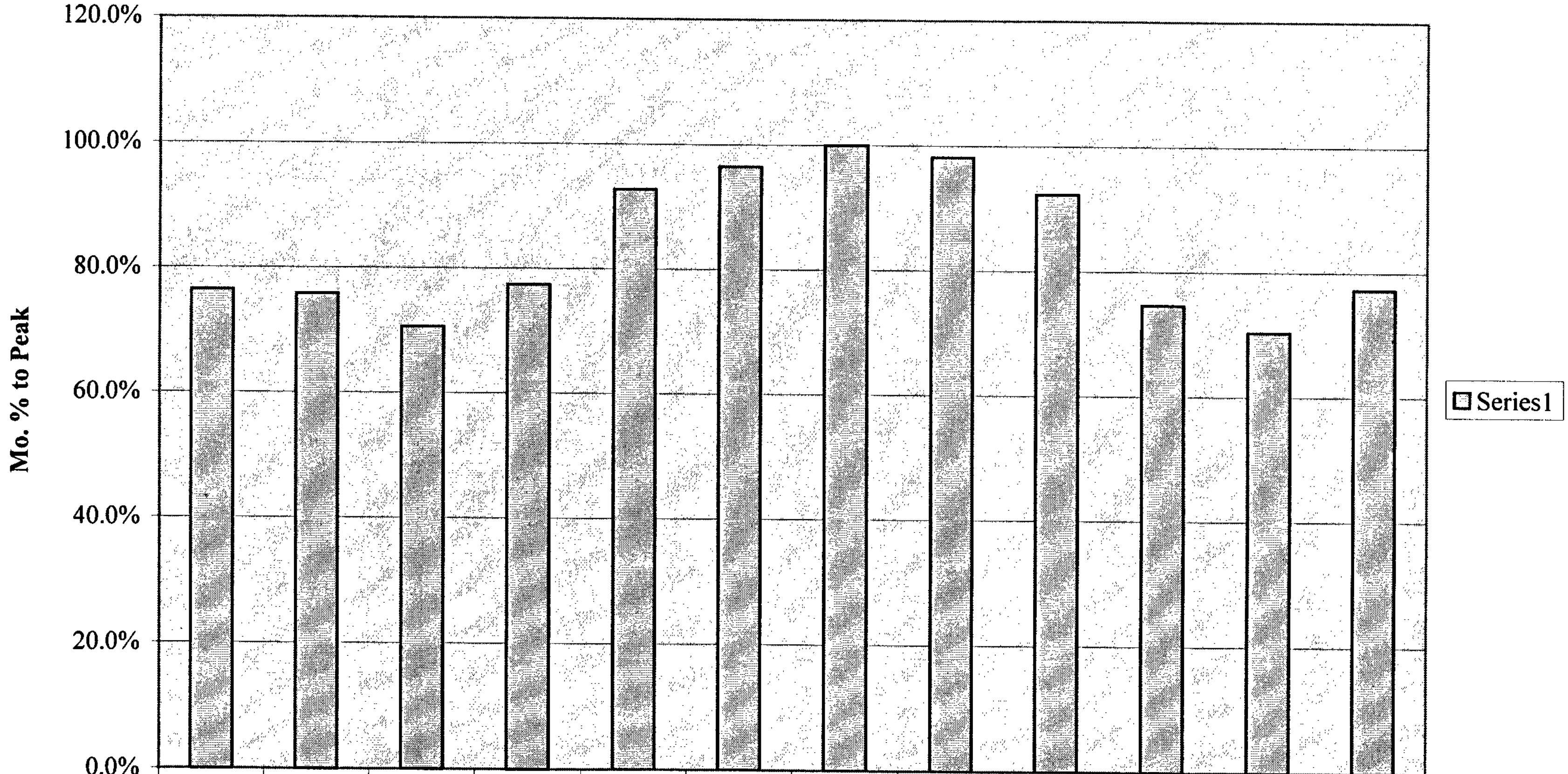
Attachment D
Page 4 of 6



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

Month - 2001

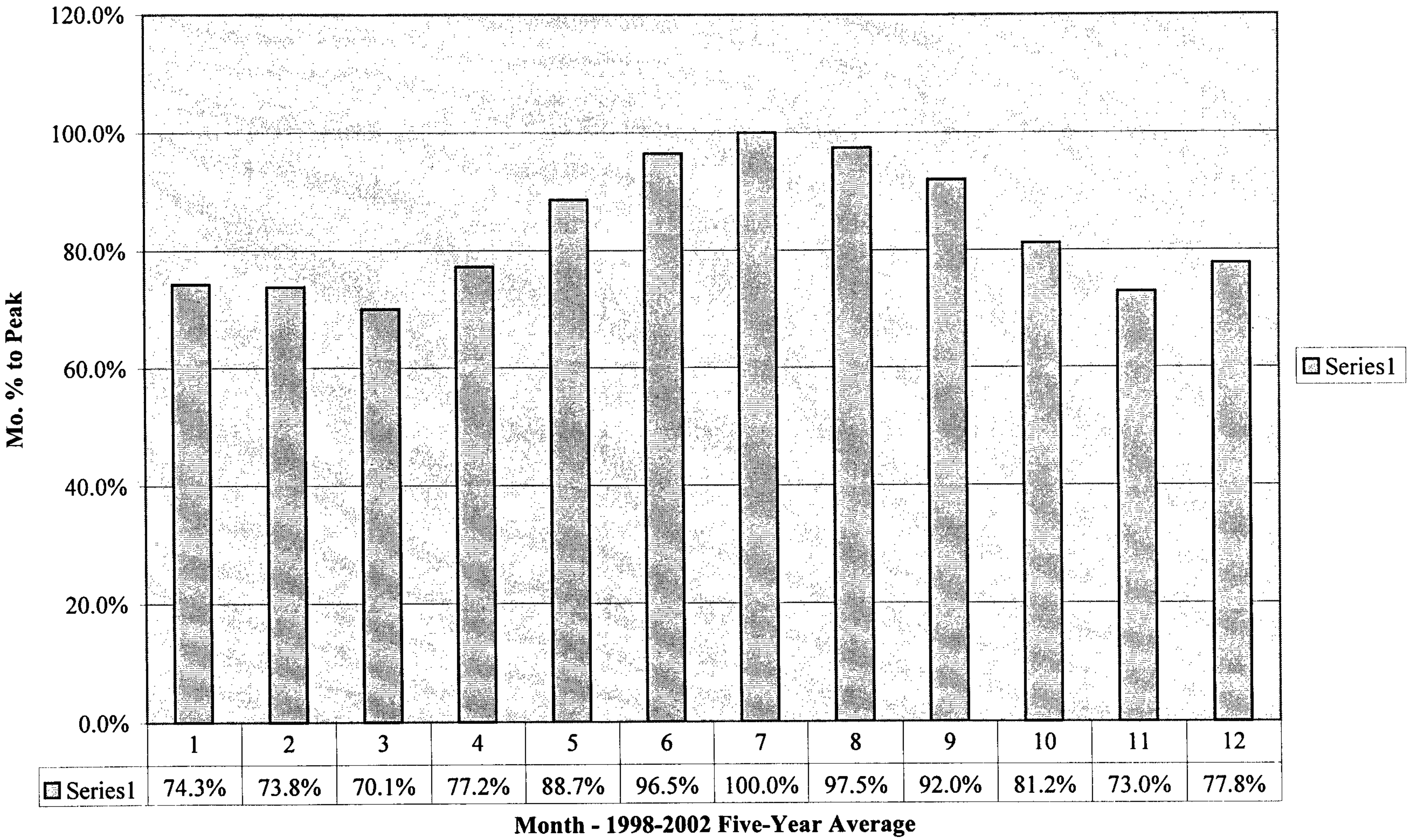
AEPCO - 2002 Peak %s



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

Month - 2002

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



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

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

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

Attachment F

5-Year Average Reserves as % of Load and Capacity

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

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

Attachment F

5-Year Average Reserves as % of Load and Capacity

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

Exhibit SPD-2

C

DIRECT TESTIMONY OF

GARY E. PIERSON

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Q. Please state your name and address for the record.

A. My name is Gary E. Pierson. My business address is Sierra Southwest Cooperative Services, Inc., P. O. Box 2165, 1000 S. Highway 80, Benson, Arizona, 85602.

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

A. I am employed by Sierra Southwest Cooperative Services, Inc. ("Sierra Southwest") as the Manager of Financial Services. As Manager of Financial Services, I am responsible for directing and administrating the treasury, cash management and risk management functions for Sierra Southwest. In addition, as a result of staffing agreements that Sierra Southwest has with Arizona Electric Power Cooperative, Inc. ("AEPCO") and Southwest Transmission Cooperative, Inc. ("SWTransco"), I am responsible for the same functions as well as rate design/implementation for these two cooperatives as well.

Q. Please briefly summarize your educational and professional background.

A. I graduated in 1974 from Western State College, Gunnison, Colorado, with a Bachelor of Arts Degree specializing in Accounting and Business Administration. In June 1974, I was employed by Colorado-Ute Electric Association, Inc. and worked there for seventeen years in various positions in the areas of ratemaking, budgeting, financial forecasting and power requirements studies. In May 1992, I was employed by AEPCO as a Rates Administrator in the Financial Services Division where my principal responsibilities and duties included the preparation of rate filings, the design of rate structures and rate analysis studies. In 1993, I was promoted to the position of Manager of Financial Services. In August 2001, as a result of the restructuring of AEPCO into three separate cooperatives, I was employed by Sierra Southwest in the same position. I have testified as an expert witness before the Public Utilities Commission of the State of Colorado, the United States Bankruptcy Court in Denver, Colorado and the Arizona Corporation Commission in connection with various proceedings involving rate cases.

Q. What is the purpose of your testimony in this proceeding?

A. I will testify in support of the application for a general rate filing for AEPCO. My testimony is primarily directed to the financial schedules, which were filed in support of the application (the "Schedules").

Q. Please describe the Schedules.

A. They are a multi-page exhibit containing the Schedules A-H that are described in A.A.C. R14-2-103 and are divided into the following categories:

Schedule Category	Section Tab
Summary Schedules	A
Rate Base Schedules	B
Test Year Income Statements	C
Cost of Capital Schedules	D
Financial Statements and Statistical Schedules	E
Projections and Forecast Schedules	F
Cost of Service Analysis Schedules	G
Effect of Proposed Tariff Schedules	H

Q. Please describe Section A of the Schedules.

A. Section A contains the summary schedules that pertain to the rate filing. Schedule A-1 shows the computation of the increase in gross revenue requirements that results from the development of the financial schedules. An increase in revenues from AEPCO's Class A Member Distribution Cooperatives ("Class A Members") of $8,450,016 results from the change in the existing all-requirements Class A member rates from a Demand Rate of $12.44/kW to $13.79/kW and the Energy Rate from $0.01989/kWh to $0.02071/kWh. Also, the partial-requirement contract rates for Mohave Electric Cooperative, Inc. increase from a Fixed Charge of $688,556 per month to $705,795 per month; the O&M Rate moves from $4.76/kW month to $7.25/kW month; and the Energy Rate adjusts from $0.01989/kWh to $0.02071/kWh. The coverage ratios produced by this proposal are a

Times Interest Earned Ratio ("TIER") of 1.29 and a Debt Service Coverage Ratio ("DSCR") of 1.05, as discussed in the testimony of Mr. Minson of AEPCO and Mr. Edwards of the National Rural Utilities Cooperative Finance Corporation ("CFC"). The $8,450,016 represents an increase of 9.86% over the revenues generated by present rates. Current rates produced an approximately $4.5 million loss in the 2003 test year, as adjusted. Based upon a test period adjusted rate base of $222,147,011, the revenue requirements generate a rate of return of 7.39%.

Schedule A-2 sets forth summary results of operations for the calendar years 2001, 2002 and 2003 and the adjusted test year with present rates and with proposed rates. As I mentioned, on an adjusted test year basis, column 5 shows that AEPCO had a net margin loss of $4,527,610, a TIER of 0.67 and a DSCR of 0.70 in 2003. Schedule A-3 summarizes AEPCO's capital structure and capitalization ratios for calendar years 2001 and 2002 as well as the test year 2003. Schedule A-4 provides data concerning construction expenditures, net plant additions and gross utility plant in service and Schedule A-5 summarizes AEPCO's changes in financial position.

Q. Please describe Section B of the Schedules.

A. Section B contains supporting rate base schedules that are used in the AEPCO rate filing. Schedule B-1 summarizes the components of the original cost rate base of $222,147,011 as of December 31, 2003. That includes gross utility plant in service of $389,603,749, accumulated depreciation and amortization of $186,190,519, allowances for working capital of $16,778,408 and deferred debits of $1,955,373. Schedule B-2 reflects that adjustments were made to the original cost rate base for the inclusion of the coal blending facility at Apache Station that will be discussed later in my testimony. Schedules B-3 and B-4 concerning reconstructed cost net of depreciation ("RCND") rate base have not been completed. AEPCO, as a non-profit cooperative, stipulates to the use of its original cost rate base as its fair value rate base.

Schedule B-5, page 1 of 5, provides the computation of working capital by components, which add up to total working capital of $16,778,408 and the remaining pages show the calculation of the different components. Schedule B-5, page 2 of 5, concerning the calculation of cash working capital, has not been completed. In Docket U-1773-92-214, AEPCO was directed, in future rate cases, to provide a lead/lag study if AEPCO desired to include cash working capital as a part of its total working capital. In consultation with senior management, it was decided not to incur the considerable time and expense of the lead/lag study and AEPCO stipulates to the use of a zero value for its cash working capital.

Q. Please describe Section C of the Schedules.

A. Section C contains adjusted test year income statements and supporting schedules to the income statement. Schedule C-1, pages 1 through 4, provides the adjusted test year income statement for the test year 2003 and the as-adjusted test year income statement for the test year 2003. Pages 1 and 2 of Schedule C-1 provide per books and reclassified test year income statements for 2003. The first column represents the revenues and expenses of

AEPCO during the test year, which is the twelve months ended December 31, 2003. As noted on Schedule C-1, page 2, AEPCO had an operating margin <u>loss</u> last year of $5,202,265, non-operating margins of $1,963,753 and an extraordinary loss of $3,810,335 that together produced a net margin <u>loss</u> of just over $7 million. The second column represents reclassification adjustments that are made to the test period which have a zero effect on the net margins of AEPCO.

Schedule C-2, pages 1 through 10, provides detail on the reclassification and pro forma adjustments to revenues and expenses. They are as follows:

<u>Reclassification Adjustments – Schedule C-2, Pages 1 and 2</u>:

1. <u>SWTransco Revenue Reclassification</u> – This adjustment reclassifies the network service, system control and load dispatching and regulatory asset charge revenues that AEPCO collects from its all-requirements members and then pays to SWTransco. These revenues and charges are a pass-through at cost of network services provided by SWTransco to AEPCO's all-requirements Class A Members. Therefore, AEPCO has removed them from its cost of service. The net effect of this reclassification on net margins is zero.

2. <u>Property Tax Reclassification</u> – This adjustment reclassifies property taxes, which are recorded in various operation and maintenance expense categories according to Rural Utilities Service ("RUS") accounting procedures to taxes so that these expenses can be shown separately for ratemaking purposes. The net effect of this reclassification on net margins also is zero.

3. <u>Mohave Schedule B Reclassification</u> – This adjustment reclassifies certain extraordinary revenues billed and collected from Mohave Electric Cooperative, Inc. ("Mohave") during the test period pursuant to Schedule B of the Partial Requirements Agreement between AEPCO and Mohave. These Schedule B charges are reclassified from Class A Member revenue to the non-Class A, non-firm and non-member revenue category. These Schedule B Revenues should be stated as non-member revenues since their pricing is not directly tied to Class A Member rates. Again, the net effect of this reclassification on net margins is zero.

<u>Pro Forma Adjustments – Schedule C-2, Pages 3 through 10</u>:

1. <u>Mohave Schedule A Adjustment</u> – This adjustment removes revenues and expenses associated with certain sales to third parties made by Mohave during the extended outage of Steam Turbine Unit 3, using energy from AEPCO resources at the AEPCO tariff rate. Under the Partial Requirements Agreement between AEPCO and Mohave, Mohave may make sales to third parties whenever available power and energy under Schedule A exceeds its native load. However, these sales during the extended outage of Steam Turbine 3 actually resulted in AEPCO generating from higher cost resources and purchasing more expensive replacement power to supply Mohave, but selling that power to Mohave at the lower contract energy rate. AEPCO is in the process of negotiating an amendment to the Partial Requirements Agreement to address this issue and, accordingly, has made an adjustment to the test year to remove its effect. AEPCO has removed $382,774 of revenues and $884,010 of expenses associated with these

sales during the extended outage. The effect of this adjustment is to increase net margins by $501,236.

2. City of Mesa Contract Adjustment – This adjustment annualizes the test year effect of the termination of the 17.5 MW sales contract to the City of Mesa that occurred on May 31, 2003. AEPCO has reviewed the hourly generation and purchased power that was dispatched in connection with this contract and made assumptions as to sales to other sources or decreased generation and purchased power expenses that would have occurred if this contract had not been in effect for the first five months of the test year. In addition, AEPCO has reduced the associated charges that were paid to SWTransco to wheel the power associated with this contract. The effect of this adjustment also results in an increase in net margins of $356,072.

3. Ancillary Services Revenue Adjustment – This adjustment removes $76,586 of ancillary services revenue that AEPCO collected from SWTransco during the test period in connection with 100 MW of non-firm transmission service to Morenci Water & Electric ("MW&E"). Having completed its tap line to the Greenlee substation, MW&E will be wheeling this power over the Tucson Electric Power, not SWTransco system and, therefore, AEPCO will not be collecting this ancillary services revenue. This adjustment reduces net margins by $76,586.

4. Labor Expense Adjustment – This adjustment annualizes labor expense and associated payroll taxes and benefits to reflect wage increases that occurred during the test period. The net effect of this adjustment decreases net margins by $520,342.

5. Fuel Expense Adjustment – This adjustment reduces the test year coal expense to $1.45 per MMBtu which AEPCO expects to achieve as a result of the new coal blending facility installed at Apache Station. The adjustment reduces production fuel expenses by $1,534,274 but is offset by reductions in revenues of $551,934. The revenue reductions result from the pass-through of these coal cost reductions in the charges to Salt River Project, City of Mesa and Electrical District 2 by AEPCO under sales agreements which are tied to cost formulas. The net effect of this adjustment is to increase net margins by $982,340.

6. SO2 Allowance Adjustment – This adjustment also reduces production expenses by $167,069 to reflect the decreased requirement for purchases of SO2 Allowances that is expected to occur as a result of the new coal blending facility at Apache Station. The net effect of this adjustment is to increase net margins by $167,069.

7. Ash Sales Credit Adjustment – This adjustment increases production expense to reflect the reduced levels and price of sales of ash from Apache Station. The coal blending facility will not produce an ash quality sufficient to provide the same volume of sales achieved during the test period. In addition, due to the decreased volume of ash, the price will be lower as well. This adjustment reduces net margins by $820,611.

8. Coal Blender Adjustment – This adjustment reflects the fixed charges such as long-term interest expense, depreciation and taxes associated with the addition of the coal blending facility at Apache Station. This adjustment decreases net margins by $1,005,214.

9. GT4 FFB Financing Adjustment – This adjustment annualizes the increased interest expense of $1,190,178 associated with Gas Turbine 4 to reflect the drawing of $28.9 million of RUS guaranteed FFB financing in order to repay the $23.7 million of CFC interim financing and to reimburse AEPCO for $5.2 million of general funds expended during construction. The effect of this adjustment is to decrease net margins by $1,190,178.

10. Depreciation Adjustment – This adjustment annualizes the depreciation expense associated with plant placed in service during the test year and also reflects the proposed lower deprecation rates for Steam Turbines 2 and 3 which are discussed in Mr. Minson's testimony. This adjustment increases net margins by $1,473,878.

11. Purchased Power Adjustment – This adjustment annualizes the purchase of power from TECO Panda Gila River at a rate of $4.84/kW month and replacement power purchases for the PacifiCorp purchased power contract that terminated during the test period. The effect is to decrease net margins by $88,139.

12. Wheeling Expense Adjustment – This adjustment annualizes transmission expense for (a) wheeling expenses associated with the Western Area Power Administration ("WAPA") West Wing – Marana Transmission Agreement that became effective on January 1, 2004, (b) the El Paso Palo Verde – West Wing Transmission Agreement that became effective on July 1, 2003 and (c) the proposed increase in point-to-point transmission rates that SWTransco charges AEPCO for wheeling associated with contractual sales to Salt River Project, City of Mesa and Electrical District 2 as well as

point-to-point service from Apache – Mead. This adjustment decreases net margins by $1,329,483.

13. Interest Expense Adjustment – This adjustment annualizes interest expense based upon debt balances and interest rates at the end of the test year and decreases interest expense by $375,891. Net margins are increased by the same amount.

14. Other Deductions Adjustment – $266,003 of write-offs of preliminary survey and investigation charges and prior period adjustments should not be reflected in the test year. This adjustment increases net margins by $266,003.

15. Asset Retirement Obligation Adjustment – This adjustment removes the extraordinary loss item of $3,810,335 resulting from the required recognition of an Asset Retirement Obligation to close the combustion waste disposal ponds at Apache. AEPCO proposes to recover this expense over a ten-year period and therefore has included $381,034 in other deductions expense. The ten-year amortization period matches the ten-year unsecured financing that AEPCO will obtain from CFC to finance the cost of the closure. The effect of this adjustment is to increase net margins by $3,429,301.

As indicated on page 10 of Schedule C-2, these pro forma adjustments in expenses and revenues resulted in an increase in net margins of $2,521,237. Finally, Schedule C-3 lists the computation of the gross revenue conversion factor.

Q. Please describe Section D of the Schedules.

A. Section D contains information on AEPCO's cost of capital for the calendar years 2001, 2002 and 2003. Schedule D-1 sets forth the computed cost of capital as of December 31, 2003 for the actual and projected test year. Invested debt capital amounted to $213,294,620 with a composite cost rate of 5.60%. Schedule D-2 shows long-term and short-term debt balances by lender that comprise the total, the interest rates associated with the debt balances and the computation of the composite cost rate for three years. Schedules D-3 and D-4 on preferred stock and common equity are obviously not applicable to AEPCO since it is a member-owned, non-profit cooperative.

Q. Please describe Section E of the Schedules.

A. Section E sets forth financial statements and statistical schedules for the calendar years 2003, 2002 and 2001. Schedule E-1 provides comparative balance sheets and Schedule E-2 shows comparative income statements. Schedule E-3 provides a comparative statement of changes in financial position and Schedule E-4 reflects changes in equity. Schedule E-5 provides detail of utility plant additions during the test year and balances as of December 31, 2002 and 2003. Schedule E-6 is not applicable to AEPCO. Schedule E-7 provides AEPCO operating statistics while Schedule E-8 lists taxes charged to operations. Attached to my testimony as Exhibit GEP-1 are the Consolidated Financial Statements which include the Independent Auditor's Report to the AEPCO Board of Directors, dated March 25, 2004. It contains the information that is referenced in Schedule E-9.

Q. Please describe Section F of the Schedules.

A. Section F contains various projections and forecast schedules. Schedule F-4 discusses certain assumptions used in developing the projections contained in the previous F schedules.

Q. Please describe Section G of the Schedules.

A. Section G contains schedules presenting cost of service information. Schedule G-1 provides a cost of service summary for the pro forma adjusted test year based upon present rates, while Schedule G-2 provides a cost of service summary for the pro forma adjusted test year based upon developed rates. Schedule G-2A, page 1, shows the derivation of revenue requirements and proposed rates, which have been developed based upon the recommended 12 CP methodology discussed in Mr. Daniel's testimony. Lines 17 through 20 of Schedule G-2A, page 1, show the development of the proposed energy rate of $0.02071/kWh. Lines 21 through 39 of Schedule G-2A, page 1, show the development of the proposed Mohave O&M rate of $7.25/kW month and the O&M component of the all-requirements demand rate of $7.29/kW month. Lines 8 though 16 of Schedule G2-A, page 1, show the development of the proposed Mohave Fixed Charge of $705,795 and the fixed component of the all-requirements demand rate of $6.50/kW month. Schedule G-2A, page 2, compares the present rates and proposed rates. Schedules G-3 and G-4 are not applicable to AEPCO. Schedule G-5 provides a distribution of rate base by function.

Schedule G-6 provides a distribution of expenses and revenue credits by function for the test period. Schedule G-7 is not applicable to AEPCO. Schedule G-8 information is shown on Schedule H-2A.

Q. Please describe Section H of the Schedules.

A. Section H shows the effect of the proposed rate tariff schedules on the revenues generated by sales to the Class A Members. Schedule H-1 summarizes the revenues generated by present rates and the proposed rates for the pro forma test year 2003. Schedule H-2, page 1, compares revenues generated by present and proposed rates for each of the Class A Members. Schedule H-2, pages 2 through 7, analyzes revenues on a monthly basis from each Class A Member and pages 8 and 9 analyze revenues from all Class A Members. Page 10 shows the average costs in $/kWh to each of the Class A Members based upon present and proposed rates. Schedule H-2A is a schedule displaying the derivation of the proposed pro forma member fuel cost adjustor base factor. Schedules H-4 and H-5 are not applicable to AEPCO because it does not have retail customers.

Q. What is the member fuel cost adjustor that AEPCO is proposing in this proceeding?

A. AEPCO requests that the Commission approve an adjustor mechanism that would be formula-based and would enable the recovery of increases in the fuel and purchased energy costs over which AEPCO has little control. Conversely, the adjustor mechanism would also allow AEPCO to refund any decreases in fuel and purchased energy costs to the Class A

Members. The adjustor would allow a pass-through of fuel and purchased energy cost changes without the time and expense of a rate case and would provide greater margin stability to AEPCO.

Q. How would the proposed member fuel cost adjustor work?

A. We will work with Staff to refine the details of the procedure. But, in concept, we would suggest that the adjustor base shown on Schedule H-2A be established in this rate order as the clause base. Changes from that adjustor base would be tracked monthly and recouped as a positive or negative charge in the next quarter's billing to the Class A Members. Regular reporting would be performed to keep the Commission timely apprised of the status of the clause.

Q. Why is AEPCO requesting the member fuel cost adjustor clause?

A. As shown on Schedule G-6, page 1, AEPCO's fuel and purchased power expenses amounted to almost one-half of AEPCO's total expenses for the adjusted 2003 test year. In recent years, AEPCO has experienced price increases for natural gas that have been very volatile and beyond AEPCO's control. For example, in 2002, the average price of natural gas burned in AEPCO plants was $3.65/MMBtu versus the average price of $5.17/MMBtu in the 2003 test year. That represents a 41% increase in price during only one year. In his testimony, Mr. Minson discusses the fact that this volatility was one of the primary reasons AEPCO suffered a margin loss in the test year. As a non-profit cooperative, AEPCO has no other way to recoup or refund volatile changes in fuel and purchased power other than through the rate making process. Given the time, expense and length of a general rate filing, an adjustor mechanism is appropriate to provide financial stability to AEPCO and reduce costs for both our members and the Commission.

Q. Does this conclude your prepared direct testimony?

A. Yes it does.

1204174/10421-36

Exhibit GEP-1

KPMG

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Consolidated Financial Statements

December 31, 2003 and 2002

(With Independent Auditors' Report Thereon)

KPMG

KPMG LLP
Suite 700, Two Park Square
6565 Americas Parkway NE
PO Box 3990
Albuquerque, NM 87190

Independent Auditors' Report

The Board of Directors
Arizona Electric Power Cooperative, Inc.

We have audited the accompanying consolidated balance sheets of Arizona Electric Power Cooperative and subsidiary (the Cooperative) as of December 31, 2003 and 2002, and the related consolidated statements of revenues and expenses and unallocated accumulated margins, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Arizona Electric Power Cooperative and subsidiary as of December 31, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in note 18 to the consolidated financial statements, the Cooperative adopted Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations,* effective January 1, 2003.

In accordance with *Government Auditing Standards*, we also issued a report dated March 25, 2004 on our consideration of the Cooperative's internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grants. That report is an integral part of the audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

KPMG LLP

March 25, 2004

Arizona Electric Power Cooperative, Inc.
Consolidated Balance Sheets
December 31, 2003 and 2002

Assets	**2003**	2002
Utility Plant:		
Plant in service	**$ 379,651,130**	$ 377,308,895
Construction work in progress	**9,795,448**	2,334,254
Total utility plant	**389,446,578**	379,643,149
Less - Accumulated depreciation	**(185,881,988)**	(179,550,283)
Utility plant, net	**203,564,590**	200,092,866
Investments and Other Property:		
Restricted held to maturity investments	**9,601,463**	7,831,350
Other	**4,002,042**	3,387,182
Total investments and other property	**13,603,505**	11,218,532
Current Assets:		
Cash and cash equivalents-		
General unrestricted	**7,420,590**	7,690,546
Restricted	**4,576,885**	3,995,094
Accounts receivable, less allowance for uncollectible accounts of $1,900,000 for 2003 and 2002	**15,742,346**	19,047,152
Inventories, at average cost:		
Coal	**3,382,266**	12,593,707
Materials and supplies	**5,798,889**	5,199,650
Prepayments and other current assets	**1,246,971**	1,238,923
Notes receivable	**300,465**	348,122
Total current assets	**38,468,412**	50,113,194
Deferred Debits	**5,607,305**	6,309,633
Total Assets	**$ 261,243,812**	$ 267,734,225

See accompanying notes to consolidated financial statements.

Arizona Electric Power Cooperative, Inc.
Consolidated Balance Sheets
December 31, 2003 and 2002

Membership Capital and Liabilities	2003	2002
Membership Capital:		
Membership fees	$ 330	$ 330
Patronage capital	17,803,238	13,904,668
Unallocated accumulated (loss) margins	(7,048,846)	3,898,570
Total membership capital	10,754,722	17,803,568
Long-Term Debt:		
Federal Financing Bank	105,461,962	114,914,607
Cooperative utility trust	26,353,577	27,304,914
Solid waste disposal revenue bonds	17,395,100	17,867,061
Cooperative Finance Corporation	40,798,343	25,534,758
Pollution control revenue bonds	5,673,635	7,392,918
Rural Utilities Service	4,018,036	4,850,508
Total long-term debt	199,700,653	197,864,766
Current Liabilities:		
Member advances	2,529,176	15,278,804
Current maturities of long-term debt	15,801,553	12,553,239
Accounts payable	11,032,390	7,733,171
California power sales refund liability	4,107,752	4,107,752
Accrued property taxes	1,727,253	2,119,162
Accrued interest	854,965	931,190
Other	940,767	622,360
Total current liabilities	36,993,856	43,345,678
Asset Retirement Obligation	3,917,790	-
Deferred Credits	9,876,791	8,720,213
Total Membership Capital And Liabilities	$ 261,243,812	$ 267,734,225

See accompanying notes to consolidated financial statements.

Arizona Electric Power Cooperative, Inc.
Consolidated Statements of Revenues and Expenses and Unallocated Accumulated Margins
For the Years Ended December 31, 2003 and 2002

	2003	2002
Operating Revenues:		
Sales of electric energy-		
Members-		
Class A - Firm	$ 87,642,606	$ 81,886,781
Class A - Non-firm	656,736	2,715,363
Class B	7,411,125	24,078,851
Class C	29,941,937	27,162,485
Non-members	11,916,025	7,381,722
Other, net	13,610,967	12,153,414
Total operating revenues	151,179,396	155,378,616
Operating Expenses:		
Power generation-		
Fuel	62,295,417	56,992,331
Operation	12,615,443	10,671,436
Maintenance	12,714,072	9,694,627
Purchased power and interchange	18,554,563	24,394,795
Administration and general	9,289,462	9,660,298
Depreciation and amortization	8,774,081	7,808,510
Transmission-		
Operation	15,341,229	15,949,082
Maintenance	28,046	15,442
Property and other taxes	3,959,957	4,237,863
Total operating expenses	143,572,270	139,424,384
Operating Margin	7,607,126	15,954,232
Interest Expense	12,226,803	12,584,729
Other Income, net	1,381,166	529,067
Net (Loss) Margin Before Cumulative Effect of Change in Accounting Principle for Asset Retirement Obligation	(3,238,511)	3,898,570
Cumulative Effect of Change in Accounting Principle for Asset Retirement Obligations	(3,810,335)	-
Net (Loss) Margin	(7,048,846)	3,898,570
Unallocated Accumulated Margins, January 1	3,898,570	9,298,056
Patronage Capital Allocation	(3,898,570)	(9,298,056)
Unallocated Accumulated Margins, December 31	$ (7,048,846)	$ 3,898,570

See accompanying notes to consolidated financial statements.

Arizona Electric Power Cooperative, Inc.
Consolidated Statements of Cash Flows
For the Years Ended December 31, 2003 and 2002

	2003	2002
Cash Flows from Operating Activities:		
Net (loss) margin	$ (7,048,846)	$ 3,898,570
Adjustments to reconcile net (loss) margin to net cash flows provided by operating activities-		
Depreciation and amortization	8,692,283	7,726,667
Amortization of deferred charges	94,391	94,334
Amortization of other deferred credits	(337,278)	(337,280)
Cumulative effect of change in accounting principle	3,810,335	-
Changes in assets and liabilities-		
Restricted cash and cash equivalents	(581,791)	1,954,400
Accounts receivable	3,352,463	4,822,758
Inventories	8,612,202	(4,807,128)
Deferred debits	(47,035)	543,392
Accounts payable	3,299,219	(2,299,311)
Accrued interest	(76,225)	(681,892)
Accrued overhaul	1,606,156	(69,618)
Other, net	(349,102)	263,527
Net cash provided by operating activities	21,026,772	11,108,419
Cash Flows from Investing Activities:		
Construction expenditures, net	(11,928,062)	(23,155,056)
Maturities of investments	159,037	717,090
Purchase of investments	(1,929,150)	(86,497)
Patronage capital retirement	66,875	36,512
Net cash used in investing activities	(13,631,300)	(22,487,951)
Cash Flows from Financing Activities:		
Member advances, net	(12,749,628)	1,335,418
Issuance of long-term debt	15,429,150	19,587,886
Retirement of long-term debt	(10,344,950)	(12,505,358)
Net cash (used in) provided by financing activities	(7,665,428)	8,417,946
Net Decrease in Cash and Cash Equivalents	(269,956)	(2,961,586)
Cash and Cash Equivalents, January 1	7,690,546	10,652,132
Cash and Cash Equivalents, December 31	$ 7,420,590	$ 7,690,546
Supplemental Disclosures:		
Cash paid for interest, net of amount capitalized	$ 12,303,028	$ 13,266,621

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Arizona Electric Power Cooperative, Inc.
For The Years Ended December 31, 2003 and 2002

1. Organization:

Arizona Electric Power Cooperative, Inc. is a member owned, non-profit Arizona rural electric generation cooperative organized in 1961 to provide wholesale electric power to its member distribution cooperatives, municipalities, and other customers. Carbon Coal, Inc. ("Carbon"), its wholly owned subsidiary, was organized for the purpose of coal mining. These entities are hereinafter referred to as the Cooperative.

Membership of the Cooperative is restricted to electric utilities. The Cooperative has three classes of Members. Class A Members consist of five distribution cooperatives with all requirements contracts and one distribution cooperative with a partial requirements contract. Class B and Class C Members consist of three electrical utilities with partial requirements contracts. Class A, Class B, and Class C Members are collectively referred to herein as Members.

2. Summary of Significant Accounting Policies:

System of Accounts - The Cooperative maintains its accounts in accordance with policies and procedures as prescribed by the Rural Utilities Service (RUS) in conformity with the Uniform System of Accounts. The Cooperative's accounting policies conform to accounting principles generally accepted in the United States as applied in the case of regulated public utilities and are in accordance with the accounting requirements and rate-making practices of the RUS and the Arizona Corporation Commission (ACC), the regulatory authorities having jurisdiction.

Principles of Consolidation - The accompanying consolidated financial statements include the accounts of Arizona Electric Power Cooperative, Inc. and Carbon, its wholly owned subsidiary. All significant inter-company accounts and transactions have been eliminated in consolidation.

Accounting for the Effects of Regulation - The Cooperative prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, regulated enterprise to reflect the impact of regulatory decisions in its financial statements. It is the Cooperative's policy to assess the recoverability of costs recognized as regulatory assets and the Cooperative's ability to continue to account for its activities in accordance with SFAS No. 71, based on each regulatory action and the criteria set forth in SFAS No. 71.

Utility Plant - Utility Plant is stated at historical cost and includes the costs of outside contractors, direct labor and materials, allocable overhead, and interest charged to construction.

In accordance with the Uniform System of Accounts, the Cooperative capitalizes the interest costs associated with the borrowing of funds used to finance construction work in progress (CWIP). Interest income from construction funds held in trust, if any, are credited to CWIP. Interest costs capitalized on construction projects approximated $69,000 and $335,000 for 2003 and 2002, respectively.

Depreciation is computed on a straight-line basis over the estimated useful lives of depreciable property in accordance with rates prescribed by the RUS, averaging 2.3 percent and 2.2 percent in 2003 and 2002, respectively. Depreciation expense approximated $ 8,692,000 and $7,727,000 for 2003 and 2002, respectively. Minor replacements and repairs are charged to expense as incurred. Retirements of utility plant, together with the cost of removal, less salvage, are charged to accumulated depreciation.

The Cooperative assesses its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the fair value is less than the carrying amount of the asset, a loss is recognized for the difference. The Cooperative has not recorded losses resulting from impairment of its long-lived assets.

Investments - The Cooperative reports its investments in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." SFAS No. 115 provides that the Cooperative classify investments in securities as either trading securities, held to maturity securities, or available-for-sale securities. At December 31, 2003 and 2002, the total investment balances were classified as held to maturity investments and are therefore recorded at amortized cost. (See Note 3).

Cash and Cash Equivalents - For purposes of reporting cash flows, the Cooperative considers all marketable securities with an original maturity of 90 days or less to be cash equivalents. The Cooperative maintains its cash in bank accounts, which, at times, may exceed federally insured limits. The Cooperative has not experienced any losses in such accounts.

Receivables - The Cooperative records its receivables at net realizable value. A bad debt reserve has been established for those accounts that management believes are probable of not being collectible in their entirety.

Inventories - Inventories, consisting of coal, and materials and supplies, are carried at the lower of cost or market. Unit prices are determined using average cost.

Deferred Debits – Deferred debits are recorded at cost and either: 1) amortized over their expected period of benefit or alternate period of time as may be mandated by ACC order, if different, or 2) eliminated upon determination of their ultimate disposition.

Unamortized Debt Costs – Costs incurred for the issuance or repricing of long-term debt are deferred and amortized over the life of the related debt (See Note 7).

Overhaul Costs - Minor overhaul costs are those costs associated with the maintenance of significant operating components of the generating units not including the turbine and generator and significant operating components related to the turbine and generator. Estimated minor overhaul costs are expensed in the year in which the overhaul occurs. Frequency of the overhauls is based on the operating characteristics and operating profiles of each generating unit. For baseload generating units, minor overhauls occur approximately every 24 months. For non-baseload generating units, minor overhauls occur between 12 and 60 months. (See Note 7).

Accrued Overhaul Expenses - Major overhaul costs are those costs that exceed the average cost of a minor overhaul and include costs that are associated with the maintenance of the turbine and generator and significant operating components related to the turbine and generator. Estimated major overhaul costs are accrued and expensed in advance of the actual maintenance. The amounts are accrued based on the operating hours or the number of starts depending on the operating characteristics and profiles of the generating units. Frequency of the overhauls is also based on the operating characteristics and operating profiles of each generating unit. (See Note 10). For baseload generating units, major overhauls occur approximately every 96 months. For non-baseload generating units, major overhauls occur between 24 and 96 months. Differences between the estimated and actual overhaul costs incurred are adjusted in the year determined.

Deferred Credits – Deferred credits are recorded at cost and either: 1) amortized over their expected period of benefit or alternate period of time as may be mandated by ACC order, if different, or 2) eliminated upon determination of their ultimate disposition.

Revenues - Revenues are recognized as power is delivered.

Fuel Costs - Purchased power and fuel costs are charged to expense as incurred. In the past, the Cooperative has periodically gone before the ACC to request a ruling on the disposition of its calculated under or over recovered fuel and purchased power costs (the "adjustor"), as the case may be. The latest ruling, dated March 27, 2002, authorized the recovery of $8,294,176 of under-collected fuel and purchased power expenses (See Note 5) and at the same time discontinued the adjustor as of July 31, 2001. The discontinuance of the fuel adjustor eliminates the regulatory authorization to record and/or reimburse or collect any over or under collected fuel or purchased power expenses incurred after July 31, 2001.

Use of Estimates - The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

3. Investments:

The Cooperative has a cash management program, which provides for the investment of cash balances in financial instruments. Investments at December 31, consist of the following:

		2003	
	Cost	**Unrealized Gains**	**Fair Value**
Restricted – Municipal bonds	**$ 2,808,481**	**$ 137,339**	**$ 2,947,820**
Restricted - Term certificates	**6,792,982**	**-**	**6,792,982**
Total	**$ 9,601,463**	**$ 137,339**	**$ 9,740,802**

		2002	
	Cost	Unrealized Gains/(Losses)	Fair Value
Restricted – Municipal bonds	$ 2,808,481	$ 47,874	$ 2,856,355
Restricted - Term certificates	5,022,869	-	5,022,869
Total	$ 7,831,350	$ 47,874	$ 7,879,224

Contractual maturities of investments at December 31, are as follows:

	2003		2002	
	Cost	**Fair Value**	Cost	Fair Value
Due in one year or less	$ **-**	$ **-**	$ -	$ -
Due from one year to five years	**1,929,150**	**1,929,150**		
Due from five years to ten years	**1,276,250**	**1,276,250**	1,276,250	1,276,250
Due after ten years	**6,396,063**	**6,535,402**	6,555,100	6,602,974

As a condition of National Rural Utilities Cooperative Finance Corporation's (CFC) guarantee of the Solid Waste Disposal Revenue Bonds (See Note 8), the Cooperative was required to purchase a non-interest bearing Debt Service Reserve Certificate (the "certificate") totaling $2,808,000 and maturing in 2024 upon final payment of the debt. The proceeds of the certificate, totaling 2,809,606 and $2,808,481 as of December 31, 2003 and 2002, are held by CFC in a Debt Service Reserve Fund (DSRF). The fair market value of the underlying investments in the DSRF totaled $2,947,820 and $2,856,355 as of December 31, 2003 and 2002, respectively. One of the underlying investments, totaling $2,762,250 and maturing in 2022, has a call feature exercisable by the issuer in 2008.

The Cooperative is a member of the CFC, a not-for-profit cooperative financing institution, owned and controlled by more than 1,000 rural electric member systems and their affiliates. As a condition of membership, the Cooperative was required to purchase Subscription Capital Term Certificates (SCTCs). The SCTCs, totaling $2,759,517 at December 31, 2003 and 2002, bear interest at 5 percent per annum and have maturity dates ranging from 2070 to 2080. As a condition of the Pollution Control Revenue Bonds and Solid Waste Disposal Revenue Bonds (See Note 8), which are guaranteed by the CFC, the Cooperative was required to purchase Subordinated Term Certificates (STCs). The STCs purchased in connection with the Solid Waste Disposal Revenue Bonds, totaling $813,000 and $936,000 at December 31, 2003 and 2002, respectively, bear interest at 7.6 percent per annum and mature in full in 2024 upon final repayment of the related debt. The STCs purchased in connection with the Pollution Control Revenue Refunding Bonds, totaling $1,276,000 at December 31, 2003 and 2002, bear interest at 5.9 percent and mature in 2008 upon final maturity of the related debt. As a condition of the long-term debt due to the CFC (See Note 8), the Cooperative was required to purchase Zero Term Certificates (ZTCs) and one STC. One of the ZTCs, totaling $15,065 and $51,352 as of December 31, 2003 and 2002, respectively, is non-interest bearing and matures in 2013. Three of the ZTCs, totaling $1,929,150 and $0 as of December 31, 2003 and 2002, respectively, bear interest at 3.2 percent per annum and mature in 2007. The STC purchased in connection with the debt due to the CFC matured in 2002 upon final payment of the related debt. The SCTCs, STCs, and ZTCs, are unrated, uncollateralized debt securities of the CFC.

4. Restricted Cash and Cash Equivalents:

Restricted cash and cash equivalents at December 31, consist of the following:

	2003	2002
California power sales collateral security (See Note 11)	**$ 2,500,000**	$ 2,500,000
Coal resourcing project (See Note 11)	**1,190,250**	1,190,250
Cushion of credit program	**482,866**	-
Other deposits on account	**403,769**	304,844
Total restricted cash and cash equivalents	**$ 4,576,885**	$ 3,995,094

Cushion of credit program: RUS has established a Cushion of Credit Payment Program, whereby borrowers may make advance payments on their RUS and Federal Financing Bank (FFB) notes (Notes). These advance payments earn interest at the rate of 5 percent per annum. The advance payments, plus any accrued interest, can only be used for the payment of principal and interest on the Notes.

5. Accounts Receivable:

Accounts receivable at December 31, consist of the following:

	2003	2002
Member energy sales	**$ 10,866,566**	$ 11,105,431
Accumulated net under-recovered fuel costs	**1,368,611**	5,417,107
Non-member energy sales (net of allowance for doubtful accounts of $1.9 million for 2003 and 2002)	**1,203,665**	1,118,503
Other	**2,303,504**	1,406,111
Total accounts receivable	**$ 15,742,346**	$ 19,047,152

Member energy sales: Member energy sales consist of sales to Members under their wholesale power sales contracts (See Note 11 – *Member Wholesale Power Sales Contracts*) and generally are not collateralized. Non-member energy sales consist of non-firm sales to unrelated electric utilities and are also generally not collateralized.

Accumulated net under-recovered fuel costs: In 2001, the ACC approved the recovery of an accumulated net under-recovery of fuel costs (See Note 2 – Fuel Costs). The balance of net under-recovered fuel costs is being collected from the Class A Members through a surcharge. Current estimates anticipate the balance to be recovered by July 2004.

6. Notes Receivable:

In 1998, the Cooperative was awarded a $400,000, Rural Utilities Service Rural Economic Development Grant. In accordance with grant guidelines, the initial loans made to qualifying recipients carry a zero interest rate and are repaid over a ten-year period. Loan repayments are required to be used to establish a revolving loan fund, which in turn, will be for the purpose of providing loans to foster rural economic development. Loans made from repayments of the initial loans may carry an interest rate. Notes receivable from the qualifying recipients totaled $300,465 and $348,122 as of December 31, 2003 and 2002, respectively.

7. Deferred Debits:

Deferred debits at December 31, consist of the following:

	2003	2002
Deferred contract costs	**$ 4,226,488**	$ 4,271,349
Unamortized debt costs	**684,284**	760,531
Redemption premium		
(See Note 8 - *Cooperative Utility Trusts*)	**266,121**	284,265
Other deferred debits	**430,412**	993,488
Total deferred debits	**$ 5,607,305**	$ 6,309,633

Deferred contract costs: The Cooperative entered into long-term power sales agreements that provide for the billing of certain overhaul costs after such costs have been paid. Deferred contract costs consist of accrued overhaul expenses (see Note 10 – *Accrued Overhaul Expenses*) that are not currently billable under the terms of these long-term power sales agreements.

8. Long-Term Debt:

Federal Financing Bank (FFB) - Long-term debt due the FFB is payable at interest rates based on long-term obligations of the United States Government as determined on the date of advance. Interest rates on existing FFB debt range from 4.7 percent to 9.1 percent and 5.0 percent to 9.1 percent for 2003 and 2002, respectively. Interest rates on the advances averaged 6.2 percent in 2003 and 2002. Equal quarterly principal and interest installments on these obligations extend through 2021. The obligations are guaranteed by the RUS. The Cooperative may prepay all outstanding notes by paying the principal amount plus the lesser of: 1) the difference between the outstanding principal balance of the loan being refinanced or the present value of the loan discounted at a rate equal to the current cost of funds to the Department of the Treasury for obligations of comparable maturity; 2) 100 percent of the amount of interest for one year on the outstanding principal balance of the loan being refinanced; or 3) present value of 100 percent of the amount of interest for one year on the outstanding principal balance of the loan.

Cooperative Utility Trust - The Cooperative issued a note, underlying a Certificate of Beneficial Interests (the Certificate), to a Cooperative Utility Trust. Principal on the note is due annually in installments ranging from $823,908 to $3,254,503 from 2004 to 2018. The interest rate on the note is 7.7 percent. Payments are made semi-annually. The note is guaranteed by the RUS. The Certificate is callable, only in whole, at any time on or after September 1, 2006, at redemption prices declining from an initial redemption price of 103.50 percent of par to 100 percent of par from and after September 1, 2013. The Certificate is also subject to prepayment at par at any time on or after September 1, 2006.

Solid Waste Disposal Revenue Bonds - The Cooperative has issued Guaranteed Solid Waste Disposal Revenue Bonds to finance the cost of solid waste disposal facilities. Principal is due in annual installments ranging from $471,960 to $1,483,304 from 2004 to 2024. Interest rates on the bonds are variable and are subject to revision semi-annually. The interest rate in effect as of December 31, 2003 and 2002 was 1.0 percent. The interest rate on the bonds averaged 1.2 percent and 1.9 percent in 2003 and 2002, respectively. Accrued interest is paid semi-annually. These bonds are guaranteed by the CFC. The Cooperative may redeem the bonds in whole or in part, subject to a premium of one-eighth of 1 percent of the principal amount.

Pollution Control Revenue Refunding Bonds - Principal payments on the Series 1997 Pollution Control Revenue Refunding Bonds are payable semi-annually through mandatory sinking fund payments ranging from $1,719,284 to $1,985,604 from 2004 through 2007. The interest rates in effect at December 31, 2003 ranged from 4.8 percent to 5.1 percent. The interest rate on the bonds averaged 4.9 percent in 2003 and 2002. Interest is paid semi-annually. These bonds are guaranteed by the CFC. The bonds are not subject to optional redemption prior to maturity.

Rural Utilities Service - Long-term debt due to the RUS consists of notes at interest rates of 2 percent and 5 percent for 2003 and 2002. The interest rate on the notes averaged 4.4 percent in 2003 and 2002. Quarterly principal and interest payments on these obligations extend through 2010. The Cooperative may prepay the notes at the lesser of the outstanding principal balance of the loan or the discounted present value. The discount rate is the rate specified in the *Treasury Constant Maturities* section of the weekly publication of the *Federal Reserve Statistical Release*.

Cooperative Finance Corporation - Long-term debt due to the CFC is payable at a variable interest rate that is established monthly and effective on the first day of each month. The interest rate in effect at December 31, 2003 was 2.6 percent. The interest rate on such borrowing averaged 2.7 percent and 4.0 percent in 2003 and 2002, respectively. Quarterly principal and interest payments on this obligation extend through 2013. This obligation is guaranteed by RUS. The variable interest rate on the debt is convertible to a fixed rate. The fixed rate would be equal to the rate of interest offered by CFC at the time of the conversion request. The Cooperative may prepay fixed rate notes in whole or in part, subject to a prepayment premium prescribed by CFC.

Maturities of long-term debt for the next five years are as follows:

2004	$ 15,801,553
2005	14,423,403
2006	15,308,436
2007	16,264,692
2008	15,117,242
Thereafter	138,586,880
Total	$215,502,206

Under covenants of the mortgage held by RUS and RUS general and pre-loan policies and procedures, the Cooperative must, among other things, obtain approvals from both the RUS and the CFC for certain transactions and contracts and design its rates with a view to maintaining, on an annual basis, an average times interest earned ratio of 1.05 and debt service coverage ratio of 1.0 calculated retrospectively using the highest ratios from two of the three most recent years. The average times interest earned ratios, calculated using the highest ratios from two of the three most recent years, were 1.66 for the years ended December 31, 2003 and 2002. The average debt service coverage ratios, calculated using the highest ratios from two of the three most recent years, were 1.25 for the years ended December 31, 2003 and 2002.

Long-term debt is collateralized by the pledge of all assets through the mortgage.

Components of interest expense at December 31, consist of the following:

	2003	2002
Total interest costs	**$ 12,295,388**	$ 12,919,900
Interest capitalized	**(68,585)**	(335,171)
Total interest expense	**$ 12,226,803**	$ 12,584,729

9. Member Advances:

Member investment program: The Cooperative offers all Members the ability to invest funds with the Cooperative on a short-term basis for periods of up to nine months. Interest rates offered on the notes (1 to 270 day maturity) are the rates announced by the Cooperative as its note participation program rates as of the date of the note. The Cooperative had recorded liabilities for notes of $1,834,000 and $4,978,804 at December 31, 2003 and 2002, respectively. The interest rate on these notes averaged 1.3 percent and 2.0 percent in 2003 and 2002, respectively. Interest expense on these notes was approximately $78,000 and $139,000 for the years ended December 31, 2003 and 2002, respectively.

Prepaid power program: The Cooperative also offers a program for all members whereby the members may make interest-bearing prepayments of their monthly power billings. The prepayment and accrued interest are applied to the members' power billings on the date such billings become due. The Cooperative recorded liabilities for prepayments of $695,176 and $10,300,000 at December 31, 2003 and 2002, respectively. The interest rate on these prepayments averaged 1.3 percent and 2.0 percent in 2003 and 2002, respectively. Interest expense on these prepayments was approximately $92,000 and $171,000 for the years ended December 31, 2003 and 2002, respectively.

Interest rates on the notes and prepayments, offered by the member investment program and prepaid power program, vary depending on the length of the maturity period selected by the Members. Interest rates offered to Members ranged from 1.0 percent to 1.4 percent and 1.2 percent to 1.6 percent at December 31, 2003 and 2002, respectively.

10. Deferred Credits:

Deferred credits at December 31, consist of the following:

	2003	2002
Customer advance payments	**$ 2,951,199**	$ 3,288,479
Accrued overhaul expenses	**6,013,325**	4,407,168
Postretirement benefit obligation (See Note 14 - *Postretirement Benefits*)	**323,800**	311,100
Other deferred credits	**588,467**	713,466
Total deferred credits	**$ 9,876,791**	$ 8,720,213

Customer advance payments: In 1987, the Cooperative entered into a long-term power sale agreement with a non-member customer for an initial term of twenty-five years. The customer made advance payments for demand charges under this agreement totaling $8,432,000. The advance payments are being amortized as revenue on a straight-line basis over the term of the agreement.

11. Commitments and Contingencies:

Member Wholesale Power Sales Contracts - The Cooperative holds wholesale power sales contracts with five of its six Class A Member Cooperatives pursuant to which each Class A Member Cooperative agrees to purchase from the Cooperative all of its electric power requirements to the extent that the Cooperative has such power available. In 2003, the expiration of the wholesale power contracts were extended from December 31, 2020 to December 31, 2035 and will remain in effect thereafter until terminated by either party upon six months notice. Management believes the Cooperative will be able to fulfill the requirements of these long-term contracts.

Partial Requirements Capacity and Energy Agreement – The Cooperative holds a wholesale power sales contract, expiring December 31, 2035, with one of its Class A Member Cooperatives pursuant to which the Class A Member has agreed to purchase from the Cooperative electric energy and capacity up to the member's allocated capacity in the Cooperative's total resources existing at the time of execution of the contract.

Wholesale Power Purchase Contracts - The Cooperative's current power supply includes hydroelectric power purchases from Western Area Power Administration ("Western"), a federal power marketing agency. Under the terms of its Salt Lake City Integrated Project (formerly Colorado River Storage Project) contract, which expires September 30, 2004, the Cooperative can receive up to 2.4 MW during October through March and 12.1 MW during April through September for service to its Class A Members. Effective October 1, 2004, the Salt Lake City Integrated Project may reduce the Cooperative's seasonal allocations by 7 percent to be used by Western for its redistribution of the available hydroelectric capacity to new preference customers. Additionally, under the terms of a contract with the Parker Davis Project , which expires September 30, 2008, the Cooperative receives 18.4 MW during October through February and 23.8 MW during March through September. The Cooperative had a summer season power purchase agreement with PacifiCorp, which expired on September 30, 2003, to purchase capacity ranging from 15 MW in 2002 to 25 MW in 2003. Beginning in 2003, the Cooperative has a summer season power purchase agreement with Panda Gila River, expiring on September 30, 2007, to purchase capacity ranging from 30 MW in 2003 to 85 MW in 2007. The Cooperative also has a power purchase agreement with the Public Service Company of New Mexico, expiring on December 31, 2008, to purchase capacity of 15 MW.

Network Service Agreement (Class A) – The Cooperative holds an agreement with SWTransco for network integration transmission service for delivery of its power sales to the Cooperative's five all-requirements Class A Members. This agreement remains in effect as long as any existing wholesale power contract between the Cooperative and any of the five members remains in effect.

AEPCO Bundled Transmission Service Agreements – The Cooperative holds agreements with SWTransco for both point-to-point and network integration transmission service for AEPCO's bundled power sales agreements. These agreements provide for reserved transmission capacity ranging from 8 MW to 100 MW. They remain in effect as determined by each service agreement.

Retail Electric Competition - Retail electric competition in Arizona continues to be stayed by developments from a number of fronts.

The ACC continued the slowdown it began in 2002 when it posed a number of questions on the issue and ordered a review of the ACC's electric competition rules (Rules). The Commission is proceeding on two paths, the first is to develop a viable competitive wholesale market through requiring the state's investor owned utilities to bid out a portion of their resource needs from competing wholesale suppliers. The second is to maintain the electric utilities' obligation to serve while thoroughly reviewing the Rules through an electric competition advisory group formed in 2003 for that purpose.

Although the Rules are still in place, there are no retail competition electric services being offered nor purchased in Arizona in spite of a number of service areas being open since 2001. The service areas of AEPCO's Class A member distribution cooperatives have not been opened to competition by the ACC and will not be until the ACC hears and decides those cooperatives' stranded cost cases.

In addition, the Arizona Court of Appeals, in January 2004, issued its decision on the lower court case brought successfully by the Cooperative and others challenging the jurisdictional, constitutional and statutory bases for the ACC Rules. The Court held a number of the Rules invalid, directed some stayed to be submitted for approval by the Arizona Attorney General, invalidated the Certificates of Convenience & Necessity (CC&Ns) issued by the ACC to all competitive suppliers, and required such suppliers to undergo rate and other regulatory review before doing business as competitive electric service providers in Arizona. It is unknown yet whether any party will appeal that decision. It is unknown what effect the ruling may have on the current Rules' review and the willingness of the Commissioners to go forward with retail electrical competition.

In the interim (and also in the event of such competition), the Cooperative will continue to provide electric power to its all and partial requirements members pursuant to long term contracts (now extended to December 31, 2035) for resale to their Standard Offer customers at regulated rates.

Since the Cooperative cannot currently determine the potential for electric competition and the affects of these various events and is currently recovering its costs of providing electric service from regulated rates charged to its members for power sold to Standard Offer customers, it continues to apply SFAS No. 71 to its operations.

California Power Sales -
Collateral Security – When the Cooperative entered into scheduling coordinator agreements with the California Independent System Operator Corporation (ISO) and California Power Exchange Corporation (CPX) in 2000 for the sale of energy into California, the ISO and CPX required the Cooperative to provide security in the form of irrevocable letters of credit to be drawn against in the event of default by the Cooperative.

The Cooperative continues to maintain two letters of credit, totaling $3,500,000, to the CPX as required by both the CPX bankruptcy court and the Federal Energy Regulatory Commission (FERC) even though the Cooperative as a seller was in the position of creditor to the CPX. The court deferred to FERC's decision on the collateral and FERC has ordered them kept in place until it decides whether and which sellers of energy into the California market must make refunds of monies received for those sales because of the dysfunctionality of the California energy market (California Refunds). The decision from FERC on this matter is not expected before August 2004. One letter of credit, totaling $2,500,000, was extended April 17, 2005. A second letter of credit, totaling $1,000,000, was extended to January 14, 2005. The interest rate on draws, if any were to be made on these letters of credit, will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2002 was 4.00 percent. No amounts were drawn on the letters of credit for the year ended December 31, 2003.

As a condition to issuing the $2,500,000 letter of credit, the Cooperative is required to maintain collateral security in the form of an investment in commercial paper for the duration of the term of the letter of credit. The balance of the investment in commercial paper, totaling $2,500,000 as of December 31, 2003 and 2002, is included in restricted cash and cash equivalents.

The core participants of the CPX were also required to provide an additional level of collateral security in the form of performance bonds executed by a surety on behalf of the core participants. The Cooperative in conjunction with the other core participants entered into an indemnity agreement with a surety for the issuance of performance bonds totaling $20,000,000. The Cooperative's indemnity to the surety is limited to only the amount of loss and expenses caused by the Cooperative's default as provided for in the agreement with the CPX. At this time, the CPX is in bankruptcy and no longer conducts transactions and the Cooperative withdrew as a core participant. The bonds were seized by the State of California in 2001 and the CPX is litigating their return on behalf of its creditor participants including the Cooperative.

Refund Liability – During 2000, the Cooperative was a participant of and sold power to both the CPX and ISO. In December 2000, two California utilities buying from the CPX, Southern California Edison (SCE) and Pacific Gas & Electric (PG&E), defaulted on their payments. The CPX tariff provided that in the event amounts owed to the CPX participants could not be paid due to an insufficiency of funds in the CPX clearing accounts, the CPX would allocate the shortage to the CPX participants using a charge-back methodology proportionate to the sales made by a participant. At the end of 2000, the Cooperative estimated that the potential exposure at that time resulting from the proportional charge-back of the shortfall ranged between the asserted claim of approximately $2,300,000 and $5,300,000, which included the estimated range of potential loss for unasserted claims of an amount up to $3,000,000. As a result, in 2000 the Cooperative accrued its best estimate of the associated obligation, totaling approximately $4,100,000, in its financial statements.

In early 2001, the charge-backs were challenged by a group of participant sellers in two separate proceedings before the Federal Energy Regulatory Commission (FERC) and the United States District Court, Southern District of California, arguing that the charge-backs provided in the tariff were never intended to apply in the instant situation involving the bankruptcy of both the CPX as well as PG&E. The District Court enjoined the CPX from enforcing the charge-back and required the CPX to place any funds paid because of it into escrow pending decision by the FERC. The FERC, in a decision not yet final and appealable, agreed with the participant sellers that the charge-back should not be used in this situation and has consolidated that matter (and requests for reconsideration concerning that decision) with the participant sellers' requests for release of the letters of credit (see above "Collateral Security" and other collateral held by the CPX with the California Refunds issues into one case. The FERC ordered reruns of all transactions in these matters to determine the amount of refunds to be made. The reruns are not expected to be completed until at least August 2004. In the interim, the majority of the sellers into the California market, including AEPCO, have appealed the FERC's early orders to the U.S. Court of Appeals, both in the Ninth and D.C. Circuits. The Cooperative's estimate of the maximum potential refund liability, using the least favorable set of proposed mitigated market clearing prices recently proposed by the ISO, approximates $9,300,000.

In 2001, SCE made payment of the amounts it owed to the CPX, which is holding the monies in escrow pending the FERC overall decision. As well, the PG&E bankruptcy case continues with a plan having been approved by the Court, which provides for repayment of the PG&E default. Any distribution under that plan also awaits the FERC decision.

Although the Cooperative cannot predict the outcome of these proceedings, the Cooperative continues to believe that the $4,100,000 previously accrued related to these matters, less related legal costs of approximately $660,000, is the best estimate of its probable loss associated with all these proceedings. In the event that the Cooperative's exposure to these matters is greater than currently estimated, the resulting refund could be material to the Cooperative's financial position, results of operations and cash flows.

<u>Fuel Procurement Contracts</u>
Coal Supply Agreements: To ensure an adequate fuel supply, the Cooperative enters into various long-term fuel contracts. Deliveries of coal under contracts in effect at December 31, 2003 provide for substantially all the Cooperative's coal requirements in the near term.

Rail Transportation Agreement: AEPCO's rail transportation contracts expired on December 31, 2000. Once it was evident new agreements could not be reached, the Cooperative became a railroad common carrier customer. As such, all the rights and duties of the Cooperative and the railroad are governed by tariffs. Believing the tariff rates unjust, the Cooperative in 2000 filed a complaint with the Surface Transportation Board (STB) seeking the establishment of reasonable rates and other terms for unit train coal transportation service. AEPCO has reached a partial settlement with one of the carriers for unit train coal transportation from some of the coal origins resulting in a contract for that service. AEPCO continues to seek a rate prescription from the STB regarding transportation from the remaining coal origins.

Coal Railcar Lease Agreements: To provide for the shipment of the coal supply, the Cooperative entered into lease agreements for the lease of coal railcar trainsets (See Note 15 – *Coal Railcar Trainsets*).

Coal Railcar Maintenance Agreement: The Cooperative entered into a ten-year railcar maintenance service agreement, effective December 17, 2002, for the maintenance of the coal railcar trainset leased under the twenty-year lease agreement (See Note 15 – *Coal Railcar Trainsets*). The agreement shall continue for successive twelve-month terms unless the agreement is cancelled or the last car covered by the agreement is released. The Cooperative has leased property at its generating station to the company performing the railcar maintenance. The term of the property lease coincides with the railcar maintenance agreement.

Personnel Staffing Agreement – The Cooperative has a personnel staffing agreement with Sierra, whereby Sierra provides personnel staffing services for all positions except certain key staff and management positions, who are employees of the Cooperative (See Note 18). The personnel staffing agreement provides that the Cooperative shall pay for the actual and verifiable costs incurred by Sierra for personnel, materials, supplies and all other direct, indirect and overhead costs incurred by Sierra in carrying out its responsibilities under the personnel staffing agreement. The term of the staffing agreement is for five years from August 1, 2001. The agreement is automatically extended for five successive years unless terminated by either party no later than two years prior to the conclusion of such fifth contract year.

Approximately 42% percent of the personnel employed by Sierra are subject to a collective bargaining agreement. Sierra entered into a three-year collective bargaining agreement, effective March 1, 2002.

Office Facilities and Machinery and Equipment Lease Agreements - The Cooperative entered into two separate 60 month lease agreements with Sierra and SWTransco, effective August 1, 2001, for the lease of the Cooperative's office facilities and substantially all of its non-generating machinery and equipment (See Note 18).

Coal Resourcing Project - In 1987, a coal resourcing project was implemented, whereby a coal mining arrangement with Carbon was terminated and the remaining assets and liabilities of Carbon were acquired by the Cooperative. The Cooperative continues to be responsible for reclamation costs under the coal resourcing project. The reclamation obligation remaining at December 31, 2003, is estimated to be $175,000. Reclamation costs approximated $245,000 and $267,000 for 2003 and 2002, respectively, and are included as a component of fuel expense (See Note 2 – Fuel Costs).

Also as part of the coal resourcing project, the Cooperative provided the State of New Mexico with a surety bond in the amount of $1,587,000 to ensure future reclamation work will be performed. As a condition of the surety bond, the Cooperative is required to provide collateral in the form of a cash deposit in a non-interest bearing escrow account. The cash deposit, totaling $1,190,250 as of December 31, 2003 and 2002, is included in restricted cash and cash equivalents on the consolidated balance sheets. The collateral will be released to the Cooperative after the New Mexico Minerals and Mining Division has fully released the Cooperative from the reclamation liability.

Lines of Credit –
Short-term financing: The Cooperative maintains a line of credit for short-term financing with the CFC of $12,000,000. The term of the agreement is for 12 months from August 20, 2003. The interest rate on all advances will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*" published n the *Money Rates* column of the *Wall Street Journal,* plus one percent per annum. The bank prime rate at December 31, 2003 was 4.00 percent. No amounts were drawn under the line of credit for the year ended December 31, 2003.

Company credit card program: The Cooperative also maintains a line of credit agreement with the CFC of $250,000 as part of its company credit card program. The term of the agreement is for 12 months from July 23, 2003. The agreement automatically renews for subsequent periods of 12 months. Interest rates on all advances under the line of credit will be equal to the total rate per annum as may be fixed by CFC from time to time, which shall not exceed the *Prevailing Bank Prime Rate*, as published in the *Money Rates* column of the *Wall Street Journal*, plus one percent per annum. The bank prime rate at December 31, 2003 was 4.00 percent. No amounts were drawn under the line of credit for the year ended December 31, 2003.

12. Patronage Capital:

	2003	2002
January 1	**$ 13,904,668**	$ 4,606,612
Patronage capital allocation	**3,898,570**	9,298,056
Patronage capital retirement	**-**	-
December 31	**$ 17,803,238**	$ 13,904,668

Patronage capital allocation: In accordance with the Cooperative's by-laws, net margins are accounted for on a patronage basis in the following sequence:

1. Offset prior year's unallocated accumulated losses.
2. Assign to Members' accounts as credits based on specific excesses of revenues over operating costs and expenses.

Patronage capital retirement: RUS mortgage provisions require written approval of any declaration or payment of capital credits. These provisions restrict the payment of capital credits to 25 percent of the margins received by the Cooperative in the preceding year, unless total membership capital exceeds 40 percent of the total assets of the Cooperative.

13. Income Tax Status:

For the years ended December 31, 2003 and 2002, the Cooperative qualified for tax-exempt status under Internal Revenue code section 501(c)(12), which requires that 85 percent or more of income consist of amounts collected from Members for the sole purpose of meeting losses and expenses.

14. Employee Benefit Plans:

Pension Plans - The Cooperative has a defined benefit pension plan covering substantially all of its employees. The benefits are based on years of service, age, retirement interest rate, and the employee's highest five years of compensation during the last ten years of employment. The Cooperative's policy has been to fund retirement costs annually as they accrue.

Pension benefits for substantially all employees are provided through participation in the National Rural Electric Cooperative Association (NRECA) Retirement and Security Program. The Cooperative contributes a percentage of salaried and union employees' earnings to the program, as prescribed by the NRECA. Contributions made to this plan approximated $128,000 and $108,000 for the years ended December 31, 2003 and 2002, respectively.

The Cooperative also offers participation in the NRECA Selectre Pension Plan to all employees meeting certain minimum service requirements. This plan has 401(k) salary deferral features. Under this plan, the Cooperative matches a percentage of the employees' contributions to the plan. The Cooperative's contributions to the plan approximated $41,000 and $36,000 for the years ended December 31, 2003 and 2002, respectively.

Postretirement Benefits - The Cooperative reports its postretirement benefits in accordance with SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." This statement requires that the Cooperative calculate and record the liability and related expense associated with providing postretirement benefits other than pensions.

The Cooperative has a contributory health care plan covering active employees and retirees under which retirees pay 100 percent of the average cost of benefits determined based on the combined experience of active employees and retirees. The incremental cost of heath care premiums, resulting from the inclusion of retirees' health care experience ratings with active employees' experience ratings, is viewed as a benefit earned through employment service, subject to accrual during the years an employee is working.

	2003	2002
Benefit obligation at January 1	**$ (311,100)**	$ (204,200)
Recognition of current year expense	**(12,700)**	(106,900)
Benefit obligation at December 31	**(323,800)**	(311,100)
Fair value of plan assets at December 31	**0**	0
Funded status	**$ (323,800)**	$ (311,100)

Assumptions: The accumulated postretirement benefit obligation was determined using a 7 percent discount rate. A health care cost trend rate of 9 percent was assumed for 2001, decreasing to 5 percent by 2010 and remaining at 5 percent thereafter. A one percent increase in the health care trend cost would result in a $12,400 increase in the accumulated postretirement benefit obligation and a $17,800 increase in the expected postretirement benefit obligation.

15. Operating Leases:

Commercial Office Building: In 1999, the Cooperative entered into a non-cancellable lease agreement for the lease of a commercial office building (office lease). The initial lease term is for a period of ten years and has a renewal option to extend the term of the lease for an additional five years. The Cooperative has sub-leased the building to Sierra and other tenants. The term of the lease with Sierra is for 89.5 months commencing on August 1, 2001. Rental income received from the sublease of the commercial office building was approximately $211,000 and $203,000 for 2003 and 2002, respectively.

The following summarizes the future minimum sub-lease income under leases that had initial or remaining non-cancelable lease terms in excess of one year at December 31, 2003:

Fiscal Year	Leases
2004	$209,810
2005	98,701
2006	91,287
2007	88,691
2008	88,691
Thereafter	0
Total	$577,180

Computer Equipment: The Cooperative entered into a master lease agreement for the lease of substantially all the Cooperative's personal computers and peripheral equipment. Individual certificates of acceptance (COAs), underlying the master lease agreement, were entered into as groups of computers and equipment were delivered. The terms of the COAs are for three years from the first day of the month subsequent to the delivery of equipment under the COA.

Rent expense for the lease of the commercial office building and computer equipment was approximately $702,000 and $785,000 for the years ended December 31, 2003 and 2002, respectively, and is included in administration and general on the statements of revenues and expenses.

Coal Railcar Trainsets: The Cooperative entered into lease agreements for the lease of coal railcar trainsets. Lease payments are included as a component of fuel expense (See Note 2 – *Fuel Costs*). At December 31, 2003, these lease agreements consist of:

- A twenty-year lease agreement, effective December 17, 2002. Lease payments under this agreement totaled approximately $400,000 and $538,000 for 2003 and 2002, respectively. The Cooperative has the option of canceling this agreement effective December 31, 2012 subject to the following: 1) the Cooperative notifies the lessor in writing on or before 180 days prior to the effective date of the termination, and 2) the Cooperative pays an additional amount of $5,971 per car for each car terminated.
- A sixty-month lease agreement, effective January 1, 2004. Lease payments under this agreement totaled approximately $94,800 for 2003.
- A twelve-month lease agreement, effective January 1, 2003. This lease provides for the periodic use of a coal railcar trainset. Lease payments under this agreement totaled approximately $16,000 for 2003.

The following summarizes the future minimum lease payments under operating leases that had initial or remaining non-cancelable lease terms in excess of one year at December 31, 2003:

Fiscal Year	Leases
2004	$ 1,403,520
2005	1,285,315
2006	1,218,453
2007	1,184,600
2008	1,137,200
Thereafter	5,594,400
Total	$11,823,488

16. Concentration of Customers and Credit Risk:

Revenue for the year ended December 31, 2003 included revenue from four customers, whom each individually represented more than 10 percent of the total operating revenue. Revenue from these customers collectively represented approximately 72 percent of total operating revenue for 2003. Accounts receivable at December 31, 2003 included amounts owed from four customers, whom each individually represented 10 percent of the total accounts receivable balance. The amounts owed from these customers collectively represented approximately 64 percent of the total accounts receivable balance at December 31, 2003.

Revenue for the year ended December 31, 2002 included revenue from four customers, whom each individually represented more than 10 percent of the total operating revenue. Revenue from these customers collectively represented approximately 66 percent of total operating revenue for 2002. Accounts receivable at December 31, 2002 included amounts owed from four customers, whom each individually represented 10 percent of the total accounts receivable balance. The amounts owed from these customers collectively represented approximately 51 percent of the total accounts receivable balance at December 31, 2002.

17. Fair Value of Financial Instruments:

Many of the Cooperative's financial instruments lack an available trading market as characterized by a willing buyer and willing seller engaged in an exchange transaction. The Cooperative's general practice and intent is to hold its financial instruments to maturity and not to engage in trading or sales activities. As a result, significant estimations and present value calculations are used by the Cooperative for purposes of disclosure.

Estimated fair values are determined by the Cooperative using the best available data and an estimation methodology suitable for each category of financial instruments. For those financial instruments, which mature or reprice within 90 days, the carrying amounts approximate fair value.

The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value:

a. *Cash and Cash Equivalents* - For cash and cash equivalents, cost is a reasonable estimate of fair value.
b. *Investments* - For all investments, except for capital term certificates, which are carried at cost as fair market value is not readily determinable, fair value is estimated based on quoted or market prices for those similar investments.
c. *Member Advances* - For Member advances, the carrying value (cost plus accrued interest) of advances with maturities of 90 days or less approximates the fair value. The fair value of advances with maturities greater than 90 days are estimated by recalculating the redemption value at December 31 using the rate, offered by the Cooperative on the original purchase date, for investments that would have a maturity date of December 31.
d. *Long-Term Debt* - The fair value of the Cooperative's long-term debt is estimated by discounting the future cash flows required under the terms of each respective debt agreement by the currently quoted or offered rates for the same or similar issues of debt with similar maturities. The principal amounts of variable rate debt outstanding at December 31, 2003 and 2002, of the Solid Waste Disposal Revenue Bonds and Cooperative Finance Corporation long-term debt are considered reasonable estimates of their fair value, as these are variable interest rate liabilities.

The estimated fair values of the Cooperative's financial instruments at December 31, consist of the following:

	2003 Carrying Value	2003 Fair Value
Investments and Other Property:		
Restricted held to maturity investments	**$ 9,601,463**	**$ 9,740,803**
Long-Term Debt:		
(including current maturities):		
Federal Financing Bank	**117,122,303**	**116,994,000**
Cooperative utility trust	**27,304,914**	**28,437,403**
Pollution control revenue bonds	**7,392,918**	**7,887,363**
Solid waste disposal revenue bonds	**17,867,061**	**17,867,061**
Rural Utilities Service	**4,851,102**	**5,056,538**
Cooperative Finance Corporation	**40,963,908**	**40,963,908**
Current Liabilities:		
Member advances	**2,529,176**	**2,529,582**

	2002 Carrying Value	2002 Fair Value
Investments and Other Property:		
Restricted held to maturity investments	$ 7,831,350	$ 7,879,224
Long-Term Debt:		
(including current maturities):		
Federal Financing Bank	123,605,087	138,639,411
Cooperative utility trust	28,151,070	26,916,830
Pollution control revenue bonds	9,034,665	9,668,826
Solid waste disposal revenue bonds	18,271,598	18,271,598
Rural Utilities Service	5,662,114	5,892,430
Cooperative Finance Corporation	25,693,471	25,693,471
Current Liabilities:		
Member advances	15,278,804	15,278,804

18. Related Parties:

The Cooperative is a class B member of Sierra and SWTransco. Class B members of Sierra are collectively represented by one director seated on Sierra's board of directors. Class B members of SWTransco are also collectively represented by one director seated on SWTransco's board of directors. Directors for both SWTransco and Sierra are entitled to one vote on each matter submitted to a vote at a meeting of the members.

The Cooperative has entered into an agreement with Sierra, whereby Sierra provides personnel staffing services (See Note 11 – *Personnel Staffing Agreement*). For 2003 and 2002, the Cooperative recorded expenses for personnel staffing services from Sierra totaling approximately $17,225,000 and $16,923,000, respectively.

The Cooperative has entered into lease agreements with SWTransco and Sierra for the lease of Office Facilities and Machinery and Equipment (See Note 11 - *Office Facilities and Machinery and Equipment Lease Agreements*). For 2003, rents received by the Cooperative from SWTransco and Sierra totaled approximately $839,000 and $1,435,000, respectively. For 2002, rents received by the Cooperative from SWTransco and Sierra totaled approximately $839,000 and $1,431,000, respectively.

The Cooperative has also entered into agreements with SWTransco for transmission service (See Note 11 - *Network Service Agreements (Class A and Class B), and AEPCO Bundled Transmission Service Agreements)*. For 2003 and 2002, the Cooperative recorded transmission expenses from these agreements totaling approximately $16,868,000 and $15,519,000, respectively.

As of December 31, 2003, the Cooperative had recorded accounts payable to SWTransco totaling approximately $1,175,000 and accounts receivable from Sierra totaling approximately $456,000. As of December 31, 2002, the Cooperative had recorded accounts payable to SWTransco totaling approximately $1,124,000 and accounts receivable from Sierra totaling approximately $27,000.

19. Asset Retirement Obligations:

Effective January 1, 2003, the Cooperative adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 sets forth accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. An asset retirement obligation (ARO) associated with long-lived assets included within the scope of SFAS No. 143 is that for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. Under the statement, these liabilities are recognized as incurred if a reasonable estimate of fair value can be established and are capitalized as part of the cost of the related tangible long-lived assets. The increase in the ARO due to the passage of time (accretion expense) is an operating expense. Upon adoption of SFAS No. 143, the Cooperative recorded the cumulative effect of the accounting change, totaling $3,810,335, in the consolidated statements of revenues and expenses and unallocated accumulated margins. The Cooperative also recognized the present value of its projected asset retirement costs, totaling $1,962,630, as a component of its capitalized utility plant on the consolidated balance sheets. Subsequently, the Cooperative recognized accretion of the liability, totaling $185,802, as a component of interest expense and depreciation of the asset retirement cost, totaling $69,445, as depreciation expense in the consolidated statements of revenues and expenses and unallocated accumulated margins. The net asset retirement obligation as of January 1, 2003, the date of the adoption, and December 31, 2003, and the changes in the net liability for the twelve months ended December 31, 2003, were as follows:

Liability at January 1, 2003	**$ 4,381,198**
Accretion expense in 2003	**185,802**
Liabilities incurred	**5,762**
Liability at December 31, 2003	**$ 4,572,762**

End of Audited Financial Statements.

D

DIRECT TESTIMONY OF

WILLIAM K. EDWARDS

BEFORE THE

ARIZONA CORPORATION COMMISSION

ON BEHALF OF

ARIZONA ELECTRIC POWER COOPERATIVE, INC.

Q. What is your name and business address?

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

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

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

Q. What is your educational background and experience?

A. I received my B.S. Degree in Business with a concentration in economics from Christopher Newport College of the College of William & Mary in 1977, and an M.A. degree in Economics from Old Dominion University in 1979. My major fields of study included mathematical economics, econometrics and microeconomics. I have completed a number of courses toward a Ph.D. in Economics from the Virginia Polytechnic Institute & State University. I have worked for the firm of Ernst & Ernst as a consultant principally in the electric utility industry. From 1982 to 1985, I was employed by Mississippi Power & Light Company (Entergy - Mississippi) as a supervisor responsible for rate research. From January 1986 until early 1995, I was employed by Central Louisiana Electric Company, Inc. as Manager of Rate Research and subsequently as Director of Rates. In that capacity I was responsible for regulatory affairs, regulatory accounting, rate design, cost of service studies, rate administration and the attendant litigation associated with regulatory issues before both the Louisiana Public Service Commission and the Federal Energy Regulatory Commission. Since 1996, I have been employed by CFC.

Q. What is the purpose of your testimony?

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

THE ROLE OF CFC

Q. What is CFC?

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

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

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

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

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

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

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

Q. Is AEPCO a member of CFC?

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

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

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

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

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

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

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

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

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

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

Table 1
Key Ratios

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

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

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

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

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

[1] Total Equity/Total Assets.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2
S&P Median Values of
Utility Financial Ratings

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

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

Presently, the proposed operating TIER of 1.29 places AEPCO below investment grade, while the present equity ratio, of course, is far below any of the ratings.

Q. Would the proposed 1.29 TIER and 1.05 DSCR ratios allow AEPCO to borrow money from CFC and RUS?

A. I believe it would qualify for lending by both organizations. Furthermore, it will return AEPCO to its more recent course of gradual, but steady, financial improvement. AEPCO, its members and the retail members they serve will all benefit from that improvement.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit WKE-1

Exhibit WKE-1
AEPCO's Historical Parameters

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